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, 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**

In the Matter of:

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**

TESTIMONY OF
PAUL W. THOMPSON
PRESIDENT AND CHIEF EXECUTIVE OFFICER
KENTUCKY UTILITIES COMPANY AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Filed: November 25, 2020

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

A. My name is Paul W. Thompson. I am President and Chief Executive Officer of 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, which provides services to the Companies. My business address is 220 West Main Street, Louisville, Kentucky 40202.

Q. Please describe your educational and professional background, and your experience testifying before the Kentucky Public Service Commission ("Commission").

A. In 1991, I joined the management of LG&E Energy Corp. Over the course of 29 years, I have held a number of leadership roles. I served as Chief Operating Officer from 2013 until January 2017 when I became President and Chief Operating Officer. In March 2018, I was promoted to Chief Executive Officer. A complete statement of my work experience, civic roles, and education is contained in Appendix A. I have testified in numerous proceedings before the Commission for many years. Most recently, I testified in KU's and LG&E's 2018 base rate cases.[1]

Q. Are you sponsoring any required schedules or Exhibits?

A. Yes, I am sponsoring and providing the attestation required under 807 KAR 5:001 Section 16(7)(e), that the Companies' most recent business plan is the source of financial projections for these proceedings. I also present a benchmarking study

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[1] *Electronic Application of Kentucky Utilities Company for an Adjustment of Its Rates*, Case No. 2018-00294, Testimony of Paul W. Thompson (Ky. PSC Sep. 28, 2018); *Electronic Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Rates*, Case No. 2018-00295, Testimony of Paul W. Thompson (Ky. PSC Sep. 28, 2018).

comparing our costs to other utilities using publicly-available FERC Form 1 information, marked as Exhibit PWT-1.

I. Purpose of Testimony and Executive Summary

Q. What is the purpose of your testimony?

A. I first provide some insight into the business philosophy of our organization and review important performance factors for our Companies along with how we have responded to the challenges presented by the current pandemic. I discuss our focus on economic development, the ingrained commitment to our customers we demonstrate in the communities we serve, and our assistance to low-income customers. I also provide my perspective on significant changes we are seeing in the energy industry. Finally, I will highlight our ongoing efficiency and productivity efforts before explaining our decision to file the rate proceedings today.

Q. As the CEO of LG&E and KU, what is the primary focus of the Companies?

A. Customer service is always at the forefront of our actions, whether it involves a brief dialogue with a customer to establish service or to respond to a question for a years-long, several hundred million dollars decision in an investment that will serve customers for decades. I am very proud of the Companies' ongoing satisfaction of our obligation to serve our customers. I believe that, based on an objective review of the Companies' record, we have a history of making very sound and prudent short- and long-term decisions. Our business processes and employee culture are designed to encourage thoughtful and customer-focused decision-making. We identify the needs to be met, we conduct a thorough analysis of our options, evaluate past decisions for lessons learned, and reach our recommendations. We then take action. Throughout every step in the process, our customers' interest is consistently the driving force. And we always endeavor to improve our performance. We strive to serve as a trusted energy partner with our customers to power our communities and to explore new opportunities to better serve our customers. My role as the CEO is to ensure that we continuously act in this way. I am proud of the way we balance all stakeholder interests and deliver safe, reliable, environmentally sound energy to our customers at low costs.

Q. What conditions have prompted the filing of this application?

A. Based on my nearly 30 years of experience with the Companies, I believe the utility industry is going through a period of considerably more change than typical. Major forces impacting our business today include digitalization, proliferation of inexpensive energy control technologies, renewable clean energy and societal expectations, increased regulations on operating and cyber security requirements, customer expectations for more options, energy efficiency efforts and tech-driven products (e.g. the LED bulb), and electrical energy storage at large scale. Importantly, this energy evolution is top of mind in our decision-making process. At all times, whether the world is relatively stable or rather tumultuous, we carefully consider our options with an eye towards the future. I believe if you look at our Companies' history and our results, it is clear that we carefully plan and strategically execute for the benefit of our customers. In this same vein, today we are proposing to invest in Advanced Metering Infrastructure and a base rate change that is fair, balanced, and necessary to continue reliably operating and providing for our customers just as we have over our 100-plus year history.

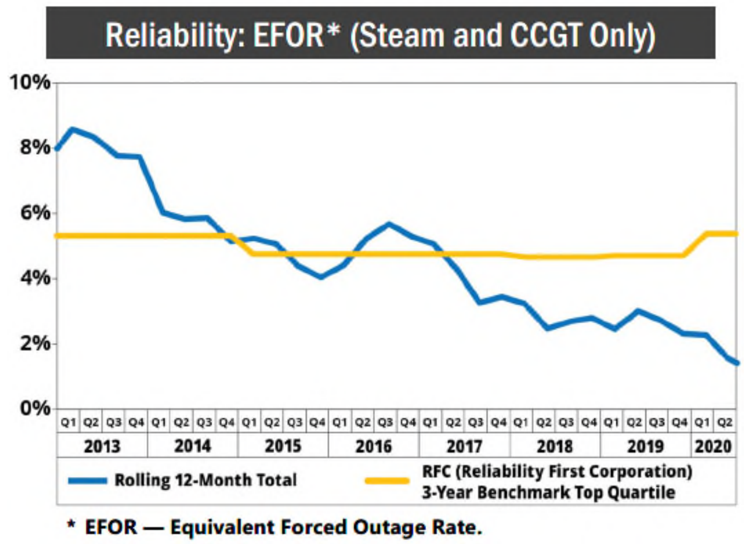
II. Performance of KU and LG&E

Q. Will you please comment on how the Companies measure operational effectiveness?

A. The generation and delivery of safe and reliable energy to over a million customers is a data-intensive business. Every day there are thousands of operating parameters that are captured, analyzed, and acted upon by the Companies. This mode of operation is a must in order to achieve operational excellence. But in a changing environment with new demands and challenges, the Companies must continuously explore opportunities for improvement. Accordingly, I regularly focus on certain parameters from various parts of the Companies that capture and indicate overall operational effectiveness. The metrics I reference below demonstrate the very strong performance of the Companies and our continuous improvement efforts. We have enhanced the safety, operation and efficiency of our already reliable generation fleet, electrical transmission and distribution network, and natural gas distribution network in an environmentally responsible manner at reasonable costs and with exceptional customer service.

Q. What are some of the Companies' significant operational achievements with the generation of electricity?

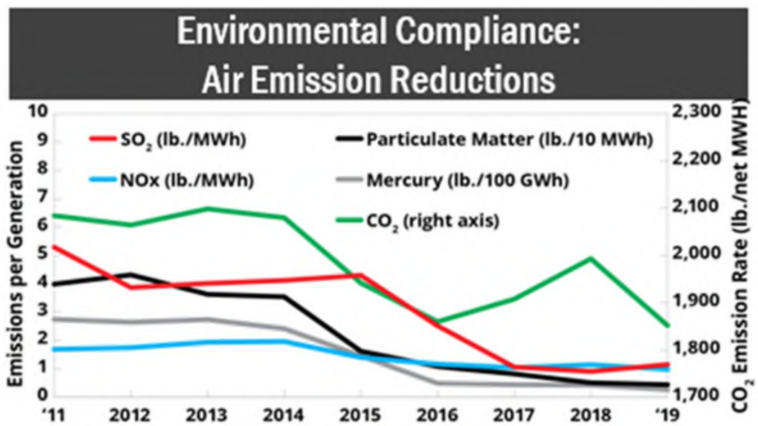
A. Our generation fleet has the largest capital investment among the lines of business. The reliability of the Companies' generation resources, particularly over the past few years, has significantly exceeded that of our peers. Average Equivalent Forced Outage Rate ("EFOR") is an established industry measure of reliability and is the best indicator of overall performance level. The data shown in the following chart demonstrates the Companies' dramatic improvement in generation reliability over the past seven years using the EFOR metric, as well as our sustained excellence in this area compared to industry benchmarked performance:



Q. Have the Companies achieved environmental compliance while accomplishing this operational excellence with its generation fleet?

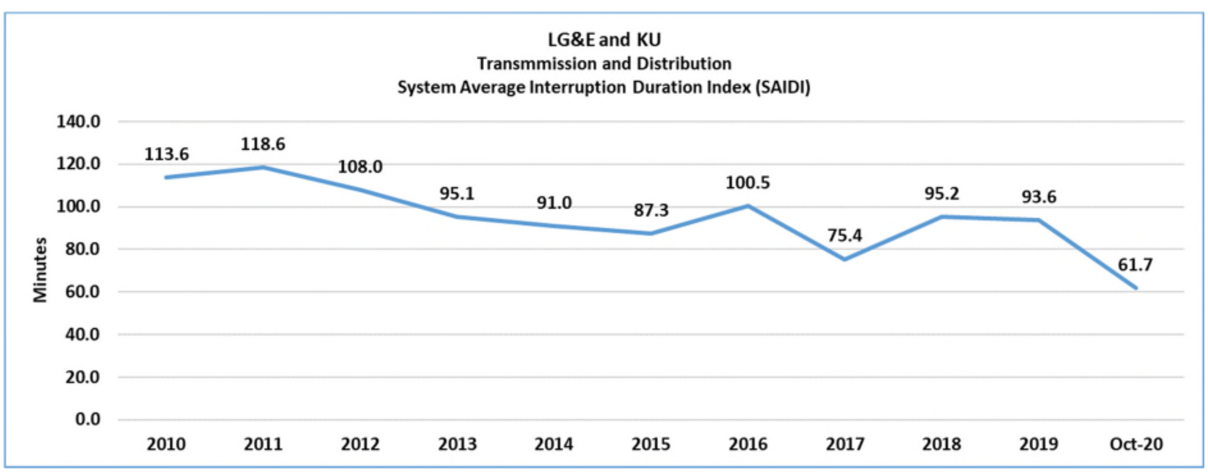
Yes. This operational success has been achieved in tandem with the Companies' compliance with increasingly stringent environmental regulations and resulting reduction in environmental impact. The following chart shows the significant degree to which generation operations has achieved air emission reductions over the last decade:[2]

[2] CO_2 emissions were elevated in 2018 because weather conditions led to significantly higher load, and thus a higher volume of energy production than in surrounding years.



Q. Have the Companies' achieved operational excellence with their electric transmission and distribution network?

Yes. For electric transmission and distribution, key indicators are the System Average Interruption Frequency Index ("SAIFI") and the System Average Interruption Duration Index ("SAIDI"). The data in the following chart shows the Companies' historical combined Transmission and Distribution SAIDI dating back to 2010 and demonstrates the Companies' SAIDI performance for the combined transmission and distribution systems has improved significantly over the past 10 years:



This performance also compares favorably to first quartile performance in utility industry benchmarking surveys. The 2020 combined Transmission and Distribution

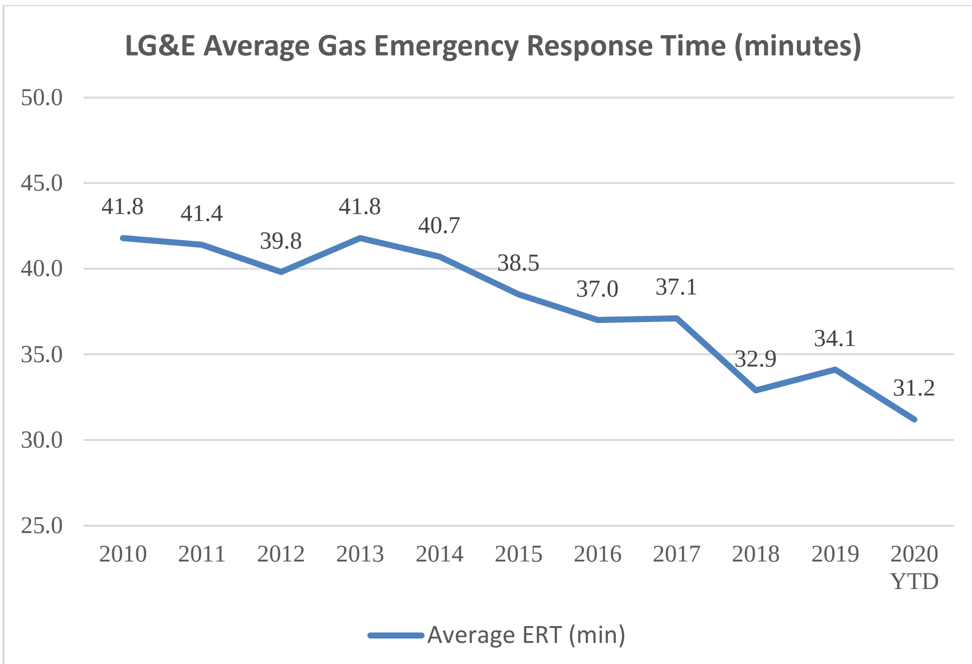
SAIDI is on track to be the lowest (best) in the history of the combined Companies. Likewise, the Companies' performance in combined Transmission and Distribution SAIFI (outage frequency) has been the best in the Companies' history in three of the last four years.

These metrics demonstrate that the Companies' investments are significantly improving reliability of electric service to customers. This means more reliable service and relatively fewer and shorter service disruptions for our customers, both compared to utility customers in other areas and compared to past experience with the Companies' electric service here in Kentucky. Mr. Bellar's testimony provides more detail on the performance of transmission operations and the investments driving improved performance, while Mr. Wolfe's testimony does the same for distribution.

Q. Has LG&E's gas business also performed safely, reliably and efficiently?

A. Yes, LG&E's gas distribution business has also excelled. Beginning in the mid-1990s, ahead of many of our peers, LG&E initiated a main replacement program to replace aging gas mains constructed with cast iron, wrought iron, and bare steel with modern materials. This program started with approximately 540 miles of these materials in its distribution system. The program expanded in the following decade to include a leak mitigation program to replace company service lines. More recently, LG&E has implemented systematic replacement programs for gas service risers (including assumption of responsibility of customer owned services) and steel customer service lines. These proactive large-scale replacements have had a tremendous positive impact on the overall safety and reliability of the gas system which will yield benefits to customers for many years to come. What was twenty-five years ago a safe and efficient system with declining assets is now a safer and much more efficient system with predominately modern equipment that is built to last. LG&E has been able to work towards modernization of its system and maintain reasonable rates for gas service all while facing increased costs due to increased federal safety regulations.

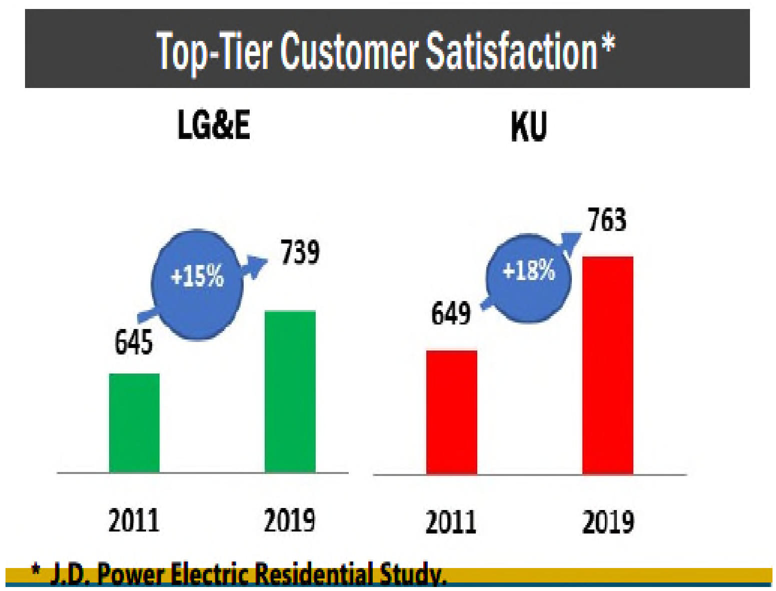
Gas operations are also performing efficiently. Over the past decade, the gas business has improved its emergency response time by 25 percent:



LG&E has also improved its underground line locating and damage prevention processes. Year-to-date LG&E has achieved a 99.9% on time performance for underground locate requests; and the year-to-date gas damage rate is almost 30% improved over the average of the previous two years.

Q. Have the Companies achieved operational excellence in their customer services operations?

A. Yes. As I stated previously, all of our actions are driven by customer interests. Our customer commitment is reflected in positive customer feedback and industry recognition. We have several methods for evaluating our customers' experience and their satisfaction. A widely used comparative measure is the J.D. Power study. As Eileen L. Saunders summarizes in her testimony, both KU and LG&E are consistently top performers in J.D. Power surveys for residential and business customer satisfaction within their peer group for the Midwest region. Furthermore, since 2011 our residential customer satisfaction has increased by 15 percent for LG&E and 18 percent for KU as shown below:

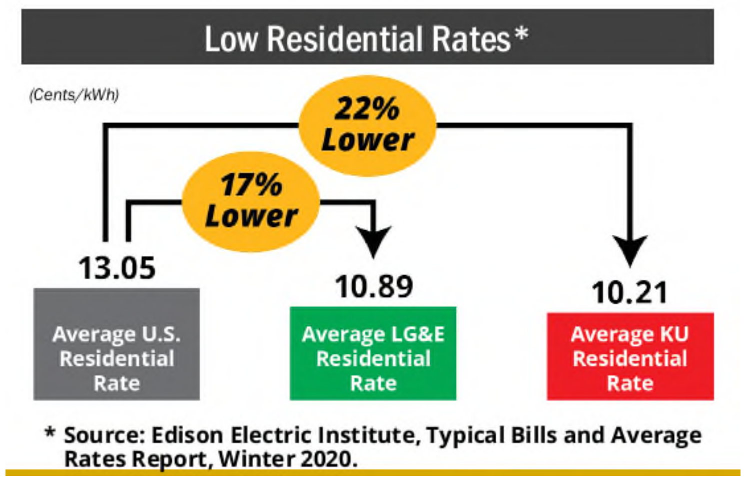


Q. Will you please comment on the Companies' efforts to effectively manage costs?

A. The Companies perform an annual benchmarking study where we compare our costs to other utilities using publicly-available FERC Form 1 information. We use a five-year average to smooth out single-year anomalies. The Companies are top quartile performers among peer vertically-integrated utilities for cost control. The results of the most current study are shown in Exhibit PWT-1 and demonstrate that the Companies continue their excellent performance in cost containment. The Companies are very proud of their favorable cost position highlighted in this analysis, and we continue to balance cost control with providing the safe and reliable service our customers expect.

Q. Are these low operating costs reflected in the Companies' residential rates?

A. Absolutely. Better cost containment means our customers pay less for costs embedded in rates than customers of most of our peers throughout the country. The following chart shows the significant difference between LG&E's and KU's residential rates verses the average U.S. residential rate:



When the rates proposed in these proceedings are implemented, residential rates for both LG&E and KU electric service will remain below average U.S. residential rates.

Q. What do these achievements say about the Companies' planning and decision-making processes?

A. In sum, the Companies have demonstrated the ability over many years to deliver excellent operational performance while containing costs and maintaining reasonable rates, resulting in high customer satisfaction rankings. This is a testament to our prudent decision-making and shows that we have the business processes in place to continue making good business decisions. Our employees are acutely focused on customer satisfaction and always try to do the "right thing." We also continuously search for improvements. We know what we are doing and can be trusted to perform.

We use the Companies' five-year business planning process, described in detail in Mr. Arbough's testimony, to prioritize investments and manage and control costs with accountability. Each line of business proposes a budget with capital projects within the five-year planning horizon. All budget proposals are reviewed by our Resource Allocation Committee, comprised of leaders from across the Companies, to ensure that budgets are consistent with our customer-focused mission and the needs of the business.

But our business planning process is not merely a budget exercise – it extends to careful and ongoing evaluation of every operational area of the business. For example, the Companies' Integrated Resource Planning process continuously assesses generation resources to ensure that customer capacity needs are met at the lowest reasonable cost. Investment strategies like the Transmission System Improvement Plan[3] and Distribution Reliability and Resiliency Plan[4] demonstrate the great care and planning the Companies undertake to ensure that our power delivery systems will safely and reliably serve customers long into the future, at a reasonable cost. The evaluation of the need for a base rate adjustment and investment in Advanced Metering Infrastructure sought in these proceedings has been performed with the same level of detail and forethought as these other planning processes.

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[3] *Application of Kentucky Utilities for an Adjustment of its Electric Rates and for Certificates of Public Convenience and Necessity*, Case No. 2016-00370, Testimony of Paul W. Thompson, Exhibit PWT-2 (Ky. PSC Nov. 23, 2016).

[4] Case No. 2020-00349, Testimony of John K. Wolfe, Exhibit JKW-1 (Ky. PSC Nov. 25, 2020).

Q. Is LG&E and KU's performance during the COVID-19 emergency an example of your point about employees doing the "right thing"?

A. Yes. The COVID-19 pandemic has created unprecedented challenges for our customers and the communities we serve. The Companies acted to help protect our employees and customers, and sought ways to ease some of the stresses facing our communities. We quickly implemented technology to have over 1,000 employees do their jobs from home safely without sacrificing productivity. We controlled costs without resorting to furloughs or layoffs of our employees or contractors. The Companies implemented enhanced safety protocols, including the use of additional Personal Protective Equipment, to keep our customers and employees safe while work is being performed. When the Companies learned of attempted scams directed at our customers, we took steps to notify the public to prevent our customers from being financially harmed. In short, we made every effort to continue to conduct business and serve customers because our service is essential to customers.

Acting with the Commission, KU and LG&E suspended disconnections for nonpayment and waived new late fees. The Companies further deployed an employee in mid-March to work with Kentucky's State Emergency Operations Center to ensure effective communication between the Companies and the state concerning energy-related response efforts. LG&E joined other partners in supporting the newly established One Louisville: COVID-19 Response Fund—a community-wide coalition that rapidly deployed resources to individuals and community-based organizations working at the frontlines of our region's coronavirus outbreak. The LG&E and KU Foundation partnered with the Bluegrass Community Foundation and other businesses and organizations to initiate the Coronavirus Response Fund to provide grants to organizations and programs in Central Kentucky that have experience with providing residents with access to food, prescriptions and healthcare, childcare, and other basic needs. The Companies also posted contact information for other assistance organizations on its website. Our Companies have made it a priority to affirm our commitment to being a community partner during this challenging period.

When the Commission issued its decision to lift the moratorium on customer disconnects for nonpayment, there were more than 100,000 Kentucky residential customers in arrears of 31 days or more. Of those, more than 50,000 were eligible for disconnection under the Companies' normal disconnection policies and procedures. The Companies are complying with all requirements of COVID-related Orders, including the creation of flexible payment plans for customers with arrearages accumulated under the specified timeframe. The details of the Companies' approach for working with their customers to establish reasonable payment plans that ensure both continuity of service and payment for that service are discussed in the testimony of Ms. Saunders.

III. KU and LG&E Economic Development and Community Service

Q. Please describe the ways in which KU and LG&E promote economic development in the communities they serve.

A. We view this as a core strength. We work tirelessly to empower business growth and expansion throughout Kentucky. Some of LG&E and KU's efforts include working with communities to identify the possibility of new industrial and commercial sites throughout their service territories, while also helping to evaluate existing sites to determine if additional investment may increase exposure to local communities. We are also developing a grant program to provide incentives for communities to make proactive investments in product readiness and development.

Site Selection Magazine, an international publication focused on economic development, recently named Louisville Gas and Electric and Kentucky Utilities Company among the Top 20 utilities in the U.S. for corporate facility investment and job creation in 2019. The evaluation included a field of approximately 3,300 electric utilities (including cooperatives) across the country. Our efforts led to customers announcing more than $2.8 billion in capital investment and the creation of more than 5,700 jobs in 2019.

The testimony of Mr. Blake describes a proposed additional economic development initiative based on the Commission-approved settlement between LG&E and Big Rivers Electric Cooperative.[5]

Q. In what other ways do the Companies serve their communities?

A. Our commitment to the communities we serve is a critical cultural value we have modeled over many decades. The LG&E and KU Foundation reflects that commitment by supporting Kentucky nonprofits that focus on education, the environment, diversity, or health and safety. LG&E, KU and the LG&E and KU Foundation collectively donate $5 to $6 million annually to these organizations. All of these contributions are funded solely by our shareholders.

[5] *Electronic Joint Application of Louisville Gas and Electric Company, Meade County Rural Electric Cooperative Corporation, and Big Rivers Electric Corporation for (1) Approval of an Agreement Modifying an Existing Territorial Boundary Map and (2) Establishing Meade County Rural Electric Cooperative Corporation as the Retail Electric Supplier for Nucor Corporation's Proposed Steel Plate Mill in Buttermilk Falls Industrial Park in Meade County, Kentucky*, Case No. 2019-00370, Order (Ky. PSC Feb. 24, 2020). The terms of the settlement payment are subject to a Petition for Confidential Protection, which was granted by the Commission in its March 9, 2020 Order in Case No. 2019-00370.

Our employees have also demonstrated a deep commitment to giving their time and money to support community causes. Since 2005, the Companies' annual Power of One campaign has raised millions of dollars to support hundreds of nonprofit organizations throughout Kentucky. More than two-thirds of our active employees participate in this effort, which is twice the national average for employee participation in charitable giving. Through a Power of One initiative called "Day of Caring," hundreds of employees spend personal time serving agencies or other nonprofits. Also, KU and LG&E employees serve in leadership roles on nearly 200 community boards throughout Kentucky.

Q. Do the Companies take affirmative steps to assist the low-income customers in their service territory?

A. Yes. Providing assistance to our low-income customers is another integral part of our culture and commitment to the community principles discussed above. The Companies are aware of our low-income customers' needs through frequent direct contact with our customers and through the Companies' long-standing relationships with several organizations engaged in community-assistance programs and efforts, including the Community Action Council for Lexington-Fayette, Bourbon, Harrison, and Nicholas Counties, Inc. and the Association of Community Ministries based in Louisville. The Companies meet and communicate with these groups on a regular basis to understand low-income customers' needs, how community organizations are working to meet those needs, and how the Companies can help. The Companies have used the information they receive to provide various forms of assistance to low-income customers over the years, both on our own and in conjunction with community groups.

Examples of our assistance include Project Warm and the Low-Income Weatherization Program or the "WeCare" program.

The LG&E and KU Foundation currently makes $1.45 million in annual shareholder contributions to low-income assistance programs ($570,000 per year for KU and $880,000 per year for LG&E). These examples and the specifics of our shareholder assistance to low-income assistance programs are more fully explained in the testimony of Ms. Saunders.

IV. Industry Trends

Q. Can you comment on the current utility industry trends?

A. Yes. For many years, the utility industry experienced year over year growth in sales. Conservation and energy efficiency have flattened sales notwithstanding new customer growth, and this trend is expected to continue at least in the near term. David Sinclair's testimony summarizes the Companies' sales forecasts. While others are turning to non-utility businesses to improve their financial performance, we have remained focused on finding efficiencies and cost-effective prudent planning.

The industry is also experiencing a sea change brought on by digitalization. Now more than ever before, advances in technology that allow for increased sharing of information are redefining the relationship between utilities and their customers. Customers' expectations continue to grow with the evolution of technology. Customers are increasingly interested in understanding how their behavior drives their energy bills, how their energy use affects the environment, and which programs or products are available that make sense for their needs. And they want the exchange of information on these issues to be a two-way dialogue with their utility provider.

Regulatory, social, technological, and economic factors continue to shape the strategy for utilities in planning for their future generation mix. Environmental restrictions have become more stringent over the past ten years and that trend is expected to continue. There is increasing societal and market pressure for utilities to transition to cleaner gas-fired and renewable generation to reduce carbon emissions. The cost of renewable generation continues to decline and become more economically viable, but serving on-demand load with intermittent, as-available renewable energy resources (like solar) remains a significant challenge to economically engineer.

Q. How are the Companies strategically responding to these industry trends?

A. First and foremost, the Companies are applying the business processes and decision-making I described above with the goal of best serving our customers. Those processes have translated into a few broad strategies to meet the challenges and trends described above: (1) implementation of Advanced Metering Infrastructure ("AMI") to meet customer expectations in an increasingly digital world; (2) evaluation of the Companies' generating fleet mix now and in the future; and (3) goalsetting for reducing the Companies' carbon emissions to respond to regulatory and societal demands.

Q. Please summarize the benefits of the Companies' AMI strategy.

A. AMI effectively provides customers with more tools and the information and control that customers desire at the least cost over the next 30 years. The proposed deployment of AMI provides a proven technology that further modernizes our operations, reduces costs to customers, and affords customers access to detailed and personalized consumption data along with corresponding tools to actively manage energy consumption. For example, as discussed in Mr. Wolfe's testimony, AMI allows the intelligent management and operation of reclosers, capacitor banks, load tap changes, and voltage regulators on our distribution system. Using AMI meters as sensors, we can enhance our management of those devices to achieve overall distribution benefits to better serve our customers.

For these reasons, we are proposing to invest in AMI implementation. The testimony of Mr. Bellar, Mr. Wolfe, and Ms. Saunders describe the numerous benefits for electric and gas customers from this investment into advanced digital technology and away from outdated and limited capability analog technology. Mr. Bellar further presents an analysis on a net present value revenue requirement basis to demonstrate that the investment is both prudent and cost-effective. The cost of AMI investment is not included in this rate case increase. We believe the investment will pay for itself over the years. Under our ratemaking proposal and current projections, discussed in Mr. Blake's testimony, customers will not pay higher rates for full deployment of advanced metering infrastructure and meters.

Q. Please address the Companies' recent evaluation of retirement dates for the generation fleet.

A. Our recommendations on new energy and capacity resources will continue to be based on economics from the customers' perspective which is the least-cost, most reasonable option. Consistent with our customer-focused philosophy and in light of declining costs for gas-fired and renewable generation and the impact of environmental regulations, the Companies must face the realities in assessing a reasonable end of economic life for coal-fired generation units to minimize the risk of stranded assets and inter-generational inequities. The testimony of Mr. Bellar presents the analysis and update of the end of economic lives for the coal-fired units in the fleet. The testimony of Mr. Spanos, using these projected retirement dates, recommends the associated changes in depreciation expense. These changes to the reasonable end of economic lives of certain units advance the recovery of cost of older coal-fired generation to avoid generational inequities.

Q. What is the position of LG&E and KU on the reduction of carbon emissions?

A. In 2017, we, together with our parent, PPL Corporation conducted a detailed assessment of how future requirements and technological advances aimed at limiting global warming to 2° Celsius over pre-industrial levels could potentially impact our generation fleet and thus PPL. In conducting the assessment, the recommendations of the Financial Stability Board's Task Force on Climate-Related Financial Disclosures were considered. The assessment examined several policy and technology scenarios, including a scenario consistent with limiting global temperatures to an increase of 2° Celsius over pre-industrial levels. Under each policy scenario considered, including the 2° Celsius scenario, the analysis indicated carbon dioxide emissions from our Kentucky generation assets would be expected to decline 45-90 percent from 2005 levels by 2050.[6] The current voluntary corporate goal is to reduce CO_2 emissions 80% from 2010 levels by 2050 and 70% by 2040.[7] These goals strike the right balance between safe, reliable, and cost effective service to our customers, providing fair, just, and reasonable returns to our shareholders, and contributing to the progressive, but orderly reduction in carbon emissions.

[6] https://www.pplweb.com/wp-content/uploads/2017/12/PPL-Corporation-Climate-Assessment-Report.pdf
[7] The Climate Action status report may be found at https://www.pplweb.com/sustainability/climate-action/

V. Efficiency and Productivity

Q. Please summarize the Companies' efforts and programs to achieve improvements in efficiency and productivity.

A. We continuously strive to operate our business in the most efficient and productive manner possible without sacrificing the safety of our employees and our customers or the reliability of service to our customers. These principles govern the Companies' business practices in the construction, operation, and maintenance of our systems and services. Executing on these principles has produced favorable results for our customers.

The testimonies of Mr. Blake, Mr. Bellar, Ms. Saunders, and Mr. Wolfe provide an extensive description of many of the Companies' existing programs and practices to achieve efficiency and productivity. This focus on efficiency, along with our focus on safety, reliability, and customer service and satisfaction, are core principles of our business culture that we continue to reinforce with our employees and contractors.

Q. Have these efficiencies been able to completely offset the need for an increase to collect additional revenues at this time?

A. Unfortunately, no. Notwithstanding the flattening of sales I referenced earlier, our industry remains a capital-intensive industry. Like previous rate cases, this case includes planning for significant investments in the infrastructure and systems necessary to provide safe, reliable service to customers. It also involves an environment of escalating cost in every operational area of the business. These cost increases are discussed in detail in the testimonies of Mr. Bellar, Ms. Saunders, and Mr. Wolfe. Additionally, the facts and circumstances surrounding our remaining coal-fired generation units have changed so significantly that the changes must be addressed now in depreciation rates to avoid the problems of stranded assets and inter-generational inequities. Mr. Blake's testimony provides further detail on this and the other causes driving the increases.

While the Companies are striving through efficiencies and prudent mitigation strategies to minimize the bill impact to our customers, additional resources are required to address current and future challenges and meet the expectations of customers to provide for the delivery of safe and reliable electric and gas service. This request for an increase in rates is in service of, rather than antagonistic to, our commitment to putting customers first and making decisions with customers' best interests at the forefront.

VI. Decision to File These Rate Proceedings.

Q. Please explain the timing of the Companies' decision to file these rate proceedings.

A. We are aware of and sensitive to the current challenges facing our customers and the local economy brought on by the COVID-19 pandemic. As part of the deliberate and comprehensive planning process I summarized earlier in my testimony, we have taken those circumstances into consideration in determining the timing of filing these proceedings. Under my direction, the Companies delayed this filing two months from what was previously planned, to a time when Kentucky's moratorium on disconnections for non-payment has been lifted and the economy has begun to reopen. Furthermore, we have taken unique measures to minimize the bill impact occasioned by a rate increase through the middle of 2022, including a proposed economic relief surcredit. These proposed measures to minimize the customer bill impact are described in detail in Mr. Blake's testimony.

But we will not be in this pandemic forever. The changes we describe in these proceedings, including the deployment of AMI and the adjustments to retirement dates of coal-fired generating units, are more beneficial to customers if they are done now rather than waiting for our social and economic environment to normalize. Ultimately, we have conviction that the investments the Companies have made and planned to make as part of these proceeding are beneficial and least-cost to customers, and thus are beneficial in the current environment and in the future as life and the economy recover from the pandemic. We must continue to position ourselves to best serve the needs of our customers, even as we collectively face unprecedented challenges.

As always, the Companies' decision to file this case is not taken lightly, and balances the provision of safe, reliable, cost effective service to our customers with the need for fair, just and reasonable returns for our investors. Our Companies can only be successful if we do both.

Q. Please briefly describe the proposed increase in revenues.

A. KU is requesting an increase of approximately $172.3 million a year in its electric revenue. LG&E is requesting an increase of approximately $138.2 million a year in its electric revenue, and an increase of approximately $23.5 million a year in its gas revenue. The causes or drivers of the need for the additional revenue are discussed in detail in Mr. Blake's testimony including the need to change depreciation rates to avoid the risk of stranded assets and inter-generational inequities. The support for these revenue increases is discussed in specific detail in the testimony of Mr. Arbough. The complete list of the witnesses' testimony is identified in our applications. Together with the applications' schedules, they demonstrate that KU's and LG&E's requested increases in base rates are necessary for the Companies to continue to provide safe and reliable high-quality service to customers and earn a fair and reasonable return adequate to attract capital investment.

VII. Recommendation

Q. Do you have a recommendation for the Commission?

A. Yes. For these reasons and the evidence presented in our applications, the Commission should authorize the requested AMI investment and proposed ratemaking treatment, increase in revenues through adjustments to our base rates, including the updated depreciation rates and the other specific forms of relief set forth in our applications. By obtaining the requested relief, the Companies hope to continue providing safe, reliable, and excellent service to our customers into the future, while keeping rate base relatively flat. If we are able to do this, we believe we can avoid base rate cases for the foreseeable future.

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

The undersigned, **Paul W. Thompson**, being duly sworn, deposes and says that he is President and Chief Executive Officer of Kentucky Utilities Company and Louisville Gas and Electric Company and an employee of LG&E and KU Services Company, and 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.

Paul W. Thompson

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 20th day of November 2020.

Notary Public

Notary Public, ID No. 595712

My Commission Expires:

March 28, 2022

APPENDIX A

Paul W. Thompson
President, and Chief Executive Officer
Louisville Gas and Electric Company
Kentucky Utilities Company
220 West Main Street
Louisville, KY 40202
(502) 627-3324

Education

University of Chicago, MBA in Finance and Accounting (1981)
Massachusetts Institute of Technology (MIT), BS in Mechanical Engineering (1979)

Professional Experience

LG&E and KU Energy LLC
2018-current President and Chief Executive Officer
2017-2018 President and Chief Operating Officer
2012-2017 Chief Operating Officer
2000-2012 Senior Vice President, Energy Services
LG&E Energy Marketing, Louisville, KY
1998–1999 – Group Vice President
Louisville Gas and Electric Company, Louisville, KY
1996–1999 – Vice President, Retail Electric Business
LG&E Energy Corp., Louisville, KY
1994–1996 (Sept.) – Vice President, Business Development
1994–1994 (July) – Louisville Gas & Electric Company, Louisville, KY
General Manager, Gas Operations
1992–1993 – Director, Business Development
Koch Industries Inc.
1990–1991 Koch Membrane Systems, Boston, MA
National Sales Manager, Americas
1989–1990 John Zink Company, Tulsa, OK
Vice President, International
Lone Star Technologies (a former Northwest Industries subsidiary)
1988–1989 John Zink Company, Tulsa, OK
Vice Chairman
1986–1988 Hydro-Sonic Systems, Dallas, TX
General Manager
1986–1986 (July) Ft. Collins Pipe, Dallas, TX
General Manager
1985–1986 Lone Star Technologies, Dallas, TX
Assistant to Chairman
1980–1985 Northwest Industries, Chicago, IL
Manager, Financial Planning

Professional Memberships

Center for Applied Energy Research, Advisory Board Member

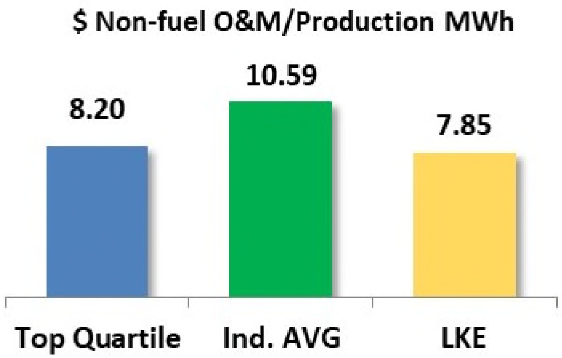
Prior Affiliations:
FutureGen Industrial Alliance, Board Member and former Chairman of the Board
Electric Energy Inc., Board Member
Ohio Valley Electric Corporation, Board Member

Civic

Kentucky Chamber of Commerce,
Chairman 2018
Board Member (2015 – current)
Greater Louisville Inc. Board (2005 - 2016)
Louisville Downtown Development Corporation Board (2006 -2017)
Fund for the Arts Board
2017 Campaign Chair
Louisville Free Public Library Foundation Board,
Chairman (2006–2012)
Chair, Annual Appeal (2002–2003)
Co-Chair, Annual Children's Reading Appeal (1999–2001)
Trees Louisville (2016 – current)
Jefferson County Public Education Foundation Board (2008–2013)
University of Kentucky College of Engineering, Project Lead The Way, Council Member (2007–2012)
March of Dimes, Honorary Chair (1997–1998)
Habitat for Humanity, Representing LG&E as co-sponsor
Friends of the Waterfront Board (1998–2002)
Leadership Louisville (1997–1998)

FERC Form 1 Benchmarking Five Year Average [2015-2019] Comparisons

Generation



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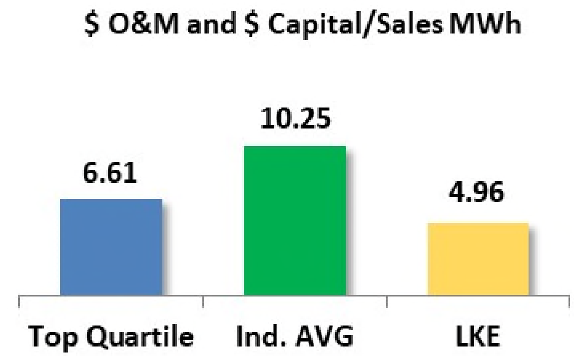

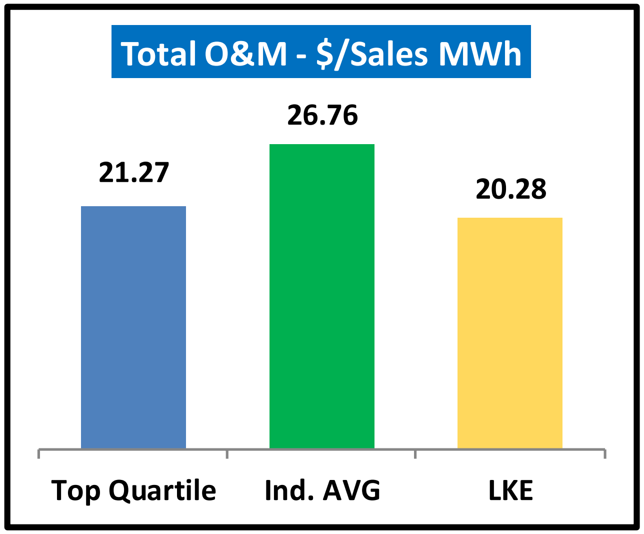

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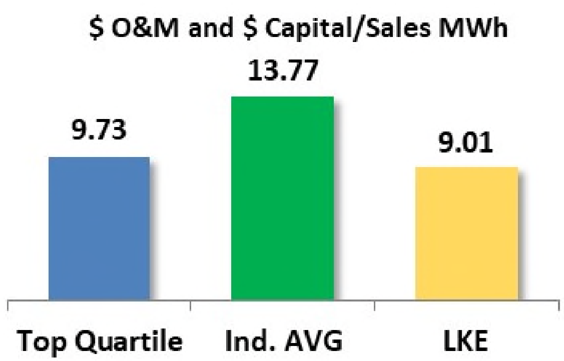
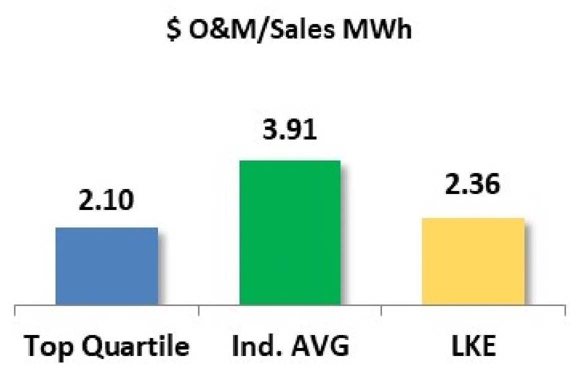


Customer Service



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, 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**

In the Matter of:

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**

KENT W. BLAKE
CHIEF FINANCIAL OFFICER
KENTUCKY UTILITIES COMPANY AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Filed: November 25, 2020

TABLE OF CONTENTS

I. INTRODUCTION

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

A. My name is Kent W. Blake. I am the Chief Financial Officer of 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, which provides services to KU and LG&E. I have held this role for more than eight years. My business address is 220 West Main Street, Louisville, Kentucky 40202.

Q. Please describe your educational and professional background, as well as your history testifying before this Commission.

A. A complete statement of my work experience and education is contained in Appendix A attached hereto. I have testified in numerous proceedings before the Commission. Most recently, I testified in KU's and LG&E's 2018 base rate cases.[1]

Q. What are the purposes of your testimony?

A. The purposes of my testimony are to (1) review the specific steps the Companies took to minimize the bill impact to customers from the requested increases in base rates; (2) discuss the proposed ratemaking treatment of the investment in Advanced Metering Infrastructure ("AMI"); (3) discuss the drivers of the increase in the Companies' revenue requirements sought in these proceedings; and (4) discuss efforts in the financial and administrative areas of our companies to achieve improvements in efficiency and productivity. (Mr. Lonnie Bellar will address efficiency and

[1] *Electronic Application of Kentucky Utilities Company for an Adjustment of Its Rates*, Case No. 2018-00294, Testimony of Kent W. Blake (Ky. PSC Sept. 28, 2018); *Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Rates,* Case No. 2018-00295, Testimony of Kent W. Blake (Ky. Sept. 28, 2018).

productivity efforts within Operations). I also sponsor the schedule required by 807 KAR 5:001 Section 16 to be filed with the applications.

II. STEPS TO MINIMIZE CUSTOMER BILL IMPACT

Q. Do you concur with Mr. Thompson's testimony as to why the Companies are seeking an increase in revenue requirements at this time?

A. Yes. The provision of safe, reliable, and cost effective service to our customers is being funded with a net investment of approximately $11 billion by debt and equity investors. Our continued ability to provide that service to our customers is dependent upon the ability to attract and retain those debt and equity investors. We constantly seek to strike the right balance between delivering excellent service and low rates for our customers while also delivering an appropriate return of and on the investments of our creditors and shareholders. That balance can be challenging at times. After months of thoughtful consideration, and after the Commission has lifted its moratorium on disconnections for non-payment, we are making this much needed filing. In addition, with this timing, our requested rate changes would not take effect until the middle of 2021. Moreover, the Companies are proposing a one-year surcredit ("Economic Relief Surcredit") to temper the impact of that change until the middle of 2022 when many economists project a return to a pre-COVID economy.[2]

Q. In preparing their applications, did the Companies take steps to mitigate the impact of rate increases on their customers?

[2] Case Nos. 2020-00349 and 2020-00350, Application, Attachment to Tab 16 Section 16(7)(c) Filing Requirement, Item C, Page 4.

A. Yes. In addition to the efficiency and productivity measures we take to keep the Companies' costs down, the Companies also sought thoughtful ways to (1) make these proceedings the last base rate cases the Companies will file for a number of years; (2) minimize the requested increase in these proceedings; (3) return certain funds to customers in the form of the Economic Relief Surcredit; and (4) provide for cost recovery of the Companies' proposed AMI investment in a manner which, based on the Companies' current projections, will not result in an increase in our customers' rates currently or when cost recovery of that investment is ultimately sought.

Q. How do the Companies intend to avoid filing base rate cases for some time and for how long?

A. Since 2008, KU and LG&E have generally filed base rate cases every two years.[3] This has been necessary due to the significant amount of capital investment by the Companies over this time period without load growth. With many unique and large scale capital projects completed by the end of 2021, the Companies hope to achieve a level of capital spend starting in 2022 that will allow the Companies to continue providing safe, reliable, and excellent service to our customers, while allowing us to keep rate base relatively flat. Once we determined that might be possible, we set a goal to maintain operation and maintenance expenses flat to the level included in this forecast test year, meaning we must find sufficient efficiencies going forward to offset inflation and any other new costs of operation. This is required to avoid an increase in the Companies' revenue requirement due to our forecast of relatively flat load growth. While we have begun generating ideas on how to meet this goal, at this time, it remains

[3] The Companies' last six base rate cases were filed in 2018, 2016, 2014, 2012, 2010, and 2008.

just that – a goal. The Companies still must address other future sources of higher revenue requirements and regulatory lag, including increases in the cost of debt and higher depreciation expense. A large portion of the Companies' debt is at fixed rates, thus limiting their exposure to future changes in interest rates, especially if they are able to hold rate base flat and thus not incur significant levels of incremental debt. However, even if the Companies are able to flatten rate base growth starting in 2022, Plant in Service and thus depreciation expense will still increase. The Companies' must find some way to offset this impact. But, if the Companies are able to do this, the Companies believe they can avoid base rate cases for the foreseeable future. Replacement generation capacity for future plant retirements, whether that comes in the form of purchased power arrangements or owned generation, would likely be the next principal driver for future base rate cases.

The outcome of these base rate cases, including the proposed ratemaking treatment for the AMI project, is a prerequisite for meeting the Companies' objective of avoiding base rate cases for some time. The Companies believe the resulting rate stability from such a cessation of base rate cases will benefit their customers and assist the economic recovery in Kentucky.

Q. Will you please describe the Companies' specific actions that have reduced the base revenue requirement increase in these proceedings from what it otherwise would have been?

A. First, in evaluating the depreciation rates proposed by Mr. Spanos, KU and LG&E considered the current economic environment and the Commission's Order in Case No.

2019-00271.[4] Having agreed to depreciation rates for electric and gas distribution, transmission and common plant in their last base rate case proceedings and not having experienced any significant changes to the expected lives of those assets, the Companies chose not to request the increases recommended by Mr. Spanos for those asset classes. The impact of this decision was to reduce the requested revenue requirements in these proceedings by $37.8 million (KU $21.8 million, LG&E Electric $11.3 million, and LG&E Gas $4.7 million). However, as further discussed in the testimony of Mr. Bellar and Mr. Spanos, the Companies have experienced significant changes in facts and circumstances surrounding their remaining coal-fired generation fleet that must be addressed now in depreciation rates to avoid the risk of stranded assets and inter-generational inequities. KU and LG&E also considered the impacts of using forecasted capital for the depreciation study and chose to use historic plant in service as the more conservative measure consistent with that used by the Companies in prior rate cases. The decision to use historic plant in service balances rather than forecasted plant in service balances to calculate depreciation rates reduced the base revenue requirement in these cases by $6.5 million, principally at KU.

Further, in forecasting bad debt expense in these proceedings, KU and LG&E are using a 5-year historical average (2015-2019) which does not reflect the COVID-19 pandemic and resulting recession. This decision resulted in a reduction in the revenue requirements in this proceeding of $5.1 million (KU $2.2 million, LG&E Electric $2.4 million, and LG&E Gas $0.5). The Companies recognize there is

[4] *Electronic Application of Duke Energy Kentucky, Inc for 1) An Adjustment of the Electric Rates; 2) Approval of New Tariffs; 3) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; and 4) All other Required Approvals and Relief*, Order (Ky. PSC Apr. 27, 2020).

uncertainty around the ultimate size of the expected increase in bad debts with the moratorium on disconnects having just been lifted last month. In the event the Companies ultimately experience any significant increase in bad debt expense resulting from restrictions put in place during the 2020 pandemic, the Companies would expect to file, and the Commission to fairly consider, a request for a regulatory asset for any expenses significantly beyond that embedded in base rates during these proceedings.

Finally, the Companies also removed any revenue requirement associated with the AMI project from the requested increase in these proceedings and instead proposed the ratemaking treatment discussed later in my testimony. This decision resulted in a $4.7 million (KU $2.7 million, LG&E Electric $1.7 million, and LG&E Gas $0.3 million) reduction in the proposed revenue requirements.

Q. Please explain the Economic Relief Surcredit the Companies are proposing in these proceedings.

A. The Companies are proposing to provide customers a one-year surcredit to distribute more rapidly and directly certain benefits. The surcredit will be applied to customers' bills during the first year that the Companies' base rates established in these proceedings take effect and will serve to mitigate the increase for this first year. The items to be returned through this surcredit include (1) the remaining fees the Companies were able to secure for its customers through their negotiation of refined coal facility agreements at the Ghent (KU), Mill Creek (LG&E), and Trimble County (KU and LG&E) generation plants; (2) the Companies' remaining unprotected excess accumulated deferred income tax ("ADIT") balances (KU and LG&E); and (3) the payment received by LG&E in connection with the resolution of a disputed electric service territory matter in Case No. 2019-00370.[5] The total from these three items to be returned to customers through this surcredit is $53.5 million (KU $11.9 million; LG&E Electric $38.9 million, and LG&E Gas $2.7 million). The details of the surcredits and resulting tariffs are discussed in the testimony of Mr. Conroy.

Q. Why do the Companies believe it is appropriate to provide these bill credits to customers?

A. The Companies are attempting to ease the burden of the proposed increase in these proceedings for one year as the local economy recovers from the impact of the COVID-19 pandemic by returning these regulatory liabilities to customers in a more rapid fashion than might otherwise be the case or than previously agreed to in other proceedings.

With respect to the proceeds from the refined coal agreements, all of those agreements are set to expire during the forecast test period. By returning them as a one-year surcredit, customers receive the full benefit to be provided while the Companies avoid embedding a permanent credit into base rates for a benefit it derived for its customers for a period of time that now no longer exists.

With respect to the unprotected excess ADIT, it was agreed in Case No. 2018-00034 that a 15-year amortization period was appropriate. The Companies would now like to provide the remaining balances to customers over a one-year period beginning with the change in base rates in these cases. In the event corporate tax rates are changed

[5] *Electronic Application of Louisville Gas and Electric Company, Meade County Rural Electric Cooperative Corporation, and Big Rivers Electric Corporation for (1) Approval of an Agreement Modifying an Existing Territorial Boundary Map and (2) Establishing Meade County Rural Electric Cooperative Corporation as the Retail Electric Supplier for Nucor Corporation's Proposed Steel Plate Mill in Buttermilk Falls Industrial Park in Meade County, Kentucky*, Order (Ky. PSC Feb. 24, 2020).

via legislation after these balances are provided to customers but before the underlying timing differences reverse, the Companies expect a regulatory proceeding would take place to address the impact on all recorded ADIT balances with the resulting amortization periods addressed in that future proceeding. The Companies also believe this proposed treatment is not inconsistent with the Commission's Order in Case No. 2020-00176[6] in that (a) this treatment is being proposed in the context of a base rate proceeding and (b) the Companies did not argue in Case No. 2018-00034[7] that a shorter amortization would cause them to "suffer dire financial consequences."

With respect to the payment LG&E received from Case No. 2019-00370, LG&E had previously agreed to record this amount as a regulatory liability when received. The payment was received on September 15, 2020, which means this is the first proceeding in which LG&E has an opportunity to propose a means to return this regulatory liability to customers. For the reasons noted above, we believe this one-year surcredit provides a proper method. The only concern in doing so is that the payment is refundable by LG&E in the event Nucor does not eventually begin operations in Kentucky within the Meade County Rural Electric Cooperative's service territory. The Companies currently have no reason to believe that situation is likely to occur and certainly hope that it does not given the resulting harm to Kentucky's economy; however, in the unlikely event this were to occur, the Companies would expect to file, and the Commission to carefully consider, a regulatory asset for such a refund. The

[6] *Electronic Application of Kentucky Power Company to Amend the Settlement Agreement Approved in Case No 2018-00035 to Provide for the One-Time Amortization of Unprotected Accumulated Deferred Federal Income Tax in an Amount Sufficient to Eliminate Customer Delinquencies Greater than 30 Days as of May 28, 2020*, Order (Ky. PSC Oct. 2, 2020).

[7] *Kentucky Industrial Utility Customers, Inc. vs. Kentucky Utilities Company and Louisville Gas and Electric Company*, Case No. 2018-00034, Order (Ky. PSC Sept. 28, 2018).

amortization period for such a resulting regulatory asset would also be considered in a future proceeding.

Q. The settlement reached in Case No. 2019-00370 also included an annual payment to LG&E for a period of time under certain circumstances. Are the Companies proposing those amounts be included in the surcredit as well?

A. No. This annual payment is to be paid to LG&E at the beginning of each year after Nucor Corporation commences operations. Based on limited knowledge of Nucor's development process, the Companies project the first payment will not be due until 2023. As the settlement involved LG&E surrendering what it believed to be its rights to the service territory in question, the Companies propose that such payments be directed toward economic development within the LG&E service territory. LG&E is willing to provide annual reporting on any such payments received and funds expended toward economic development.

III. ADVANCED METERING INFRASTRUCTURE RATEMAKING TREATMENT

Q. Is the AMI project a driver of the Companies' requested base rate increases in this proceeding?

A. No. The Companies have removed all revenue requirements associated with AMI from the forecast test period in these proceedings.

Q. How do the Companies propose to recover its costs associated with the AMI project?

A. While the Companies could have proposed a separate tracker mechanism to recover actual costs from and provide actual savings to customers on a nearly real-time basis, the Companies propose that cost recovery of the AMI investment be addressed after the project is fully implemented. Under this proposal, the Companies will record their investment in the AMI project as Construction Work In Progress ("CWIP") and accrue an allowance for funds used during construction ("AFUDC") during the projected implementation period of approximately five years. The Companies also propose to record a regulatory liability until its first base rate proceedings following implementation to the extent their actual meter reading and field service expenses are less than the forecast test period level embedded into base rates during these current proceedings. Finally, the Companies would propose recording a regulatory asset during this implementation period comprised of three components: (1) operating expenses associated with the project implementation ; (2) the remaining net book value of electric meters replaced and retired as part of this project; and (3) the difference between AFUDC accrued at the Companies weighted average cost of capital per Filing Requirement: Tab 63 – Sec 16(8) (j) Schedule J-1.1 and that calculated using a strict interpretation of the methodology approved by the Federal Energy Regulatory Commission ("FERC").

Q. Have you prepared an exhibit to detail this proposed ratemaking treatment for the AMI during implementation?

A. Yes. It is included as Exhibit KWB-1 to my testimony and uses the same cost and savings projections included in Exhibit LEB-3. It shows the accumulation over the next five years of a CWIP balance of $352.1 million, a regulatory liability balance of $64.5 million, and a regulatory asset balance of $74.9 million, comprised of the following: $36.8 million representing operating expenses associated with the AMI project implementation, $26.8 million representing the remaining net book value of electric meters retired and replaced as part of the AMI project implementation, and $11.3 million representing the difference in recorded AFUDC using the Companies' weighted average cost of capital ("WACC") and that calculated using a strict adherence to FERC's methodology, the latter of which is used to accumulate AFUDC in the CWIP balance.

The exhibit goes on to show the projected ADIT balance of $7.7 million for the retired and replaced electric meters. As the tax basis in the retired and replaced electric meters would be zero at this point, this ADIT balance will reverse as the regulatory asset for the net book value of those meters is amortized. It also shows the projected ADIT balance of $38 million resulting from the difference in book and tax depreciation for the AMI project during implementation. For tax purposes, depreciation will begin as the AMI meters, network and systems are put into service at interim dates during the implementation period, while no book depreciation expense will be recorded until the entire project is placed in service for the benefit of customers. The net impact of all recorded assets and liabilities during the AMI project implementation result in the projected AMI capitalization of $316.8 million shown on Exhibit KWB-1.

Q. Are the Companies suggesting no cost recovery until the entire AMI project, inclusive of meters, systems, and networks, are put in service?

A. Yes. The Companies request Commission authorization to defer billing customers for any of the costs of the AMI investment until the entire project is fully implemented, which is projected to be in March 2026. The AMI capital project is a single project that includes interdependent systems. The investment, inclusive of capitalized property taxes, would remain in Account 107 "Construction Work in Progress" until that time.

KU and LG&E further request authority to accrue AFUDC for the capital and financing costs during the implementation period. AMI's benefits, including improved outage response, the provision of customer usage information, and a reduction in meter reading and field services costs, cannot be fully achieved until the project is fully implemented, meaning the point at which all underlying systems and the RF mesh network are completed and all meters are installed and communicating to these systems through the network. Each component is an integral step in the AMI project achieving its intended purpose of providing LG&E and KU with current customer use information to support outages, support customer inquiries and provide savings through decreased meter reading and field service costs. The AMI project is not complete until all components are complete, synchronized and functional throughout the companies' service areas. For these reasons, it is appropriate to treat the entire AMI project as a single project for ratemaking purposes, including the accrual of AFUDC.[8]

FERC recently approved a similar request by Duke Energy Corporation to treat its Cybersecurity Program as a single project and to continue to accrue AFUDC over 36 to 42 months on all of the Cybersecurity Program's costs until all phases of implementation were complete.[9]

The Companies' request for AFUDC treatment is exclusively for the AMI project. This allows the Companies to install this technology over a four to five year period without impacting the bills of customers while accruing the financing costs

[8] *Accounting Release No. 5 (Revised), Capitalization of Interest During Construction*, effective January 1, 1968, FERC Stats. & Regs. ¶ 40,005; *Revision to Accounting Release No. 5, Capitalization of Allowance for Funds Used During Construction,* Docket No. AI11-1-000 (issued Feb. 16, 2011).

[9] *Duke Energy Corporation*, 169 FERC ¶ 61,232 (2019), Order Granting Accounting Request (Dec. 19, 2019).

incurred related to the project. KU and LG&E will continue including CWIP in rates for all other projects.

Q. Please explain how the Companies will accrue AFUDC during the AMI implementation period.

A. The Companies propose to accrue AFUDC using the Companies' WACC shown on Filing Requirement Tab 63, Schedule 16(8)(j) Schedule J-1.1 for the forecasted test period, because it reflects the Companies' true cost of capital. The Companies propose that strict adherence to the FERC methodology places undue weight on short-term debt and does not provide the Companies' full recovery of its cost of capital. This is even more exaggerated in applying AFUDC to a single project. Exhibit KWB-1, shows that strict adherence to the FERC methodology would result in the Companies recording a cost of equity that is significantly below any projection as to what constitutes a fair, just, and reasonable cost of equity. Over the five-year period, the implied cost of equity ranges from 5.49% to 8.06% (calculated by dividing the AFUDC Average Equity Rate ("FERC") percentages shown on Exhibit KWB-1 by the Companies 53% equity capital structure). It is important to note that the Companies will finance the AMI project with the same balanced capital structure used in these proceedings both during implementation and beyond. The Companies do not project finance and use all forms of capital to finance their construction projects.

Q. Have other state public utility commissions modified the FERC methodology for retail ratemaking purposes?

A. Yes, several state public utility commissions have approved utilities' requests to accrue AFUDC using the utility's WACC. In particular, the Public Service Commission of

Wisconsin has authorized the use of the WACC to compute AFUDC, stating that the use of the FERC AFUDC methodology results in the under-recovery of a utility's carrying costs and the double counting of short-term debt.[10] Additionally, the Florida Public Service Commission requires the use of WACC when accruing AFUDC on CWIP.[11] Section 25-6.0141 of Florida's Administrative Code sets out the calculation of AFUDC, stating that it should be derived using all sources of capital.[12]

Q. Has the Kentucky Commission allowed utilities to accrue AFUDC based on the WACC?

A. Yes. In its most recent rate case, Kentucky-American Water proposed to increase forecasted operating revenues to include an allowance for AFUDC that was calculated based on the company's WACC and the Commission approved it.[13] The Commission

[10] *Request of Wisconsin Power and Light Company for Deferral of Incremental Pre-Certification Costs and Pre-Construction Costs Associated with New Generation Resource*, Case No. 6680-GF-134 (May 8, 2014 Order); *Application of Wisconsin Public Service Corporation for Authority to Adjust Electric and Natural Gas Rates*, Case No. 6690-UR-122 (Dec. 18, 2013 Order); *Application of Northern States Power Company-Wisconsin for Authority to Adjust Electric and Natural Gas Rates*, Case No. 4220-UR-118 (Dec. 27, 2012 Order); *Application of Northern States Power Company-Wisconsin for Authority to Adjust Electric and Natural Gas Rates*, Case No. 4220-UR-117 (Dec. 22, 2011 Order); *Application of Madison Gas and Electric Company for Authority to Change Electric and Natural Gas Rates*, Case No. 3270-UR-117 (Jan. 12, 2011 Order); *Application of Wisconsin Power and Light Company for a Certificate of Authority to Construct a Wind Electric Generation Facility and Associated Electric Facilities, to be Located in Fond du Lac County, and an Application for Approval of Fixed Financial Parameters and Capital Cost Rate-Making Principles for the Facility, to be Known as the Cedar Ridge Wind Farm*, Case No. 6680-CE-171 (May 10, 2007 Order).

[11] Upon a petition to modify its AFUDC rate, Fla. Amin. Code 25-6.0141(4) requires the utility to file a schedule showing the capital structure, cost rates, and weighted average cost of capital that are the basis for the AFUDC rate.

[12] "(2) The applicable AFUDC rate will be determined as follows: (a) The most recent 13-month average embedded cost of capital … shall be derived using all sources of capital and adjusted using adjustments consistent with those used by the Commission in the utility's last rate case…"

[13] *Electronic Application of Kentucky-American Water Company for an Adjustment of Rates*, Case No. 2018-00358, Order (Ky. PSC June 27, 2019).

accepted a similar calculation using WACC for AFUDC in Kentucky-American's 2012, 2010, and 2004 rate cases.[14]

Q. How will the Companies treat the retired electric meters as they are retired and replaced with AMI meters?

A. AMI meters will be placed in service throughout the implementation period, which will cause the retirement of the electric meters that are replaced. Once the AMI project is fully implemented, the Companies plan to reclassify any remaining unrecovered net book value of the retired meters to a regulatory asset.

Q. Has the Commission previously allowed electric utilities to recognize a regulatory asset for such a purpose?

A. Yes. In Case No. 2014-00376,[15] the Commission authorized Kenergy Corp. to record as a regulatory asset the net book value of electric meters Kenergy Corp. planned to retire as part of its deployment of an AMI system. The Commission has authorized the creation of regulatory assets under similar circumstances for Shelby Electric Cooperative[16] and Taylor County Rural Electric Cooperative Corporation.[17]

Q. How do the Companies expect to recover costs of the AMI project after the project is fully implemented?

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[14] *Application of Kentucky-American Water Company for an Adjustment of Rates Supported by a Fully Forecasted Test Year*, Case No. 2012-00520, Order at 31 (Ky. PSC Oct. 25, 2013); *Application of Kentucky-American Water Company for an Adjustment of Rates Supported by a Fully Forecasted Test Year*, Case No. 2010-00036, Order at 23 (Ky. PSC Dec. 14, 2010); *Adjustment of the Rates of Kentucky-American Water Company*, Case No. 2004-00103, Order at 43, 75 (Ky. PSC Feb. 28, 2005).

[15] *Request of Kenergy Corp. for Approval to Establish a Regulatory Asset in the Amount of $3,884,717 Amortized Over a Ten (10) Year Period*, Case No. 2015-00141, Order (Ky. PSC Aug. 31, 2015).

[16] *Request of Shelby Electric Cooperative for Approval to Establish a Regulatory Asset in the Amount of $443,562.75 and Amortized the Amount Over a Period of Five (5) Years*, Case No. 2012-00102, Order (Ky. PSC Apr. 16, 2012).

[17] *Filing of Taylor County Rural Electric Cooperative Corporation Requesting Approval of Deferred Plan for Retiring Meters*, Case No. 2008-00376, Order (Ky. PSC Dec. 9, 2008).

A. Once the project is fully implemented with the actual implementation costs known, the Companies would address cost recovery in the first base rate case proceedings following implementation. Using the same projections used in Exhibit LEB-3 and the implementation costs shown in Exhibit KWB-1, Exhibit KWB-2 shows the annual revenue requirements of the AMI project relative to the status quo case over three scenarios on pages 1-3. Page 4 then shows an annual rollforward of AMI capitalization for each of these scenarios.

Given the incremental capital investment associated with the complete changeout of over one million electric meters, the addition of AMI communication modules on most gas meters, and the associated system and network related costs associated with the AMI project, the AMI project does show an incremental revenue requirement relative to the status quo scenario for a few years after implementation. Page 1 of Exhibit KWB-2 shows that, before any amortization of regulatory assets or liabilities, this incremental annual revenue requirement ranges from $13.4 million to $3.9 million and totals $36.7 million over a four-year period before reaching a break-even point relative to the status quo in year 5.

However, these same projections also suggest the total nominal revenue requirements are $94.8 million lower for the AMI project relative to the status quo over the entire 15-year period shown. The Companies would expect to use the amortization of the regulatory assets and liabilities associated with the AMI project to address this up-front cost and long-term benefit issue such that customers would never see an increase in revenue requirements associated with implementing AMI. Page 2 of Exhibit KWB-2 shows that based on the Companies' current projections, this could be accomplished by amortizing the regulatory liability over the five years after implementation in a manner that eliminates any net incremental revenue requirement. A remaining regulatory liability balance of $13.9 million would remain to be amortized in year 6. The Companies would then begin amortization of the regulatory asset associated with the AMI project over years 6 through 10 at a level that would not create an incremental revenue requirement. That would leave a remaining regulatory asset balance of $36.1 million which would be amortized on a straight-line basis over the following 5 years at $7.2 million per year. Despite this regulatory asset amortization, the AMI project would still reflect a lower revenue requirement of $40.5 million, or an average of $8.1 million per year, over this five-year period. With all regulatory assets and liabilities fully amortized over this 15-year period, the savings associated with the AMI implementation would continue from that point forward.

We believe this ratemaking treatment is the most appropriate method in that it best matches costs incurred with benefits received. It will also be based on actual costs after the implementation is complete.

Q. Exhibit LEB-3 presents a scenario in which a 20-year depreciable life is used for AMI meters rather than a 15-year depreciable life. How would this change in the depreciable life impact this post-implementation revenue requirement scenario?

A. Page 3 of Exhibit KWB-2 performs the same exercise as that shown on Page 2 except that it assumes a 20-year depreciable life for AMI meters and extends the revenue requirement analysis out to 20 years. In this scenario, after using the regulatory liability amortization to eliminate any additional revenue requirement from the AMI project for the first five years after implementation, a regulatory liability balance of $21.6 million remains to be amortized in year 6. After amortizing the regulatory asset associated with the AMI project in years 6 through 10 at a level that does not create an incremental revenue requirement for the AMI project, a remaining regulatory asset balance of $35 million is amortized on a straight-line balance over the following ten-year period at $3.5 million per year. Despite this regulatory asset amortization, the AMI project would still reflect a lower revenue requirement of $177.1 million, or an average of $17.7 million per year, over this ten-year period. Consistent with the 15-year scenario, after the regulatory assets and liabilities have been fully amortized, the savings associated with the AMI implementation would continue from that point forward.

Q. Since the Information Technology group of the Companies reports up through you as Chief Financial Officer, can you confirm that Exhibit LEB-3 reflects the projected cost of the supporting information technology requirements of the AMI project?

A. Yes. The information technology aspects of the AMI project generally fall into two interdependent categories: (1) development of a complete RF mesh network across the Companies' service territories; and (2) the underlying systems required to implement AMI and deliver the reliability and customer service benefits discussed in detail in the testimonies of Ms. Saunders and Mr. Wolfe. The network component includes the physical collectors and routers needed to transmit interval data from meters to the head end system. The projected capital cost for this aspect of the project includes both vendor labor and collector/router hardware costs. The ongoing expenses for the network include one IT Telecom employee to maintain the network across our service territories and other costs associated with upkeep of the network.

With regard to the multiple system deliverables for the AMI project, the operating expenses during implementation include customer communications, staff training, and project management. Ongoing operating expenses include an IT support employee, hardware and software maintenance, vendor fees, and cloud data storage. The primary deliverables associated with the software applications are also interdependent and are as follows:

1) Meter Deployment Systems: Allows for information transfer and updates as meters are deployed and registered into our systems, enhances existing systems to manage meter assets across the deployment and enables support of the new assets as they are deployed.

2) Cyber Security Assessment: Includes an analysis of cybersecurity vulnerabilities and mitigation strategies.

3) Command Center Head End ("HE"): The HE is the application that communicates with the RF mesh network collectors, and receives the interval data and communication events. That interval data and communication events are then passed to the Meter Data Management ("MDM") for processing.

4) MDM: This system takes the interval data from the HE, and validates, edits and estimates missing intervals. The MDM then generates billing determinates and sends those to SAP. This project also involves enhancing the Siemens Energy IP application to support the data and allow for more complex rate structures.

5) Remote Service Switch: This is functionality that will be built to allow for remote disconnects and reconnects and achieve the Field Services benefits of AMI. This functionality resides primarily within the MDM, but SAP will be significantly impacted, as business process will originate and close within SAP.

6) Customer Engagement Tools: This deliverable is to provide customers with tools that facilitate improved customer engagement. This engagement will be critical to achieving the ePortal benefit and improved customer experience referenced in the case.

7) Electric Distribution Integration: This is the integration scope that enables electric distribution benefits related to improved outage

handling as well as in-service asset maintenance and voltage management ("CVR").

IV. RATE CASE DRIVERS

Q. Briefly explain the primary reasons for the increase in the Companies' revenue requirements.

A. KU's application requests Commission approval of rates to reflect a revenue requirement increase of $170.1 million. LG&E's application requests Commission approval of rates to reflect a revenue requirement increase of $131.1 million for its electric operations and $30 million for its gas operations.

Like previous rate cases, these cases are driven largely by investments in the infrastructure and systems necessary to provide safe, reliable service to customers. This includes increases in the Companies' 13-month average capitalization between the forecasted test period used in their last base rate proceedings and that detailed in this proceeding. It also includes changes in the Companies' cost of capital, the amount of Plant in Service, depreciation rates, and property taxes. Overall, these changes account for 69%, 79%, and 55% of the requested increase for KU, LG&E's electric operations, and LG&E's gas operations. On a combined basis, the Companies experienced a $2.3 billion increase in Kentucky base rate adjusted capitalization in this proceeding relative to that used to set base rates in the Companies' last rate case proceedings. After removing $1.5 billion of capitalization associated with Environmental Cost Recovery and Gas Line Tracker projects which are simply being moved from those mechanisms to base rates in this proceeding with no net revenue increase, that means the Companies have experienced an approximately $800 million increase in capitalization that can only be recovered in a base rate proceeding. This translates to a $77.7 million increase in the Companies' base revenue requirement (KU $43.4 million; LG&E Electric $25.4 million; LG&E Gas $8.9 million). The weighted average cost of capital proposed in this proceeding relative to that awarded in the Companies' last base rate proceeding increased the revenue requirement by $9.2 million (KU $5.8 million; LG&E Electric $2.6 million; LG&E Gas $0.7 million). The larger Plant in Service balances increased annual depreciation expense, or the recovery of investment, by $31.8 million (KU $15.5 million; LG&E Electric $10.1 million; LG&E Gas $6.2 million) and property taxes by $10.8 million (KU $4.2 million; LG&E Electric $6.0 million; LG&E Gas $0.6 million). Finally, the changes in depreciation rates for the Companies' remaining coal-fired generation units recommended by Mr. Spanos and included in the Companies' requested revenue increase added $48.3 million for KU and $59.2 million for LG&E Electric. The updated assessment of the remaining economic lives of these assets discussed in the testimonies of Mr. Thompson and Mr. Bellar advance the recovery of older coal-fired generation to avoid inter-generational inequities while there is still time to do so in a systematic and rational manner.

Q. What are the other drivers of the requested revenue requirement increase of the Companies?

A. The other drivers of the KU requested revenue requirement increase include an additional $38.3 million in operation and maintenance expenses, a $15 million reduction in load and other net revenues, and $11.5 million from the expiration of the refined coal agreements at its Ghent and Trimble County facilities. These increases were partially offset by a $2.5 million reduction between cases in the purchased power demand charge on KU's OVEC contract, a $5.6 million increase in wholesale transmission revenue, and a net $3.8 million reduction in income taxes driven by an increase in the amortization of protected excess ADIT under the previously approved Average Rate Assumption Method ("ARAM").

The other drivers of the LG&E requested revenue requirement increase for its electric operations include a $24.5 million increase in operation and maintenance expenses, a $6 million reduction in load and other net revenues, and $7.9 million from the expiration of the refined coal agreements at its Mill Creek and Trimble County facilities. These increases were partially offset by a $4.2 million reduction between cases in the purchased power demand charge on LG&E's OVEC contract, $0.2 million of incremental wholesale transmission revenue, and a $6.2 million reduction in income taxes driven by an increase in the amortization of protected excess ADIT under the previously approved ARAM method.

The other drivers of the LG&E requested revenue requirement increase for its gas operations include a $14.2 million increase in operating and maintenance expenses partially offset by a $0.4 million benefit from load and other net revenues and a $0.2 million reduction in income taxes.

The majority of the increases in operation expenses have occurred across various areas of operations and are discussed in the testimonies of Mr. Bellar, Mr. Wolfe and Ms. Saunders. However, they do include a net increase of $4.3 million associated with corporate-wide costs not allocated to functional areas of the Companies. This increase is primarily driven by a $6.7 million increase in insurance premiums and an $8.3 million increase in pension expense, partially offset by an $8.9 million reduction in storm cost amortization and other cost savings. The insurance premium increase is mainly property insurance where the Companies have seen 15-20% annual premium increases since the expiration of their rate lock in April 2020. Such premium increases have been attributed to natural disasters such as flooding and wind damage experienced by covered entities other than the Companies. The Companies did attempt to mitigate the premium increase, while maintaining reasonably accepted industry coverage, by reducing their coverage limit from $4 billion to $2 billion per occurrence. The increase in pension expense is due to the amortization of incremental actuarial losses within the qualified plan.

The increases in operation expenses also include a net increase of $7 million in the area of Information Technology due to increased hardware and software maintenance expenses, along with additional investments to address cybersecurity threats which continue to increase and become more complex. Section V of my testimony discusses the efficiency and productivity efforts in the Information Technology area that have served to mitigate this cost increase relative to what it otherwise could have been. There was no significant change between rate cases in expenses of any other financial or administrative service group.

V. EFFICIENCY AND PRODUCTIVITY

Q. Have the Companies taken steps to improve efficiency and productivity?

A. Yes. We seek the most reasonable and effective least-cost option that will ensure the delivery of safe and reliable service to our customers. Efforts include a multi-layered, rigorous approach to investment projects and contract approvals, including a requirement that all procurement contracts be competitively bid subject to limited exceptions. The testimony of Mr. Thompson discusses the Companies' top quartile cost performance which demonstrates that the Companies continue to balance cost control with providing the safe and reliable service our customers expect.

Q. What are some specific actions the Companies have taken to improve efficiency within the financial and administrative areas?

A. KU and LG&E continually look for more efficient ways to deliver service. As noted above, other than information technology, all financial and administrative service groups have continued to implement efficiencies to the point that they have avoided increases in annual operating expenses relative to the Companies' previous rate case. Some examples of actions taken to gain efficiencies and increase productivity across these groups include the following:

- Use of on-line, recorded video first interviews in staffing and advanced data analytics throughout Human Resources.
- An internal realignment and expanded use of technology in the Legal department resulting in a reduction of four full-time equivalents and one intern within the department.
- Implementation of six robotic process automation ("RPA") projects in Accounting resulting in a reduction of one full-time employee and three interns.
- Alignment of pay weeks and pay periods across LG&E, KU and LG&E and KU Services through labor negotiations and IT enhancements resulting in a reduction in Payroll processing from two weeks to one week.

- Significant initiatives within the Tax department to pursue and obtain R&D and other tax credits and limit property taxes for the benefit of our retail customers.
- Corporate Finance's negotiation of lower bank fees for two years beginning in early 2020 with annual savings projected at $134,000.
- Negotiation of the replacement of surety bonds for coal combustion residual facilities with a corporate guaranty resulting in annual savings of $850,000.
- Implementation of the Zycus Sourcing and Contract Management system by Supply Chain providing for more consistent contracting and sourcing processes, workflows and productivity with more tightly controlled bid requests and contract templates, while also providing better document access and retention.
- Growing use, both within Supply Chain and across the Companies, of DocuSign since early 2018 has streamlined approval processes and enabled more remote work capabilities.

In addition, the Companies' three primary financial systems have either recently completed an upgrade (PowerPlan), are in the final testing phases of an upgrade (Utilities International or "UI") or are in the development process for an upgrade expected to be completed in the Spring of 2021 (Oracle E-Business Suites or "OeBS"). The PowerPlan system includes modules for fixed assets, tax depreciation, tax repairs, tax provisions, property taxes, leases, and forecasting and budgeting. The UI system is the Companies' financial planning software and is used by 21 of the 25 largest utilities in the United States. It is the system that generates and houses the Companies' annual budgets and five-year business plans which support the Companies' base rate proceedings. The OeBS system includes the Companies' general ledger and associated work flows from procurement to payables. These three systems are interfaced with each other as well as the Companies' work management, human resource, transportation, and other systems providing an automated flow of work and information of which the Companies are especially proud. While the upgrades were necessary in order to stay on a supported version of the application, they also have provided or will provide multiple enhancements to further improve the Companies' efficiency and productivity. In fact, due to the continuous innovation capability of the newer 12.2 version of OeBS, the next major upgrade is not expected to be required for some time (current projection is 2030). The Companies have received a commitment from the vendor to support this version of the on-premises version of OeBS until it is economically justified for the Companies to move to a cloud-based version of OeBS.

With the sustained reliance on automation and data analytics across the Companies, and growing cybersecurity threats, the Companies have continued to seek out efficiencies in Information Technology to help mitigate cost increases. The following are some examples of such initiatives taken since the Companies filed their previous base rate cases:

- Sought out and took advantage of opportunities to move to less expensive solutions from our existing solutions:
  - Netezza replacement – replaced an expensive solution for data analytics for PI data with open source software (PostgreSQL)

on standard hardware. This new solution has proven to be very efficient and has enabled the Companies' to apply true Artificial Intelligence to generation data. As more data is pulled into this solution, it will open up years of historized data to the Companies' engineering, operation and maintenance staffs across the fleet.

    - Oracle Service-Oriented Architecture replacement – implementing RabbitMQ which will provide the same functionality at a lower O&M cost.
    - Adobe Pro replacement – implementing FoxIT as the Companies' PDF software to mitigate the impact of the current vendor's support expense increase .
    - AppSense replacement – moving to FSLogix which is now bundled in with our Microsoft subscription, eliminating the O&M costs associated with AppSense.

- Implemented Session Initiation Protocol to get improved performance / redundancy while reducing O&M costs.
- Implemented automation across our information technology infrastructure and operations including the use of software-designed approaches where applicable:
    - Implemented automation that will enable us to quickly identify vulnerabilities in our network gear and apply updates to the hundreds of devices across our network.

- Combined Configuration Management Database & Tanium data in order to address various operational initiatives and Enterprise Security Standards.
- Implemented intelligent monitoring for network devices to reduce the noise and make troubleshooting more efficient.
- Utilized Cisco Identity Services Engine to provide device profiling and reduce the need for additional firewalls.
- Implementing Cisco Application Centric Infrastructure which will enable the Companies to micro-segment our network without additional hardware.
- Implementation of Hyperconverged Infrastructure will also enable us to reduce our investment in Storage Area Networks and associated switches.

- Re-negotiated many of our contracts to drive down support costs while providing new capabilities, including:
  - RedHat Enterprise License support subscription, moving a number of licenses to the "Data Center" model, saving money and providing for more growth.
  - Microsoft Enterprise Agreement
  - EMC Transformational License Agreement
  - Oracle Universal License Agreement

- Implemented several operational technologies to improve cybersecurity posture while absorbing the O&M labor costs of supporting these new capabilities, including:
  - AppDefense for Application Allowlisting which will prevent unauthorized software from running on our most critical servers
  - Tanium Integrity Monitoring which will monitor our servers and prevent alteration of executable files on our servers with higher classifications of data
  - Expanded use cases of CyberArk for privileged access management to manage accounts that have administrative access to infrastructure and systems
  - Custom dashboards and applications built from Tanium and Microsoft System Center Configuration Manager data for improved vulnerability and patch management

The Companies also continue to enhance their cybersecurity defense mechanisms and security awareness through programs such as ongoing employee education and mandatory annual security awareness training. The Companies are currently implementing initiatives to achieve National Institute of Standards Technology higher maturity and compliance with Enterprise Security Standards. Some recent examples include the following:

- Expanded use of Qradar Security Information Event Management ("SIEM") system. The SIEM provides a centralized location for logging and monitoring of cybersecurity related events in the IT environment. It is the primary tool used by Security Operations for monitoring of any potential security incidents. Additional systems and applications were added to expand the visibility into the IT environment. Additionally, the SIEM has been integrated into the IT Service Management System to help track security incidents and track root cause.

- Deployed Tanium Unified Endpoint Management and Security Platform throughout the IT environment to provide better visibility into the environment for monitoring of assets, vulnerabilities and enable the threat hunting function of IT Security. This system allows IT Security search for known advanced malicious files in the environment quickly if threat intelligence is received to check our environment.

Q. How is the business and financial planning process used to improve efficiency and productivity?

A. Our process begins with the development of our corporate objectives. Those objectives consider relevant economic, market, regulatory, and legislative developments as they relate to the Companies' current performance and the Companies' mission, vision, and corporate values. Next, we identify the operating requirements necessary to accomplish those objectives. In turn, the business planning process translates the operational requirements into the resource requirements necessary to achieve those objectives. It is a "bottoms up" process with each business unit preparing detailed five-year plans addressing its individual areas of responsibility. Those plans are reviewed by successive levels of management to ensure not only that they are coordinated but also make efficient and productive use of the Companies' resources. The resulting budget and five-year business plan then serve as ongoing measures to track whether the Companies' objectives are being accomplished as planned or if additional action is required due to external factors or other changes. In summary, the Companies plan the work and then work the plan.

VI. SCHEDULE REQUIRED BY 807 KAR 5:001 SECTION 16

Q. Are you sponsoring any schedules required by the Commission's regulation 807 KAR 5:001 Section 16?

A. Yes. I am sponsoring Section 16(7)(c), the complete description of all factors used to prepare the forecasted test period.

VII. CONCLUSION

Q. What are your recommendations for the Commission in these proceedings?

A. The Companies recommend the Commission approve the proposed ratemaking treatment for the AMI investment to allow customers to begin receiving the substantial benefits of this technology without an impact to their bills in these cases. The Companies further recommend the approval of the proposed one-year surcredit mechanisms effective with the change in base rates in these cases. In addition, through the proposed changes in electric and gas base rates in these applications, the Companies recommend the Commission approve the recovery of the identified revenue deficiencies.

Q. Does this conclude your testimony?

A. Yes.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

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

KW Blake

Kent W. Blake

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 20th day of November 2020.

Judy Schooler

Notary Public

Notary Public, ID No. 603967

My Commission Expires:

July 11, 2022

APPENDIX A

Kent W. Blake

Chief Financial Officer
Louisville Gas and Electric Company
Kentucky Utilities Company
220 West Main Street
Louisville, Kentucky 40202
Telephone: (502) 627-2573

Previous Positions

LG&E and KU Energy LLC (f/k/a E.ON U.S., LG&E Energy LLC)	
Vice President, Corporate Planning and Development	2007-Feb 2012
Vice President, State Regulation and Rates	2003-2007
Director, State Regulation and Rates Director, Regulatory Initiatives	
Director, Business Development	2002-2003
Director, Finance and Business Analysis	
Mirant Corporation (f/k/a Southern Company Energy Marketing)	1998-2002
Senior Director, Applications Development	
Director, Systems Integration	
Trading Controller	
LG&E Energy Corp.	
Director, Corporate Accounting and Trading Controls	1997-1998
Arthur Andersen LLP	1988-1997
Manager, Audit and Business Advisory Services	
Senior Auditor	
Audit Staff	

Education/Certifications

University of Kentucky, B.S. in Accounting
Certified Public Accountant, Kentucky
Leadership Louisville, 2007

Current Professional and Community Affiliations

American Institute of Certified Public Accountants
Kentucky State Society of Certified Public Accountants
Edison Electric Institute
Metro United Way, Board Member, Immediate Past Chair and member of Executive Committee (completed two-year term as Board Chair in October 2020)
Louisville Downtown Development Corporation, Treasurer, Chair of Finance & Audit Committee and member of Executive Committee

LG&E and KU
AMI Project Ratemaking
Implementation Period

	Implementation Period					
	7/1/21 to 6/30/22	7/1/22 to 6/30/23	7/1/23 to 6/30/24	7/1/24 to 6/30/25	7/1/25 to 6/30/26	Total
CWIP						
Capital Expenditures	$38,215,041	$78,961,112	$82,646,643	$67,026,049	$35,654,219	$302,503,064
Capitalized Property Taxes	23,980	337,783	1,248,068	2,526,645	5,918,089	10,054,565
AFUDC - Equity (FERC)	586,971	2,699,600	6,392,848	9,581,921	9,205,331	28,466,672
AFUDC - Debt (FERC)	239,751	1,050,681	2,440,360	3,726,287	3,586,115	11,043,194
	$39,065,743	$83,049,176	$92,727,919	$82,860,902	$54,363,754	**$352,067,494**
Regulatory Liability - Meter Reading & Field Services	($1,239,169)	($6,584,842)	($14,350,634)	($19,340,635)	($23,014,319)	**($64,529,599)**
Regulatory Assets						
AMI Implementation Expenses	$2,813,123	$9,318,266	$9,872,211	$8,246,052	$6,517,816	$36,767,468
Remaining Net Book Value - Retired & Replaced Meters						26,839,963
AFUDC - Equity (WACC>FERC)	491,148	1,319,142	2,092,413	2,996,005	2,307,961	9,206,669
AFUDC - Debt (WACC > FERC)	137,427	354,337	525,490	670,483	438,499	2,126,237
	$3,441,699	$10,991,745	$12,490,114	$11,912,539	$9,264,276	**$74,940,337**
ADIT - Retired & Replaced Meters						($7,689,221)
ADIT - AMI Placed In Service For Income Tax Purposes						($37,961,090)
Total AMI Capitalization						**$316,827,920**
Assumptions and Information						
Implementation Start Date (w/ 3 month mobilization)	7/1/2021					
Implementation Completion Date	3/31/2026					
Return on Equity	10.00%					
Average Cost of Debt	4.02%					
Capital Structure	53:47					
Income Tax Rate	24.95%					
Blended Property Tax Rate	1.68%	1.73%	1.76%	1.78%	1.76%	
AFUDC Average Equity Rate (FERC)	2.91%	3.59%	4.03%	4.07%	4.27%	
AFUDC Average Debt Rate (FERC)	1.19%	1.40%	1.54%	1.58%	1.66%	
AFUDC Average Equity Rate (WACC)	5.34%	5.34%	5.34%	5.34%	5.34%	
AFUDC Average Debt Rate (WACC)	1.87%	1.87%	1.87%	1.87%	1.87%	
Monthly Average CWIP Balance	$20,175,236	$75,204,178	$158,787,752	$235,375,245	$287,269,827	
Beginning of Year CWIP Subject to Prop Tax (2022-2026)	$2,862,193	$36,288,871	$106,448,277	$179,129,297	$245,625,983	

LG&E and KU
AMI Project Ratemaking
Post-Implementation
Before Regulatory Asset and Liability Amortization
$ Millions

	7/1/26 to 6/30/27	7/1/27 to 6/30/28	7/1/28 to 6/30/29	7/1/29 to 6/30/30	7/1/30 to 6/30/31	7/1/31 to 6/30/32	7/1/32 to 6/30/33	7/1/33 to 6/30/34	7/1/34 to 6/30/35	7/1/35 to 6/30/36	7/1/36 to 6/30/37	7/1/37 to 6/30/38	7/1/38 to 6/30/39	7/1/39 to 6/30/40	7/1/40 to 6/30/41
AMI Case															
Cost of Capital	$26.4	$24.2	$22.3	$20.5	$18.6	$16.8	$15.0	$13.4	$12.0	$10.7	$9.3	$8.2	$8.3	$9.9	$11.9
Depreciation - Meters	17.0	17.1	17.2	17.4	17.5	17.7	17.9	18.2	18.4	18.7	19.1	19.7	21.3	24.2	22.5
Depreciation - Systems, Networks, Other	7.0	7.2	7.5	7.9	8.0	7.6	7.5	7.4	7.3	7.5	7.8	7.8	7.7	7.6	5.6
Meter Reading	0.6	0.5	0.5	0.5	0.6	0.6	0.6	0.6	0.6	0.6	0.7	0.7	0.7	0.7	0.7
Field Services	10.1	10.4	10.7	11.0	11.3	11.6	11.9	12.3	12.6	13.0	13.4	13.7	14.1	14.5	15.0
Electric Distribution Savings	(0.2)	(0.2)	(0.2)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)
Fuel Savings	(2.6)	(3.5)	(4.4)	(5.4)	(5.9)	(6.0)	(6.2)	(6.2)	(6.2)	(6.3)	(6.2)	(6.0)	(6.0)	(6.1)	(6.2)
Ongoing Costs (Meters, Network, Systems)	3.5	3.6	3.6	3.7	3.8	3.9	4.0	4.1	4.2	4.3	4.4	4.5	4.6	4.7	4.8
Property Taxes	2.3	4.4	4.1	3.8	3.5	3.3	3.0	2.7	2.4	2.2	1.9	1.6	1.5	1.7	2.1
Regulatory Asset Amortization															
Regulatory Liability Amortization															
	$64.1	$63.7	$61.4	$59.3	$57.2	$55.2	$53.5	$52.1	$51.1	$50.4	$49.9	$49.9	$51.8	$57.0	$56.1
Status Quo Case															
Cost of Capital - Existing Meters	$1.8	$1.7	$1.5	$1.3	$1.2	$1.0	$0.9	$0.7	$0.6	$0.5	$0.4	$0.3	$0.2	$0.1	$0.1
Depreciation - Existing Meters	2.7	2.6	2.5	2.4	2.2	2.1	2.0	1.9	1.8	1.7	1.6	1.5	1.4	0.7	0.3
Revenue Requirement - New Meters	3.5	4.1	4.7	5.3	6.0	6.7	7.4	8.0	8.7	9.4	10.0	10.4	10.8	11.1	11.5
Revenue Requirement - Voltage Meters	1.0	1.2	1.4	1.6	1.8	2.0	2.0	1.9	1.8	1.8	1.7	1.6	1.6	1.5	1.5
Revenue Requirement - Handhelds and MAM	0.9	0.7	0.6	0.9	1.1	1.0	1.0	0.8	0.7	1.0	1.2	1.2	1.1	0.9	0.6
Revenue Requirement - Other	1.8	1.8	1.7	1.6	1.5	1.4	1.3	1.3	1.2	1.1	1.0	1.0	0.9	0.8	0.5
Meter Reading	21.6	22.3	22.9	23.6	24.3	25.0	25.7	26.5	27.2	28.0	28.9	29.7	30.5	31.4	32.3
Field Services	16.8	17.2	17.7	18.3	18.8	19.3	19.9	20.5	21.1	21.7	22.3	22.9	23.6	24.2	24.9
Property Taxes - Existing Meters	0.5	0.5	0.4	0.4	0.3	0.3	0.2	0.2	0.2	0.2	0.1	0.1	0.1	0.0	0.0
	$50.7	$52.1	$53.5	$55.4	$57.2	$58.9	$60.4	$61.8	$63.3	$65.3	$67.2	$68.7	$70.2	$70.9	$71.8
AMI Greater (Less) Than Status Quo	**$13.4**	**$11.6**	**$7.8**	**$3.9**	**$0.0**	**($3.7)**	**($7.0)**	**($9.6)**	**($12.2)**	**($14.9)**	**($17.3)**	**($18.8)**	**($18.3)**	**($13.9)**	**($15.7)**

Assumptions Throughout All Scenarios:

Depreciable Life - Systems Implementation, Network	15 years	
Depreciable Life - IT Hardware and System Upgrades	5 years	(also includes handhelds, mobile collectors)
ROE	10.00%	
Cost of Debt	4.02%	
Tax Rate	24.95%	
Capital Structure	53:47	

LG&E and KU
AMI Project Ratemaking
Post-Implementation
15-Year Meter Life
$ Millions

	7/1/26 to 6/30/27	7/1/27 to 6/30/28	7/1/28 to 6/30/29	7/1/29 to 6/30/30	7/1/30 to 6/30/31	7/1/31 to 6/30/32	7/1/32 to 6/30/33	7/1/33 to 6/30/34	7/1/34 to 6/30/35	7/1/35 to 6/30/36	7/1/36 to 6/30/37	7/1/37 to 6/30/38	7/1/38 to 6/30/39	7/1/39 to 6/30/40	7/1/40 to 6/30/41
AMI Case															
Cost of Capital	$27.1	$26.1	$25.4	$24.4	$23.2	$21.7	$20.0	$18.2	$16.3	$14.3	$12.2	$10.3	$9.7	$10.7	$12.0
Depreciation - Meters	17.0	17.1	17.2	17.4	17.5	17.7	17.9	18.2	18.4	18.7	19.1	19.7	21.3	24.2	22.5
Depreciation - Systems, Networks, Other	7.0	7.2	7.5	7.9	8.0	7.6	7.5	7.4	7.3	7.5	7.8	7.8	7.7	7.6	5.6
Meter Reading	0.6	0.5	0.5	0.5	0.6	0.6	0.6	0.6	0.6	0.6	0.7	0.7	0.7	0.7	0.7
Field Services	10.1	10.4	10.7	11.0	11.3	11.6	11.9	12.3	12.6	13.0	13.4	13.7	14.1	14.5	15.0
Electric Distribution Savings	(0.2)	(0.2)	(0.2)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)
Fuel Savings	(2.6)	(3.5)	(4.4)	(5.4)	(5.9)	(6.0)	(6.2)	(6.2)	(6.2)	(6.3)	(6.2)	(6.0)	(6.0)	(6.1)	(6.2)
Ongoing Costs (Meters, Network, Systems)	3.5	3.6	3.6	3.7	3.8	3.9	4.0	4.1	4.2	4.3	4.4	4.5	4.6	4.7	4.8
Property Taxes	2.3	4.4	4.1	3.8	3.5	3.3	3.0	2.7	2.4	2.2	1.9	1.6	1.5	1.7	2.1
Regulatory Asset Amortization						12.7	2.0	4.9	7.9	11.3	7.2	7.2	7.2	7.2	7.2
Regulatory Liability Amortization	(14.0)	(13.5)	(10.8)	(7.8)	(4.5)	(13.9)									
	$50.7	$52.1	$53.6	$55.4	$57.2	$58.9	$60.4	$61.8	$63.3	$65.4	$60.0	$59.3	$60.5	$65.0	$63.4
Status Quo Case															
Cost of Capital - Existing Meters	$1.8	$1.7	$1.5	$1.3	$1.2	$1.0	$0.9	$0.7	$0.6	$0.5	$0.4	$0.3	$0.2	$0.1	$0.1
Depreciation - Existing Meters	2.7	2.6	2.5	2.4	2.2	2.1	2.0	1.9	1.8	1.7	1.6	1.5	1.4	0.7	0.3
Revenue Requirement - New Meters	3.5	4.1	4.7	5.3	6.0	6.7	7.4	8.0	8.7	9.4	10.0	10.4	10.8	11.1	11.5
Revenue Requirement - Voltage Meters	1.0	1.2	1.4	1.6	1.8	2.0	2.0	1.9	1.8	1.8	1.7	1.6	1.6	1.5	1.5
Revenue Requirement - Handhelds and MAM	0.9	0.7	0.6	0.9	1.1	1.0	1.0	0.8	0.7	1.0	1.2	1.2	1.1	0.9	0.6
Revenue Requirement - Other	1.8	1.8	1.7	1.6	1.5	1.4	1.3	1.3	1.2	1.1	1.0	1.0	0.9	0.8	0.5
Meter Reading	21.6	22.3	22.9	23.6	24.3	25.0	25.7	26.5	27.2	28.0	28.9	29.7	30.5	31.4	32.3
Field Services	16.8	17.2	17.7	18.3	18.8	19.3	19.9	20.5	21.1	21.7	22.3	22.9	23.6	24.2	24.9
Property Taxes - Existing Meters	0.5	0.5	0.4	0.4	0.3	0.3	0.2	0.2	0.2	0.2	0.1	0.1	0.1	0.0	0.0
	$50.7	$52.1	$53.5	$55.4	$57.2	$58.9	$60.4	$61.8	$63.3	$65.3	$67.2	$68.7	$70.2	$70.9	$71.8
AMI Greater (Less) Than Status Quo	**$0.0**	**($0.0)**	**$0.0**	**($0.0)**	**$0.0**	**($0.0)**	**($0.0)**	**$0.0**	**$0.0**	**$0.0**	**($7.2)**	**($9.4)**	**($9.6)**	**($5.9)**	**($8.4)**

LG&E and KU
AMI Project Ratemaking
Post-Implementation
20-Year Meter Life
$ Millions

	7/1/26 to 6/30/27	7/1/27 to 6/30/28	7/1/28 to 6/30/29	7/1/29 to 6/30/30	7/1/30 to 6/30/31	7/1/31 to 6/30/32	7/1/32 to 6/30/33	7/1/33 to 6/30/34	7/1/34 to 6/30/35	7/1/35 to 6/30/36	7/1/36 to 6/30/37	7/1/37 to 6/30/38	7/1/38 to 6/30/39	7/1/39 to 6/30/40	7/1/40 to 6/30/41	7/1/41 to 6/30/42	7/1/42 to 6/30/43	7/1/43 to 6/30/44	7/1/44 to 6/30/45	7/1/45 to 6/30/46
AMI Case																				
Cost of Capital	$27.2	$26.4	$25.8	$25.0	$23.9	$22.8	$21.4	$20.0	$18.6	$17.1	$15.5	$14.2	$12.8	$11.6	$10.7	$10.1	$9.9	$10.2	$10.7	$11.1
Depreciation - Meters	12.8	12.9	12.9	13.0	13.2	13.3	13.4	13.6	13.8	14.1	14.3	14.6	15.0	15.4	15.9	16.4	17.3	18.5	19.9	17.6
Depreciation - Systems, Networks, Other	7.0	7.2	7.5	7.9	8.0	7.6	7.5	7.4	7.3	7.5	7.8	7.8	7.7	7.6	5.6	1.4	1.7	1.7	1.6	1.4
Meter Reading	0.6	0.5	0.5	0.5	0.6	0.6	0.6	0.6	0.6	0.6	0.7	0.7	0.7	0.7	0.7	0.7	0.8	0.8	0.8	0.8
Field Services	10.1	10.4	10.7	11.0	11.3	11.6	11.9	12.3	12.6	13.0	13.4	13.7	14.1	14.5	15.0	15.4	15.8	16.3	16.7	17.2
Electric Distribution Savings	(0.2)	(0.2)	(0.2)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)
Fuel Savings	(2.6)	(3.5)	(4.4)	(5.4)	(5.9)	(6.0)	(6.2)	(6.2)	(6.2)	(6.3)	(6.2)	(6.0)	(6.0)	(6.1)	(6.2)	(6.2)	(6.3)	(6.5)	(6.6)	(6.8)
Ongoing Costs (Meters, Network, Systems)	3.5	3.6	3.6	3.7	3.8	3.9	4.0	4.1	4.2	4.3	4.4	4.5	4.6	4.7	4.8	5.0	5.1	5.2	5.3	5.5
Property Taxes	2.3	4.5	4.3	4.1	3.9	3.7	3.5	3.3	3.1	2.9	2.7	2.5	2.3	2.2	2.1	1.9	1.9	2.0	2.1	2.3
Regulatory Asset Amortization						20.4	1.4	3.6	5.9	8.6	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5
Regulatory Liability Amortization	(11.7)	(11.5)	(9.2)	(6.6)	(3.9)	(21.6)														
	$49.0	$50.2	$51.5	$53.1	$54.6	$55.9	$57.3	$58.3	$59.6	$61.5	$55.7	$55.2	$54.4	$53.8	$51.7	$47.9	$49.2	$51.4	$53.6	$52.3
Status Quo Case																				
Cost of Capital - Existing Meters	$1.8	$1.7	$1.5	$1.3	$1.2	$1.0	$0.9	$0.7	$0.6	$0.5	$0.4	$0.3	$0.2	$0.1	$0.1	$0.1	$0.1	$0.0	$0.0	$0.0
Depreciation - Existing Meters	2.7	2.6	2.5	2.4	2.2	2.1	2.0	1.9	1.8	1.7	1.6	1.5	1.4	0.7	0.3	0.3	0.3	0.2	0.2	0.2
Revenue Requirement - New Meters	2.0	2.3	2.7	3.1	3.5	3.9	4.3	4.7	5.1	5.5	5.9	6.3	6.8	7.2	7.7	8.1	8.5	8.8	9.2	9.6
Revenue Requirement - Voltage Meters	1.0	1.2	1.4	1.6	1.8	2.0	2.0	1.9	1.8	1.8	1.7	1.6	1.6	1.5	1.5	1.4	1.3	1.2	1.1	1.0
Revenue Requirement - Handhelds and MAM	0.9	0.7	0.6	0.9	1.1	1.0	1.0	0.8	0.7	1.0	1.2	1.2	1.1	0.9	0.8	1.2	1.4	1.3	1.2	1.0
Revenue Requirement - Other	1.7	1.6	1.5	1.5	1.4	1.3	1.3	1.2	1.1	1.1	1.0	1.0	0.9	0.9	0.8	0.8	0.7	0.7	0.6	0.4
Meter Reading	21.6	22.3	22.9	23.6	24.3	25.0	25.7	26.5	27.2	28.0	28.9	29.7	30.5	31.4	32.3	33.3	34.2	35.2	36.2	37.2
Field Services	16.8	17.2	17.7	18.3	18.8	19.3	19.9	20.5	21.1	21.7	22.3	22.9	23.6	24.2	24.9	25.7	26.4	27.1	27.9	28.7
Property Taxes - Existing Meters	0.5	0.5	0.4	0.4	0.3	0.3	0.2	0.2	0.2	0.2	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	$49.0	$50.2	$51.4	$53.1	$54.6	$55.9	$57.2	$58.3	$59.6	$61.4	$63.1	$64.6	$66.2	$67.1	$68.5	$70.8	$72.9	$74.6	$76.5	$77.9
AMI Greater (Less) Than Status Quo	**($0.0)**	**($0.0)**	**$0.0**	**$0.0**	**$0.0**	**($0.0)**	**$0.0**	**($0.0)**	**($0.0)**	**$0.0**	**($7.4)**	**($9.4)**	**($11.8)**	**($13.3)**	**($16.8)**	**($22.9)**	**($23.7)**	**($23.3)**	**($22.8)**	**($25.6)**

LG&E and KU
AMI Project Ratemaking
Post-Implementation
Support: Capitalization Rollforward

$ Millions	7/1/26 to 6/30/27	7/1/27 to 6/30/28	7/1/28 to 6/30/29	7/1/29 to 6/30/30	7/1/30 to 6/30/31	7/1/31 to 6/30/32	7/1/32 to 6/30/33	7/1/33 to 6/30/34	7/1/34 to 6/30/35	7/1/35 to 6/30/36	7/1/36 to 6/30/37	7/1/37 to 6/30/38	7/1/38 to 6/30/39	7/1/39 to 6/30/40	7/1/40 to 6/30/41	7/1/41 to 6/30/42	7/1/42 to 6/30/43	7/1/43 to 6/30/44	7/1/44 to 6/30/45	7/1/45 to 6/30/46
Before Regulatory Asset (Liability) Amortization																				
Beginning Balance	$308.4	$282.7	$259.3	$238.7	$218.8	$198.0	$177.7	$158.6	$140.9	$126.1	$112.0	$96.9	$89.6	$100.8	$121.0					
Capital Additions	2.0	2.5	4.2	4.6	3.4	3.4	4.0	4.8	6.9	7.6	6.8	15.4	35.9	48.7	51.3					
Depreciation - Meters	(17.0)	(17.1)	(17.2)	(17.4)	(17.5)	(17.7)	(17.9)	(18.2)	(18.4)	(18.7)	(19.1)	(19.7)	(21.3)	(24.2)	(22.5)					
Depreciation - Systems, Networks, Other	(7.0)	(7.2)	(7.5)	(7.9)	(8.0)	(7.6)	(7.5)	(7.4)	(7.3)	(7.5)	(7.8)	(7.8)	(7.7)	(7.6)	(5.6)					
Change in ADIT	(3.7)	(1.6)	(0.1)	0.9	1.3	1.7	2.2	3.1	3.9	4.6	4.9	4.8	4.2	3.3	0.8					
Regulatory Asset Amortization																				
Regulatory Liability Amortization																				
Reversal of ADIT - Retired & Replaced Meters																				
Ending Balance	$282.7	$259.3	$238.7	$218.8	$198.0	$177.7	$158.6	$140.9	$126.1	$112.0	$96.9	$89.6	$100.8	$121.0	$145.1					
13-Month Average Balance	$295.2	$270.9	$249.6	$229.3	$208.1	$187.6	$167.7	$149.5	$134.2	$119.6	$104.1	$91.2	$92.3	$111.1	$132.6					
15-Year Meter Life																				
Beginning Balance	$308.4	$296.7	$286.8	$277.0	$264.9	$248.6	$230.9	$209.9	$187.9	$165.9	$141.7	$120.1	$106.3	$111.0	$124.8					
Capital Additions	2.0	2.5	4.2	4.6	3.4	3.4	4.0	4.8	6.9	7.6	6.8	15.4	35.9	48.7	51.3					
Depreciation - Meters	(17.0)	(17.1)	(17.2)	(17.4)	(17.5)	(17.7)	(17.9)	(18.2)	(18.4)	(18.7)	(19.1)	(19.7)	(21.3)	(24.2)	(22.5)					
Depreciation - Systems, Networks, Other	(7.0)	(7.2)	(7.5)	(7.9)	(8.0)	(7.6)	(7.5)	(7.4)	(7.3)	(7.5)	(7.8)	(7.8)	(7.7)	(7.6)	(5.6)					
Change in ADIT	(3.7)	(1.6)	(0.1)	0.9	1.3	1.7	2.2	3.1	3.9	4.6	4.9	4.8	4.2	3.3	0.8					
Regulatory Asset Amortization	0.0	0.0	0.0	0.0	0.0	(12.7)	(2.0)	(4.9)	(7.9)	(11.3)	(7.2)	(7.2)	(7.2)	(7.2)	(7.2)					
Regulatory Liability Amortization	14.0	13.5	10.8	7.8	4.5	13.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0					
Reversal of ADIT - Retired & Replaced Meters						1.3	0.2	0.5	0.8	1.2	0.7	0.7	0.7	0.7	0.7					
Ending Balance	$296.7	$286.8	$277.0	$264.9	$248.6	$230.9	$209.9	$187.9	$165.9	$141.7	$120.1	$106.3	$111.0	$124.8	$142.4					
13-Month Average Balance	$302.3	$292.0	$283.4	$273.0	$258.8	$242.4	$223.4	$202.9	$182.6	$160.3	$136.2	$115.6	$108.9	$120.0	$133.7					
20-Year Meter Life																				
Beginning Balance	$310.0	$299.2	$290.4	$282.3	$272.3	$258.7	$245.1	$228.0	$210.5	$193.9	$175.6	$160.7	$145.9	$132.2	$119.7	$111.2	$108.7	$110.5	$116.0	$122.1
Capital Additions	2.0	2.5	4.2	4.6	3.4	3.3	4.0	4.8	6.9	7.6	6.5	7.0	8.3	9.9	13.1	16.6	22.2	27.6	29.8	26.3
Depreciation - Meters	(12.8)	(12.9)	(12.9)	(13.0)	(13.2)	(13.3)	(13.4)	(13.6)	(13.8)	(14.1)	(14.3)	(14.6)	(15.0)	(15.4)	(15.9)	(16.4)	(17.3)	(18.5)	(19.9)	(17.6)
Depreciation - Systems, Networks, Other	(7.0)	(7.2)	(7.5)	(7.9)	(8.0)	(7.6)	(7.5)	(7.4)	(7.3)	(7.5)	(7.8)	(7.8)	(7.7)	(7.6)	(5.6)	(1.4)	(1.7)	(1.7)	(1.6)	(1.4)
Change in ADIT	(4.7)	(2.7)	(1.1)	(0.2)	0.3	0.6	1.1	2.0	2.8	3.5	3.8	3.9	3.8	3.7	3.1	1.9	1.7	1.3	0.9	(0.2)
Regulatory Asset Amortization	0.0	0.0	0.0	0.0	0.0	(20.4)	(1.4)	(3.6)	(5.9)	(8.6)	(3.5)	(3.5)	(3.5)	(3.5)	(3.5)	(3.5)	(3.5)	(3.5)	(3.5)	(3.5)
Regulatory Liability Amortization	11.7	11.5	9.2	6.6	3.9	21.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Reversal of ADIT - Retired & Replaced Meters						2.1	0.1	0.4	0.6	0.9	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Ending Balance	$299.2	$290.4	$282.3	$272.3	$258.7	$245.1	$228.0	$210.5	$193.9	$175.6	$160.7	$145.9	$132.2	$119.7	$111.2	$108.7	$110.5	$116.0	$122.1	$126.0
13-Month Average Balance	$304.3	$294.9	$287.7	$279.2	$267.3	$254.3	$239.3	$223.1	$207.7	$191.0	$173.6	$158.2	$143.1	$129.7	$119.2	$112.9	$110.4	$114.5	$119.4	$124.5

Stub Period (4/1/26-6/30/26) Activity:	**15-Year**	**20-Year**
AMI Capitalization at Implementation:	$316.8	$317.5
Capital Additions	0.4	0.4
Depreciation	(7.0)	(5.8)
Change in ADIT	(1.8)	(2.1)
AMI Capitalization 6/30/26	$308.4	$310.0

Difference is due to the book depreciable life of meters and assumed replacement of existing AMI meters during implementation period.

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, 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**

In the Matter of:

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**

TESTIMONY OF
LONNIE E. BELLAR
CHIEF OPERATING OFFICER
KENTUCKY UTILITIES COMPANY AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Filed: November 25, 2020

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I. BACKGROUND

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

A. My name is Lonnie E. Bellar. I am the Chief Operating Officer 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 220 West Main Street, Louisville, Kentucky 40202.

Q. Please describe your educational and professional background.

A. A complete statement of my work experience and education is contained in the Appendix attached hereto.

Q. Please briefly describe your professional history with the Companies.

A. My career with the Companies dates back to 1987, when I started as an electrical engineer with KU's generation system planning group. From there, I served in various management positions within generation planning and generation services, financial planning and controlling, and electric transmission. In 2007 I was promoted to Vice President, State Regulation and Rates, and from 2013 to early 2017 I served as Vice Present, Gas Distribution. In January 2017, I was promoted to Senior Vice President of Operations. I served in that position until I was promoted to Chief Operating Officer ("COO") in March 2018.

Q. Please describe your area of responsibility for the Companies.

A. As COO, I am responsible for oversight and direction of all operational areas of the Companies' business, including power generation, energy supply and analysis, electric distribution and transmission, gas transmission, distribution and storage, safety, environmental and customer services. I report directly to Paul Thompson, the Companies' President and CEO.

Q. Have you previously testified before the Kentucky Public Service Commission ("Commission")?

A. Yes. I have testified in numerous proceedings before the Commission. Most recently, I testified earlier this year on behalf of the Companies in support of their request for approval of a solar power contract and two renewable power agreements under the Companies' green tariff.[1] I also testified as COO in KU's and LG&E's 2018 base rate cases and as Vice President, Gas Distribution in LG&E's 2016 base rate case.[2]

Q. What changes in the Companies' operational management have been made since the 2018 base rate cases?

A. While the Companies' chief-level management team remains the same as in the 2018 base rate cases, there have been a number of management changes at the Vice President and Director levels on the operational side of the business. In January 2020, Tom Jessee, formerly the Vice President – Transmission, assumed the role of Vice President – Gas Operations upon the retirement of John Malloy, who formerly held that position. At the same time, Beth McFarland transitioned from her role as Vice President – Customer Services to become Vice President – Transmission. Eileen Saunders was promoted to the role of Vice President – Customer Services. Amanda Chambers filled Ms. Saunders' former role as Director of Safety & Technical Training. Steven Turner,

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[1] *Electronic Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for Approval of a Solar Power Contract and Two Renewable Power Agreements to Satisfy Customer Requests for a Renewable Energy Source Under Green Tariff Option 3*, Case No. 2020-00016, Joint Testimony of Lonnie E. Bellar, Christopher M. Garrett, and Robert M. Conroy (Ky. PSC Sep. 18, 2020).

[2] *Electronic Application of Kentucky Utilities Company for an Adjustment of Its Rates*, Case No. 2018-00294, Testimony of Lonnie E. Bellar (Ky. PSC Sep. 28, 2018); *Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Rates,* Case No. 2018-00295, Testimony of Lonnie E. Bellar (Ky. PSC Sep. 28, 2018). *Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Rates and for Certificates of Public Convenience and Necessity,* Case No. 2016-00371, Testimony of Lonnie E. Bellar (Ky. PSC Nov. 23, 2016).

a former general manager of the Ghent Generating Station, was promoted in 2020 to Vice President – Power Production upon the retirement of Ralph Bowling. These five individuals report directly to me in their new roles.

Q. Who are your other direct reports?

A. In addition to the five individuals who assumed new management roles in 2020 discussed above, three other members of our management team report directly to me in the same roles they held in 2018: John Wolfe, Vice President – Electric Distribution, David Sinclair, Vice President, Energy Supply and Analysis, and Gary Revlett, Director, Environmental Affairs.

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring Exhibits 1-5 attached to the Companies' Applications which are required to support of the Companies' request for a certificate of public convenience and necessity for advance metering infrastructure. I am also sponsoring the following exhibits, which are attached to my testimony:

Exhibit LEB-1 Generation Portfolio

Exhibit LEB-2 Analysis of Generating Unit Retirement Years

Exhibit LEB-3 Analysis of Metering Alternatives

Exhibit LEB-4 Smart Grid Investment Summary

II. OVERVIEW

Q. What is the purpose of your testimony in this case?

A. I will provide an overview of the Companies' operations and describe how the Companies are investing in energy production and delivery to ensure that customers receive safe, reliable, and reasonably priced electric and gas service now and long into the future. I will describe the Companies' operational performance using objective metrics. I will describe how the Companies are facing cost increases across all operational functions, but also how the Companies are committed to efficiency programs to manage those costs. I will also provide operational context and analytical support for the Companies' request for approval of full deployment of Advanced Metering Infrastructure ("AMI").

Q. Are the Companies' operations performing safely?

A. Safety is our first priority above all others. This value is pervasive within the Companies' culture. Recordable safety metrics demonstrate that the Companies' safety culture actually translates into safer work and increased safety for employees, contractors, and the public. Recordable Injury Incident Rate ("RIIR") measures the rate of recordable injuries per 200,000 employee hours worked. For 2020 year to date through September, total operations employee RIIR is just 1.21, or a total of 26 recordable injuries over the more than 4.3 million employee hours worked. For contractors, the RIIR was just 1.25 through September 2020, compared to a target of 1.45, meaning that recordable injuries to contractors are occurring at a rate well below the Companies' target. For reference, the national general industrial contractor average RIIR as reported by 2018 Bureau of Labor Statistics data is 3.4.

Days Away/Restricted/Transferred ("DART") rate tracks the rate of injuries resulting in a day away, restricted duty or transferred status over 200,000 hours worked. The DART rate for operations employees is 0.70 for 2020 year-to-date through September and was 0.63 for all of 2019. This is below the industry average DART as tracked by Edison Electric Institute (EEI) for 2019. The consistently outstanding performance of the Companies' employees and contractors in recordable incident and DART rates is a testament to the Companies' steadfast commitment to safe work.

Q. How are the Companies' operations performing overall?

A. Exceptionally well. In addition to operating safely, the Companies have demonstrated sustained excellence in all areas of operations. Generation reliability is at historically high levels in 2020 and has been trending that way for the past several years. The Companies are seeing their significant investments in modernizing transmission infrastructure and improving transmission reliability over the past several years begin to yield measurable reliability benefits, particularly at the circuit level. Investments in centralized grid operations, smart grid technology, and distribution automation are positioning the Companies' electric distribution operations extremely well for a technology-driven future. Customer satisfaction continues to be reported at very high levels and the Companies have been recognized for their achievements in that area. Finally, LG&E's gas operations are performing safely and efficiently, and targeted capital investments are being made in gas infrastructure to ensure future demand is reliably served.

Q. Please describe the Companies' operational technology cybersecurity initiative.

A. Certainly. The Companies have devoted significant resources to assessing potential cybersecurity vulnerabilities with their operational technology infrastructure and are developing a plan for mitigating those vulnerabilities. By identifying these risks and planning security around them, the Companies expect to achieve a more connected operational technology system across operational functions while ensuring that these systems and assets are not prone to malicious cyberattacks. In furtherance of this effort, the Companies have identified, assessed, and prioritized various threats to connected infrastructure, including ransomware, malware, phishing schemes, and vendor security flaws, and developed specific incremental processes to mitigate those risks. Security controls and access will be standardized across all operational business units. Implementation of the cybersecurity plan is scheduled to begin in 2021.

III. ELECTRIC GENERATION

Generation Portfolio and Performance

Q. Please describe the Companies' generation systems.

A. Generation output is jointly dispatched between KU and LG&E to achieve operational efficiencies. Pursuant to the Companies' *Power Supply System Agreement* filed with the Federal Energy Regulatory Commission ("FERC"), the joint planning objectives of the Companies are to maximize the economy, efficiency, and reliability of their combined systems as a whole. Dispatch of generation, whether from the Companies' own generating plant or from purchased power, is determined by lowest variable operating cost regardless of ownership.

The Companies own and operate approximately 7,561 MW of summer net generating capacity in Kentucky with a net book value of approximately $7.0 billion. The combined Companies serve approximately 958,000 electric customers across a footprint of 79 Kentucky counties.[3] The generating system consists of four coal-fired generating stations: the E.W. Brown Generating Station in Mercer County, the Ghent Generating Station in Carroll County, the Mill Creek Generating Station in Jefferson County, and the Trimble County Generating Station. The Companies own and operate

[3] KU also serves electricity customers in five Virginia counties, doing business as Old Dominion Power Company.

Cane Run Unit 7, a natural gas combined cycle generating unit located in Jefferson County. The Companies also own and operate multiple natural-gas-fired combustion turbines ("CTs"), which supplement the system during peak periods, hydroelectric generating stations at Dix Dam and Ohio Falls, which provide base load supply subject to river and flow constraints, and two solar facilities: the Brown Solar generating plant and the Solar Share array located in Simpsonville. The Companies also purchase power from the Ohio Valley Electric Corporation ("OVEC") through a long-existing *Inter-Company Power Agreement*.[4] A complete list of the Companies' current generating units and associated capacity is attached to my testimony as Exhibit LEB-1.

Q. Are the Companies' generating units performing reliably?

A. Yes, the reliability of the Companies' generation resources over the past few years in particular has been exceptional. Average Equivalent Forced Outage Rate ("EFOR") is a standard industry metric which measures the percentage of steam generation that is unavailable due to forced outages or derates. The Companies' average EFOR for all steam generating units plus the natural gas combined cycle unit (Cane Run 7) for calendar year 2020 through September is just 1.24 percent, a historically low outage level. EFOR was just 2.79 percent for calendar year 2018 and 2.34 percent for calendar year 2019. These outage rates are well below (better than) industry 3-year average first quartile performance for steam generating units as tracked by Reliability First

[4] The Commission approved the Inter-Company Power Agreement between KU and LG&E and OVEC in *Application of Kentucky Utilities Company for an Order Pursuant to KRS 278.300 and for Approval of Long-Term Purchase Contract*, Case No. 2004-00395, Order (Ky. PSC Dec. 30, 2004), and *Application of Louisville Gas & Electric Company for an Order Pursuant to KRS 278.300 and for Approval of Long-Term Purchase Contract*, Case No. 2004-00396, Order (Ky. PSC Dec. 30, 2004).

Corporation, demonstrating sustained excellence in generation reliability in recent years.

CTs are also performing reliably. Because combustion turbines are typically deployed as “peaking” or on-demand units, the startup consistency of these units is critical. Starting reliability measures the percentage of time a CT unit starts when called upon. From 2018 through September 2020, the average starting reliability of the Companies’ CTs has been at or above 97 percent.

Q. What has contributed to the consistently reliable performance of the Companies’ generating units?

A. A number of factors are responsible for the sustained reliability of the Companies’ generating units. Chief among them are carefully planned and coordinated maintenance and outage procedures designed to maximize the operating life of the units and minimize unplanned downtime. Generation has also benefitted from enhanced monitoring technology that can signal a potential problem before it causes an unplanned outage. Targeted reliability programs have also contributed significantly to a reduction in unplanned outages. For example, the Boiler Reliability Program was implemented to maximize the reliability and life of boiler pressure parts through engineering best practices for inspection, repairs, and capital replacements. The emphasis of the program is reducing boiler tube failures through tracking and root cause analysis and detailed outage inspection procedures. The program has resulted in a dramatic decrease in the number of boiler tube failures contributing to EFOR in the past six years, from 38 in 2014 to just 7 in 2019, and 6 for calendar year 2020 through September.

Changes in Economic Lives for Generating Units

Q. Have the Companies evaluated the retirement dates for their generating units?

A. Yes, the Companies have evaluated current retirement dates for their steam generating units and based on that evaluation have determined that the projected remaining economic lives of certain units are no longer reasonable due to changed circumstances. The Companies have further determined new retirement dates are reasonable estimates of the remaining economic lives of these units. The existing and updated retirement dates for affected units are as follows:

	Retirement Year	
Unit	**Current**	**Updated**
Brown 3	2035	2028
Ghent 4	2038	2037
Mill Creek 1	2032	2024
Mill Creek 2	2034	2028
Mill Creek 3	2038	2039
Mill Creek 4	2042	2039
Trimble County 1	2050	2045

Exhibit LEB-2 to my testimony contains the description and results of the study that examined the existing retirement dates for these coal-fired generating units as reflected in existing depreciation rates. The purpose of the study was to examine existing economic lives based on maintaining system reliability to determine whether they are reasonable estimates of the remaining economic lives of generating units due to changes in operational and economic circumstances and, if not, to determine new retirement dates.

Q. What factors were considered in assessing the remaining economic lives of generating units?

A. The Companies' Generation Planning and Analysis function continuously assesses generation resources as part of the Integrated Resources Planning ("IRP") process. When assessing remaining economic life for particular units, the planning process considers a range of factors, including the impact of environmental regulations, fuel price scenarios, the cost of replacement generation, and the risk of catastrophic failures. The analysis also considers existing unit operational costs and major maintenance costs that may be avoided by economic retirements.

Q. What supports the decision to update the projected economic life of Mill Creek Unit 1 to the end of 2024?

A. In its most recent environmental cost recovery ("ECR") Plan and related case, LG&E evaluated the retirement date of Mill Creek Unit 1 in order to determine whether an investment in Effluent Limitations Guidelines ("ELG") water treatment capacity for all four coal-fired units at Mill Creek was cost justified.[5] Mill Creek Units 1 and 2 face significant operating constraints due to possible compliance restrictions imposed by the 2015 National Ambient Air Quality Standards ("NAAQS") for ozone. Neither of these units is equipped with selective catalytic reduction ("SCR") technology to reduce NO_x emissions. Jefferson County, where the Mill Creek Generating Station is located, is currently in marginal non-attainment for ozone levels. As a result, in April 2020, LG&E entered into an enforceable agreement with Louisville Metro Air Pollution

[5] *Electronic Application of Kentucky Utilities Company for Approval of its 2020 Compliance Plan for Recovery by Environmental Surcharge*, Case No. 2020-00060; *Electronic Application of Louisville Gas and Electric Company for Approval of its 2020 Compliance Plan for Recovery by Environmental Surcharge*, Case No. 2020-00061, Direct Testimony of Stuart A. Wilson (Ky. PSC Mar. 31, 2020).

Control District placing a station limit of 15 tons per day of NO_x emissions from Mill Creek station during Ozone season. This agreement and the lack of SCR facilities on Mill Creek 1 and 2 effectively precludes the Companies from operating both of these two units simultaneously in excess of 50 percent capacity from May 1, 2020 to October 31, 2020.[6]

Based on achieved 2020 levels, it is reasonable to expect Jefferson County to be escalated to moderate non-attainment in 2021, resulting in even further restrictions of NO_x emissions at Mill Creek station in 2021 and beyond. Assuming those restrictions continue or increase in severity, the Companies concluded in the ECR case that retirement of Mill Creek 1 at the end of 2024 would be least cost, and that ELG water treatment capacity would not be built to accommodate all four Mill Creek steam generating units operating simultaneously.[7] It will not be necessary given capacity and demand projections to replace Mill Creek 1's production with new generation resources immediately.

Q. What supports the decision to update the remaining economic life of Mill Creek Unit 2 from 2034 to 2028?

A. In order to comply with expected future NAAQS limitations on NO_x emissions, SCR technology would have to be installed on Mill Creek Unit 2 at a capital cost of approximately $135 million by 2028 in order to continue operating the unit beyond 2028. If that capital investment is required to keep Mill Creek Unit 2 operating, then

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[6] *Electronic Application of Louisville Gas and Electric Company for Approval of its 2020 Compliance Plan for Recovery by Environmental Surcharge*, Case No. 2020-00061, Response of Louisville Gas and Electric Company to Commission Staff's Initial Request for Information, No. 6 (Ky. PSC May 6, 2020).

[7] LG&E sized the water treatment system at Mill Creek to treat only 600 gallons per minute (gpm) instead of the 750 gpm that would be required if all four Mill Creek units are operated simultaneously. The 600 gpm could be reduced further if warranted.

retirement of the unit in 2028 is the least cost alternative. Exhibit LEB-2 to my testimony sets forth this analysis in detail.[8]

Q. What supports the decision to update the remaining economic life of Brown Unit 3 from 2035 to 2028?

A. While the projected retirement dates of Mill Creek Units 1 and 2 are largely being driven by environmental regulations, the rationale behind updating the remaining economic life of Brown Unit 3 is largely economic. Under the Companies' current outage and maintenance practices, a major capital investment of $23.1 million and an additional $8 million in O&M costs would be required in 2026 and 2027 to continue operation of Brown Unit 3 through its current retirement year of 2035. Assuming this maintenance occurs, operation of Brown Unit 3 through 2035 is not economic, and 2028 is a more reasonable date given the potential to avoid major maintenance and lower overall revenue requirements with replacement generation by 2028.

Q. Could other capital expenses be avoided by updating projected retirement dates for Mill Creek Units 1 and 2 and Brown Unit 3?

A. Yes. Assuming these three units are retired on the dates identified in Exhibit LEB-2, the Companies could cancel some capital work over their standard five-year planning horizon (2021-2025), resulting in a savings of $17.0 million—savings that are reflected in the Companies' current business plans. Planned investments outside of the 5-year planning period (2026-2028) would have to be assessed against the Capital Evaluation

[8] As suggested by the Commission's September 30, 2020 Order in LG&E's ECR proceeding, LG&E will use all reasonable efforts to delay construction of the water treatment system (ECR Project 31) to satisfy the 2015 ELG Rule facilities at Mill Creek until more is certain about the future of Mill Creek Units 1 and 2. LG&E acknowledges that if it determines in the future that Mill Creek Unit 2 will be scheduled for retirement before 2025 at any point before ECR Project 31 must begin to avoid noncompliance by the December 31, 2025 deadline, then LG&E will need to request a CPCN for a revised Project 31. LG&E will notify the Commission of such a change in the retirement date of Mill Creek Unit 2 within 30 days.

Model ("CEM") as they come into the planning period. However, not all maintenance costs could be avoided. For example, the cooling tower on Mill Creek Unit 2 is being replaced because the current tower is not structurally sound and cannot be safely operated or repaired in a manner that would permit operation of the unit through 2028. Additionally, some expenditures in environmental controls such as replacement catalyst would be required to operate the units within regulatory limits through retirement, but could be managed conservatively to achieve capital expense reductions.

Q. Does the Companies' analysis mean that each affected unit will definitely be retired in the updated year?

A. Not necessarily. The Companies' analysis sets a reasonable end of economic life for the affected generating units based on economics, environmental regulations, planned outage projects and maintenance, and other factors. As each unit nears the end of its expected economic life and replacement capacity must be considered, the Companies will assess the conditions at the time to determine whether adjustments to retirement dates are prudent and in the best interests of customers.

Capital Investment

Q. Please summarize the capital investment the Companies plan to make in their generation operations.

A. The following chart summarizes non-mechanism capital expenses in generation, by company, from November 1, 2019 through December 31, 2021 (in millions):

	KU	**LG&E**	**Total**
Outages for Coal Fired Units	122.6	67.2	189.8
Outages for Combustion Turbines	53.9	20.3	74.2

Generation Reliability	53.7	48.9	102.6
Plant Demolitions	3.4	15.9	19.3
Other	43.3	42.0	85.3
Total:	276.9	194.3	471.2

Q. What generation outage projects involve significant capital investment during the cited time period?

A. As the table above shows, planned outage projects for generating units contribute significantly to overall generation capital spending. For the cited period, there will be significant outage work performed for Brown Unit 7, Cane Run Unit 7, and Trimble County Unit 5.

Brown Unit 7, a combustion turbine, will undergo its first turbine overhaul during the period from November 1, 2019 to December 31, 2021, at a total capital cost of $21.5 million. All turbine and combustor (hot gas path) parts will be exchanged with either new or reconditioned parts to allow the unit to operate until its next scheduled outage. Inspections will be made to components that are to remain in service to determine their condition and suitability for continued use. Various upgrades to ancillary equipment will also be made. Once the inspection is complete, the unit will be released to operate 32,000 equivalent operating hours (EOH) or 1,200 equivalent starts, whichever comes first. The outage is expected to occur in the fall of 2021 and last approximately eight weeks.

Cane Run Unit 7, the Companies' natural gas combined-cycle generating unit, is scheduled to undergo its second combustion inspection in spring of 2022, with an estimated $22.4 million in capital spending between the period from November 1, 2019 through December 31, 2021. This outage will include inspection and cleaning of combustor components, inspection of row 1 turbine blades and vanes, inspection of row 4 blades, inspection of compressor inlet guide vanes and variable guide vanes, and inspection of last row outlet guide vanes.

Starting this month, Trimble County Unit 5, a gas combustion turbine, will undergo a hot gas path inspection at a capital cost of $13.2 million for the period from November 1, 2019 through December 31, 2021. The turbine portion of the work will involve sending all the hot gas path and combustion parts offsite for refurbishment and life extension before being reinstalled in the unit along with a compressor reliability upgrade. The turbine rotor will be sent offsite for refurbishment and life extension along with replacement of six compressor wheels. The generator portion of the work will involve removing the generator rotor to perform a full generator stator re-wedge.

The Companies are also rebuilding the cooling towers on Ghent Units 1 and 4, and, as mentioned above, Mill Creek Unit 2 during outages for these units during the period from November 1, 2019 through December 31, 2021, at a total capital cost during this period of $27.1 million. The scope of the projects includes demolition of the towers, not including the basin, and construction of new towers from fiberglass structural members. Additionally, new fans, motors, variable speed drives (Ghent Units 1 and 4 only), and controls were installed. The fan shrouds and variable speed drives will be reused on Mill Creek Unit 2. These projects were required to address structural concerns with aging towers which were approaching the end of their useful life. Construction of the Ghent Unit 4 tower and initial project milestones for the Ghent Unit

1 tower were achieved in 2020. The Ghent Unit 1 and the Mill Creek Unit 2 towers will be completed in 2021.

Q. What kinds of capital investment are required for generation reliability projects?

A. Compared to planned outages, most generation reliability projects are relatively small, with fewer than twenty such projects exceeding the $1 million capital threshold and none exceeding $4.0 million for the period from November 1, 2019 through December 31, 2021. These minor but numerous projects are critical to the upkeep and continued reliability of the generating fleet. There are nearly 1,200 generation reliability projects identified in the Companies' business plans. These projects include replacement of the coal conveyor concrete flooring panels at Trimble County at a capital cost of $4.0 million, to ensure continued safe and reliable operations of Trimble County Units 1 and 2, and an overhaul of the Ghent Unit 1 number 4 pulverizer gearbox at a capital cost of $0.7M to replace long lead time components that have historically been subject to failure.

Q. What is the status of the Companies' demolition of generating plant?

A. In 2019 the Companies completed demolition of the retired Pineville coal plant at a capital cost of $6.7 million. In 2020 the Companies completed demolition of two additional retired coal plants – Green River in Western Kentucky ($12.8 million) and Tyrone in Central Kentucky ($12 million). These demolition projects will make these sites much safer and eliminate significant long-term costs and potential liabilities associated with maintaining a mothballed retired generating plant.[9] For the same reasons, recently the Companies have substantially completed demolition of all Cane

[9] All of these sites will require ongoing operations and maintenance expense associated with inspections, maintenance of closed impoundments, site security and permits.

Run coal-fired units and Cane Run Unit 11, a gas combustion turbine. All hazardous substances, general demolition debris, and recyclable steel have been removed from the site. The remaining work to be completed involves general site repair and demobilization of trailers and equipment. This work creates valuable brown field space for possible development at Cane Run station in the future. The Companies have also selected a contractor and have commenced work on a project to abate, demolish, and restore the site for the Canal Generating Station, a retired coal plant in Louisville. This project is expected to be substantially complete by the end of 2021. Total capital costs for demolition of generating plant included in the period from November 1, 2019 to December 31, 2021 are expected to be $19.3 million.

RTO Analysis and SEEM Initiative

Q. Have the Companies continued to evaluate whether Regional Transmission Organization ("RTO") membership would benefit their customers?

A. They have. The results for analyses performed to date do not support RTO membership. In the Companies' 2018 base rate applications, I sponsored an RTO analysis attached to my testimony therein, which concluded that the benefits of RTO membership did not at the time offset the costs, were too uncertain, and were too dependent on external factors to offset a loss of control of the Companies' operations.[10] In the final Orders entered into those cases, the Commission required the Companies to file an update of the 2018 RTO study as part of its annual report to the Commission.[11]

[10] Case No. 2018-00294, Testimony of Lonnie E. Bellar, Exhibit LEB-2 (Ky. PSC Sep. 28, 2018); Case No. 2018-00295, Testimony of Lonnie E. Bellar, Exhibit LEB-2 (Ky. PSC Sep. 28, 2018).
[11] Case No. 2018-00294, Final Order at 31 (Ky. PSC Apr. 30, 2019).

In compliance with this Order, an update was filed with the Companies' annual report in March 2020.[12]

Q. What did the 2020 RTO update report conclude?

A. Much like the original 2018 report, the 2020 RTO Membership Analysis concluded that "the costs and uncertainties of membership in either MISO or PJM continue to exceed the known potential benefits."[13] However, the Companies also stated that "[c]onsidering the continuing evolution of the RTOs, their markets, and membership, it would be prudent to continue to monitor and study the RTOs to see how market dynamics and uncertainties evolve over time."[14]

Q. Do the Companies still hold the view that conducting periodic analysis of RTO membership would be beneficial?

A. Yes, but they request to file the next study as part of their IRP in 2021. The integrated resource planning process and RTO analysis contain many common inputs and analyses and it would be more efficient for the Companies to complete these requirements together at the time of IRP filing, as opposed to filing an updated RTO analysis annually under the Commission's current Order.

Q. What is the Southeast Energy Exchange Market?

A. The Southeast Energy Exchange Market, known as SEEM, is a regional, automated intra-hour market concept, with the goal of sub-hourly trading (fifteen-minute increments) between SEEM participants utilizing leftover transmission to achieve cost savings within the region.

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[12] *E.g.*, Case No. 2018-00294, 2020 RTO Membership Analysis filed in POST Case Files (Ky. PSC Mar. 31, 2020).
[13] *Id.* at 4.
[14] *Id.* at 23.

Q. Is SEEM an RTO?

A. No. The SEEM concept is a platform to supplement a process that the Companies already use to trade with other utilities and wholesale market participants on a bilateral, hourly basis to purchase economy energy and sell excess energy. Unlike in an RTO, SEEM members would not cede control over their generation and transmission assets or investment decisions to a third-party. Each SEEM transmission provider would remain independent with its own transmission tariff. Also, membership and subsequent day-to-day and hour-to-hour participation in the SEEM market are purely voluntary. Thus it is anticipated there will be very low barriers and cost to exit SEEM membership if an exit is determined to be in the best interests of our customers.

Q. Have the Companies been involved in discussions about the formation of SEEM?

A. Yes, the Companies have participated in discussions and planning about the formation of SEEM, along with many other electric utilities in the region, including Associated Electric Cooperative, Duke Energy, Southern Company, Tennessee Valley Authority, Dominion Energy South Carolina, Santee Cooper, Oglethorpe Power, and Georgia Transmission.

Q. How would ratepayers benefit from the Companies' participation in SEEM?

A. Participation in SEEM would allow the Companies to efficiently and cost-effectively supplement existing day ahead and hour-ahead bilateral transactions with sub-hourly trading opportunities. Off-system energy sold by the Companies is 75 percent attributable to customers based on the existing Off-System Sales tracker mechanism, while economy purchases lower customer cost of energy.

Q. What are the costs associated with the Companies' participation in SEEM?

A. Participation in SEEM is expected to involve some relatively small startup costs associated with FERC approval and creation of a trading platform, which the Companies expect would be recovered within one year of participation in the market. SEEM members would also be expected to pay an allocated share of annual operating costs to maintain the trading platform and administer the market. There would also be some costs associated with training the Companies' own employees to use the platform.

Q. Would the benefits of the Companies' participation in SEEM outweigh the costs?

A. Based on the preliminary information available to the Companies currently, participation in SEEM would be favorable to the Companies and ratepayers insofar as expected benefits would significantly outweigh the costs to participate. Further, with few anticipated barriers to exit, the risk of participating, should the economics not be as expected, is quite low. The Companies are continuing to assess possible costs and benefits of participation in SEEM as more information becomes available.

Q. What is the current status of SEEM formation?

A. SEEM members are currently developing applicable regulatory filings, including revisions to relevant Open Access Transmission Tariff language, to be filed with the Federal Energy Regulatory Commission sometime in late 2020 or early 2021. In addition, requests for proposals will be issued for the development of the trading platform, administrator, and auditor.

Q. Would participation in SEEM have any significant operational impact on the Companies?

A. Participation in the market would require use of a new energy trading platform, but is not expected to cause any major changes to current generation or transmission operations. Trading in the market would be handled by the Companies' existing power supply trading function, with no new headcount expected.

Increasing Operational Costs

Q. Do the Companies expect operational costs for non-mechanism generation operations to increase significantly?

A. The Companies project an increase in operations and maintenance costs for generation of $57.2 million in the forecast test year, compared to the forecast test year in the Companies' last base rate cases. However, the bulk of this cost increase is attributable to three discrete items: (1) reallocation of expenses from the environmental cost recovery mechanism to base rates; (2) changes in the way the Companies account for past and future outage expense; and (3) removal of refined coal proceeds from base rates.

Q. Please explain the operational reasons for the incorporation of O&M expenses from the environmental cost recovery mechanism to base rates.

A. Of the total cited above, almost half or $26.5 million of the increase is attributable to O&M costs associated with ECR projects that are now complete and in service or will be before the end of the projected test period and their costs are being moved from ECR recovery to base rates through a series of "roll ins" of completed projects. These reallocated costs are associated with expenses for the Selective Catalytic Reduction ("SCR") system on Brown Unit 3 (KU ECR Project 28), storage expenses for the Ghent and Brown Generating Stations (KU ECR Projects 29 and 30), costs for air compliance equipment at Mill Creek and Trimble County Generating Stations (LGE ECR Projects 26 and 27 and KU ECR Projects 34 and 35), and expenses for mercury control projects at Mill Creek, Trimble County, and Ghent (LGE ECR Project 28 and KU ECR Project 38). The testimony of Robert M. Conroy explains the ratemaking steps to incorporate these O&M costs into base rates.

Q. How is the change in outage expense normalization contributing to increased O&M expenses?

A. More than a third of the projected cost increase for Generation - $20.6 million – is attributable to increased O&M expense for generating unit outages. $13.7 million of this expense is tied to a change in the way the Companies are normalizing for outage expense, and the remaining $6.9 million is for amortization of the regulatory asset balance from the 2016 case over a period of six years and the 2018 case over a period of eight years.

In the Companies' last base rate cases, we sought to recover for outage expense based on an eight-year average, combining the last three years of actual outage expense with five years of forecasted expense.[15] As a concession in settling the cases, all parties stipulated to the use of a five-year historical average of generator outage expense, and to the continued use of regulatory asset and liability accounting for generator outage expense.[16] The use of a five-year historical average had the effect of reducing the revenue requirement sought in the 2018 base rate cases, but also had the effect of under-recovery of outage expense, which again is subject to regulatory asset treatment and

[15] See, e.g., Case No. 2018-00294, Testimony of Christopher M. Garrett, at 36-37 (Sept. 28, 2018).
[16] Case No. 2018-00294, Exhibit KWB-1 to Stipulation Testimony of Kent W. Blake, at 5-6 (Mar. 1, 2019).

recovery through future base rates. As this experience demonstrates, an 8-year average is a more accurate and reliable method of normalizing outage expense. This is because major outage maintenance is typically done in eight-year cycles, and because past maintenance costs are not necessarily predictive of future maintenance costs.

Accordingly, in these cases, the Companies propose to use average actual outage expense for 2017, 2018, 2019, and 2020 through August, combined with forecasted outage expense for the balance of 2020 through 2024. This approach has the effect of increasing expense associated with outage maintenance, but will ultimately be more accurate than 5-year historical average and will reduce the need to recover past outage expense in future rate increases through regulatory accounting.

Q. Please describe the operational status of refined coal agreements.

A. In my testimony in the Companies' last base rate cases, I described the status of refined coal projects at the Ghent, Mill Creek, and Trimble County Generating stations, and how those projects were generating revenue for the direct benefit of ratepayers through third-party license agreements.[17] From project inception through September 2020, these agreements have generated \$49.3 million in proceeds from site reservation fees, license fees, and coal yard service fees, passed on to ratepayers through amortization of the associated regulatory liability. Another \$16.2 million is expected to be generated prior to expiration of the agreements. The proceeds from these agreements have served to offset other costs in base rates. These refined coal agreements are set to expire during the forecast test period, and as Kent W. Blake describes in his testimony the Companies

[17] See, e.g., Case No. 2018-00294, Testimony of Lonnie E. Bellar, at 20-21 (Sept. 28, 2018).

seek to directly distribute the benefits from these agreements to customers earlier than would otherwise occur in the form of a one year surcredit.

Efficiency and Revenue Programs

Q. How much revenue are the Companies bringing in for the benefit of ratepayers through beneficial reuse of coal combustion residuals ("CCR")?

A. For calendar year 2019, the Companies passed along to customers $9.1 million from CCR beneficial reuse programs and contracts, primarily through the environmental cost recovery mechanism. In 2020, the Companies project this figure will reach $9.6 million, compared to $700,000 in 2016. This revenue source has grown exponentially due to the sustained and focused efforts of generation operations to negotiate lucrative contracts for sale of fly ash and gypsum, use of alternative materials to fill closed ponds so that CCR could be sold, implementation of CCR handling systems to more efficiently move material for reuse, and permanent processing solutions which have expanded the Companies' capacity to produce wallboard-grade gypsum. Properly processed CCR have a number of useful commercial applications in addition to wallboard. In fact, both the Lincoln and Lewis and Clark bridges spanning the Ohio River near Louisville were constructed using cement with fly ash from the Mill Creek Generating Station.

Q. Please describe new programs or improvements to existing programs that are being utilized to maximize generation efficiency.

A. Generation is seeking to leverage the utility of state-of-the-art data analytics to enhance the reliability and performance of the Companies' generating units. Data analytics enables operators to make better decisions to optimize generation resources, maximize maintenance efficiencies, and support complex engineering and operational analysis.

Recently, the Companies' have employed an O&M cost dashboard which uses data analytics to highlight gradual increases in O&M costs, and can be reviewed by engineers to spot trends that may need to be addressed. Enhancements have also been made to the Analytics Generation Equipment Navigation Tool which provides a one-stop-shop for plant personnel to easily access information from different systems. These enhancements include a drawing search tool that makes the search for drawings more efficient, improved search and reporting capabilities for work orders, and a new tool that assists the predictive maintenance group by reporting oil testing results more efficiently.

Generation plant maintenance personnel are also now using visual planner software which greatly simplifies the scheduling of maintenance activities up to four weeks in advance. The software allows planners to quickly assess resource availability before scheduling maintenance, and to schedule maintenance through a simple "drag and drop" interface. This facilitates long term planning and scheduling of maintenance activities in a manner that promotes accurate resource planning and well-designed work plans.

Drones are now routinely used to visually inspect areas at generation facilities that are difficult, unsafe, or costly to access manually. The use of drones in appropriate circumstances leads to safer, quicker, and more economical inspections of equipment, including building exteriors and the inside of boilers during inspection. This can avoid the need for costly scaffolding or aerial rigs, and can save significantly on time needed to set up and tear down for inspections. Drones are also being used to capture same-day birds eye views of landfills and impoundments, allowing the Companies to make more accurate decisions about CCR and waste processing and storage.

Since 2006, the Companies have used predictive maintenance program in place for generating units since 2006. However, several improvements to this program have been made in the past two years that leverage new technology and improve operational efficiency. Remote monitoring capability on Trimble County Unit 1 now includes infrared thermography cameras that can help monitor for temperature spikes on transformer bushings or leads, providing an early warning for a potential problem. Motor Current Signature Analysis has been installed on plant electrical switchgear to monitor motor feeds for abnormal current that can signal a fault in the motor. Furthermore, the Companies have implemented internal oil testing capabilities that otherwise would have to be performed by outside vendors, including viscosity and water separability testing. This saves on vendor costs and allows for more testing capacity.

IV. ELECTRIC TRANSMISSION

Transmission Performance

Q. Please describe the Companies' electric transmission system.

A. LG&E and KU jointly plan and operate their combined transmission system as a single interconnected and centrally controlled system pursuant to the Transmission Coordination Agreement filed with FERC at the time the Companies merged in 1998. Joint operation of the system allows the Companies to achieve greater efficiencies and reliability benefits than could be achieved with separately operated systems.

The Companies' combined transmission system serves its approximately 958,000 electricity customers in a total of 79 Kentucky counties. The Companies' transmission plant in Kentucky covers more than 5,200 circuit miles and has a net book value of approximately $1.1 billion.

Q. Is the Companies' transmission system performing reliably in 2020?

A. Yes, reliability performance has exceeded the Companies' expectations this year. Transmission System Average Interruption Duration Index ("SAIDI") measures transmission reliability by quantifying the average electric service interruption in minutes per customer for a particular system. It is the primary metric by which the Companies' overall transmission performance is assessed. Because SAIDI measures average minutes of interruption, lower numbers are better. The Companies usually measure SAIDI exclusive of Major Event Days ("MEDs"), when weather contributes to widespread system outages, in order to get a more accurate picture of the overall reliability of the system and its component parts.

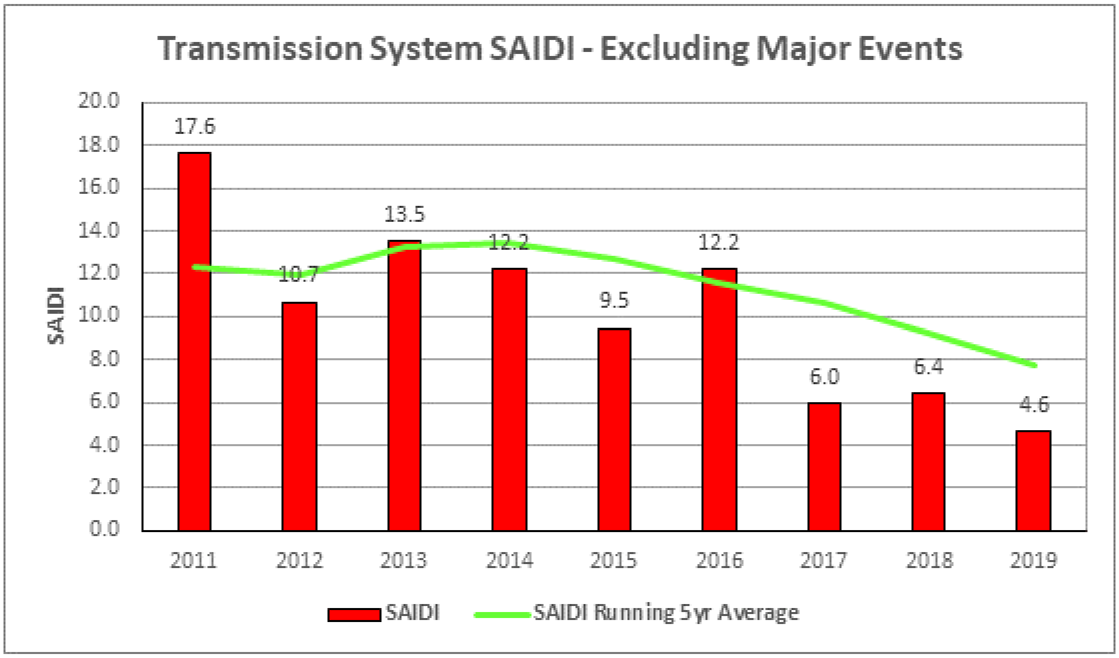
Year to date through the end of September 2020, the Companies' combined Transmission SAIDI is just 3.8 minutes, which is near the same level of overall reliability performance that the Companies had achieved through the same period in 2019. Further, this figure represents significantly better performance than the Companies' target SAIDI for 2020 through September, which was expected to be in excess of 7.0 minutes at this point in the year. KU's transmission system in particular has markedly improved in reliability from years past. For example, in 2016 KU's transmission SAIDI was 20.8 minutes, while in 2020 through the end of September, KU's transmission system SAIDI is just 6.5 minutes. KU's transmission SAIDI for the entire calendar year 2019 was 7.8 minutes.

Q. Do other reliability metrics support the Companies' continuously improving Transmission reliability performance?

A. Yes, the Companies are also performing well in outages per hundred-line miles per year ("OHMY"), a standard metric used for benchmarking reliability by the North American Transmission Forum, a leading industry organization whose membership represents the vast majority of the transmission mileage in the United States and Canada. This metric helps to inform reliability performance for transmission systems that serve rural areas, like much of KU's transmission system, because it takes into account outage rate in relationship to the geographic reach of the system. Year to date through September 2020, the Companies' combined Transmission OHMY is 5.9, compared to a year to date through September 2019 of 7.5, which represents a 25% reduction. LG&E's Transmission OHMY is 5.4 through September 2020, compared to 7.1 for the same period time in 2019 and KU's Transmission OHMY is 5.9 through September 2020, compared to 7.4 for the same time period in 2019. The Companies' combined OHMY for 2019 was 9.4, whereas LG&E and KU OHMY in 2019 were 9.9 and 9.1, respectively.

Q. To what do you attribute the Companies' improvements in transmission reliability?

A. Even excluding MEDs, the frequency and severity of weather events can cause variances in year to year system reliability performance. But weather does not explain the consistent trend of the Companies' improved transmission reliability performance over the past decade, dating back to 2011:



Rather, the overall trend of reliability improvement is attributable to the Companies making carefully planned and targeted investments in their transmission infrastructure, and through improvements to reliability programs such as vegetation management, line switch maintenance, and line sectionalizing. Many of those programs and investments were outlined in the Transmission System Improvement Plan ("TSIP"), which the Companies submitted to the Commission in their 2016 rate case filings.[18]

TSIP Spending and Resulting Reliability Improvements

Q. How have the Companies implemented TSIP investments and programs to improve reliability?

A. In short, the Companies have done what they said they would do in the 2016 plan and are continuing to execute the strategy set forth in that plan. For calendar years 2017 to

[18] *E.g.*, *Application of Kentucky Utilities for an Adjustment of its Electric Rates and for Certificates of Public Convenience and Necessity*, Case No. 2016-00370, Testimony of Paul W. Thompson, Exhibit PWT-2 (Ky. PSC Nov. 23, 2016).

2019, the Companies made the following TSIP capital investments and operations and maintenance expense ($MM):

	2017	2018	2019	**Total 2017-2019**
System Integrity (line equipment, underground lines, substation equipment and controls) (capital)	96.6	99.1	124.5	**320.2**
Reliability programs (vegetation management, switch maintenance, corrosion protection) (O&M)	9.9	14.5	14.9	**39.3**
Line sectionalizing (capital)	8.5	8.1	12.0	**28.6**

Pursuant to the Commission's Orders in the 2016 rate cases, the Companies have summarized and reported to the Commission annually about these investments and expenses, how they compared to the previous year's forecasts, and summarized the reliability benefits yielded from these investments and programs.[19]

Q. How are system integrity and modernization investments being applied?

A. Spending on TSIP system integrity and modernization has focused on replacement of aging transmission assets, including primarily wood poles, underground lines, circuit breakers, insulators, and line arresters at substations. The investment required to replace wood transmission poles in particular has been greater than anticipated, due in large part to more rigorous inspections being performed throughout the system starting in 2013. At the end of 2019, there were approximately 4,300 poles in the transmission system that were slated for replacement. A total of 907 transmission poles were replaced during calendar year 2019. Thus, the Companies will continue a significant level of investment in pole replacements until the backlog can be addressed. In

[19] *See, e.g.* Case No. 2016-00370, POST Case Files, Annual TSIP Reports for 2018, 2019, 2020.

calendar year 2019, the Companies spent $91.2 million of the $124.5 million in system modernization investments on line equipment. These investments include not only pole replacements but also replacements of aging conductor, switches, cross-arms, and insulators. These investments are required to secure the longevity of the Companies' transmission system.

Q. How is TSIP reliability program spending being applied?

A. In 2017 the Companies initiated a 5-year cycled approach to vegetation management on transmission lines to supplement the just-in-time approach used in the past. Implementation of a cycled approach to vegetation management has increased expense from previous levels due to the cycled clearing being performed in addition to just-in-time clearing. The first five-year cycle is expected to be complete in 2022. Also, in 2019 alone, the Companies completed hazard tree patrols on over 750 miles of transmission lines across the system. The Companies removed approximately 1,000 ash trees and 1,800 total hazard trees in 2019. Hazard trees pose a risk of line interference and resulting service disruption. Early identification and removal of hazard trees improves the overall reliability of the transmission system and mitigates the risk of tree related outages.

The TSIP also implemented an annual inspection cycle for all automated and motor operated line switches. Annual inspections of this equipment allow the Companies to quickly identify switches that need repair or replacement.

As seen in the table above, the Companies have also invested $28.6 million from 2017-2019 on the addition of line sectionalizing equipment to transmission lines, including motor operated switches and breakers, on circuits which have disproportionately contributed to SAIDI. Line sectionalizing allows the Companies to greatly reduce the number of customers affected by an outage and the duration of outages, thus contributing to improvements in overall system reliability.

Q. What specific reliability benefits have resulted from TSIP capital spending?

A. Reliability benefits achieved from replacement of aging transmission infrastructure will be long-lasting. The assets being replaced under the TSIP are nearing end of life, obsolete, or both. Replacement assets installed under the programs outlined in the TSIP employ modern technology which enhances the overall safety and resiliency of the system. Furthermore, many of the lines being improved were previously designed for medium loading under the National Electrical Safety Code ("NESC"). New equipment installed on these lines is designed for heavy loading under the NESC, improving the ability of the line to withstand weather events such as wind and ice. These asset replacements have a measurable SAIDI impact. The Companies estimate that pole and conductor replacements have resulted in lower SAIDI attributed to pole failure, with a cumulative system SAIDI savings of 1.85 minutes, excluding MEDs, since 2012, and SAIDI including MEDs of 4.39 minutes during the same time period.

In addition to the overall trend of reduced transmission system SAIDI, the reliability impact of TSIP projects can be immediately seen on specific lines. Line sectionalizing projects in particular have been highly effective in reducing SAIDI minutes from lines that historically underperformed in system reliability. For example, on the Farley to Sweet Hollow 69 kV transmission line, KU added a motor operated switch in 2017 at the Corbin Steel tap on this line. From 2012 until the time this switch was installed, this circuit experienced three (3) sustained events and accounted for 0.91

minutes of SAIDI for an average SAIDI of 0.30 minutes per event. Since this project was completed, this circuit experienced one (1) sustained event with no SAIDI impact. The motor operated switch was used to sectionalize the line and restore the customers in less than 5 minutes. Likewise, on the Boyle County to Lancaster transmission line, KU installed a breaker which has reduced the SAIDI contribution from two outage events on this line from 1.48 minutes pre-installation to just 0.37 minutes post-installation.

Vegetation Management

Q. What is the status of the 5-year cycled approach to vegetation management for transmission lines?

A. As of September 30, 2020, cycled clearing was complete on 86 percent of the Companies' high voltage (345kV-500kV) lines, with 483 out of 561 corridor miles completed. For lower voltage (69kV-161kV) lines, approximately 52 percent of the line miles have been cleared, with 2,035 of 3,882 corridor miles completed. Cycled clearing activities are on schedule and the Companies expect the first cycle to be complete by 2022 as set forth in the TSIP.

Q. How has the cycled approach to vegetation management contributed to reliability improvements?

A. The Companies analyzed all transmission circuits where cycled vegetation management has been completed to assess the reliability impact of the program. Based on the results of that analysis, since implementing the cycled approach to vegetation management, SAIDI events caused by vegetation issues have been cumulatively reduced by 6.67 minutes, excluding MEDs, for those circuits where vegetation was the cause code assigned to outage events. The Companies expect these reliability benefits to accumulate further as the remainder of the first cycle is completed.

Regulatory Compliance

Q. Have the Companies been subject to recent regulatory audits for transmission compliance?

A. Yes. In the 2018 base rate cases, I reported on the 2018 Critical Infrastructure Protection ("CIP") and Operations and Planning Audits performed by Southeast Electric Reliability Corporation ("SERC"), and the Companies' excellent performance documented in the audit's conclusions. These audits are conducted once every three years, so the Companies are preparing for another audit cycle to occur in 2021. However, starting in late 2019, the Companies were subject to another transmission regulatory audit – this one conducted by FERC for compliance with the terms of the Companies' Open Access Transmission Tariff ("OATT") and regulations regarding Open Access Same-Time Information Systems ("OASIS"). The audit was conducted for a compliance period from January 1, 2016 through October 31, 2019.

Q. What is the purpose of an OATT and OASIS audit?

A. An OATT is governed by and approved by FERC. It sets forth the terms, conditions, and rates at which the Companies must provide transmission services for their combined transmission system. The OATT audit evaluates, among other things, whether the Companies: (1) provided transmission and ancillary services on a non-discriminatory basis; (2) used network service only to serve native load customers and not to support off-system sales; and (3) followed established principles in their transmission planning process. The audit also evaluates the independent performance of TranServ, the Companies' Independent Transmission Organization, including its calculation of Available Transfer Capacity ("ATC") and operation and maintenance of the Companies' OASIS Website.

OASIS is a web-based system that provides information to transmission customers about the Companies' electric system. FERC's OASIS audit evaluates the performance of the Companies and TranServ in posting required information to OASIS, including daily load forecasts, prices and terms and conditions of transmission products, and denied service requests, among other information.

Q. What were the results of the OATT and OASIS audit?

A. FERC's final report for this audit was issued on February 21, 2020. The audit results were outstanding, with FERC concluding that for the audit period spanning nearly four years, there were no findings or recommendations requiring corrective action.

<u>Transmission Capital Projects</u>

Q. What is the Transmission Expansion Plan ("TEP")?

A. The TEP is the product of a long-term analysis performed by the Companies to ensure that expected firm demand levels and power flows will be adequately accommodated without exceeding system limits based on NERC requirements and the Companies' planning guidelines. The plan is prepared annually and approved by TranServ in its capacity as the Companies' ITO.

Q. What significant capital projects are included in the TEP?

A One major project identified in the TEP process is expansion of transmission infrastructure in Hardin County. In the event of an outage of the existing 345/138 kV transformer in Hardin County, significant low voltage violations would occur and would therefore not meet NERC Reliability Standard TPL-001-4 and the Companies' planning guidelines. In order to achieve compliance with reliability standards and improve reliability, the Companies will add a second 345/138 kV transformer, a second 138/69 kV transformer, a 1.3-mile 69 kV line from Hardin County to Elizabethtown, and 69 kV bus tie breakers to Hardin County and Elizabethtown. The total project is expected to cost $27.5 million, $21.0 of which is expected to be incurred between November 1, 2019 and December 31, 2021. Other than doing nothing, which would put customer load at risk and violate NERC reliability standards, the proposed investments were the lowest cost alternative, as compared to other infrastructure configurations necessary to avoid violations.

Another TEP project is the replacement of 1.7 miles of 69kV conductor and supporting structures on the Ford to Freys Hills Tap line. The need for this project was identified by the TEP process, specifically a finding of overload conditions on the Ford-Freys Hill line under summer peak conditions in the event of an outage on the Middletown-Lyndon or Lyndon-Freys Hill 69kV lines. The existing 795 all aluminum conductor will be replaced by 954 aluminum conductor steel reinforced, and the existing static wire will be replaced with new optical ground wire. In addition, 41 existing wood structures on the line will be replaced with steel structures. This conductor replacement project is expected to cost approximately $5.2 million, which represents a far lower cost than the alternative of building a redundant line and construction of a four breaker 69kV ring bus at the Lyndon substation.

Q. What other significant transmission capital projects are planned?

A Outside of TEP investments, other asset replacements are planned for the purpose of modernizing the Companies' transmission system, and ensuring system integrity and reliability in the future, just as the Companies envisioned in the TSIP. Many of these projects are focused on replacement of wood structures with steel based on physical inspection, and replacement of conductors which are approaching their expected useful life.

For example, KU is in the process of replacing 13.5 miles of overhead conductor and related structures on the Farmers-Spencer Road 69 kV line in Montgomery and Bath counties as part of its TSIP investments. The project will replace the existing conductor installed in 1930, add a new static wire, and replace 223 wood structures with 132 steel structures. The project will use a new design to optimize structure placement and result in removal of nearly 100 structures from the line. The conductor on this line was tested and found to be in poor condition, and the structures supporting a portion of the line were constructed using non-traditional transmission framing consisting of short wood poles with vertical post insulators mounted on cross arms, more commonly used in distribution framing. Additionally, the lack of static wire on this line makes it prone to lighting strikes, as evidenced by a total of 37 interruptions since 2012. Replacement of this line is exactly the type of long-term system integrity project contemplated by the TSIP. The project is expected to cost approximately $16 million in capital, with approximately $13 million incurred from November 1, 2019 through December 31, 2021.

<u>**Transmission Cost Increases**</u>

Q. What O&M cost increases do transmission operations face between the prior case forecasted test year and the current case forecasted test year?

A. The Companies project an increase of $8 million in transmission O&M between these two periods. Depancaking expense is expected to be $2.5 million higher, primarily due to a new MISO transmission service request purchased by an eligible customer.

Labor costs are expected to be $2.2 million higher, in part because certain labor expenses previously booked as capital are now booked as O&M, and in part due to wage growth and the addition of incremental headcount for new positions (EMS Administrator, Compliance Engineer, System Operations Trainer, and OT Security personnel). Vegetation management expenses are expected to be $1.5 million higher due to higher contracted costs from the Companies' business partners in the forecasted test year. The remaining expected cost increases are attributable to line and substation maintenance and cybersecurity and IP connectivity initiatives.

Efficiency Programs

Q. What initiatives are the Companies pursuing to reduce cost and increase the efficiency of transmission operations?

A. The cycle-based approach to vegetation management is itself a major efficiency program. By shifting to the cycle-based approach, contractor crew mobilization is minimized throughout the service territory. Work planning efforts are improved by focusing on complete circuits instead of circuit fragments. Quality control is simplified by enabling a complete view of work that remains unfinished on an entire circuit, rather than a patchwork of vegetation encroachment which can often result from a just-in-time clearing strategy.

In order to further maximize the efficiencies gained from cycle-based vegetation management, the Companies are currently in the midst of implementing Work Studio, a work management solution supporting vegetation management activities. Full implementation is set to be completed in 2021. The mobile software system includes functionality to create annual work plans from a central repository and eliminate the reliance upon multiple manual spreadsheets. It allows users to provide detailed prescriptions of the work needed within the right-of-way on digital maps. Clearing crews will be able to receive assignments electronically through a mobile application. The status of work can be updated on the mobile devices and synced with the server in real-time.

Q. How have the Companies been able to leverage better information from technology upgrades to the system to create efficiencies?

A. Owing to modernization of line equipment throughout the transmission system, digital fault records ("DFRs") and microprocessor relays are now much more prevalent on the system than they once were. DFRs capture data associated with faults. In some cases, the data captured by DFRs allows responding technicians to pinpoint a section of line rather than patrol an entire line (by rolling vehicle or aerial inspection) for the source of a fault. Where targeted response is achieved, this results in reduced expense for outage response. Microprocessor relays have resulted in a significant decrease in average misoperations attributable to relay failures, from 12.0 during 2015-2017 to 7.7 from 2018-2020. This improved functionality not only improves overall system reliability but also reduces operational expense associated with outage response.

Q. Please summarize the capital investment the Companies plan to make in their transmission business.

A. The following chart summarizes capital expenses in transmission, by company, from November 1, 2019 to December 31, 2021 (in millions):

	KU	LG&E	Total
Proactive Replacement	242.2	63.2	305.4
Reliability	23.1	5.4	28.5
Transmission Expansion Plan	61.7	14.6	76.3
All Other	27	10.5	37.5
Total:	354	93.7	447.7

V. ELECTRIC DISTRIBUTION

Q. Is the Companies' electric distribution system performing reliably?

A. Yes. Just as customers are benefitting from improved reliability on the electric transmission system, they are likewise benefitting from improved reliability on the distribution system. The Companies continue to make targeted investments in the distribution system to minimize the frequency, scope, and duration of customer outages. The objective metrics tracking reliability performance of the combined transmission and distribution systems against industry benchmarks show that these investments are significantly improving reliability of electric service to customers. As Paul W. Thompson's testimony highlights, the Companies' combined Transmission and Distribution SAIDI has improved significantly over the past ten years and closely tracks first quartile performance in utility industry benchmarking surveys. The 2020 combined Transmission and Distribution SAIDI is on track to be the lowest (best) in the history of the combined Companies. In other words, customers are experiencing more reliable service and relatively fewer and shorter disruptions as a result of this excellent performance by the distribution and transmission system.

Q. To what do the Companies attribute improved reliability on the distribution system?

A. John K. Wolfe's testimony provides the operational support testimony for electric distribution operations for both Companies. His testimony describes in detail the programs that have been implemented to improve reliability, replace aging infrastructure, centralize grid operations, effectively manage and maintain the distribution system, and prepare for future challenges. Mr. Wolfe's testimony also supports the Companies' request for approval of full deployment of AMI from the electric distribution perspective.

VI. CUSTOMER SERVICES

Q. Are you offering operational testimony about the Companies' customer services function?

A. No. Eileen L. Saunders' testimony provides the operational support testimony for customer services for both Companies, and supports the Companies' request for approval of full deployment of AMI from the customer service perspective. I defer to Ms. Saunders' testimony on these topics.

VII. GAS OPERATIONS

Q. Please describe LG&E's gas system.

A. LG&E's gas operations business serves approximately 331,000 customers in Jefferson and sixteen surrounding counties in Kentucky. LG&E owns significant infrastructure used to distribute gas to its customers, including five underground storage fields and three compressor stations. LG&E operates an approximate total of 4,400 miles of gas distribution pipe and 370 miles of gas transmission pipe on its system. The net book value of LG&E's gas system assets in Kentucky is approximately $929 million.

LG&E's total annual throughput for the base period is estimated to be 45 billion cubic feet (Bcf).

Q. Please describe the Company's safety performance for its gas operations.

A. The safety of LG&E's employees, customers, and the general public is the highest priority of LG&E's gas operations. LG&E's performance in several key safety metrics reflects that commitment. For example, the RIIR for employees in gas operations through September 2020 is 0.86, roughly just half of LG&E's target rate of 1.58.

Q. Can you please discuss the measures gas operations has taken with regard to the safety of its system for the communities it serves?

A. Certainly. The safety and security of LG&E's gas infrastructure is paramount. Not only is this a cultural value for LG&E, it is embodied in how LG&E operates its system, designs its infrastructure, and complies with regulatory requirements, including the Safety of Gas Transmission Pipelines: Maximum Allowable Operating Pressure ("MAOP") Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments ("Mega Rule Part 1") promulgated by the Pipeline and Hazardous Materials Safety Administration ("PHMSA") finalized in October 2019.[20] As an example, with its major new construction and replacements, LG&E is designing transmission pipelines to be at lower stresses at their MAOP and typical operating pressures through design considerations such as pipeline wall thickness and material strength.

LG&E has followed through with its plans to utilize additional in-line inspection tools as technology has evolved. Those tools provide a better understanding of the

[20] 49 CFR Parts 191 and 192.

threats to the pipeline and its condition. The in-line inspection tools that are now commonly being used by LG&E include geometry, axial magnetic flux leakage, circumferential magnetic flux leakage, electromagnetic acoustic transducer, and pipe grade sensors. Leveraging this expanded set of in-line inspection tools enables LG&E to achieve a higher overall level of pipeline safety. The expanded in-line inspection program also supports compliance with the Mega Rule Part 1 relating to expanding construction documentation requirements for natural gas transmission pipelines and reconfirming MAOPs. In addition, use of an expanded set of inline inspection technologies enables LG&E to achieve a higher overall level of pipeline safety. LG&E is running in-line inspections in about 85% of its dry gas transmission pipelines. These inspections are providing crucial data about the Company's infrastructure.

Earlier this year, PHMSA also issued a final rule regarding Safety of Underground Natural Gas Storage Facilities.[21] To comply with the new regulatory requirements, LG&E is focusing on the integrity of its storage fields. LG&E is installing new control valves and is also performing well logging, in which the Company makes a detailed inspection, similar to the in-line inspections performed in pipelines, utilizing a vertical inspection tool.

Q. Does LG&E anticipate that PHMSA will release additional parts to the Mega Rule?

A. Yes. Part 2 of the rule making will focus on the expansion of transmission integrity management program regulations and corrosion control regulations. PHMSA has proposed requiring each operator to develop and implement a monitoring and

[21] 49 CFR Parts 191, 192, and 195.

mitigation program to identify potentially corrosive constituents and mitigate the corrosive effects. In order to comply with these new regulations, LG&E's expenses related to corrosion control will increase, as LG&E will be performing additional corrosion monitoring and surveys. Part 3 of the rule focuses on issues related to gas gathering lines which LG&E does not operate, and thus is not expected to materially impact operations.

Q. Please describe how LG&E's damage prevention efforts, including line locating, are contributing to the safety of the gas system.

A. LG&E has a robust damage prevention plan, of which line locating is a crucial component. LG&E has continued to improve its performance with respect to KRS 367.4909, which requires the Company to respond to facility locate requests within two (2) working days after receiving notification from an excavator, excluding large projects. As LG&E has explained, there has been an upward trend in locate volumes which plateaued in 2017 and has remained consistent due to (1) fiber projects and (2) continued marketing and education of the excavating and public communities regarding the use of 811.

LG&E has devoted increased efforts and costs to promptly respond to the increased volume of facility locate requests, and LG&E's performance shows substantial progress. In 2019, LG&E responded to 135,026 locate requests, and 99.1% were responded to within the statutory timeframe. Through September 2020, LG&E has responded to 103,461 locate requests, and 99.9% were responded to within the timeframe. LG&E continues to strive for 100%, and its results this year are very close to that target.

Q. Have there been recent changes in the leadership of the gas business?

A. Yes. As I referenced previously, following the retirement of John Malloy, Tom Jessee was named Vice President-Gas Operations in January 2020. Mr. Jessee has 34 years of experience in the gas and electric industry. In addition, Joseph Ryan has been promoted internally to a newly created director position for asset integrity management and compliance. Mr. Ryan now oversees many of the new and emerging federal regulatory requirements that are discussed in my testimony.

Q. Can you please describe the capital investments LG&E is making to ensure that the Company can continue to provide reliable and safe operations into the future?

A. Certainly. LG&E is engaged in a number of capital projects to expand and improve safe and reliable gas service to its customers. These projects include the continued deployment of the Transmission Modernization Program, modifications to certain transmission pipelines to facilitate use of in-line inspection tools, and other gas system improvement projects.

Q. Please provide an update on the Transmission Modernization Program.

A. LG&E obtained Commission approval of the Transmission Modernization Program ("TMP"), the costs of which have been included in the Gas Line Tracker ("GLT") mechanism. LG&E had identified approximately 15.5 miles of transmission pipeline in the backbone of its transmission system to replace and has installed approximately 6.9 miles and placed approximately 3.1 miles into service as of October 2020. This portion of the system was constructed between 1957 and 1972 with the materials and by the prevailing construction methods of that time. The TMP is designed to achieve compliance with regulations while avoiding unplanned repairs, replacements, and pressure reductions that can jeopardize system reliability.

The TMP encompasses the replacement of three segments of transmission pipeline, which are: (1) Blanton Lane Regulator Station to Penile Gate Station; (2) Penile Gate Station to Preston Gate Station; and (3) Preston Gate Station to Piccadilly Valve Nest. The work, which began in 2017, is progressing, and the scope has not changed, but the timeline for completion has been extended with primary drivers including obtaining required easements prior to construction (due to proximity of other utilities in the existing easements and for access) and rock that LG&E has encountered during construction. The large amount and hardness of rock that LG&E has encountered has increased its construction contract costs, especially costs associated with rock removal and the resulting increased duration. This project continues to meet the key objectives of replacing the existing segments in this critical section of the system from a reliability standpoint.

Q. Is the Company planning modifications to other transmission pipelines?

A. Yes, LG&E is planning modifications to the Western Kentucky A and B pipelines to facilitate running 16-inch by 20-inch dual-diameter in-line inspection tools. These modifications include replacing about 2.5 miles of 22-inch pipeline primarily on the Western Kentucky A pipeline and a short segment on the Western Kentucky B pipeline with 20-inch diameter pipeline. This will result in both pipelines having only 16-inch and 20-inch pipeline diameters. Additionally, approximately 0.7 miles of short 16-inch pipeline segments will be replaced with 20-inch diameter pipeline across both pipelines. Replacing the short 16-inch sections in both pipelines reduces the number of diameter changes on the pipelines, minimizing potential in-line inspection tool speed excursions that can lead to data issues. This work will facilitate the use of dual-diameter in-line inspection tools that can gather data on both 16-inch and 20-inch diameter pipeline supporting compliance with current regulations including MAOP reconfirmation. LG&E initiated the development of a circumferential magnetic flux leakage in-line inspection tool and electromagnetic acoustic transducer in-line inspection tool capable of gathering data on pipelines containing both 16-inch and 20-inch diameter pipe because the tools were not commercially available. Development of the new in-line inspection tools is expected to be completed by January 2021. The tools will be used in LG&E's Western Kentucky A and B pipelines, as well as elsewhere in LG&E's gas system.

Q. What other investments is LG&E gas operations making in its system?

A. LG&E continues to work on its elevated pressure system, which is made up of four primary separate pressure systems within Jefferson County. Elevated pressure systems have a MOAP of 3 psig, versus medium pressure systems, which have a MOAP of 15 psig to 60 psig. Combined, the elevated pressure systems make up approximately 150 miles of gas mains and 12,650 services, and are surrounded by medium pressure systems. The load on these systems has continued to grow, and reinforcement work is needed to continue to safely and reliably serve these customers. LG&E plans to convert targeted sections of the elevated pressure system to medium pressure. Work is expected to include uprating existing plastic service lines and plastic main lines, replacing steel service lines with polyethylene service lines, replacing steel main lines, and installing new regulator facilities. Much of the steel pipe in the elevated pressure area dates back to the early 1950s and will be replaced when reinforcement work occurs in those areas. LG&E expects to spend $7.9 million in capital on this project from November 1, 2019 through December 31, 2021.

LG&E will also continue work on the previously approved Steel Customer Service Replacement program. This program proactively replaces steel customer services (service line between the property line and meter), which were mostly installed prior to the mid-1980's and prone to corrosion leaks over time with polyethylene plastic service lines. The program consists of replacing steel customer service lines, replacing county loops and removing steel curbed services. The main threat posed by county loops (meter above grade at the property line) and curbed services (active service attached to the main but capped at the property line line) is the threat of third-party damage arising from their exposed physical locations. Through September 2020 the program has replaced 7,732 customer steel services, 176 county loops and 3,028 steel curbed services. All known county loops have been replaced and the majority of steel curbed services are expected to be removed by the end of 2021. This project was approved to be recovered through the GLT in 2016 but will be moved to base rates effective July 1, 2021, which is discussed in Mr. Conroy's testimony. LG&E expects to spend $5.2 million in base capital on this project from November 1, 2019 through December 31, 2021.

The Company plans to continue upgrading city gate stations and gas distribution regulation facilities to ensure providing safe and reliable gas supply to the distribution system. Upgrades include replacing aging gas regulation equipment, overpressure protection equipment, controls, buildings, and associated piping. LG&E expects to spend $19.4 million in capital on city gate station and gas regulation facility upgrades from November 1, 2019 through December 31, 2021.

LG&E is also completing a major upgrade to its supervisory control and data acquisition (SCADA) systems that are used to monitor and control gas supply and operations. The upgraded SCADA systems provide enhanced cybersecurity features, operate on the latest Microsoft operating systems, and leverage new technologies such as virtualized servers that enhance maintenance and reliability of the system. LG&E expects to spend $1.0 million in capital on the SCADA upgrade project from November 1, 2019 through December 31, 2021.

Q. Please provide an update on the Bullitt County Pipeline.

A. LG&E obtained a Certificate of Public Convenience and Necessity ("CPCN") to construct a new, approximately 12 mile pipeline to improve reliability and provide capacity needed to serve new and expanded demand for gas service in the Bullitt County area in LG&E's 2016 rate case and had estimated completing the pipeline by 2019. Due to delays in acquiring the necessary easements and permits, LG&E has not yet completed the pipeline. LG&E is not seeking to recover the capital costs associated with the construction of the pipeline in this proceeding. The only costs included in this case are the costs of obtaining the necessary permits and rights to construct the pipeline. As to property rights, LG&E has acquired 88% of the easements, with 9 properties remaining. LG&E has also obtained nearly every permit related to the project and is in the process of obtaining the necessary authorizations from the Army Corps of Engineers and the Kentucky Division of Water. The need for the pipeline has increased since LG&E obtained a CPCN for it in 2017. The demand for gas in this area continues to grow. Due to LG&E's inability to construct the pipeline according to its planned timeline, LG&E is deferring requests for new and expanded commercial and residential gas service in that part of its system.

Q. Is LG&E projecting any additional headcount positions for the gas business beyond as a result of the regulatory requirements and safety measures you have discussed?

A. Yes, LG&E has restructured its gas operations, including the creation of the director position for Mr. Ryan. The Company also projects adding analysts, technicians, gas controllers and an engineer, for a total incremental increase of 11 positions from the end of the forecasted test year in LG&E's last base rate proceeding compared to the end of the forecasted test year in this case. These new positions are all related to maintaining and improving the safety of the Company's gas delivery while meeting ever-expanding regulatory requirements.

Q. What O&M cost increases does gas operations face between the prior case forecasted test year and the current case forecasted test year?

A. LG&E projects an increase of $11.8 million in O&M costs for Gas Operations between these two periods. The primary driver for this increase is compliance with regulatory requirements and initiatives to ensure a safe and reliable gas pipeline system. Regulatory requirements including PHMSA's Mega Rule Parts 1 and 2 are projected to increase costs by $4.2 million. The costs to meet the current demand for underground facility locate requests while seeking to minimize the likelihood of damage to pipelines along with compliance with distribution integrity management requirements are projected to increase $3.9 million. Labor costs are expected to be

$2.1 million higher, in part due to wage growth as well as an increase in headcount as previously described to meet ever increasing regulatory requirements and continually enhance pipeline safety. The remainder of the cost increase is attributed to cyber security and cost increases for outside services and materials.

Gas Operating Efficiencies

Q. Can you describe the amine replacement program LG&E is undertaking?

A. Yes. As explained in its last rate case, LG&E is in the process of replacing four of its five amine gas processing plants, which remove hydrogen sulfide from gas withdrawn from underground gas storage. The four amine gas processing plants are being replaced with hydrogen sulfide scavenging technology. Replacement of the amine plants with H2S scavenging technology will improve gas storage reliability, reduce sulfur dioxide air emissions, lower employee exposure risk to hydrogen sulfide, and reduce manpower required to operate gas processing systems.

Q. Is LG&E implementing a new geographic information system ("GIS")?

A. Yes, LG&E is implementing a new GIS system to be used in the field for several of its mobile applications. These mobile applications include mapping and work orders and will allow for the consolidation of multiple systems that had exceeded their useful lives. The GIS systems will provide our employees with enhanced capabilities to better serve our customers.

Q. Are you sponsoring any schedules required by the Commission's regulation 807 KAR 5:001 Section 16?

A. Yes, I am co-sponsoring, along with Mr. Blake, the schedules required by Section 16(7)(c). These documents are submitted with the Companies' applications. I am also sponsoring the schedule required by Section 16(7)(h)(8), mix of gas supply forecast for 2021, 2022 and 2023. This schedule is submitted with LG&E's application.

Q. Please summarize the capital investment LG&E plans to make in its gas operations.

A. The following chart summarizes non-mechanism capital expenses in LG&E gas operations from November 1, 2019 through December 31, 2021 (in millions):

	LG&E
Connect New Customers	$12.9
Enhance the Network	
Gas Transmission Modernization (Penile-Blanton, Penile-Preston, Preston-Piccadilly,)	$28.6
Western Kentucky A and B Modernization	$20.7
Elevated Pressure	$7.9
Magnolia Crossings	$6.0
Steel Service Line Replacement	$5.2
Bullitt County System Reinforcement	$3.6
Other	$30.0
Maintain the Network	
Muldraugh & Magnolia Amine Replacements	$14.6
St. Helen's Regulator Station	$6.5
Preston City Gate	$5.2
Cannon's Lane Regulator Station	$3.9
Other	$38.4
Repair the Network	$2.5
Miscellaneous	$2.8
Total:	**$188.8**

VIII. ADVANCED METERING

Q. Are the Companies requesting the Commission's approval of Advanced Metering Infrastructure ("AMI")?

A. Yes. I will explain the Companies' AMI proposal in these cases, the desirability, need and cost-effectiveness of AMI, and how it is different from the Companies' previous AMI proposals made to the Commission. Several of the Companies' other witnesses describe various aspects and benefits of full deployment of AMI. Mr. Blake presents the Companies' ratemaking proposal. Mr. Wolfe describes the benefits AMI will create for electric distribution. Ms. Saunders describes the benefits AMI will provide to customer service. Mr. Conroy explains how the requirements for a certificate of public convenience and necessity are met.

Q. Please summarize the Companies' AMI proposal.

A. The Companies' AMI proposal in this case is vastly different than its previous proposals. Most importantly, we have carefully considered previous Commission and intervenor concerns and have addressed them. In brief, the AMI proposal in this case contains the following fundamental positions:

- Full deployment of AMI in our electric only and combined electric and gas areas and full deployment of automatic meter reading ("AMR") in our gas-only areas are the most cost-effective methods to read meters by $46.4 million compared to the Status Quo;
- The time to deploy is now -- any delay will result in a lost opportunity for savings;
- Usage data will be available to customers in near real time;
- AMI will generate significant electric distribution and customer service benefits;

- Under the ratemaking proposal Mr. Blake presents, there will be no rate impact to customers as a result of these rate cases and customers will ultimately receive the cost savings AMI will provide; and

- Innovative tariff pricing (as explained by Mr. Conroy) will be offered so that customers can take advantage of the full capabilities AMI will provide to them.

Q. Please explain the basics of the Companies' AMI proposal.

The Companies have an essential need to accurately measure customers' consumption of service on a monthly basis so we can accurately bill them for their electricity and gas usage. For decades, we have used meter readers to accomplish that meter reading task. Either on foot or in a truck driven by nearby meters, a meter reader has always had to be in close physical proximity to a customer's meter to gather usage information used to generate a bill. We primarily rely on contractors to perform that meter reading work. We have approximately 1 million electric meters and 340,000 gas meters, the vast majority of which are read monthly. To say the least, meter reading is a significant task.

As we always strive to do, we investigate ways to accomplish such a tremendous task in the most cost-effective way possible. To that end, we have performed a comprehensive analysis to determine what is the most cost-effective way to read meters reliably. The Companies' analysis in Exhibit LEB-3 demonstrates that fully deployed AMI is the most reasonable, cost-effective way to read meters of the various alternatives considered, including the Status Quo. In addition to being the least expensive way to read meters, fully deployed AMI will result in numerous significant operational and customer service improvements. Those improvements are significant, and we believe it is incumbent upon us to make those improvements for the ultimate benefit of our customers.

As for the fundamentals of the AMI proposal in these cases, we propose full deployment of AMI in all areas where we have electric and combined electric and gas service. Where we have gas service only, we propose to utilize existing gas meter assets to expand existing automatic meter reading ("AMR") throughout the gas-only territory instead of pure AMI. We call this AMI + AMR GO with "GO" meaning "gas only." We propose this for the exact reason the Commission expects – it is the most cost-effective solution in the gas-only areas while still allowing a move to AMI in the future if that becomes necessary and prudent. The major reasons why our proposal is the most cost-effective solution are: savings derived from reduction in meter reading and field services costs;[22] avoided meter costs; and fuel savings resulting from the ability to leverage AMI to reduce customers' energy usage by incrementally lowering distribution voltages. Contracted meter reading costs have increased significantly, and those increases are expected to continue without any additional benefit for customers absent a move to AMI.

Q. **Why are the Companies seeking approval for full AMI deployment now?**

A. We propose to fully implement AMI + AMR GO within five years after Commission approval. This implementation period is necessary to begin delivering savings as soon as possible. As shown in Exhibit LEB-3, the longer we wait, the greater the missed opportunity for savings. The time is now. In the final analysis, the AMI +AMR GO proposal is $46.4 million favorable to the Status Quo alternative which assumes replacing existing meters as they fail with non-communicating electronic meters.[23] In

[22] See LEB-3, Sections 6.3 and 6.4 for a description of meter reading and field services costs. Significantly, in 2019, the Companies' meter reading costs increased by approximately 56% when they had to enter into new meter reading contracts.
[23] See LEB-3, p. 4.

fact, of the alternatives considered, the only alternative that is more costly than the Status Quo would be a move to full AMR for 15 years and *then* a move to full AMI which we think would be required given the direction of the industry. The following table is in Exhibit LEB-3 (see p. 4) and summarizes our analysis in millions for the period 2021-2050:

Alternative	AMR Becomes Obsolete		AMR Remains Viable		AMR Obsolescence Risk (A less B)
	PVRR (A)	PVRR Delta to Status Quo	PVRR (B)	PVRR Delta to Status Quo	
Status Quo	734.5	0.0	730.2	0.0	4.3
Full AMI	690.2	-44.3	690.2	-39.9	0.0
AMI + AMR in Gas-Only Territory	688.1	-46.4	686.7	-43.4	1.4
Full AMR	757.1	22.6	691.4	-38.8	65.7

As shown, AMI + AMR GO is the most cost-effective solution for the Companies' meter reading needs.

Q. Do customers want AMI?

A. Yes. The best indication of customer desire for AMI is our current AMS Opt-In Program. In October 2018, the Commission entered an order on the Companies' 2017 DSM-EE Program Plan Application[24] that continued the AMS Opt-In Program and modified it to increase the customer cap to 10,000 meters for each of KU and LG&E (electric only). LG&E became fully subscribed at 10,000 customers in May 2019 and KU became fully subscribed in June 2019 -- both within only eight months of the

[24] *In the Matter of: 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, Application (Dec. 6, 2017).

program expansion. Upon reaching full subscription, the Companies ceased direct education campaigns for the program but have allowed customers to continue to enroll but making clear to customers that they are waitlisted. As customers move or otherwise leave the program then a slot is made available to customers on the waitlist. To date, approximately 5,200 customers have enrolled on the waitlist for the AMS Opt-In Program.

Q. The Companies have proposed AMI previously and the Commission has not approved it. How is this proposal different?

A. In Case No. 2018-00005,[25] the Companies proposed a move to full AMI. Multiple entities participated in the case including the Office of the Attorney General ("OAG"). The OAG expressed numerous concerns about the Companies' AMI proposal and the Commission ultimately denied the Application without prejudice by Order dated August 30, 2018. In the Order, the Commission stated:

> The Commission sees the benefits in advanced metering. However, the Companies failed to provide sufficient evidence to persuade us that the AMS proposal satisfies the requirements of KRS 278.020(1) by demonstrating that the current meters are obsolete or that the benefits of the AMS proposal outweigh the costs here. Although the application is denied without prejudice, the Commission finds that the cap on the pilot opt-in AMS program should be increased from 5,000 LG&E and 5,000 KU residential and small commercial customers, to 10,000 LG&E and 10,000 KU residential and small commercial customers. The increased investment in AMS will not result in wasteful duplication because the pilot program meters can be used going forward if the Companies refile an application of AMS that satisfies the evidentiary requirements for a CPCN. The Commission strongly encourages the Companies to consider making usage data available to customers that is closer aligned

[25] *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.

> to real-time data and to consider prepay metering and real-time pricing options to enhance the customer experience.

Given the Order's acknowledgment of the benefits in advanced metering, its expansion of the Companies' pilot AMS program, recognition that the Companies may seek AMI approval in the future, and encouragement of what should be considered in such a future filing, the Companies are again asking for Commission approval of AMI in this case.

But as I have stated above, this proposal is different and addresses the major concerns expressed in Case No. 2018-00005.

The Companies' proposal in Case No. 2018-00005 included providing customers with usage data that would be 24 to 48 hours old. In 2019, the Companies implemented improvements to the data availability for participants in the pilot AMS Program that resulted in usage data typically being available within 4-6 hours which is effectively as soon as the Companies receive the usage data from the meters themselves. And as Robert M. Conroy's testimony explains, the Companies commit in this case that, if the Commission approves the proposed AMI deployment, they will offer innovative rate designs to ensure customers receive benefits from AMI beyond the operational savings that will be reflected in their bills following future rate cases. For example, the Companies commit to offering prepaid and time-of-day rates that AMI facilitates. Thus, we have squarely followed the Commission's encouragement in its closing remarks in Case No. 2018-00005.

In addition to those closing remarks in Case No. 2018-00005, the Commission and others had additional significant concerns regarding AMI. They were: (1) criticism of the Companies' cost-benefit analysis in that it was based on 20-year, 18-year, and 15-year meter service lives and only the 20-year analysis showed a net benefit; (2) the depreciable life of the meters in question is only 15 years, so use of a 18-year and 20-year periods is inappropriate; (3) the benefits to customers do not outweigh the costs especially given the lack of proof that existing meters are obsolete or no longer being manufactured or supported; (4) alternatives such as a more gradual rollout and AMR were not included; (5) the conservation resulting from customer's use of ePortal to monitor their energy use, was overstated; (6) the non-technical losses that would be avoided, such as theft of service, were overstated; (7) a failure to include the cost of prematurely retiring existing meters was not considered; and (8) the Companies declined to guarantee that the savings achieved would be provided to customers.

Q. Have the Companies addressed each of these concerns?

A. Yes. Given the result in Case No. 2018-00005, it is important to understand that the Companies went "back to the drawing board" and reanalyzed whether they should continue to pursue AMI or just keep replacing the same type of meters that have been used for decades. Our culture requires and our customers deserve continuous examination, and, if need be, reexamination of any means by which we can reduce costs while maintaining or improving service. This is especially true for something as significant as meter reading. So, as stated above, we did reanalyze this issue. In that reanalysis, we needed to consider new facts such as the significant increase in meter reading costs and the fuel savings that can be achieved via Conservation Voltage Reduction discussed Exhibit LEB-3. At the same time, as part of our reanalysis, we considered the concerns outlined above expressed by the Commission and participants in Case No. 2018-00005.

First, the analysis based on net present value revenue requirements is clear in the amount of net benefit, $46.4 million compared to the Status Quo, provided to customers by implementing the AMI + AMR GO.

Second, that analysis adopts a useful life for meters that is consistent with the depreciable life for meters of 15 years and further demonstrates that because the assumed meter operating life impacts costs in both the Status Quo and the AMI + AMR GO options, the assumed meter operating life has little impact on the analysis.

Third, we have looked thoroughly at the issue of whether existing electric meters are obsolete and we have determined that 734,000 of the Companies' 1,008,000 electric meters are electromechanical, obsolete, and are no longer being manufactured.[26]

Fourth, on the issue of whether more gradual rollout of AMI would be more cost-effective, the analysis shows that a more gradual rollout is favorable to the Status Quo but not as favorable as the proposed five-year deployment period because a more gradual rollout delays savings to customers.

Fifth, as to the criticism that the conservation arising from customers' use of ePortal were overstated in Case No. 2018-00005, we have reflected the savings as avoided fuel expenses rather than applying them to total bill revenue.

Sixth, as to the criticism that non-technical losses (such as theft prevention) were overstated in Case No. 2018-00005, we have completely removed them from the current analysis. Although those avoided losses are real and we expect to achieve them, we have addressed that concern by focusing the analysis on revenue requirements which are not impacted by non-technical losses. Certainly, to the extent that non-

[26] See LEB-3, p.7, Table 2.

technical losses are reduced, some customers will benefit from the attribution of those costs to those who caused them.

Seventh, as for the criticism that prematurely retiring costs of existing meters was not included, here again, the analysis shows that not prematurely retiring them actually costs customers. As Exhibit LEB-3 shows, the longer we wait to deploy AMI, the more we lose the opportunity to save money.[27]

Eighth and finally, as to whether savings achieved will be shared with customers, they will. Under the ratemaking proposal Mr. Blake presents, customers will enjoy the savings AMI will generate as a result of decreased meter reading costs and fewer truck rolls.

Q. What is Conservation Voltage Reduction and how is it important to AMI?

A. As Mr. Wolfe explains, Conservation Voltage Reduction ("CVR") is the ability to manage voltage down to the lower end of the range of acceptable voltage being delivered to customers. Acting as sensors throughout the system, AMI meters will give the Companies a very high degree of visibility of voltages with the system. We can then manage those voltages to the lower end of acceptable ranges and thereby achieving significant savings on fuel expense. These savings are incorporated into the analysis in Exhibit LEB-3 and are explained in detail in Appendix D of LEB-3. By monitoring and controlling capacitor banks, voltage regulators, and load tap changers, CVR can, in some cases, reduce energy consumption for customers on a circuit by up to 4% without negatively impacting the customer experience. When deployed only on high

[27] See LEB-3, Section 5.2.

value distribution feeders (roughly 40% of distribution feeders) the annual energy consumption may be reduced by 2%.

Q. Has the OAG recently commented on the Companies providing AMI?

A. Yes. In the Companies' recent IRP case, the OAG filed comments on the Companies' IRP Plan.[28] As to the issue of AMI, the OAG provided comments on the Companies' current Advanced Metering pilot program. The OAG said that the Companies should make usage data accessible on a near real-time basis and that time-of-day rates should be provided to maximize value to customers. The Companies agree with the OAG. As stated above, we now make usage data available as close to a real-time basis as the Companies receive the usage data and we commit to offering rates that will allow customers to take advantage of that data, including prepay pricing. Although we recognize that making instantaneous usage data available to the Companies and customers would be exciting, the cost of doing so now as part of full deployment is too high for the incremental benefit that would be realized. Therefore, we will work with individual customers who want instantaneous data by advising them of products they can purchase and install to obtain it.

Q. Will the cost of the AMI proposal have any effect on customer bills as a result of this case?

A. No, not if the AMI proposal is approved as proposed. As Mr. Blake's testimony explains, in connection with the AMI ratemaking proposal, the AMI investment is excluded from the revenue requirements calculations in these cases. We believe this

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[28] *Electronic 2018 Joint Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities*, Case No. 2018-00348, Attorney General's Comments (Ky. PSC July 30, 2020).

strikes a fair balance between allowing us to proceed with a proposal that is in the long-term best interests of customer and when customers should be expected to pay for it.

IX. SMART GRID INVESTMENT SUMMARY

Q. Please summarize the Companies' smart grid investments.

A. A table listing the Companies' smart grid investments by project is attached as Exhibit LEB-4 to my testimony. KU plans to spend approximately $72.7 million in smart grid investments from November 1, 2019 through December 31, 2021, and LG&E plans to spend $44.6 in smart grid investments during the same time period.

X. RESEARCH AND DEVELOPMENT

Q. Have the Companies been recognized for participation in innovative research projects?

A. Yes, the Companies have received a number of Technology Transfer Awards from the Electric Power Research Institute ("EPRI") in recent years. Award winners have shown exceptional application of EPRI research and technology in solving a problem of size and significance, championing a technology both within their companies and across the industry, driving progress in the electricity sector, and providing meaningful benefits for their companies' stakeholders and for society.

One project for which the Companies have been recognized by EPRI is geotechnical stability of ash ponds. The Companies participated in this project as host site for research on the condition of existing ponds and large-scale field loading tests on a closing ash pond. In the course of this project, a geotechnical centrifuge was used to physically simulate the volume and extent an ash release following a pond dike failure under varying levels of ash saturation. The results of this research are critical to understanding the processes controlling ash pond stability, implementing appropriate engineering controls and design features, and accurately predicting the consequences of berm or dam failure. The 8-year project, concluded in 2019, generated a number of technical reports and conference proceedings, which represent the state-of-the-art science in geotechnical characterization of ash ponds and will assist in safe ash pond closure throughout the country.

XI. CONCLUSION

Q. Do you have a recommendation to the Commission?

A. Yes, I recommend that the Companies' applications for a Certificate of Public Convenience and Necessity to deploy AMI be approved.

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

The undersigned, **Lonnie E. Bellar**, being duly sworn, deposes and says that he is Chief Operating Officer for Louisville Gas and Electric Company and Kentucky Utilities Company and an employee of LG&E and KU Services Company, and 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.

Lonnie Bellar

Lonnie E. Bellar

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 20th day of November 2020.

Judy Schooler

Notary Public

Notary Public, ID No. 603967

My Commission Expires:

July 11, 2022

APPENDIX A

Lonnie E. Bellar
Chief Operating Officer
Louisville Gas & Electric Company
Kentucky Utilities Company
220 West Main Street
Louisville, Kentucky 40202
Telephone: (502) 627-4830

Education

Bachelors in Electrical Engineering;
University of Kentucky, May 1987
Bachelors in Engineering Arts;
Georgetown College, May 1987
E.ON Academy, Intercultural Effectiveness Program: 2002-2003
E.ON Finance, Harvard Business School: 2003
E.ON Executive Pool: 2003-2007
E.ON Executive Program, Harvard Business School: 2006
E.ON Academy, Personal Awareness and Impact: 2006
Tuck Executive Education Program, Dartmouth University: 2015

Professional Experience

Louisville Gas & Electric Company
Kentucky Utilities Company

Chief Operating Officer	Mar. 2018 - Present
Sr. Vice President – Operations	Jan. 2017 – Mar. 2018
Vice President, Gas Distribution	Feb. 2013 –Jan. 2017
Vice President, State Regulation and Rates	Nov. 2010 – Jan. 2013

E.ON U.S. LLC

Vice President, State Regulation and Rates	Aug. 2007 – Nov. 2010
Director, Transmission	Sept. 2006 – Aug. 2007
Director, Financial Planning and Controlling	April 2005 – Sept. 2006
General Manager, Cane Run, Ohio Falls and Combustion Turbines	Feb. 2003 – April 2005
Director, Generation Services	Feb. 2000 – Feb. 2003
Manager, Generation Systems Planning	Sept. 1998 – Feb. 2000
Group Leader, Generation Planning and Sales Support	May 1998 – Sept. 1998

Kentucky Utilities Company

Manager, Generation Planning	Sept. 1995 – May 1998
Supervisor, Generation Planning	Jan. 1993 – Sept. 1995
Technical Engineer I, II and Senior, Generation System Planning	May 1987 – Jan. 1993

Professional Memberships

Institute of Electrical and Electronics Engineers

Civic Activities

Greater Louisville, Inc.
Board of Directors, Chair – 2020-Present
Board of Directors, Executive Committee – 2016–Present
LG&E and KU Power of One Chair - 2018
Kentucky Science Center – Board of Directors – 2008–2016
UK College of Engineering Advisory Board – 2009 – Present
American Gas Association – Board of Directors – 2013 – Present
Southern Gas Association – Board of Directors – 2013 – Present
Metro United Way Campaign – 2008
E.ON U.S. Power of One Co-Chair – 2007

Summary of Generation Plant of KU & LG&E

Generating Facility/Unit	Unit Type	Summer Net Capacity (MW)[1]	KU Ownership (%)	LG&E Ownership (%)
Brown 3	Coal-Fired	412	100%	n/a
Brown 5	CT	130	47%	53%
Brown 6, 7	CT	292	62%	38%
Brown 8, 9, 10, 11	CT	484	100%	n/a
Brown Solar	Solar	8	61%	39%
Cane Run 7	CCGT	662	78%	22%
Dix Dam 1, 2, 3	Hydroelectric	31.5	100%	n/a
Ghent 1, 2, 3, 4	Coal-Fired	1,919	100%	n/a
Haefling 1, 2	CT	24	100%	n/a
Mill Creek 1, 2, 3, 4	Coal-Fired	1,465	n/a	100%
Ohio Falls 1-8	Hydroelectric	64	n/a	100%
Paddy's Run 11, 12	CT	35	n/a	100%
Paddy's Run 13	CT	147	47%	53%
Simpsonville Solar (Solar Share)	Solar	0.7	56%	44%
Trimble County 1[2]	Coal-Fired	370	n/a	100%
Trimble County 2[3]	Coal-Fired	549	81%	19%
Trimble County 5, 6	CT	318	71%	29%
Trimble County 7, 8, 9, 10	CT	636	63%	37%
Zorn 1	CT	14	n/a	100%

[1] Ratings represent the 2020 net summer capacity of all listed units for the portions owned by KU and LG&E. The ratings for the solar and hydroelectric resources reflect the expected output at the time of peak summer demand.
[2] LG&E owns 100% of Trimble County 1 relative to KU and LG&E. However, LG&E owns only 75% of the unit's total generating capacity. The remaining 25 percent of Trimble County 1 is owned by Illinois Municipal Electric Agency ("IMEA") and Indiana Municipal Power Association ("IMPA").
[3] KU and LG&E combined own 75 percent of the generating capacity of Trimble County 2. The remaining 25 percent of Trimble County 2 is owned by IMEA and IMPA.

Analysis of Generating Unit Retirement Years

PPL companies

Generation Planning & Analysis
October 2020

Contents

1. Summary

The Companies own and operate approximately 7,561 MW of summer net generating capacity in Kentucky. The generating system consists of four coal-fired generating stations: the E.W. Brown Generating Station in Mercer County, the Ghent Generating Station in Carroll County, the Mill Creek Generating Station in Jefferson County, and Trimble County Generating Station. The purpose of this study was to examine the existing retirement dates for certain coal-fired generating units as reflected in existing depreciation rates based on maintaining system reliability to determine whether they were reasonable based on the changes in operational and economic circumstances and, if not, to determine reasonable retirement years. This report explains the basis for the updates to the retirement years for the generating units shown in Table 1. The updated retirement years are estimates of the currently expected operating lives of these generating units. Actual retirement dates may vary depending on the circumstances involving the generating unit and operational factors that may emerge in the future. The Companies will continue to assess these retirement dates.[1]

Table 1 - Retirement Years, Current vs. Updated

	Retirement Years	
	Current	**Updated**
Brown Unit 3 ("BR3")	2035	2028
Ghent Unit 4 ("GH4")	2038	2037
Mill Creek Unit 1 ("MC1")	2032	2024
Mill Creek Unit 2 ("MC2")	2034	2028
Mill Creek Unit 3 ("MC3")	2038	2039
Mill Creek Unit 4 ("MC4")	2042	2039
Trimble Count Unit 1 ("TC1")	2050	2045

2. Mill Creek Unit 1

As presented in LG&E's 2020 ECR Plan, due to the cost of complying with Effluent Limitation Guidelines ("ELG"), MC1 will be retiring at the end of 2024.[2] Retiring MC1 on December 31, 2024 is lower cost than investing in the water treatment facilities that would be required to comply with ELG and continue its operation beyond December 31, 2024. As a result, it is no longer reasonable to continue to use 2032 as the retirement year for MC1. Based on current capacity and demand projections, the Companies are not planning for immediate replacement of MC1's generating capacity.

3. Ghent Unit 4, Mill Creek Units 3 and 4, and Trimble County Unit 1

Based on their current retirement years, GH4, MC3, and MC4 would be the last coal-fired units to retire before the retirements of the newer Trimble County units. The Companies have decided to delay the retirement year for MC3 by one year and to advance the retirement years by one year for GH4 and three years for MC4. These changes align the retirement years of Ghent Units 3 and 4 in 2037 and Mill Creek

[1] The results of this study were provided to Mr. John J. Spanos for purposes of independent assessment in connection with possible changes to existing depreciation rates.

[2] *Electronic Application of Louisville Gas and Electric Company for Approval of its 2020 Compliance Plan for Recovery by Environmental Surcharge*, Case No. 2020-00061, Direct Testimony of Stuart A. Wilson (Ky. PSC Mar. 31, 2020).

Units 3 and 4 in 2039 and reduce major maintenance costs on MC4 in 2038. This alignment also allows for planning a more orderly closure of the Ghent and Mill Creek stations and the potential for more cost-effective replacement of their collective capacities through economies of scale and coordinated procurement, construction or both. The Companies also are advancing the retirement year for TC1 to 2045, reflecting an expected age at retirement of 55 years, which better aligns with the expected lives of the Companies' other remaining coal units.

4. Mill Creek Unit 2 and Brown Unit 3

4.1. Mill Creek Unit 2 Background

2015 Ozone NAAQS

The Mill Creek station is in Jefferson County, Kentucky and currently operates four coal-fired units. Jefferson County is currently classified as marginal non-attainment to the 2015 Ozone National Ambient Air Quality Standard ("NAAQS") with a compliance date of August 2021. In 2020, the Kentucky Energy and Environment Cabinet and the Louisville Metro Air Pollution Control District ("LMAPCD") imposed additional daily limitations on nitrogen oxides ("NO_x") emissions at the Mill Creek station for the months of May through October. Despite the Companies' efforts to meet these limits, there were exceedances of the 70 ppb ozone standard in the Jefferson County area during the 2020 ozone season. LMAPCD has stated that Jefferson County will not be "in compliance" with the 2015 Ozone NAAQS by August 2021 due to these exceedances in 2020. LMAPCD currently anticipates reclassification to moderate non-attainment in 2022 and Title V facilities in Jefferson County will be required to implement NO_x Reasonable Available Control Technology ("RACT") by March 1, 2023. In the interim, the Companies expect that the ozone season NO_x limit for the MC station will remain in place pending development of the NO_x RACT standard. Therefore, LG&E will likely be limited to operating either MC1 or MC2 (but not both) during the ozone season (i.e., April through October) until MC1 retires.

Upon reclassification to moderate non-attainment with the 2015 Ozone NAAQS, Jefferson County will have a moderate non-attainment compliance date of August 3, 2024. The State Implementation Plan ("SIP") must be amended to include the RACT standards by April 2024. The NO_x emission reduction associated with the implementation of RACT at Mill Creek Station is expected to be similar to the mode of operation at Mill Creek during the summer of 2020. However, during the summer of 2020, there were still exceedances of the 70 ppb ozone standard in the Jefferson County area.

Continued non-attainment past the 2024 compliance date will result in Kentucky reevaluating RACT for the Jefferson County area in order to further reduce NO_x emissions or cause the non-attainment area to be reclassified to serious non-attainment. Such a reclassification would require additional NO_x emission reductions, which must be demonstrated by August 2027. LG&E will likely be required to install additional NO_x controls on MC2 such as selective catalytic reduction ("SCR") to achieve these reductions and continue to operate the unit.

2025 Ozone NAAQS

The Clean Air Act requires that NAAQS be evaluated every five years. The ozone and $PM_{2.5}$ NAAQS were reevaluated in 2020. EPA retained the current standard of 70 ppb for ozone and 12.0 $\mu g/m^3$ for $PM_{2.5}$. Prior to EPA's proposal to retain the current standards, many environmental groups and members on the Clean Air Scientific Advisory Committee presented data for a lower standard of 65 – 68 ppb for ozone and 10-11 $\mu g/m^3$ for $PM_{2.5}$. Both standards will be reevaluated again in 2025. At this time, there is every reason to expect both standards will be lowered following the reevaluation in 2025. Jefferson County is likely not to meet either standard. Therefore, even if Jefferson County has achieved attainment of the 70 ppb ozone standard by August 2024, it is likely that the standard would be lowered in 2025, and, once again, Jefferson County will be determined to be non-attainment for ozone. Such a determination will start the process of establishing a new RACT and implementing further NO_x reductions at all sources, including the Mill Creek station. Based on the timeframe for implementing lowered NAAQS, it is likely additional controls would be required for MC2 by 2029.

CSAPR Requirements

An additional contingency arises under EPA's interstate transport rules for NO_x that ensure that the northeastern states are meeting the ozone standards and are not exceeding these standards due to interstate transport. EPA's Cross-State Air Pollution Rule ("CSAPR") regulations were developed to accomplish this requirement. Currently certain areas in the northeastern states are not meeting the 2008 (75 ppb) ozone standard. To address this issue, on October 15, 2020, EPA issued the proposed Revised CSAPR Update rule, which will significantly reduce the NO_x allowances issued to Kentucky. Based on their modeling, electric generating units in Kentucky have an impact exceeding a screening threshold on the northeastern non-attainment areas. Additional controls at our non-SCR-equipped units may be required because of the reduced allocation of NO_x emissions allowances for Kentucky and the LG&E and KU fleet. Additional allowances will be limited under the proposed rule; and trading will be restricted to the twelve states EPA is assigning to the "Group 3" Trading Group. Because this allowance reduction was necessary to meet the 2008 (75 ppb) standard by 2021, it is reasonable to expect that even greater NO_x reductions will be necessary in order to meet a 70 ppb ozone standard.

Regional Haze

A final environmental contingency is the possible changes from the Regional Haze 3rd Planning period. Mill Creek Units 3 and 4 have permit limits from the 1st planning period to meet the visibility criteria for Mammoth Cave National Park under the rule. Mill Creek did not have to take further restrictions for the 2nd planning period due to Kentucky visibility falling well below the glide path of visibility impaired days required by the regulation for 2030. EPA's requirements for implementation of the 3rd planning period of the Regional Haze regulation will likely be published in 2028 for states to model sources impacting visibility in national parks. Kentucky is not currently below the glide path required in the next planning period. Because Mill Creek is relatively close to Mammoth Cave National Park, Units 1 and 2 could be required in the next planning period to evaluate additional controls to improve visibility at the park.

In summary, the Companies expect that SCR will be required on MC2 between 2027 and 2029 to comply with current and future NAAQS. Uncertainty related to the EPA's CSAPR regulations and the Regional Haze rule further supports this assumption. Therefore, the Companies have assumed that SCR will be required on MC2 in 2028 to operate MC2 beyond 2028. The SCR investment is approximately $135 million. Additionally, an investment in major maintenance will be required in 2026 if MC2 is planned to remain in service beyond 2028. As of 2020, MC2 is 46 years old. Its current retirement year is 2034. This analysis will determine whether either of these future investments is economically warranted and if they are not, then the current 2034 retirement year is not reasonable, and a new date must be determined.

4.2. Brown Unit 3 Background

As of 2020, BR3 is 49 years old. BR3's current retirement year is 2035. Since the retirement of Brown Units 1 and 2 in 2019, BR3 is the single remaining coal unit at the Brown Station. BR3's delivered fuel cost is higher than that of the Companies' other coal units because coal is only delivered by rail. The higher delivered fuel cost causes BR3 to operate at a significantly lower capacity factor.[3] It is outfitted with full emissions controls and its last major maintenance overhaul was in 2019.[4] A total investment in major maintenance of approximately $31 million will be required in 2026 and 2027 to continue its operation beyond 2028. An evaluation of those investments is necessary to determine if BR3's current retirement year is reasonable, or if a new retirement year should be set based on the ability to operate the unit absent these major maintenance investments.

4.3. Analysis Methodology

Given the expectations regarding compliance with environmental regulations, forecasts for required future investments, the resultant physical life of the units, and the need for replacement generation, the Companies evaluated advancing the retirement years for MC2 and BR3. The analysis was performed to determine whether the existing retirement years are reasonable and if not to determine reasonable retirement years based on current information.

Before committing to actual retirement dates, the Companies plan to evaluate the ability to replace the units as needed to continue to supply reliable, reasonable cost energy based on actual proposals from third party suppliers (gathered via a request for proposals) and self-build alternatives. The results of this process would be filed with the Kentucky Public Service Commission in an application for a Certificate of Public Convenience and Necessity.

As set forth above, MC2 is expected to require an approximately $135 million investment in SCR on or before 2028 to continue operation beyond 2028. Accordingly, the Companies are advancing the MC2 retirement year to 2028. Likewise, a 2028 retirement year was selected for BR3 because 2028 is the longest BR3 can operate without the investments in 2026 and 2027 for major maintenance. The present value of revenue requirements ("PVRR") for each alternative was computed as the PVRR of the following cost and revenue items:

1. Generation system production costs
2. Existing unit stay-open costs, including ELG compliance costs and associated O&M
3. Existing unit revenues from the sale of coal combustion residuals ("CCR")
4. Capital and stay-open costs for replacement generation units

Generation production costs for the LG&E and KU system were computed using the PROSYM production cost model from Hitachi ABB. The PVRR for all alternatives include the full PVRR for capital expenditures, even when a unit is retired before it is fully depreciated. The analysis also assumes that MC2 and BR3 would otherwise be retired by their current retirement years, 2034 and 2035, respectively. Therefore, later retirement is assumed to defer the cost of any replacement generation, but not eliminate this cost altogether. The Companies initially evaluated the retirement year for MC2, given the NAAQS compliance issues and the high cost of investing in a SCR. The Companies then evaluated the retirement year for Brown 3.

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[3] BR3's capacity factor was 28%, 35%, and 25%, in 2017, 2018, and 2019, respectively. It is forecasted to operate at a capacity factor of 24%, 22%, and 26% in 2021, 2022, and 2023, respectively.

[4] BR3's emissions controls include low NO_x burners, SCR, dry electrostatic precipitator, dry sorbent injection, powdered activated carbon injection, pulse jet fabric filter, and dry flue gas desulfurization.

For this analysis, the Companies assumed that MC2 and BR3 would be replaced with capacity from simple-cycle combustion turbines ("CTs") to create a generation portfolio that is minimally compliant for reliability, obviating the need to consider a range of fuel prices or a range of potential replacement alternatives. The point of this study was not to identify a potentially optimal future portfolio. As mentioned above, the Companies will issue a request for proposals to determine the optimal replacement resources and help inform the actual retirement dates for each of these units. The goal of this study is to determine whether the current estimated retirement years for MC2 and BR3 are reasonable given current information regarding the likely costs of operating the units to the currently projected dates.

4.4. Analysis

A primary consideration when contemplating unit retirements is the need to maintain a sufficient reserve margin for summer peak reliability. The following tables show the calculation of annual forecasted summer reserve margins and include the following assumptions:

- The Companies' 2021 Business Plan peak demand forecast;
- MC2 (297 MW) is unavailable from April through October in 2021-2024 due to the expected continuing limitation on NO_x emissions from the Mill Creek station;
- MC1 (300 MW) retires at the end of 2024; and
- Zorn (14 MW) retires at the end of 2021; the Companies remaining small-frame CTs (59 MW)[5] retire at the end of 2025.
- For presentation purposes, no additional retirements beyond 2030 are assumed.

Table 2 shows the forecasted summer reserve margins through 2035 with no coal unit retirements after MC1's retirement at the end of 2024. Table 3 shows the reserve margins assuming that MC2 retires in 2028 without replacement. Because the reserve margin remains above the lower end of the Companies' target reserve margin range of 17 percent to 25 percent, it is assumed that MC1 and MC2 can be retired without replacement. Table 4 shows the reserve margins assuming that BR3 also retires in 2028 without replacement. To maintain a 17 percent reserve margin in 2028, 278 MW of replacement capacity is needed. As a proxy for commercially available replacement capacity, the Companies assumed that two CTs similar to the Companies' existing CTs at the Trimble County station would provide this replacement capacity with net summer ratings of 159 MW each. Table 5 shows that the forecasted reserve margins with this additional 318 MW of capacity are within the Companies' target reserve margin range.

[5] The remaining small-frame CTs are Haefling 1 (12 MW), Haefling 2 (12 MW), Paddy's Run 11 (12 MW), and Paddy's Run 12 (23 MW).

Table 2 - Reserve Margin with MC1 and Small Frame CTs Retirements (MW)

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Gross Peak Load	6,399	6,433	6,430	6,428	6,420	6,406	6,391	6,369	6,358	6,344	6,332	6,324	6,325	6,320	6,320
Energy Efficiency/Demand Side Mgmt.	(288)	(294)	(300)	(305)	(311)	(311)	(311)	(311)	(311)	(311)	(311)	(311)	(311)	(311)	(311)
Net Peak Load	**6,111**	**6,139**	**6,130**	**6,123**	**6,109**	**6,095**	**6,080**	**6,058**	**6,047**	**6,033**	**6,021**	**6,013**	**6,014**	**6,009**	**6,009**
Existing Generation Resources	7,711	7,712	7,712	7,712	7,713	7,713	7,713	7,713	7,713	7,713	7,713	7,713	7,713	7,713	7,713
Curtailable Load (CSR)	127	127	127	127	127	127	127	127	127	127	127	127	127	127	127
Direct Load Control (DLC)	63	61	60	58	56	55	53	52	50	49	48	47	46	45	44
Small-Frame CT Retirements	0	(14)	(14)	(14)	(14)	(73)	(73)	(73)	(73)	(73)	(73)	(73)	(73)	(73)	(73)
MC2 Unavailable	(297)	(297)	(297)	(297)											
MC1 Retirement					(300)	(300)	(300)	(300)	(300)	(300)	(300)	(300)	(300)	(300)	(300)
Total Resources Net of MC1 and Small-Frame CTs Retirements	**7,604**	**7,589**	**7,588**	**7,586**	**7,582**	**7,522**	**7,520**	**7,519**	**7,517**	**7,516**	**7,515**	**7,514**	**7,513**	**7,512**	**7,511**
Reserve Margin %	**24.4%**	**23.6%**	**23.8%**	**23.9%**	**24.1%**	**23.4%**	**23.7%**	**24.1%**	**24.3%**	**24.6%**	**24.8%**	**25.0%**	**24.9%**	**25.0%**	**25.0%**
Reserve Margin Deficit vs. 17%	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**

Table 3 - Reserve Margin with Incremental MC2 Retirement in 2028 (MW)

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Net Peak Load	**6,111**	**6,139**	**6,130**	**6,123**	**6,109**	**6,095**	**6,080**	**6,058**	**6,047**	**6,033**	**6,021**	**6,013**	**6,014**	**6,009**	**6,009**
Total Resources Net of MC1 and Small-Frame CTs Retirements	7,604	7,589	7,588	7,586	7,582	7,522	7,520	7,519	7,517	7,516	7,515	7,514	7,513	7,512	7,511
MC2 Retirement in 2028								(297)	(297)	(297)	(297)	(297)	(297)	(297)	(297)
Totals Resources Net of MC1, Small-Frame CTs, and MC2 Retirements	**7,604**	**7,589**	**7,588**	**7,586**	**7,582**	**7,522**	**7,520**	**7,222**	**7,220**	**7,219**	**7,218**	**7,217**	**7,216**	**7,215**	**7,214**
Reserve Margin %	**24.4%**	**23.6%**	**23.8%**	**23.9%**	**24.1%**	**23.4%**	**23.7%**	**19.2%**	**19.4%**	**19.7%**	**19.9%**	**20.0%**	**20.0%**	**20.1%**	**20.0%**
Reserve Margin Deficit vs. 17%	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**

Table 4 - Reserve Margin with Incremental BR3 Retirement in 2028 (MW)

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Net Peak Load	6,111	6,139	6,130	6,123	6,109	6,095	6,080	6,058	6,047	6,033	6,021	6,013	6,014	6,009	6,009
Totals Resources Net of MC1, Small-Frame CTs, and MC2 Retirements	7,604	7,589	7,588	7,586	7,582	7,522	7,520	7,222	7,220	7,219	7,218	7,217	7,216	7,215	7,214
BR3 Retirement in 2028								(412)	(412)	(412)	(412)	(412)	(412)	(412)	(412)
Totals Resources Net of MC1, Small-Frame CTs, MC2, and BR3 Retirements	7,604	7,589	7,588	7,586	7,582	7,522	7,520	6,810	6,808	6,807	6,806	6,805	6,804	6,803	6,802
Reserve Margin %	24.4%	23.6%	23.8%	23.9%	24.1%	23.4%	23.7%	12.4%	12.6%	12.8%	13.0%	13.2%	13.1%	13.2%	13.2%
Reserve Margin Deficit vs. 17%	NA	NA	NA	NA	NA	NA	NA	278	267	252	239	231	233	228	229

Table 5 - Reserve Margin with Capacity Addition in 2028 (MW)

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Net Peak Load	6,111	6,139	6,130	6,123	6,109	6,095	6,080	6,058	6,047	6,033	6,021	6,013	6,014	6,009	6,009
Totals Resources Net of MC1, Small-Frame CTs, MC2, and BR3 Retirements	7,604	7,589	7,588	7,586	7,582	7,522	7,520	6,810	6,808	6,807	6,806	6,805	6,804	6,803	6,802
Additional 2 CTs								+318	+318	+318	+318	+318	+318	+318	+318
Totals Resources Net of MC1, Small-Frame CTs, MC2, and BR3 Retirements	7,604	7,589	7,588	7,586	7,582	7,522	7,520	7,128	7,126	7,125	7,124	7,123	7,122	7,121	7,120
Reserve Margin %	24.4%	23.6%	23.8%	23.9%	24.1%	23.4%	23.7%	17.7%	17.8%	18.1%	18.3%	18.5%	18.4%	18.5%	18.5%
Reserve Margin Deficit vs. 17%	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA

4.4.1. Mill Creek Unit 2

MC2's current retirement year is 2034. As discussed in Section 4.1, the Companies expect that SCR will be required for MC2 by 2028 in order to continue operating beyond 2028. The cost of SCR for MC2 is estimated to be at least $135 million in 2020 dollars. Furthermore, an investment in major maintenance in 2026 of $5.5 million in capital and $5.0 million in O&M costs would be required for MC2 to continue operating until 2034. Table 6 shows the difference in annual revenue requirements and PVRR between retiring MC2 in 2028 and 2034, assuming that the SCR and major maintenance expenditure could be avoided with the 2028 retirement date. It is assumed that MC2 would otherwise retire in 2034, so there are no differences in revenue requirements in 2034 and beyond. Additional savings from retiring MC2 in 2028 result from avoiding MC2's stay-open costs, which are partially offset by production cost increases and foregone CCR sales revenue. Because MC2 can be retired without replacement as shown in Table 3, there are no incremental costs for new capacity to replace MC2. The total net PVRR ("NPVRR") impact of retiring MC2 in 2028 is a savings of $131.2 million.

Table 6 – Revenue Requirement Increases/(Savings) of Retiring MC2 in 2028 vs. 2034 ($M)[6]

	2026	2027	2028	2029	2030	2031	2032	2033
Production Costs	0	0	14.2	13.9	15.2	16.2	16.6	15.4
Stay Open Costs	0	0	(26.9)	(22.3)	(30.6)	(23.0)	(31.9)	(24.0)
SCR Cost	0	0	(166.1)	0	0	0	0	0
Major Maintenance	(11.7)	0	0	0	0	0	0	0
CCR Revenue	0	0	2.9	3.0	3.1	3.2	3.2	3.1
Total	**(11.7)**	**0**	**(175.9)**	**(5.5)**	**(12.3)**	**(3.6)**	**(12.1)**	**(5.5)**
NPVRR (2020)	**(131.2)**							

As a result of the likely need for the uneconomic investment in SCR in order to operate MC2 beyond 2028, it is unreasonable to continue to use 2034 as the retirement year. Given that compliance with likely additional NAAQS ozone standards would be required by 2028, that year represents a reasonable retirement year.

4.4.2. Brown Unit 3

BR3's current retirement year is 2035. An investment in major maintenance in 2026 and 2027 of $23.1 million in capital and $8 million in O&M costs would be required for BR3 to continue operating until 2035. Given the savings from retiring MC2 in 2028, the analysis of BR3's retirement year assumes that MC2 will retire in 2028. As shown in Table 4, retiring MC2 and BR3 in 2028 results in a minimum capacity need of 278 MW in 2028 to maintain a reserve margin within the Companies' target reserve margin range. To meet this reserve margin deficit, the Companies modeled replacement capacity comprising two CTs with the same characteristics as their existing Trimble County CTs, for a total additional capacity of 318 MW.

Table 7 shows the difference in annual revenue requirements and PVRR between retiring BR3 in 2028 and 2035. It is assumed that BR3 would otherwise retire in 2035, so there are no differences in revenue

[6] For presentation purposes, the PVRR is shown for capital expenditures in the year incurred rather than the annual revenue requirements.

requirements in 2035 and beyond. In addition to the savings from avoiding the major maintenance investments in 2026 and 2027, retiring BR3 in 2028 results in the savings of its stay open costs through 2034 and a small amount of additional CCR revenue achieved by transferring some of BR3's generation to other coal units with more favorable CCR sales opportunities. These savings are more than offset on an annual basis by increases in production costs and the carrying cost of the required capacity additions. The NPVRR impact of retiring BR3 in 2028 is a revenue requirements savings of $40 million. Therefore, the existing 2035 retirement date is unreasonable and replacing it with 2028 is more reasonable given the potential to avoid major maintenance and lower overall revenue requirements with replacement generation by 2028.

Table 7 - Revenue Requirement Increases/(Savings) of Retiring BR3 in 2028 vs. 2034 ($M)[7]

	2026	2027	2028	2029	2030	2031	2032	2033	2034
Production Costs	0	0	3.3	5.7	5.4	6.1	6.8	7.8	5.0
Stay Open Costs	0	0	(40.3)	(39.5)	(40.5)	(41.3)	(42.1)	(43.0)	(43.8)
Major Maintenance	(13.9)	(22.1)	0	0	0	0	0	0	0
CCR Revenue	0	0	(0.1)	(0.1)	(0.2)	(0.2)	(0.3)	(0.2)	(0.1)
Capacity Additions	0	0	29.5	30.1	30.6	31.2	31.7	32.3	32.9
Total	**(13.9)**	**(22.1)**	**(7.5)**	**(3.9)**	**(4.7)**	**(4.2)**	**(3.9)**	**(3.0)**	**(6.0)**
NPVRR (2020)	**(40.0)**								

The analysis focused only on maintaining system reliability. Therefore, when the Companies evaluate actual potential replacement alternatives for BR3, resource additions with the potential to lower energy costs (e.g., renewables and natural gas combined cycle) will provide additional information on the retirement date for BR3.

5. Appendix - Key Analysis Inputs and Assumptions

5.1. Existing Unit Stay-Open Costs

Stay-open costs for an existing unit include the unit's ongoing capital and fixed operating and maintenance ("O&M") costs. These costs are required to continue operating the unit and saved if the unit is retired. Table 8 lists total stay-open costs for the Companies' coal units assuming no changes in current economic lives . Costs that are shared by all units are allocated to units in proportion to how they would be reduced as units retire. Total stay-open costs include costs for regular maintenance and major maintenance; the analysis assumes the additional costs for major maintenance within eight years of retirement can be avoided. Beyond 2030, stay-open costs are assumed to escalate at two percent per year.

[7] For presentation purposes, the PVRR is shown for capital expenditures in the year incurred rather than the annual revenue requirements.

Table 8 – Stay-Open Costs ($M, Nominal Dollars)

Total Stay-Open Costs	2026	2027	2028	2029	2030	2031	2032	2033	2034
MC2 – major maintenance	10.5	-	-	-	-	-	-	-	-
MC2 – annual	26.0	19.5	25.0	20.6	28.2	21.2	29.3	22.0	-
BR3 – major maintenance	11.4	19.6	-	-	-	-	-	-	-
BR3 – annual	35.8	37.1	38.7	37.9	38.9	39.7	40.4	41.3	42.1

5.2. CCR Revenue Assumptions

Coal combustion residuals ("CCR") include fly ash, bottom ash, and gypsum. CCR is either used for onsite construction projects, sold to third parties for use in the production of products like cement and wallboard, or stored in an onsite landfill. When sold to a third party, the beneficial use of CCR materials is included in the Environmental Surcharge Mechanism as a credit to offset environmental compliance costs. In 2019, CCR sales revenues totaled $9 million.

In recent years, as coal units have retired in the U.S., the market supply of CCR has decreased and the market price for CCR has increased. Table 9 lists the assumed sales prices for fly ash and gypsum from Mill Creek, Ghent, and Trimble County in this analysis. The sales prices are weighted average prices based on existing contracts rolling to market prices as existing contracts expire. The current market price for Mill Creek, Ghent, and Trimble County gypsum is approximately $10 per ton. The current market price for Mill Creek fly ash is approximately $32 per ton; based on current contracts, the Companies expect to receive 80% of market value for Mill Creek fly ash, or $25.60 per ton. The current market price for Ghent fly ash is approximately $30 per ton; based on current contracts, the Companies expect to receive 80% of market value for Mill Creek fly ash, or $24 per ton. The current market price for Trimble fly ash is approximately $9 per ton. CCR market prices are assumed to escalate at two percent per year.

Because Brown has no local market for either fly ash or gypsum, and because additional CCR loading systems at Brown are not economical, CCR revenue from Brown is assumed to be zero.

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Table 9 – Sales Price for CCR Sales ($/ton) (Confidential and Proprietary Information)

	Mill Creek		Ghent		Trimble	
Year	**Fly Ash**	**Gypsum**	**Fly Ash**	**Gypsum**	**Fly Ash**	**Gypsum**
2021	[redacted]					
2022	[redacted]					
2023	[redacted]					
2024	[redacted]					
2025	[redacted]					
2026	[redacted]					
2027	[redacted]					
2028	[redacted]					
2029	[redacted]					
2030	[redacted]					
2031	[redacted]					
2032	[redacted]					
2033	[redacted]					
2034	[redacted]					
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2037	[redacted]					
2038	[redacted]					
2039	[redacted]					
2040	[redacted]					
2041	[redacted]					
2042	[redacted]					
2043	[redacted]					
2044	[redacted]					
2045	[redacted]					
2046	[redacted]					
2047	[redacted]					
2048	[redacted]					
2049	[redacted]					
2050	[redacted]					

Table 10 lists the percent of fly ash and gypsum produced at Brown and Mill Creek that is assumed to be sold to third parties.

Table 10 – Percent of CCR Production Sold to Third Parties

Station	Fly Ash	Gypsum
Brown	0%	0%
Mill Creek	80%	97%

5.3. Fuel Prices

Fuel prices are assumed to escalate throughout the analysis period. Table 11 shows undelivered natural gas and coal price forecasts, which were developed for the Companies' 2021 Business Plan.

The Henry Hub natural gas price forecast reflects a blend of NYMEX market prices and a smoothed version of the Energy Information Administration's ("EIA's") 2020 Annual Energy Outlook ("AEO") High Oil and Gas Resource and Technology case through 2030, after which the smoothed EIA case was solely used. This case assumes higher resource availability and technological advancement, which results in lower production costs and continued growth in oil and gas production, compared to EIA's AEO 2020 Reference Case.

The Illinois Basin FOB mine coal price reflects a blend of coal price bids the Companies received, and a long-term price forecast developed by S&P Global Platts through 2025. In 2026 and beyond, the 2025 price was escalated by the coal escalation rate provided in the EIA's 2020 AEO High Oil and Gas Resource and Technology case.

CONFIDENTIAL INFORMATION REDACTED

Table 11 – Fuel Prices, Undelivered (Nominal $/mmBtu) (Confidential and Proprietary Information)

	Natural Gas[8]	Coal[9]
2021	[redacted]	[redacted]
2022	[redacted]	[redacted]
2023	[redacted]	[redacted]
2024	[redacted]	[redacted]
2025	[redacted]	[redacted]
2026	[redacted]	[redacted]
2027	[redacted]	[redacted]
2028	[redacted]	[redacted]
2029	[redacted]	[redacted]
2030	[redacted]	[redacted]
2031	[redacted]	[redacted]
2032	[redacted]	[redacted]
2033	[redacted]	[redacted]
2034	[redacted]	[redacted]
2035	[redacted]	[redacted]
2036	[redacted]	[redacted]
2037	[redacted]	[redacted]
2038	[redacted]	[redacted]
2039	[redacted]	[redacted]
2040	[redacted]	[redacted]
2041	[redacted]	[redacted]
2042	[redacted]	[redacted]
2043	[redacted]	[redacted]
2044	[redacted]	[redacted]
2045	[redacted]	[redacted]
2046	[redacted]	[redacted]
2047	[redacted]	[redacted]
2048	[redacted]	[redacted]
2049	[redacted]	[redacted]
2050	[redacted]	[redacted]

[8] Henry Hub.
[9] Illinois Basin FOB mine.

5.4. Replacement CT Assumptions

Table 12 shows the assumed characteristics of the CTs that were modeled as replacement capacity.

Table 12 – Replacement CT Assumptions (2020 In-Service; 2019 Dollars)

	Peaking Capacity (SCCT)
Capital Cost ($/kW)	586
Fixed O&M ($/kW-yr)	12.7
Firm Gas Cost ($/kW-yr)	22.7
Start Cost - maintenance ($/Start)	11,147
Heat Rate (MMBtu/MWh)	10.9
Transmission Cost ($/MW-Yr)	N/A
Nominal O&M Cost Escalation	2%
Summer Net Capacity (MW)	159
Winter Net Capacity (MW)	179

5.5. Financial Assumptions

Table 13 lists the inputs used to compute capital revenue requirements in this analysis.

Table 13 – Financial Assumptions

	Combined Companies
% Debt	47%
% Equity	53%
Cost of Debt	4.02%
Cost of Equity	10.0%
Tax Rate	24.95%
Property Tax Rate	0.15%
Insurance Rate	0.0254%
WACC (After-Tax)	6.75%

Analysis of Metering Alternatives

PPL companies

October 2020

CONFIDENTIAL INFORMATION REDACTED

Contents

1. Executive Summary

The Companies' meter assets include approximately 1 million electric meters and 340,000 gas meters. Approximately 75% of electric meters are electromechanical meters and have an average age of 32 years. Electromechanical meters are no longer manufactured and annual meter replacements are forecasted to increase over time as longer-lived meters are replaced as they fail with shorter-lived non-communicating electronic meters. Each month, the Companies manually read most meters and manually provide meter-related services ("field services") such as connecting and disconnecting meters for service. Effective 2019, total annual contract costs for meter reading and field services increased by $5.8 million (45%). Prior contracts executed in 2014 did not allow for annual increases, so spending on these services was well under market at the end of the contract terms.

Given this increase and the forecasted increase in the number of annual meter replacements, the Companies completed an analysis of metering alternatives to determine the best alternative for reliably serving customers at the lowest reasonable cost. The analysis considered alternatives with Advanced Metering Infrastructure ("AMI") and Automatic Meter Reading ("AMR") metering technologies in addition to a "Status Quo" alternative where the Companies continue to replace existing meters as they fail with non-communicating electronic meters.

The long-term viability of AMR is a key uncertainty in this analysis. The Companies issued a request for information ("RFI") in March 2020 to gather information from meter vendors regarding the future availability and pricing for various meter types. The responses, which are summarized in Appendix B – Metering RFI Summary, indicate that only one vendor is committing to future AMR research and investment. Moving forward, AMR metering costs are more likely to escalate faster than other metering technologies, and the risk of obsolescence for AMR meters is high. For this reason, the Companies evaluated the metering alternatives under two AMR obsolescence scenarios: one where AMR becomes obsolete midway through the analysis period and one where AMR remains viable for the full 30-year analysis period.

The financial analysis is focused entirely on revenue requirements and sets aside difficult-to-quantify benefits for the AMI alternatives like improved customer experience, the reduction of non-technical losses, and the ability to offer programs like prepay that depend on AMI. In both AMR obsolescence scenarios, AMI is the least-cost metering technology for electric customers and most gas customers, and AMR is least-cost in portions of the LG&E gas service territory where neither LG&E nor KU provides electric service ("gas-only" service territory). As seen in Table 1, the present value of revenue requirements ("PVRR") for this metering alternative ("AMI + AMR in the Gas-Only Territory" or "AMI+AMR_GO") is $53.3 million favorable to the Status Quo when AMR is assumed to become obsolete and $50.4 favorable when AMR is assumed to remain viable. The major drivers of PVRR differences in this analysis are meter reading and field services costs, new meter costs, and two forms of fuel savings: (1) those resulting from the ability with AMI to reduce customers' energy requirements by incrementally lowering distribution voltages through Conservation Voltage Reduction ("CVR"); and (2) those resulting from customers choosing to reduce their energy usage due to access to enhanced usage data made available by AMI through the Companies' online ePortal system. The AMI+AMR_GO alternative has higher new meter costs than the Status Quo alternative but significantly lower meter reading and field services costs as well as fuel savings.

Table 1: PVRR Summary ($M, 2020 Dollars, 2021-2050)

Alternative	AMR Becomes Obsolete		AMR Remains Viable		AMR Obsolescence Risk (A less B)
	PVRR (A)	PVRR Delta to Status Quo	PVRR (B)	PVRR Delta to Status Quo	
Status Quo	734.2	0.0	729.9	0.0	4.3
Full AMI	683.0	-51.3	683.0	-47.0	0.0
AMI + AMR in Gas-Only Territory	680.9	-53.3	679.6	-50.4	1.3
Full AMR	749.3	15.0	687.8	-42.1	61.4

Unsurprisingly, the unfavorable impact of AMR obsolescence is greatest for the Full AMR alternative. The Companies currently read approximately 105,000 electric and gas meters by vehicle using AMR metering technology. This number is reduced to 19,000 in the AMI+AMR_GO alternative and zero in the Full AMI alternative. Based on this analysis and the forecasted increases in meter reading and field services costs, if the Companies installed AMR throughout the LG&E and KU service territories and then AMR became obsolete, the most economical solution would be to replace the AMR meters with AMI. While customers would ultimately see the cost savings and other benefits associated with AMI, the early replacement of AMR meters makes this scenario very costly. AMR obsolescence increases the PVRR of the Full AMR alternative by $61.4 million and the PVRR of the AMI+AMR_GO alternative by only $1.3 million. Based on the risk of obsolescence, deploying AMR throughout the Companies' service territories is not a prudent investment for customers.

The AMI+AMR_GO alternative reduces the Companies' exposure to AMR obsolescence risk compared to the Status Quo by reducing the total number of meters read by AMR. In addition, unlike the Full AMI alternative, the AMI+AMR_GO alternative enables the Companies to utilize existing gas meter assets in the gas-only service territory. Compared to the Full AMI alternative, the favorability of the AMI+AMR_GO alternative is relatively small but it is clearly the preferred alternative for these reasons.

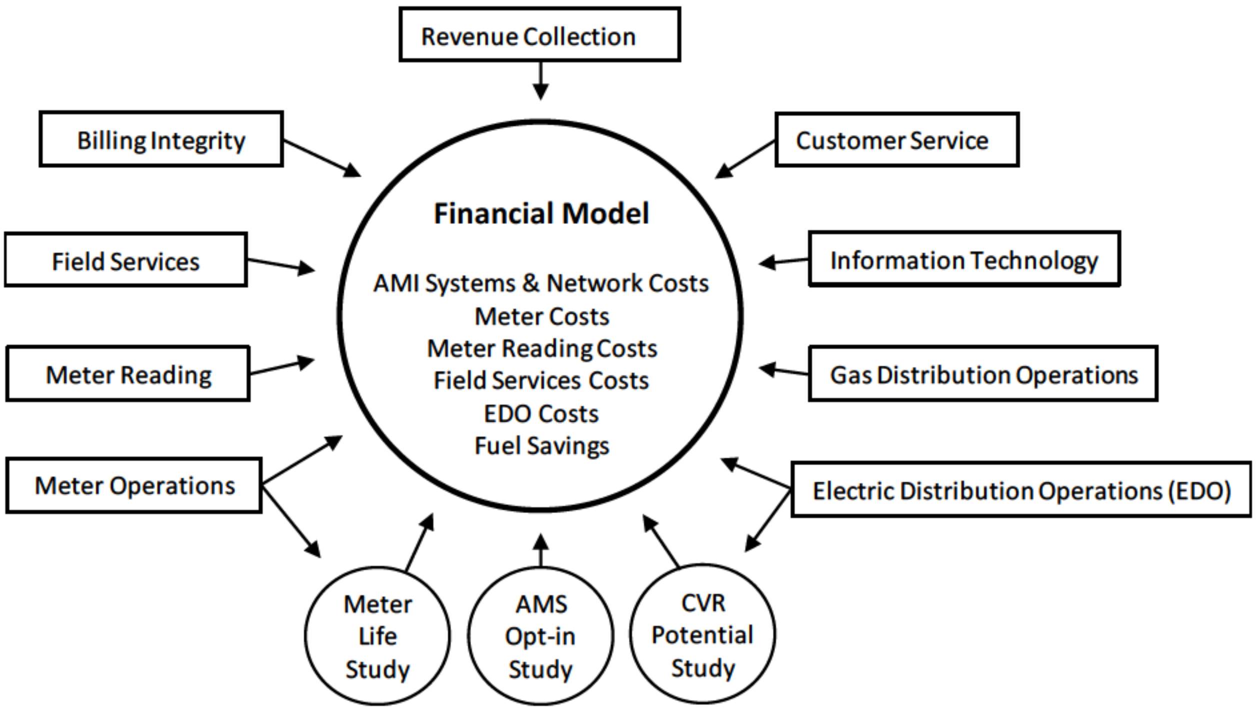
The Companies evaluated the PVRR difference between the AMI+AMR_GO and Status Quo alternatives over 243 cases created by varying input assumptions to which the analysis is most sensitive. The PVRR of the AMI+AMR_GO alternative is favorable to the Status Quo in 99.6% of the cases evaluated and ranges from only $4.2 million unfavorable to $115.4 million favorable. In addition, the favorability of the AMI+AMR_GO alternative does not depend on any single input assumption. These results demonstrate that the AMI+AMR_GO alternative has virtually no downside risk.

Finally, the timeline for implementing the AMI+AMR_GO alternative is 5 years and was developed to deliver savings as soon as possible and provide a good customer experience. In the final phase of the analysis, the Companies evaluated the AMI+AMR_GO alternative over different implementation timelines. Delaying the beginning of the 5-year implementation project or deferring AMI systems implementation so that more in-scope meters can be replaced as they fail increases the PVRR by postponing the project's benefits. This analysis shows that the AMI+AMR_GO alternative is least-cost and that the proposed 5-year implementation timeline beginning in October 2021 is optimal.

2. Analytical Framework

The Companies developed a collaborative process and analytical framework for evaluating all reasonable metering alternatives with input from all business areas impacted by the decision. This framework is illustrated in Figure 1. Annual capital and operating costs for each alternative are modeled in a financial analysis tool developed in Microsoft Excel ("Financial Model"). Section 3 contains an overview of the Status Quo alternative. Section 4 contains an overview of the other metering alternatives. The Financial Model computes annual revenue requirements and the PVRR for each alternative over a 30-year analysis period. Because electronic, AMI, and AMR meters have an average operating life of at least 15 years, the analysis period includes more than one meter replacement cycle.

Figure 1: Analytical Framework



The financial analysis is focused entirely on revenue requirements and sets aside benefits for the AMI alternatives that either have no impact on revenue requirements or are hard to quantify ("non-quantified benefits"). Non-quantified benefits include improved safety, improved reliability, improved customer experience, reduced non-technical losses, and the ability to offer additional customer programs or services like prepay. The Financial Model includes all revenue requirements for AMI systems and network, meters, meter reading, and field services costs.[1] Electric Distribution Operations ("EDO") savings and fuel

[1] Revenue requirements associated with the Companies' capital investments in existing meter assets are included in the Financial Model. The PVRR associated with this investment is assumed to be the same in all alternatives because the Companies assume in all scenarios they will recover the cost of their prudent investments, including their existing meter assets.

savings are modeled for the two AMI alternatives as differences from the Status Quo. A detailed discussion of model inputs is included in Appendix A – Model Inputs.

Three studies were completed to support key input assumptions to the financial analysis. The results of the Companies' Meter Life Study were used to forecast the need for new meters in each alternative. The results of the Companies' CVR Potential Study were used to compute the range of CVR-related fuel savings for the AMI alternatives. The results of Tetra Tech's AMS Opt-in Study were used to compute the range of fuel savings in the AMI alternatives associated with giving customers access to AMI interval data. Summaries of these studies are attached as appendices to this report. A complete summary of the financial analysis is provided in the following sections.

3. Status Quo Meter Operations

Table 2 provides a summary of the Companies' meter assets. In total, the Companies' meter assets include approximately 1 million electric meters and 340,000 gas meters. Electricity consumption for most customers with advanced meters is collected from AMI mesh meters using the RF mesh network developed for the AMS Opt-in program.[2] The Companies are not considering replacing these meters ("Existing AMI Mesh") or the roughly 2,000 specialized meters that measure consumption primarily for larger customers on time-of-day rates ("TOD Meters"). All other meters are labeled "in-scope" for the purpose of this analysis and are evaluated for replacement. In-scope meters include electromechanical and electronic meters that measure consumption for customers that are not on TOD rates as well as AMI cellular meters ("Existing AMI Cellular") for customers that require an AMI meter but are not on the RF mesh network.[3] About 98% of total electric meters are in scope, as are more than 99% of gas meters.

Table 2: Summary of Meter Assets[4]

	LG&E	KU	ODP	Total
Electric:				
TOD Meters	1,000	1,000	0	2,000
Existing AMI Mesh	11,000	8,000	0	19,000
Existing AMI Cellular*	1,000	2,000	0	3,000
Electronic Meters*	100,000	140,000	9,000	249,000
Electromechanical Meters*	318,000	395,000	21,000	734,000
Total Electric Meters	431,000	547,000	30,000	1,008,000
Total In-Scope Electric Meters*	419,000	538,000	30,000	987,000
Gas:				
Rotary Meters	2,000	0	0	2,000
Meters in Gas-Only Territory*	19,000	0	0	19,000
Other Gas Meters*	318,000	0	0	318,000
Total Gas Meters	339,000	0	0	339,000
Total In-Scope Gas Meters*	337,000	0	0	337,000
Total Meters	770,000	547,000	30,000	1,347,000
Total In-Scope Meters	756,000	538,000	30,000	1,324,000

*Denotes in-scope meters.

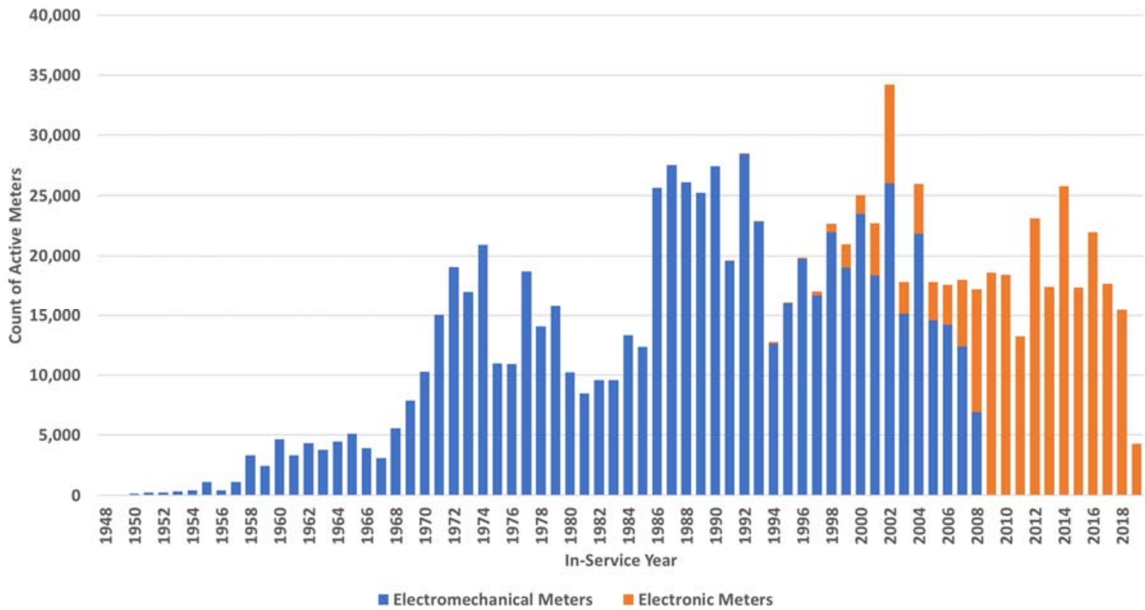
Approximately 2,000 gas meters are rotary meters that are used to measure gas consumption for large commercial and industrial customers ("Rotary Meters"). This analysis does not contemplate changes for these meters because these meters are not compatible with an AMI communications module and switching to AMI would require a full meter replacement with significant disruption to the customers'

[2] Information about the Companies' AMS Opt-In program can be found at https://lge-ku.com/advanced-meter.
[3] This analysis contemplates an expanded RF mesh network and AMI cellular meters would not be compatible with an expanded mesh network.
[4] Meter counts fluctuate over time based on customers being added or removed. This table shows approximate counts from the beginning of 2020 rounded to the nearest thousand.

operations. Of the remaining 337,000 gas meters that are in-scope, 19,000 meters are located in portions of the LG&E gas service territory where neither KU nor LG&E provides electric service ("gas-only service territory"). The analysis evaluates different metering alternatives for the gas-only service territory.

Figure 2 summarizes the age of the Companies' electromechanical and electronic meters. Approximately 75% of in-scope electric meters are electromechanical meters and have an average age of 32 years. Because electromechanical meters are no longer manufactured, they are replaced by non-communicating electronic meters ("electronic meters") when they fail.[5] The Companies' 249,000 electronic meters have an average age of 8 years.

Figure 2: Electric Meter Population by Type and In-Service Year



The Companies completed an analysis of meter failures over the past 10 years to develop failure curves for electromechanical and electronic meters ("2019 Meter Life Study").[6] Figure 3 and Figure 4 show the failure curves from this analysis. Unsurprisingly, the likelihood of failure increases with age for both meter types. Electronic meters have a shorter average operating life than electromechanical meters (20 years for electronic versus 46 years for electromechanical). A 20-year operating life for electronic meters is the same as the operating life for AMI meters according to two of the largest AMI meter manufacturers, [redacted].[7] Aside from the ability to communicate via the mesh network and remotely connect

[5] The Companies issued a request for information in March 2020 to gather information from meter vendors regarding the future availability and pricing for various meter types. All respondents stated that electromechanical meters are no longer manufactured (see Appendix B – Metering RFI Summary).
[6] This analysis is summarized in Appendix C – 2019 Meter Life Study.
[7] See Appendix B – Metering RFI Summary and Appendix F – [redacted] Meter Life Study.

and disconnect service, an AMI meter is no different than a non-communicating electronic meter; AMI and non-communicating electronic meters share the same meter platform.

Figure 3: Electromechanical Failure Rate by Age

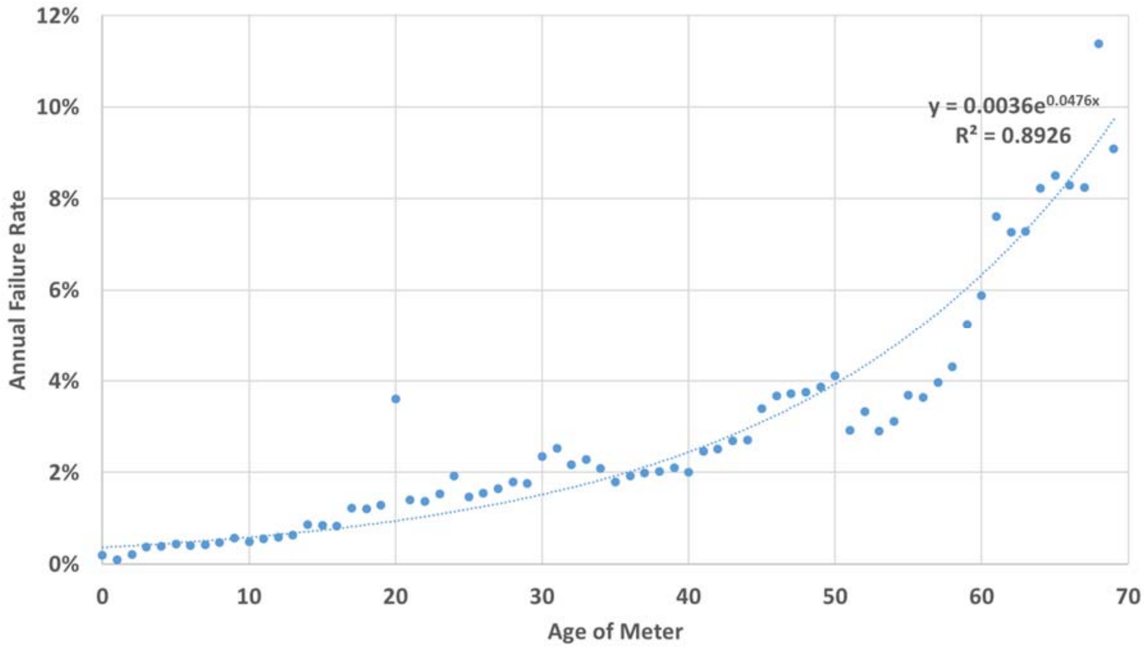


Figure 4: Electronic Failure Rate by Age

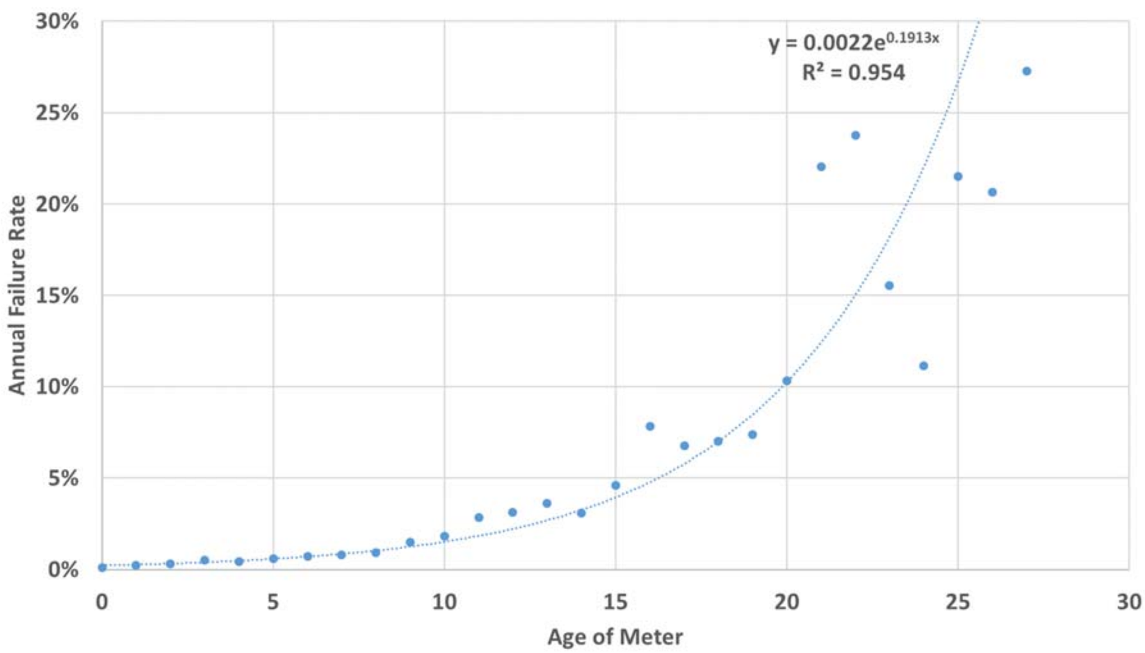
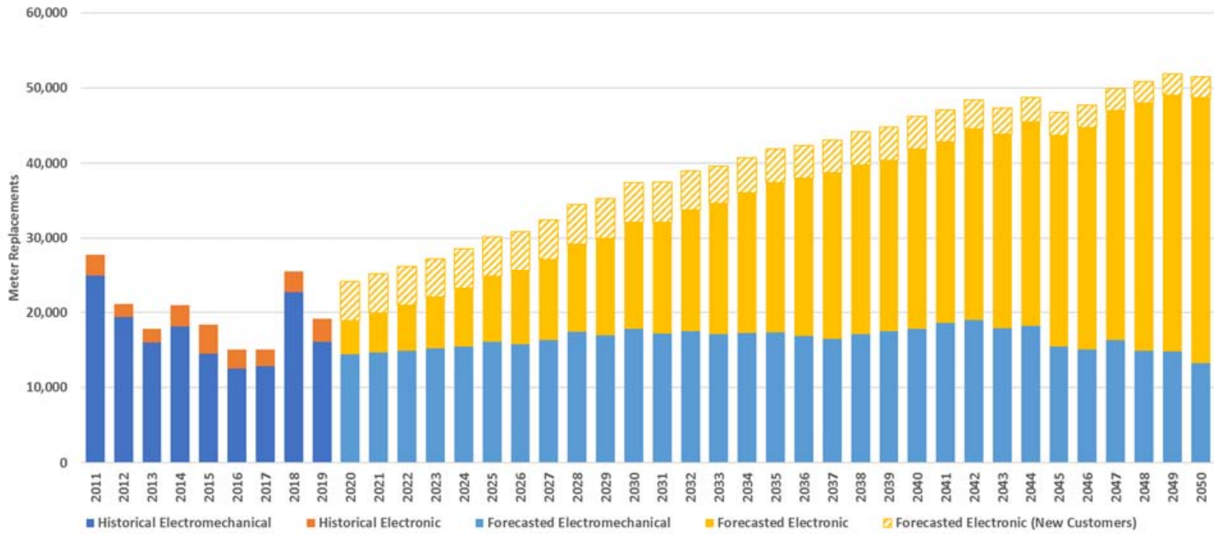


Figure 5 shows the forecasted need for new meters over the next 30 years. The forecasts of electromechanical and electronic meter replacements were developed by applying the meter failure curves from the 2019 Meter Life Study to the existing meter populations. The meter forecast for new customers is based on the Companies' customer forecasts. The total number of meters per year is expected to increase over time as longer-lived electromechanical meters are replaced with shorter-lived electronic meters.

Figure 5: Status Quo Meter Replacement Forecast (2019 Meter Life Study Failure Curves)



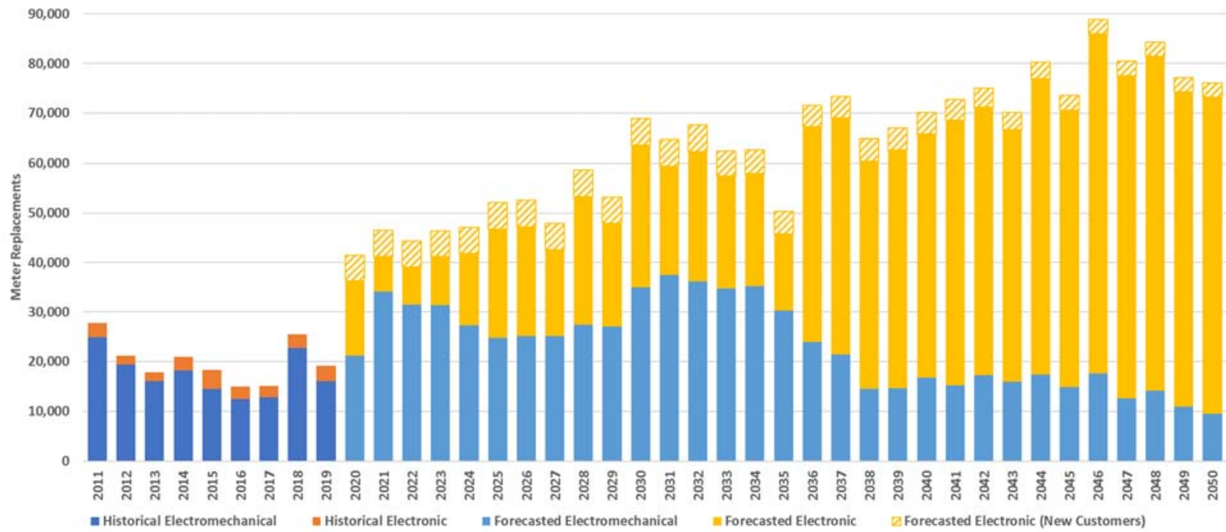
While the Companies' 2019 Meter Life Study and meter manufacturers support a 20-year operating life for electronic and AMI meters, the Companies' existing AMI meters have a 15-year depreciation life. At least in part, the shorter depreciation life reflects some likelihood that the meters will be proactively replaced before the end of their operating life. A similar assumption is made for the depreciation life of electromechanical and electronic meters, which are depreciated in one asset group. Based on the Companies' analysis, the weighted average operating life for these meters is 39.5 years but the depreciation life is 32 years on average.[8]

In addition to the operating life scenario based on failure curves from the 2019 Meter Life Study, the Companies modeled a shorter operating life scenario ("proactive replacement") where meters that haven't failed by a certain age are assumed to be replaced proactively (i.e., after 16 years for electronic meters and after 45 years for electromechanical meters). This assumption causes the average operating life to equal the depreciation life. The proactive replacement assumption causes total meter

[8] Approximately 75% and 25% of existing meters, respectively, are electromechanical and electronic meters. The weighted average operating life for all meters (39.5 years) = 75% * 46 years + 25% * 20 years. The average depreciation life for all meters (32 years) is the average of meter depreciation lives for KU (28 years) and LG&E (36 years).

replacements over the 30-year analysis period to be higher for all metering alternatives. Figure 6 shows the forecasted need for new meters in the Status Quo when meters are assumed to be replaced proactively. In the Status Quo, the impact of this assumption is greatest during the first 15 years of the analysis period as aging electromechanical meters are assumed to be replaced faster than they otherwise would be replaced.[9]

Figure 6: Status Quo Meter Replacement Forecast (Proactive Replacement Operating Life)



The Companies manually read the majority of in-scope meters each month. On average, approximately 60,000 meters are manually read each weekday. All customers are assigned to one of 20 billing cycles; the read date for each billing cycle generally occurs at the same time each month. Most meters are accessible by simply walking up to the meter. However, approximately 27,000 meters are located inside a customer's premise and must be accessed with a key or by coordinating with the customer. For each billing cycle, meter data is uploaded to the Companies' billing system where billing determinants are computed and checked for accuracy before customers are billed. In addition to total consumption, customer bills contain year-over-year comparisons of billing period usage, temperature, and other metrics to help customers manage their usage (see Figure 7).

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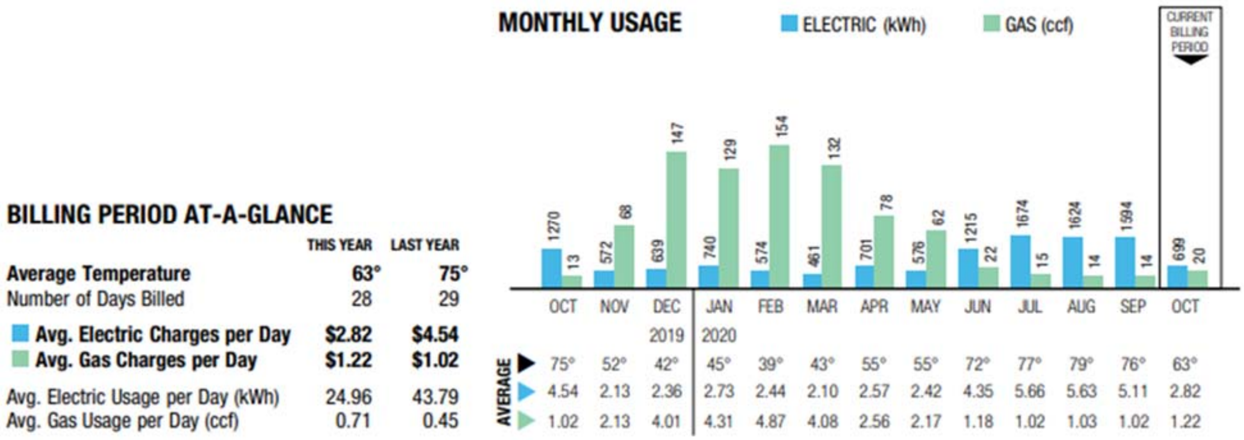
[9] Section 5.1 evaluates all alternatives under both meter operating life scenarios. Because this assumption increases revenue requirements in all alternatives, the impact of this assumption on the PVRR differences between the various metering alternatives is small.

Figure 7: Example Customer Bill



All meter-related services are also provided manually. For example, off-cycle meter reads, move-out and move-in orders, and disconnect and reconnect orders are completed with an in-person visit to the customer's premise. Move orders are typically completed the day the customer requests a move but do require advance notice from the customer. Reconnect orders are typically completed the same day as long as the customer makes payments and requests reconnection by 5 PM; otherwise, they could be without service until the next day.

The Companies have an excellent track record for safety. Nonetheless, visiting more than 1 million customer premises each month to read meters and provide field services exposes hundreds of the Companies' employees and contractors to multiple hazards including customer threats, dog bites, and other injuries. In 2019, meter reading and field service staff sustained 17 recordable injuries and were the target of more than 100 customer threats. In addition, these groups drove approximately 5.5 million miles in 2019.

The Companies' meter operations impact some aspects of their distribution system operations. For example, to reliably accommodate growth in customer-owned generation and electric vehicles, additional voltage sensing and regulating equipment will be needed along selected distribution circuits to more precisely control voltage along these circuits and prevent voltage excursions. Additionally, with the current non-communicating meters, the Companies must contact customers after restoration occurs to confirm that service has been restored. This can negatively impact the efficiency of restoration crews.

4. Metering Alternatives

The Companies' contract for meter reading and field services expired in 2018. After a competitive bidding process, total annual contract costs for meter reading and field services increased in 2019 by $5.8 million (45%). Prior contracts executed in 2014 did not allow for annual increases so spending on these services was well under market at the end of the contract terms. Given this increase and the forecasted increase in the number of annual meter replacements, the Companies completed an analysis of metering alternatives to determine the best alternative for reliably serving customers at the lowest reasonable cost. In addition to the Status Quo alternative where existing meters continue to be replaced with non-communicating electronic meters as they fail, the Companies evaluated two alternatives with expanded AMI and one alternative with expanded AMR. AMI meters have two-way communications and a remote service switch that would enable the Companies to read meters and provide some field services remotely. AMR meters have short-range one-way communications. Instead of walking by each meter and reading the meter manually, AMR meters would enable the Companies to read meters by vehicle using mobile collectors.

The Companies evaluated the following metering alternatives in addition to the Status Quo:

- Full AMI Deployment ("Full AMI"): Install AMI in the electric and gas service territories; remotely read AMI meters and remotely provide some field services for electric customers.
- AMI + AMR in Gas-Only Territory ("AMI+AMR_GO"): Install AMR in the gas-only service territory; install AMI in electric service territory and remainder of gas service territory; remotely read AMI meters and remotely provide some field services for electric customers.
- Full AMR Deployment ("Full AMR"): Install AMR in the electric and gas service territories; drive by meters to read them; continue to manually provide field services.

Table 3 summarizes the differences between these alternatives. The following sections provide a more detailed overview of each alternative.

Table 3: Comparison of Metering Alternatives

	Item	Full AMI	AMI+AMR_GO	Full AMR
Increased Costs vs. Status Quo	IT Systems	Install systems to remotely read AMI meters and remotely provide some field services to electric customers		Enhancements to existing systems to support additional volume of AMR data
	Expanded AMI Network	Expand AMI network to electric and gas-only service territories	Expand AMI network to electric service territories	N/A
	Electric Meters	Replace in-scope electric meters with AMI meters		Replace in-scope electric meters with AMR meters
	Gas Meters	Add AMI module to all in-scope gas meters	Add AMI module to in-scope gas meters in electric service territory; add ERT to in-scope gas meters in gas-only service territory	Add ERT to all in-scope gas meters
Decreased Costs vs. Status Quo	Meter Reading	Remotely read all meters	Remotely read AMI meters; read AMR meters by vehicle	Read AMR meters by vehicle
	Field Services	Remotely provide some field services to electric customers		N/A
	Electric Distribution	Outage-related labor savings; avoided costs for voltage sensing equipment		N/A
	Fuel Savings	CVR; incremental energy efficiency		N/A
Non-Quantified Benefits	Improved Safety	Reduced threats and injuries to meter reading and field services staff		Reduced threats and injuries to meter reading staff
	Improved Reliability	Reduced customer inconvenience due to outages		N/A
	Improved Customer Experience	Ability to offer programs like prepay		N/A
	Reduced Non-Technical Losses	Limited impact to revenue requirements but reduced theft can place downward pressure on rates		N/A

4.1. Full AMI Deployment ("Full AMI")

In the Full AMI alternative, the existing RF mesh network is expanded throughout the electric and gas service territories and IT systems needed to support AMI are installed. All in-scope electric meters (approximately 1,000,000 meters) are replaced with AMI meters and an AMI communications module is added to all in-scope gas meters (approximately 340,000 meters).[10] The project to implement AMI will last five years and is assumed to begin in October 2021. Most AMI meters and modules are deployed during a coordinated 42-month meter deployment period beginning in September 2022. After Commission approval is received, any in-scope electric meters that fail prior to or outside the meter deployment project in a different part of the service territory will be replaced with AMI meters as they fail.

As AMI meters and modules are deployed, they will immediately begin communicating via the mesh network with a Meter Operations Center that monitors meter and network operations. Expanding the mesh network into the gas-only service territory will require pole attachment agreements with 13 neighboring electric providers for network equipment. Network installation as well as regular maintenance, inspections, and restoration for the network equipment will require coordination with these providers.

Customers will continue to be billed monthly, but because 15-minute consumption data is collected every 4 hours throughout the month, customers will be able to access this data anytime as an additional tool for managing their bill. AMI eliminates the need to manually read meters and manually upload meter data to the Companies' billing system. Instead, on the appropriate day each month, billing determinants will be automatically calculated and transferred to the Companies' existing billing system for review and for billing customers.

AMI will also eliminate the need to manually provide some field services. For example, most AMI meters will have a remote service switch that will enable the Companies to remotely connect and disconnect service based on current policies. This will enable the Companies to be more flexible and responsive to customer needs establishing service more quickly when moving in or settling overdue balances. Additionally, by eliminating the need to manually read meters and manually provide some field services, the Companies will eliminate majority of safety concerns from dog bites, unhappy customers, and other hazards.

AMI will also improve several aspects of the Companies' distribution operations. For example, AMI data will enable the Companies to anticipate transformer failures and reduce the duration of some transformer outages by replacing transformers shortly before they fail. In addition, AMI will provide automatic notification both when a customer's service is interrupted and when it is restored. The Companies will use this information to improve the efficiency of restoration crews and customer service during outage events. Furthermore, as discussed previously, additional voltage sensing and regulating equipment will be needed to reliably accommodate growth in customer-owned generation and electric vehicles. With

[10] The AMI meters included in both AMI alternatives are compatible with the AMI Mesh meters currently deployed for AMS Opt-in customers.

voltage data for every customer, AMI will not only eliminate the need for the additional voltage sensors, but it will also provide the granularity of voltage data needed to incrementally lower distribution voltages and reduce system energy requirements, thereby reducing fuel expense. The process of lowering distribution voltage to reduce system energy requirements is called Conservation Voltage Reduction ("CVR").

Finally, many AMS Opt-in customers have used their interval data to gain a better understanding of their usage and have taken actions as a result to reduce their electricity consumption. Expansion of interval data access to all other customers is likely another source of fuel savings attributed to AMI. In addition, AMI provides the foundation for offering prepay.

A number of AMI benefits either have no impact on revenue requirements or are very hard to quantify. These benefits are excluded from the financial analysis in an effort to focus on costs and benefits that are more certain. For example, with AMI, the Companies would expect to reduce theft and other non-technical losses. However, if customers who are caught stealing continue using electricity, reducing theft will place downward pressure on rates for paying customers but it will have no impact on total revenue requirements because the Companies' fixed costs and fuel expense will be unchanged. On the other hand, fuel expense would be reduced if customers who are caught stealing reduce their consumption but this reduction in fuel expense is very difficult to quantify. Therefore, in an effort to focus on costs and benefits that are more certain, the financial analysis ignores significant AMI benefits like these as well as improved customer experience, improved safety, improved reliability, and the ability to offer additional customer programs or services like prepay.

4.2. AMI + AMR in Gas-Only Territory ("AMI+AMR_GO")

The only differences between the Full AMI and AMI+AMR_GO alternatives pertain to the gas-only service territory. Of the roughly 19,000 gas meters in the gas-only service territory, about 7,500 already have an Encoder Receiver Transmitter ("ERT") for AMR. In the AMI+AMR_GO alternative, instead of adding an AMI communications module to all meters in the gas-only service territory, an ERT is added to meters that don't already have one so that all meters in the gas-only service territory can be read by vehicle using mobile collectors. The additional ERTs will be sourced from gas meters in the electric service territory that no longer need them due to AMI.[11] This alternative takes advantage of the opportunity to extend the use of existing ERTs and avoids the need to create and manage numerous 3rd party pole agreements with neighboring electric providers to support the installation and maintenance of the RF mesh network in service territories where the Companies do not typically serve.

Compared to the Status Quo, expanding AMR in the gas-only service territory actually reduces the Companies' exposure to the risk of obsolescence for AMR meters by reducing the total number of meters read by AMR. In addition, this alternative does not preclude the Companies from implementing AMI in the gas-only service territory at some point in the future.

[11] Approximately 27,000 gas meters in the electric service territory have ERTs that will be replaced by an AMI module, allowing the ERTs to be redeployed in the gas-only service territory.

4.3. Full AMR Deployment ("Full AMR")

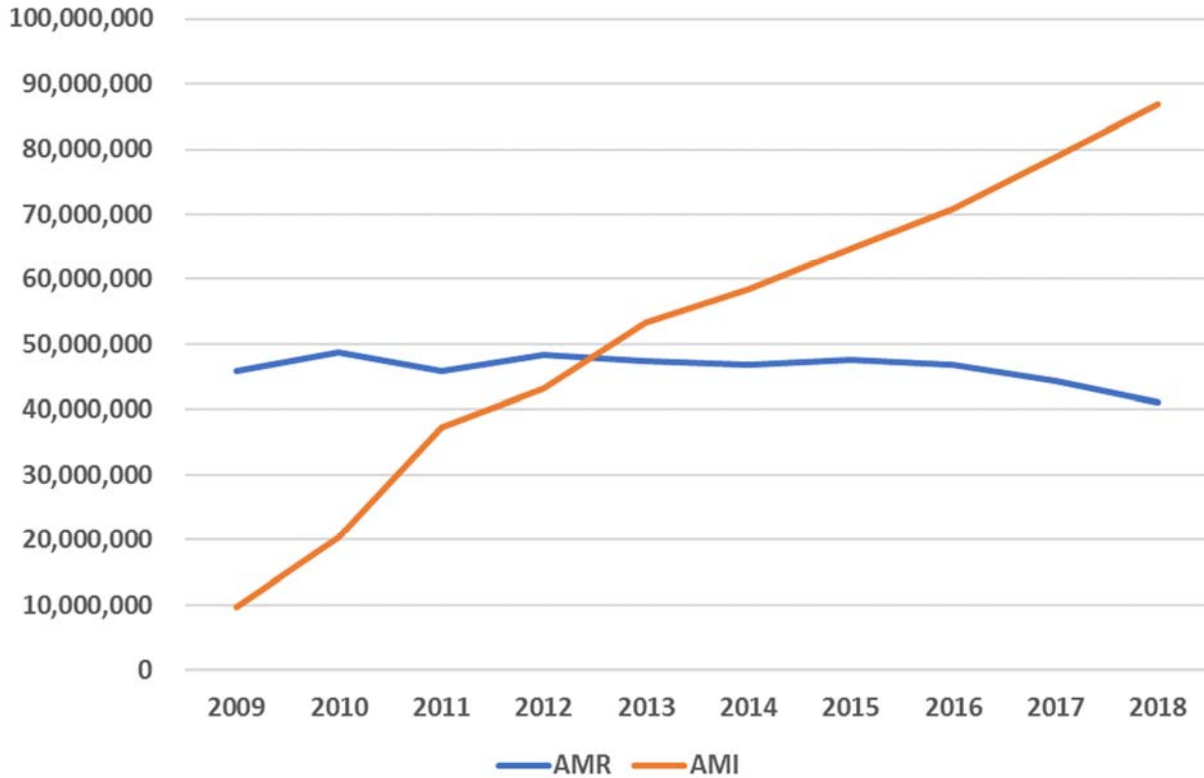
In the Full AMR alternative, most in-scope non-AMR electric meters (approximately 970,000 meters) are replaced with AMR meters and an ERT is added to all in-scope gas meters that do not already have an ERT (approximately 300,000 meters). Some portion of existing AMR electric meters and gas ERTs with limited remaining battery lives will also have to be replaced. The timeline for implementing the Full AMR alternative is the same as the AMI alternatives.

While the Full AMR alternative requires enhancements to existing IT systems, no additional IT systems are required. With the ability to read meters by vehicle, AMR will reduce the Companies' meter reading costs versus the Status Quo and reduce injuries incurred while manually reading meters. Compared to the AMI alternatives, the cost of meters in the Full AMR alternative is lower but the benefits are also lower. AMR reduces meter reading costs versus the Status Quo but not to the extent meter reading costs are reduced in the AMI alternatives. Also, AMR has no impact on the Companies' field services, energy requirements (i.e., no fuel savings from CVR or customer energy reductions), or electric distribution operations.

4.3.1. AMR Obsolescence Risk

The Full AMR alternative has significant risk relative to the other alternatives. Figure 8 shows the number of AMI and AMR meters in the United States. Since 2009, the total number of AMI meters has increased steadily while the number of AMR meters has declined since 2015. The Companies issued an RFI in March 2020 to gather information from meter vendors regarding the future availability and pricing for various meter types. The responses, which are summarized in Appendix B – Metering RFI Summary, indicate dwindling support for AMR metering, with only one vendor committing to future AMR research and investment. The market expectation for AMR meters is for higher cost increases over time relative to other meter types due to reduced economies of scale from less market share. The Companies' current experience with Power Line Carrier meters at Wilmore, Kentucky demonstrates that a non-competitive product can leave the Companies at the mercy of pricing from a sole-source vendor or be subject to the vendor dropping support altogether and rendering the product obsolete.

Figure 8: Comparison of AMR and AMI Meter Counts in United States[12]



The Companies believe that large-scale investment in AMR would be imprudent given the potential obsolescence risk. In addition, investment in AMR would hinder the Companies' ability to offer additional services to customers, such as prepay, mid-cycle usage notifications, alternative rate structures, or interval data access. AMR also does not provide the Companies with the data necessary to evaluate the impact of customer-owned generation on system reliability. Furthermore, the Companies observe other utilities' experience, such as Kentucky Power, who cite obsolescence as a key driver for moving away from AMR toward AMI.[13] To evaluate this risk, the Companies evaluated the alternatives under two AMR obsolescence scenarios: one where AMR is replaced with AMI midway through the analysis period and one where AMR remains viable throughout the entire 30-year analysis period.

AMR obsolescence would impact all alternatives except the Full AMI alternative. In the Status Quo, approximately 70,000 AMR electric meters would be replaced with mesh or cellular AMI meters, depending on the location of the meter and the economics of expanding the existing mesh network. Similarly, approximately 35,000 gas ERTs would be replaced with mesh or cellular gas AMI modules.

[12] Data source: https://www.eia.gov/electricity/annual/html/epa_10_10.html

[13] 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, Application and Testimony (Ky. PSC June 29, 2020)

Because the Companies' existing AMR meters were installed to solve problems related to accessing customers' meters, replacing AMR meters and gas ERTs with non-communicating devices is not a viable way to address AMR obsolescence.

Based on this analysis and the forecasted increases in meter reading and field services costs, the least-cost option for addressing AMR obsolescence for the AMI+AMR_GO and Full AMR alternatives would be to transition fully to AMI. For the AMI+AMR_GO alternative, this transition would entail simply expanding the LG&E mesh network throughout the gas-only territory and replacing the approximately 19,000 ERTs in the gas-only service territory with gas AMI modules. For the Full AMR alternative, this transition would require a wholesale replacement of all electric meters and gas ERTs with AMI. Customers would ultimately see the cost savings and other benefits associated with AMI, but the early replacement of meters would add significant cost to the Full AMR alternative.

5. Analysis of Metering Alternatives

The analysis of metering alternatives was completed in two phases. As discussed previously, the analysis is focused entirely on revenue requirements and sets aside non-quantified benefits. In the first phase, the Companies evaluated the PVRR for each alternative under two AMR obsolescence scenarios: one where AMR becomes obsolete midway through the analysis period and one where AMR remains viable for the full 30-year analysis period. In addition, all alternatives were evaluated with the assumption that the 5-year implementation project for the AMI and AMR alternatives would begin in October 2021. The results of this phase of the analysis demonstrate that the AMI+AMR_GO analysis is the least-cost alternative and has very little downside risk.

In the second phase of the analysis, the Companies evaluated the AMI+AMR_GO alternative over different implementation timelines. Delaying the beginning of the 5-year implementation project or deferring systems implementation so that more in-scope meters can be replaced as they fail increases the PVRR by postponing the project's benefits. The following sections summarize each phase of the analysis in more detail. A detailed discussion of model inputs is included in Appendix A – Model Inputs.

5.1. Phase 1 Analysis

Table 4 shows nominal cash flows in the Status Quo alternative under the two AMR obsolescence scenarios. Total cash flows are the same in both scenarios through 2030. Meter reading costs account for majority of total costs throughout the analysis period. As discussed previously, annual contract costs for meter reading and field services increased by 45% in 2019 and the number of meter replacements per year is expected to increase over time as electromechanical meters are replaced with non-communicating electronic meters. Both types of meters are assumed to be proactively replaced (i.e., after 16 years for electronic meters and after 45 years for electromechanical meters) so that their average operating lives equals their depreciation lives. The cash flows in Table 4 reflect base values for inputs in Appendix A – Model Inputs that are specified as a range of values. In total, annual Status Quo costs are forecasted to increase from $37.8 million in 2021 to more than $85 million in 2050.

Table 4: Status Quo Costs ($M, Capital and O&M, Proactive Replacement Operating Life)

	2021	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Both AMR Obsolescence Scenarios										
Meter Costs	4.8	3.5	4.0	3.9	4.6	5.4	4.4	5.2	5.1	6.3
Non-Meter Costs	0.0	0.0	2.5	0.0	0.0	0.0	0.0	0.0	3.0	0.0
Meter Reading	18.6	19.0	19.5	20.1	20.7	21.3	21.9	22.6	23.2	23.9
Field Services	14.3	14.7	15.1	15.6	16.1	16.5	17.0	17.5	18.0	18.5
EDO Costs	0.0	1.4	1.5	1.5	1.6	1.6	1.7	1.7	1.8	1.8
Total	37.8	38.7	42.6	41.1	42.9	44.9	45.0	47.0	51.1	50.6
	2031	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
AMR Becomes Obsolete Midway through Analysis Period										
Meter Costs	7.3	8.4	8.1	9.4	11.3	8.1	7.7	6.8	7.4	7.7
Non-Meter Costs	0.0	0.6	0.7	0.8	3.9	0.2	0.2	0.2	0.2	0.2
Meter Reading	24.6	25.3	25.9	26.6	27.3	28.0	28.8	29.6	30.5	31.4
Field Services	19.1	19.6	20.2	20.8	21.4	22.0	22.6	23.2	23.9	24.6
EDO Costs	1.9	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Total	52.8	54.1	55.1	57.7	64.1	58.4	59.5	60.1	62.2	64.1
AMR Remains Viable for 30-Year Analysis Period										
Meter Costs	7.3	6.5	6.1	6.3	8.5	8.3	7.9	7.0	7.6	7.9
Non-Meter Costs	0.0	0.0	0.0	0.0	3.6	0.0	0.0	0.0	0.0	0.0
Meter Reading	24.6	25.3	26.1	26.8	27.6	28.4	29.2	30.1	31.0	31.8
Field Services	19.1	19.6	20.2	20.8	21.4	22.0	22.6	23.2	23.9	24.6
EDO Costs	1.9	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Total	52.8	51.6	52.6	54.1	61.2	58.9	59.9	60.5	62.7	64.5
	2041	**2042**	**2043**	**2044**	**2045**	**2046**	**2047**	**2048**	**2049**	**2050**
AMR Becomes Obsolete Midway through Analysis Period										
Total	71.6	68.3	69.9	72.8	74.3	79.0	84.4	84.0	85.3	87.2
AMR Remains Viable for 30-Year Analysis Period										
Total	72.1	68.7	70.3	73.2	74.7	79.3	84.8	82.1	83.4	85.6

To model the impact of AMR obsolescence, the Companies assumed AMR becomes obsolete by the end of 2035. In this scenario, approximately 70,000 AMR electric meters and 35,000 gas ERTs are replaced from 2032 to 2035 with AMI electric meters and gas modules. Because the Companies' existing AMR meters were installed to solve problems related to accessing customers' meters, replacing AMR meters and gas ERTs with non-communicating devices is not a viable way to address AMR obsolescence. Depending on their location and the economics of expanding the existing RF mesh network, the AMR meters and ERTs will be replaced with either mesh or cellular AMI meters and modules. For this analysis, the Companies assumed limited expansion of the mesh network throughout the gas-only service territory. After the AMR metering equipment is replaced, savings in meter reading costs more than offset the incremental cost of maintaining an expanded mesh network until the majority of the replacement AMI meters installed from 2032 to 2035 begin to be replaced in 2048.

Figure 9 compares nominal cash flows in the AMI and AMR alternatives to the Status Quo in the scenario where AMR is assumed to become obsolete midway through the analysis period. Figure 10 contains the same comparison for the scenario where AMR is assumed to remain viable for the entire 30-year analysis period. In both scenarios, nominal cash flows for the AMI and AMR alternatives are initially higher than the Status Quo due to the investment in meters and IT systems but are lower after the 5-year project implementation period. AMR obsolescence has no impact on the Full AMI alternative. Based on this analysis and the forecasted increases in meter reading and field services costs, the least-cost option for addressing AMR obsolescence for the AMI+AMR_GO and Full AMR alternatives would be to transition fully to AMI. Like in the Status Quo, this transition is assumed to occur from 2032 to 2035 for both alternatives. For the AMI+AMR_GO alternative, this transition would entail simply expanding the LG&E mesh network throughout the gas-only territory and replacing the approximately 19,000 ERTs in the gas-only service territory with gas AMI modules. For the Full AMR alternative, this transition would require a wholesale replacement of all electric meters and gas ERTs with AMI. Customers would ultimately see the cost savings and other benefits associated with AMI, but the early replacement of meters causes total meter costs in this scenario to be much higher. In Figure 9, the increased costs at the end of the analysis period for the Full AMR alternative reflect the beginning of a third wave of meter replacements.

Figure 9: AMI and AMR Nominal Cost Differences ($M, Capital and O&M, AMR Becomes Obsolete Midway through Analysis Period, Proactive Replacement Operating Life)

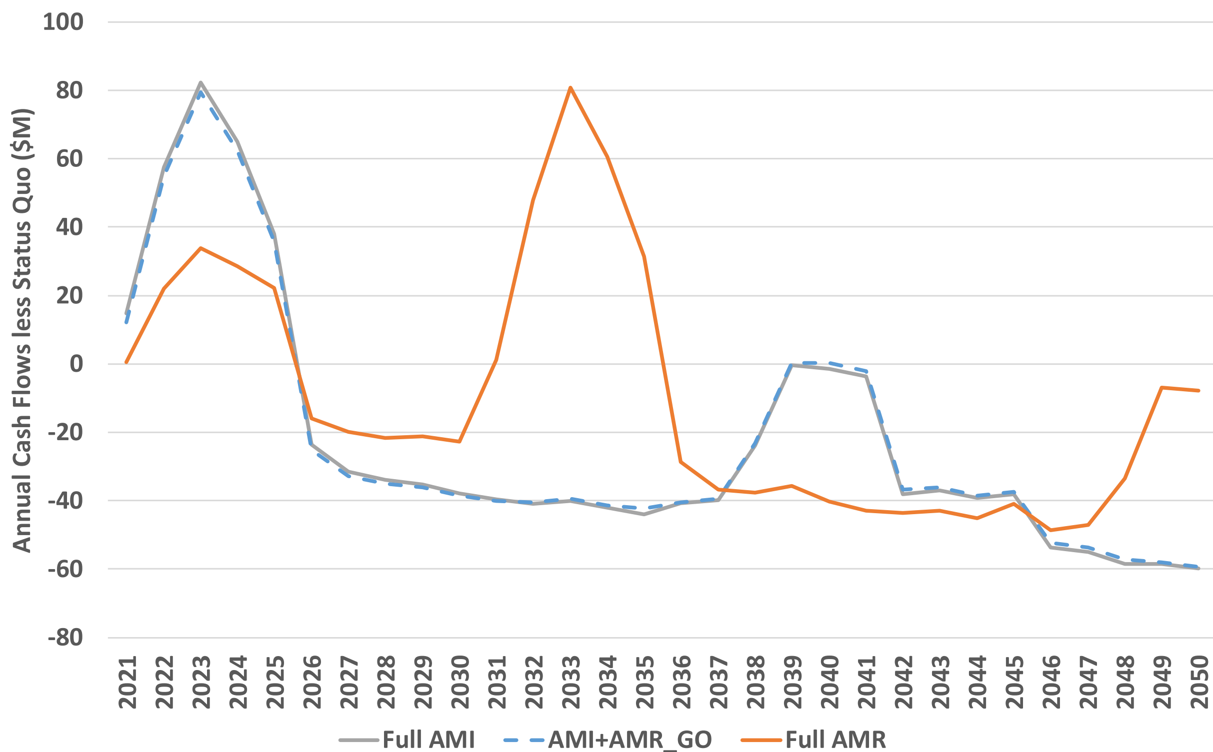
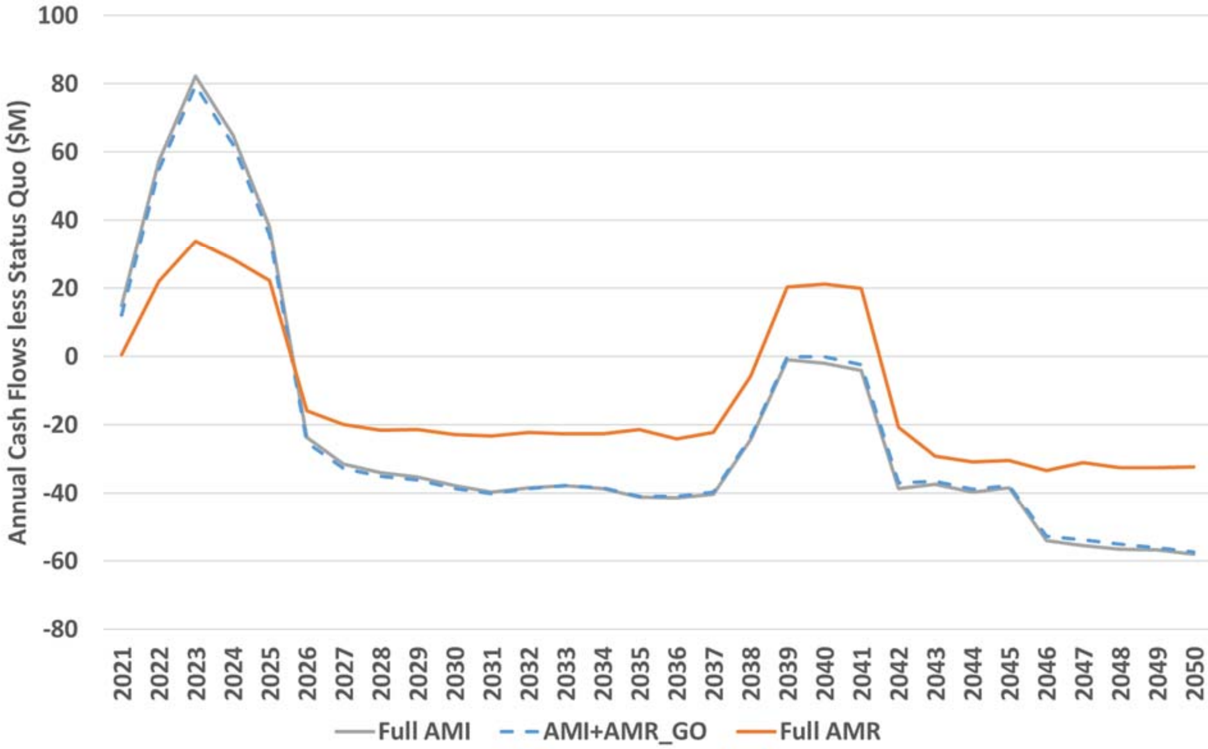


Figure 10: AMI and AMR Nominal Cost Differences ($M, Capital and O&M, AMR Remains Viable for 30-Year Analysis Period, Proactive Replacement Operating Life)



Based on the meter failure curves discussed in Section 3, the likelihood of a meter failing is initially very low and increases with age. The second wave of meter replacements is slightly less pronounced than in the initial 42-month meter deployment period due to the volume of meters that fails prior to the sixteenth year of operation when AMI and AMR meters that haven't failed are assumed to be proactively replaced. In both AMR obsolescence scenarios, total spending over the 30-year analysis period is lower for the AMI and AMR alternatives. This analysis determines whether the investment in AMI or AMR is justified by the savings.

Table 5 contains nominal cash flows for the AMI and AMR alternatives under each AMR obsolescence scenario. Total cash flows for each alternative are the same in both scenarios through 2030. For all alternatives, the cost of meters makes up the majority of total costs during the 2021 to 2026 project deployment period. The cost of meters in the Full AMR alternative is lower than in the AMI alternatives but the benefits are also lower. Additional information regarding each category of costs is included in Appendix A – Model Inputs.

Table 5: AMI and AMR Costs ($M, Capital and O&M, Proactive Replacement Operating Life)

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Full AMI										
Meter Costs	3.7	21.0	50.0	49.9	51.0	7.6	1.4	1.7	2.0	2.4
Non-Meter Costs	15.9	42.2	43.8	34.9	14.5	4.6	4.7	4.5	7.7	4.8
Meter Reading	18.6	18.3	16.3	11.3	6.6	1.2	0.4	0.4	0.5	0.5
Field Services	14.3	14.7	15.1	10.8	10.1	10.0	10.2	10.5	10.8	11.1
EDO Costs	0.0	0.0	0.0	0.0	-0.2	-0.2	-0.2	-0.2	-0.2	-0.3
Fuel Savings	0.0	-0.1	-0.3	-0.7	-1.0	-2.1	-3.1	-4.0	-4.9	-5.8
Total	52.5	96.1	124.9	106.2	80.9	21.2	13.5	13.0	15.8	12.7
AMI+AMR_GO										
Meter Costs	3.7	20.9	49.6	49.4	50.6	7.6	1.5	1.7	2.0	2.4
Non-Meter Costs	15.9	41.7	43.2	34.3	14.2	4.5	4.6	4.4	7.5	4.7
Meter Reading	18.6	18.3	16.4	11.3	6.7	1.3	0.5	0.5	0.5	0.6
Field Services	14.3	14.7	15.1	10.8	10.1	10.0	10.2	10.5	10.8	11.1
EDO Costs	0.0	0.0	0.0	0.0	-0.2	-0.2	-0.2	-0.2	-0.2	-0.3
Fuel Savings	0.0	-0.1	-0.3	-0.7	-1.0	-2.1	-3.1	-4.0	-4.9	-5.8
Total	52.5	95.6	123.9	105.2	80.3	21.1	13.5	12.9	15.8	12.7
Full AMR										
Meter Costs	3.5	14.9	34.0	33.5	34.4	5.7	2.3	1.8	2.3	2.4
Non-Meter Costs	4.6	13.2	11.1	8.5	6.8	1.0	0.0	0.0	3.0	0.0
Meter Reading	18.6	18.4	16.6	12.2	8.0	5.5	5.3	5.4	5.6	5.7
Field Services	14.3	14.7	15.1	15.6	16.1	16.5	17.0	17.5	18.0	18.5
EDO Costs	0.0	1.4	1.5	1.5	1.6	1.6	1.7	1.7	1.8	1.8
Fuel Savings	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	41.0	62.7	78.4	71.3	66.7	30.3	26.3	26.4	30.6	28.4
	2031	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
AMR Becomes Obsolete Midway through Analysis Period										
Full AMI	13.1	13.1	14.9	15.6	20.1	17.6	19.6	36.2	61.7	62.6
AMI+AMR_GO	13.1	13.8	15.7	16.3	21.6	17.6	19.6	36.2	61.7	62.6
Full AMR	52.6	102.1	136.0	118.2	91.9	25.9	18.0	17.6	21.3	17.5
AMR Remains Viable for 30-Year Analysis Period										
Full AMI	13.1	13.1	14.9	15.6	20.1	17.6	19.6	36.2	61.7	62.6
AMI+AMR_GO	13.1	13.2	15.0	15.6	20.2	17.7	19.7	36.2	61.8	62.6
Full AMR	30.0	29.6	30.1	31.4	39.6	34.5	37.3	54.2	82.2	84.0
	2041	**2042**	**2043**	**2044**	**2045**	**2046**	**2047**	**2048**	**2049**	**2050**
AMR Becomes Obsolete Midway through Analysis Period										
Full AMI	68.0	30.2	33.0	33.5	36.2	25.4	29.4	25.5	26.7	27.7
AMI+AMR_GO	67.9	29.9	32.2	32.7	35.4	25.2	29.3	25.5	26.7	27.6
Full AMR	22.4	18.2	20.5	21.0	26.6	23.4	30.3	43.3	71.9	72.9
AMR Remains Viable for 30-Year Analysis Period										
Full AMI	68.0	30.2	33.0	33.5	36.2	25.4	29.4	25.5	26.7	27.7
AMI+AMR_GO	68.0	30.1	32.3	32.8	35.5	25.3	29.5	25.6	26.8	27.7
Full AMR	90.3	46.4	39.5	40.8	42.7	44.5	52.3	48.2	50.4	52.9

Table 6 lists the PVRR for each metering alternative under each AMR obsolescence scenario. Like the other tables and figures in this section, the PVRR values in Table 6 reflect base values for inputs in Appendix A – Model Inputs that are specified as a range of values. The PVRR values include all revenue requirements for Meters, Non-Meter Deployment and On-Going Costs, Meter Reading, and Field Services. The PVRR for EDO Costs includes the cost of voltage sensing equipment and O&M savings, which are computed as a difference from the Status Quo for the Full AMI and AMI+AMR_GO alternatives. The PVRR for Fuel Savings is also computed as a difference from the Status Quo for the AMI alternatives. Revenue requirements for new meters and other deployment costs in the AMI and AMR alternatives were computed with the assumption that the Companies will record capital investments as Construction Work in Process during the 5-year implementation period and accrue an allowance for funds used during construction. After the 5-year implementation period, capital investments are assumed to be placed in service in the year the investments are made. In addition to the cost of meters during the 5-year implementation period and the cost of replacement meters over the remainder of the 30-year analysis period, the PVRR for meters includes revenue requirements associated with the Companies' existing meter assets as well as the portion of warehouse and Administrative & General ("A&G") costs that will be allocated to the AMI+AMR_GO alternative during the project implementation period. The investment in existing meter assets is a sunk cost, and the AMI and AMR alternatives will have no impact on total warehouse or A&G costs. Therefore, the PVRR for existing meter assets, warehouses, and A&G costs is the same in all alternatives.

Table 6: PVRR of Alternatives ($M, 2020 Dollars, 2021-2050)

AMR Becomes Obsolete Midway through Analysis Period				
Cost Item	**Status Quo**	**Full AMI**	**AMI+AMR_GO**	**Full AMR**
Meters	144.2	322.5	321.3	333.4
Non-Meter Deployment & On-Going Costs	9.8	180.4	179.0	124.8
Meter Reading	318.4	65.5	66.0	93.1
Field Services	248.0	165.9	165.9	206.5
EDO Costs	13.8	-2.7	-2.7	11.5
Fuel Savings	0.0	-48.6	-48.6	-20.1
Total (A)	734.2	683.0	680.9	749.3
Difference from Status Quo	0	-51.3	-53.3	15.0
AMR Remains Viable for 30-Year Analysis Period				
Cost Item	**Status Quo**	**Full AMI**	**AMI+AMR_GO**	**Full AMR**
Meters	139.7	322.5	321.3	264.7
Non-Meter Deployment & On-Going Costs	8.1	180.4	177.3	41.6
Meter Reading	320.4	65.5	66.4	119.7
Field Services	248.0	165.9	165.9	248.0
EDO Costs	13.8	-2.7	-2.7	13.8
Fuel Savings	0.0	-48.6	-48.6	0.0
Total (B)	729.9	683.0	679.6	687.8
Difference from Status Quo	0	-47.0	-50.4	-42.1
AMR Obsolescence Risk (A less B)	4.3	0	1.3	61.4

* Analysis ignores non-quantified benefits.

In both AMR obsolescence scenarios, the AMI+AMR_GO alternative is the least-cost alternative. The Status Quo alternative has the highest cost if AMR remains viable for the 30-year analysis period and the second highest cost if AMR becomes obsolete midway through the analysis period. For each alternative, AMR obsolescence risk is computed as the difference in PVRR between the two obsolescence scenarios. Unsurprisingly, the unfavorable impact of AMR obsolescence is greatest for the Full AMR alternative. AMR obsolescence increases the PVRR of the Full AMR alternative by $61.4 million and the PVRR of the AMI+AMR_GO alternative by only $1.3 million.

The favorability of the Full AMI and AMI+AMR_GO alternatives is explained primarily by meter reading and field services savings, but fuel savings are also significant. The PVRR for the Full AMI and AMI+AMR_GO alternatives is not materially different. However, because the AMI+AMR_GO alternative enables the Companies to utilize existing gas meter assets in the gas-only service territory and avoid the complexity associated with managing multiple 3rd party pole agreements, the AMI+AMR_GO alternative is clearly preferred over the Full AMI alternative. Based on the favorability of the AMI+AMR_GO alternative and the risk of obsolescence for AMR meters, further analysis is focused only on the AMI+AMR_GO alternative.

5.1.1. Sensitivity Analysis

Table 7 shows the impact of changing various input assumptions on the PVRR difference between the AMI+AMR_GO and Status Quo alternatives, and indicates to which inputs this difference is most sensitive. Because the impact of AMR obsolescence is small for both alternatives, this portion of the analysis is focused on one AMR obsolescence scenario (i.e., where AMR is assumed to remain viable for the 30-year analysis period). The basis for each range of input values is discussed in more detail in Appendix A – Model Inputs. With base inputs, the AMI+AMR_GO alternative is $50.4 million favorable to the Status Quo. Because the downside risk associated with any single input in Table 7 is less than $50.4 million, the results in Table 7 demonstrate that the favorability of the AMI+AMR_GO alternative does not depend on any single input. For example, if customers do not reduce their energy usage based on their access to interval data and incremental ePortal savings turn out to be zero, the favorability of the AMI+AMR_GO alternative is reduced from $50.4 million by $13.8 million to $36.6 million, but the AMI+AMR_GO alternative is still favorable to the Status Quo.[14]

Table 7: Sensitivity Analysis Results ($M, 2020 Dollars, 2021-2050)

Input	**Input Range**			**Impact of Changing Input on PVRR Difference (AMI+AMR_GO less Status Quo)**	
	Base	**Low**	**High**	**Low Case**	**High Case**
Outside Services Labor Escalation Rate	2.5%	2.0%	3.0%	+$20.6 M	-$23.4 M
Meter Capital Escalation Rate	0.25%	0.0%	1.0%	-$1.3 M	+$4.3 M
Average Meter Operating Life (Electromechanical/ Electronic)[15]	37 Years/ 15 Years	N/A	46 Years/ 20 Years	N/A	-$0.4
Testing Removed Meters Waiver	Not Granted	Granted	N/A	-$2.5 M	N/A
PSC Inspection Waiver	Not Granted	Granted	N/A	-$4.2 M	N/A
CVR Fuel Savings	205 GWh	140 GWh	270 GWh	+$10.2 M	-$11.0 M
ePortal Fuel Savings	0.35%	0.0%	0.7%	+$13.8 M	-$13.8 M
Generation Fuel Prices	2021 BP Base	2021 BP Low	2021 BP High	+$10.6 M	-$10.4 M

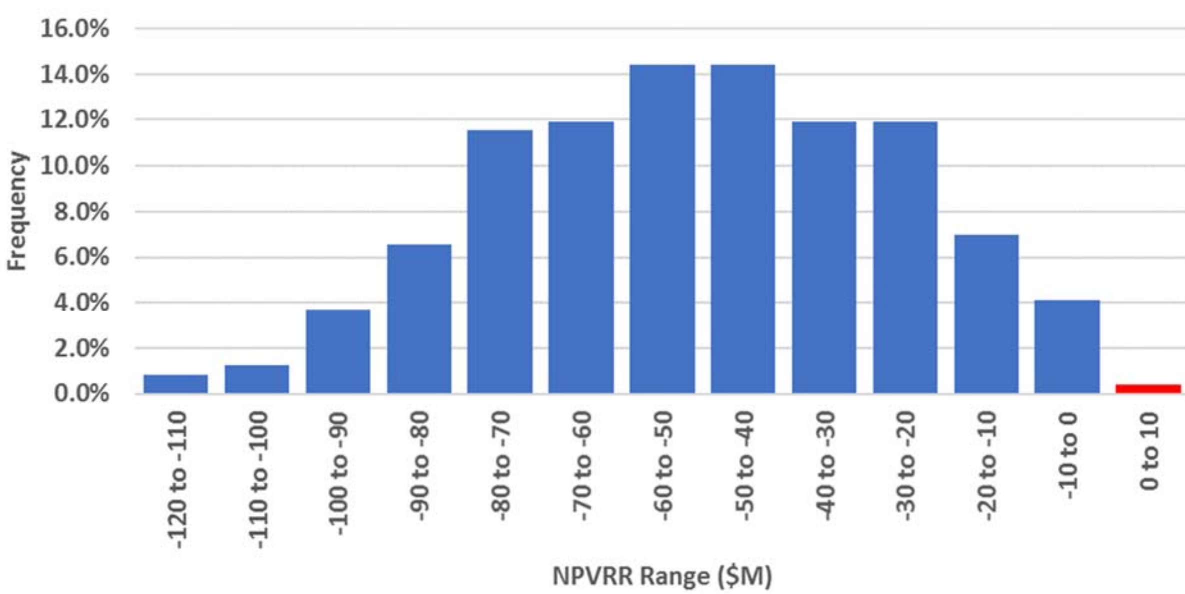
The Companies evaluated two meter operating life scenarios. In the proactive replacement operating life scenario, meters that haven't failed by a certain age are assumed to be replaced proactively (i.e., after 16 years for AMI, AMR, and electronic meters and after 45 years for electromechanical meters) so that the average meter operating life equals its depreciation life. In addition to the proactive replacement

[14] For an explanation of ePortal savings, see Section 6.6, Fuel Savings.
[15] Electronic meters include non-communicating electronic meters, AMI, and AMR meters.

operating life scenario, the Companies modeled a longer operating life scenario without proactive replacement. The proactive replacement assumption causes total meter replacements over the 30-year analysis period to be higher in both the Status Quo and AMI+AMR_GO alternatives. In the Status Quo alternative, the impact of this assumption is greatest during the first 15 years of the analysis period as aging electromechanical meters are replaced faster than they otherwise would be replaced. In the AMI+AMR_GO alternative, this assumption causes an uptick in meter replacements from 2038 to 2041 for the replacement of meters installed in the initial meter deployment period that haven't failed after 16 years. Because this assumption increases revenue requirements in both the Status Quo and the AMI+AMR_GO alternatives, the impact of this assumption on the PVRR difference is only $0.4 million. Assumptions regarding meter operating lives do not have a significant impact on deciding whether AMI is least-cost for customers.

The PVRR difference is most sensitive to outside services labor escalation, meter cost escalation, ePortal fuel savings, CVR fuel savings, and the generation fuel prices assumed for ePortal and CVR fuel savings. The Companies created 243 cases by varying these inputs (3 outside services labor escalation rate scenarios times 3 meter cost escalation rate scenarios times 3 ePortal fuel savings scenarios times 3 CVR fuel savings scenarios times 3 generation fuel price scenarios). Figure 11 plots the distribution of PVRR difference between the AMI+AMR_GO and Status Quo alternatives over these cases. The PVRR of the AMI+AMR_GO alternative is favorable to the Status Quo in 99.6% of the cases evaluated and ranges from only $4.2 million unfavorable to $115.4 million favorable. These results demonstrate that the AMI+AMR_GO alternative has very little downside risk.

Figure 11: Distribution of PVRR Difference (AMI+AMR_GO less Status Quo, $M, 2020 Dollars, 2021-2050)

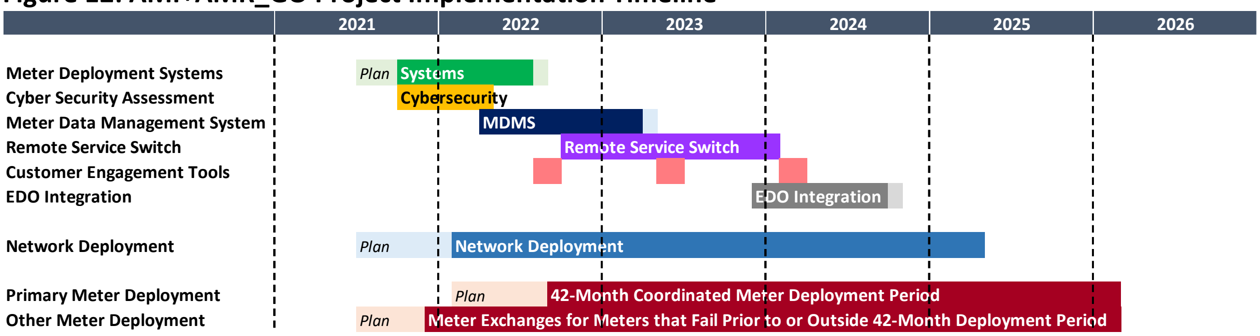


5.2. Phase 2 Analysis

In the Phase 2 analysis, the Companies evaluated the AMI+AMR_GO alternative over different implementation timelines to determine whether the 5-year implementation timeline beginning October

2021 ("base implementation timeline") is optimal. Figure 12 provides an overview of the base implementation timeline for the AMI+AMR_GO alternative. Systems development and network deployment begin in October 2021 and the coordinated 42-month meter deployment period begins in September 2022. The vast majority of meters will be replaced one neighborhood at a time through this 42-month period. Other meter replacement refers to meters that need to be replaced prior to or outside the coordinated meter deployment project in portions of the service territory where the mesh network has been installed. The timing of meter reading and field services cost savings is tied to availability of systems functionality in the Meter Data Management System ("MDMS") and the Remote Service Switch, respectively, as well as the number of meters deployed. The timing of EDO savings and CVR fuel savings is tied to the integration of AMI and EDO IT systems.

Figure 12: AMI+AMR_GO Project Implementation Timeline



A decision to delay the project would reduce the PVRR associated with deployment costs simply by deferring the capital investments. However, this delay would also defer meter reading, field services, and fuel savings benefits. In addition, a delay would cause the Companies to incur some portion of the cost of voltage sensing equipment that would otherwise be avoided. Table 8 summarizes the impact on PVRR difference between the AMI+AMR_GO and Status Quo alternatives from delaying the project. In addition to the case with base inputs, the Companies evaluated the impact of delay on the 25th and 75th percentile cases from the distribution of PVRR differences presented in Figure 11 in Section 5.1. For each case, delaying the project decreases the NPVRR by delaying the project's benefits. The base implementation timeline was developed to deliver savings as soon as possible and provide a good customer experience. Once AMI systems are in place, deploying AMI meters as soon as possible is least cost.

Table 8: NPVRR (AMI+AMR_GO less Status Quo, $M, 2020 Dollars, 2021-2050)

Implementation Start Year	Project Completion Year	25th Percentile Inputs	Base Inputs	75th Percentile Inputs
2021	2026	-67.9	-50.4	-31.9
2026	2031	-48.5	-30.5	-19.0
2031	2036	-25.2	-9.5	-2.8

For the implementation timelines evaluated thus far, network deployment and the installation of AMI systems occurs at the beginning of the implementation period. The Companies evaluated a final implementation timeline ("replace-as-meters-fail") where most systems implementation is deferred so that more in-scope meters can be replaced as they fail. This timeline requires a more robust network since AMI meters will not be able to rely on other AMI meters to communicate with systems in the Meter Operations Center (see Section 6.2).

For the replace-as-meters-fail timeline, the analysis assumes inside meters are proactively replaced to provide some immediate operational benefits and reduce presence inside customer premises. Beginning October 2021, the Companies will be able to bill residential and general service customers with an AMI meter from meter data collected remotely. Because approximately 90% of all customers are residential or general service customers, the analysis assumes the Companies will be able to remotely read 90% of the meters replaced on this timeline. However, replacing meters as they fail limits meter reading savings due to the non-contiguous nature of the meter replacements.[16] In addition, the Companies would not realize the economies of scale associated with a coordinated meter deployment project (i.e., no bulk meter cost discounts or labor savings). The Companies would avoid the cost of voltage sensing equipment but would not achieve CVR savings until AMI systems are in place and integrated to EDO systems.

Table 9 summarizes the results of this analysis. In the base timeline, AMI systems and meters are assumed to be fully deployed by 2026. In the replace-as-meters-fail timeline, AMI systems and the balance of meters are assumed to be fully deployed by 2031 or 2036. The replace-as-meters-fail timeline is favorable to the Status Quo but not as favorable as the base timeline. In addition, the sooner AMI systems and the balance of meters are fully deployed, the more favorable the PVRR.

Table 9: PVRR of Alternatives ($M, 2020 Dollars, 2021-2050, Base and Replace-as-Meters-Fail Timelines)

	Implementation Start Year	Project Completion Year	PVRR	PVRR Difference from Status Quo
Status Quo	N/A	N/A	729.9	0
AMI+AMR_GO: Base Timeline	2021	2026	679.6	-50.4
AMI+AMR_GO: Replace-As-Meters-Fail	2021	2031	688.3	-41.7
AMI+AMR_GO: Replace-As-Meters-Fail	2021	2036	706.8	-23.1

5.3. Conclusion

The results of this analysis show that the AMI+AMR_GO alternative is the least-cost metering alternative for customers and that the 5-year implementation timeline beginning October 2021 is optimal. In an effort to focus on costs and benefits that are more certain, the financial analysis sets aside hard-to-quantify benefits for the AMI alternatives such as improved customer experience, improved safety, improved reliability, the reduction of non-technical losses, and the ability to offer additional customer

[16] If non-AMI meters were replaced with AMI meters as they fail, the associated labor savings would not be as large as it would be via a coordinated replacement strategy because there would not be significant reductions in the quantities of meter reading routes nor the number of needed readers. While there would be fewer meters to read, the meter reading contract has provisions for pricing negotiations as the number of meters change. The longer the deployment lasts, the more often those provisions will come into play, limiting the overall labor savings.

programs or services like prepay. Even when these benefits are ignored, the AMI+AMR_GO alternative has very little downside risk.

6. Appendix A – Model Inputs

6.1. Meter Costs

Table 10 contains a detailed summary of meter costs for each alternative through 2030. Status Quo meter costs include the cost of replacing existing meters as they fail with non-communicating electronic meters as well as the cost of manual meter reading equipment and the cost of mobile collectors for reading AMR meters by vehicle. In the Full AMI alternative, these costs are eliminated. In the AMI+AMR_GO alternative, the cost of manual meter reading equipment is eliminated and only one mobile collector is needed to read AMR meters in the gas-only service territory by vehicle. In the AMR alternative, the cost of manual meter reading equipment is reduced, but additional mobile collectors are needed to read all meters by vehicle.

Table 10: Meter Costs ($M, Capital and O&M, Proactive Replacement Operating Life)

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Status Quo										
New Meter Costs	4.8	3.5	4.0	3.9	4.6	5.4	4.4	5.2	5.1	6.3
Total Meters	4.8	3.5	4.0	3.9	4.6	5.4	4.4	5.2	5.1	6.3
Full AMI										
New Meter Costs	0.8	18.8	46.3	46.6	47.6	7.1	1.4	1.7	2.0	2.4
Legacy Meter Costs	2.9	1.0	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Meter Base Repairs	0.0	0.9	2.3	2.3	2.4	0.4	0.0	0.0	0.0	0.0
Test Removed Meters	0.0	0.3	0.9	0.9	1.0	0.1	0.0	0.0	0.0	0.0
Total Meters	3.7	21.0	50.0	49.9	51.0	7.6	1.4	1.7	2.0	2.4
AMI+AMR_GO										
New Meter Costs	0.8	18.7	45.9	46.2	47.2	7.1	1.5	1.7	2.0	2.4
Legacy Meter Costs	2.9	1.0	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Meter Base Repairs	0.0	0.9	2.3	2.3	2.4	0.4	0.0	0.0	0.0	0.0
Test Removed Meters	0.0	0.3	0.9	0.9	1.0	0.1	0.0	0.0	0.0	0.0
Total Meters	3.7	20.9	49.6	49.4	50.6	7.6	1.5	1.7	2.0	2.4
Full AMR										
New Meter Costs	0.6	12.7	30.4	30.3	31.0	5.2	2.3	1.8	2.3	2.4
Legacy Meter Costs	2.9	1.0	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Meter Base Repairs	0.0	0.9	2.2	2.3	2.4	0.3	0.0	0.0	0.0	0.0
Test Removed Meters	0.0	0.3	0.9	0.9	1.0	0.1	0.0	0.0	0.0	0.0
Total Meters	3.5	14.9	34.0	33.5	34.4	5.7	2.3	1.8	2.3	2.4

New meter costs for the AMI and AMR alternatives includes the cost of new meters, new meter inventory, and the cost of additional resources needed to test new meters during meter deployment. Legacy meter costs includes the cost of non-communicating electronic meters and related equipment necessary to maintain current operations until the AMI and AMR alternatives are adequately deployed. Total meter costs also include the cost of any meter base repairs during deployment and the cost of testing removed meters. Even though current regulations require customers to bear the cost of meter base repairs, the Companies are proposing that this cost be treated as a utility revenue requirement during meter deployment period to streamline the meter deployment project and improve the customer experience. The Companies are not proposing that this cost be capitalized. When a meter is replaced, the Companies are required by statute to test both the removed meter and the new meter. Both costs are included in the financial analysis but the Companies are requesting a waiver for the requirement to test removed meters.

In the Full AMI, AMI+AMR_GO, Full AMR alternatives, new meters are deployed over a 42-month meter deployment period beginning September 2022. The meter deployment period was designed to balance delivering benefits to customers as quickly as possible with levelizing back office support activities to ensure to ensure a good customer experience. Lengthier deployment timeframes would further levelize back office activities but would unnecessarily delay benefits for customers. A shorter deployment timeframe may deliver benefits faster but would include considerable risk of increased exception management costs. After the initial meter deployment period, annual meter costs in AMI alternatives are lower, despite a higher cost per meter, because the failure rate for the new population of meters is low.

Table 11 summarizes total meter costs for each alternative from 2031 to 2050 under the two AMR obsolescence scenarios. In the scenario where AMR remains viable throughout the 30-year analysis period, total meter costs for each alternative simply include the cost of replacing meters as they fail and the cost of meters for new customers. To model the impact of AMR obsolescence, the Companies assumed AMR becomes obsolete by 2035. In this scenario, approximately 70,000 AMR electric meters and 35,000 gas ERTs are replaced in the Status Quo over the four-year period from 2032 to 2035 with AMI electric meters and gas modules.[17] The nature of the replacement meters and modules (i.e., either mesh or cellular) would depend on the location of the meter and the economics of expanding the existing mesh network. For this analysis, the Companies assumed limited expansion of the mesh network throughout the gas-only service territory.[18] For the AMI+AMR_GO and Full AMR alternatives, the least-cost option for addressing AMR obsolescence would be to transition fully to AMI. In the AMI+AMR_GO alternative, the mesh network is expanded to include the gas-only service territory and the approximately 19,000 gas ERTs in the gas-only service territory are replaced with gas AMI modules in 2035. In the Full AMR alternative, all electric meters and gas ERTs are replaced with AMI meters and gas modules over the four-year period from 2032 to 2035.

[17] The Companies' existing AMR meters were installed to solve problems related to accessing customers' meters. Therefore, replacing AMR meters and gas ERTs with non-communicating devices is not a viable solution.
[18] The impact to network costs is discussed in Section 6.2.

Table 11: Meter Costs ($M, Capital and O&M, Proactive Replacement Operating Life)

	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
	AMR Becomes Obsolete Midway through Analysis Period									
Status Quo	7.3	8.4	8.1	9.4	11.3	8.1	7.7	6.8	7.4	7.7
Full AMI	2.7	3.0	3.4	3.9	4.5	5.2	6.5	23.2	47.0	47.9
AMI+AMR_GO	2.7	3.2	3.5	4.0	5.7	5.2	6.5	23.2	47.0	47.9
Full AMR	7.3	23.2	55.4	55.3	56.5	8.4	1.5	1.8	2.2	2.6
	AMR Remains Viable for 30-Year Analysis Period									
Status Quo	7.3	6.5	6.1	6.3	8.5	8.3	7.9	7.0	7.6	7.9
Full AMI	2.7	3.0	3.4	3.9	4.5	5.2	6.5	23.2	47.0	47.9
AMI+AMR_GO	2.7	3.2	3.5	4.0	4.6	5.3	6.7	23.3	47.1	48.1
Full AMR	3.2	3.7	3.5	4.0	7.9	5.6	7.5	23.6	50.7	51.6
	2041	**2042**	**2043**	**2044**	**2045**	**2046**	**2047**	**2048**	**2049**	**2050**
	AMR Becomes Obsolete Midway through Analysis Period									
Status Quo	9.4	8.6	8.5	9.7	9.4	12.3	10.8	13.6	12.9	13.0
Full AMI	48.5	14.5	17.0	17.7	18.5	7.9	6.2	7.0	7.8	8.8
AMI+AMR_GO	48.5	14.3	16.2	16.9	17.7	7.7	6.2	6.9	7.7	8.7
Full AMR	3.0	3.3	3.8	4.3	4.9	5.7	7.2	25.7	52.1	53.1
	AMR Remains Viable for 30-Year Analysis Period									
Status Quo	9.5	8.8	8.7	9.8	9.5	12.3	10.8	11.3	10.7	10.8
Full AMI	48.5	14.5	17.0	17.7	18.5	7.9	6.2	7.0	7.8	8.8
AMI+AMR_GO	48.6	14.4	16.4	17.1	17.9	7.9	6.4	7.1	7.9	8.9
Full AMR	52.8	12.2	4.4	4.7	5.5	6.3	7.9	7.8	8.9	10.2

6.1.1. Forecast of New Meters

In Table 10 and Table 11, the cost of new meter capital for each alternative is a function of the Companies' forecast of new meters and the meter replacement cost. Table 12 shows the forecast of total in-scope meters over next 30 years. The forecast was developed based on the Companies' customer forecasts. Total meters are expected to grow by 0.3% to 0.5% per year during the 30-year analysis period. The forecast of total customers and meters is the same for each alternative, but the timing and need for new meters varies with each alternative.

Table 12: In-Scope Meter Forecast

Year	Electric	Gas	Total
2021	996,000	339,000	1,335,000
2022	1,001,000	340,000	1,341,000
2023	1,004,000	341,000	1,345,000
2024	1,009,000	342,000	1,351,000
2025	1,013,000	344,000	1,357,000
2026	1,018,000	345,000	1,363,000
2027	1,022,000	347,000	1,369,000
2028	1,027,000	348,000	1,375,000
2029	1,031,000	349,000	1,380,000
2030	1,036,000	350,000	1,386,000
2031	1,040,000	351,000	1,391,000
2032	1,045,000	352,000	1,397,000
2033	1,050,000	354,000	1,404,000
2034	1,055,000	355,000	1,410,000
2035	1,059,000	356,000	1,415,000
2036	1,063,000	357,000	1,420,000
2037	1,068,000	358,000	1,426,000
2038	1,072,000	360,000	1,432,000
2039	1,076,000	361,000	1,437,000
2040	1,080,000	362,000	1,442,000
2041	1,085,000	363,000	1,448,000
2042	1,088,000	364,000	1,452,000
2043	1,092,000	366,000	1,458,000
2044	1,095,000	367,000	1,462,000
2045	1,098,000	368,000	1,466,000
2046	1,101,000	369,000	1,470,000
2047	1,104,000	370,000	1,474,000
2048	1,106,000	372,000	1,478,000
2049	1,109,000	373,000	1,482,000
2050	1,112,000	374,000	1,486,000

As discussed in Section 3, while the Companies' 2019 Meter Life Study and outside report support a 20-year operating life for electronic, AMI, and AMR meters, the Companies' existing AMI meters have a 15-year depreciation life. At least in part, the depreciation life is shorter to reflect some likelihood that the meters will be proactively replaced before the end of their operating life. A similar assumption is made for the depreciation life of electromechanical and electronic meters, which are depreciated in one asset group. Based on the Companies' analysis, the weighted average operating life of these meters is 39.5 years but the depreciation life is 32 years.[19] For these reasons, the Companies evaluated two meter

[19] Approximately 75% and 25% of existing meters, respectively, are electromechanical and electronic meters. The weighted average operating life for all meters (39.5 years) = 75% * 46 years + 25% * 20 years.

operating life scenarios: one based on the 2019 Meter Life Study and a shorter meter operating life scenario ("proactive replacement") where meters that haven't failed by a certain age are assumed to be replaced proactively (i.e., after 16 years for AMI and electronic meters and after 45 years for electromechanical meters). This assumption causes the average operating life to equal the depreciation life. With an average operating life of 15 to 20 years for electronic, AMI, and AMR meters, the analysis evaluates more than one meter replacement cycle over the 30-year analysis period.

Table 13 contains the forecasted need for new meters in the proactive replacement meter operating life scenario. The forecast for new meters in the Status Quo was developed by applying the meter failure curves from the meter failure analysis to the existing electromechanical and electronic meter populations. Electronic meters that haven't failed after 16 years of life are assumed to be proactively replaced; electromechanical meters are assumed to be proactively replaced after 45 years if they haven't failed already. In the AMI and AMR alternatives, all in-scope meters are replaced by the end of the 42-month meter deployment period. After the meter deployment period, the need for new meters is driven by customer growth and meter failures. Meter failures were developed by applying the meter failure curve for electronic meters to the newly installed AMI and AMR meters. The significant uptick from 2038 to 2041 results from proactively replacing meters installed in the initial meter deployment period that have not failed after 16 years. In all alternatives, when a meter in the starting meter population is replaced, the failure of the replacement meter is modeled by applying the electronic meter failure curve to that meter.

Table 13: Forecast of New Meters (Proactive Replacement Operating Life Scenario; AMR Remains Viable for 30-Year Analysis Period)

	SQ	Full AMI			AMI+AMR_GO				Full AMR		
Year	Electronic Meters	Electronic Meters	AMI Meters	Gas Modules	Electronic Meters	AMI Meters	Gas Modules	Gas ERTs[20]	Electronic Meters	AMR Meters	Gas ERTs
2021	47,000	22,000	4,000	0	22,000	4,000	0	0	22,000	4,000	0
2022	44,000	12,000	113,000	33,000	12,000	113,000	31,000	1,100	12,000	109,000	32,000
2023	46,000	6,000	273,000	98,000	6,000	273,000	93,000	3,300	6,000	263,000	93,000
2024	47,000	0	284,000	98,000	0	284,000	93,000	3,300	0	274,000	93,000
2025	52,000	0	293,000	98,000	0	293,000	93,000	3,300	0	284,000	93,000
2026	53,000	0	48,000	18,000	0	48,000	17,000	1,600	0	46,000	17,000
2027	48,000	0	15,000	5,000	0	15,000	4,000	1,000	0	15,000	4,000
2028	59,000	0	16,000	4,000	0	16,000	4,000	1,000	0	16,000	4,000
2029	53,000	0	17,000	4,000	0	17,000	4,000	1,000	0	17,000	5,000
2030	69,000	0	18,000	4,000	0	18,000	4,000	1,000	0	18,000	5,000
2031	65,000	0	20,000	4,000	0	20,000	4,000	1,000	0	20,000	6,000
2032	68,000	0	21,000	4,000	0	21,000	4,000	1,000	0	21,000	6,000
2033	62,000	0	23,000	4,000	0	23,000	4,000	1,000	0	23,000	7,000
2034	63,000	0	25,000	4,000	0	25,000	4,000	1,000	0	25,000	8,000
2035	50,000	0	28,000	4,000	0	28,000	4,000	1,000	0	28,000	9,000
2036	72,000	0	31,000	4,000	0	31,000	4,000	1,000	0	31,000	10,000
2037	73,000	0	38,000	4,000	0	38,000	4,000	1,000	0	38,000	11,000
2038	65,000	0	126,000	4,000	0	126,000	4,000	1,000	0	126,000	39,000
2039	67,000	0	251,000	4,000	0	251,000	4,000	1,000	0	251,000	89,000
2040	70,000	0	253,000	5,000	0	253,000	4,000	1,000	0	253,000	87,000
2041	73,000	0	253,000	5,000	0	253,000	4,000	1,000	0	253,000	84,000
2042	75,000	0	54,000	35,000	0	54,000	33,000	1,000	0	54,000	20,000
2043	70,000	0	21,000	93,000	0	21,000	88,000	1,000	0	21,000	7,000
2044	80,000	0	22,000	94,000	0	22,000	89,000	1,000	0	22,000	7,000
2045	74,000	0	24,000	94,000	0	24,000	89,000	1,000	0	24,000	8,000
2046	89,000	0	26,000	22,000	0	26,000	21,000	1,000	0	26,000	9,000
2047	80,000	0	28,000	7,000	0	28,000	7,000	1,000	0	28,000	10,000
2048	84,000	0	31,000	7,000	0	31,000	7,000	1,000	0	31,000	11,000
2049	77,000	0	35,000	7,000	0	35,000	7,000	1,000	0	35,000	12,000
2050	76,000	0	39,000	7,000	0	39,000	7,000	1,000	0	39,000	14,000

The financial analysis includes the cost of meter inventories but the meter counts in Table 13 do not include meters purchased for inventory. The Companies plan to carry approximately 1% of total electric meters and 2% of total gas meters in inventory. New meters in the Status Quo and AMR alternatives carry a three-year warranty. Therefore, when a new meter fails in the first three years of its life, the cost of the replacement meter is paid by the Companies' meter vendor and the Companies incur only the cost of labor to replace the meter. The negotiated warranty in the Full AMI and AMI+AMR_GO alternatives is

[20] The Companies plan to redeploy existing gas ERTs from the electric service territory to the gas-only service territory in the AMI+AMR_GO alternative, so no additional ERT capital is needed during deployment.

5 years. The negotiated warranty of the gas modules in the AMI alternatives is 20 years with declining warranty coverage as the module ages. Gas ERTs are assumed to fail ratably throughout the analysis period after the initial meter deployment period. The analysis assumes 50% of existing ERTs will be replaced during the meter deployment period due to battery life.

The need for electronic meters in the AMI and AMR alternatives declines sharply as new meters are deployed and occurs in portions of the service territory slated to receive new meters in the latter part of meter deployment period where the mesh network has not yet been installed. Compared to the Status Quo alternative, total electric meter replacements in the AMI and AMR alternatives are lower in the years following the meter deployment period because the average failure rate for the new population of meters is low.

Table 14 compares total meter replacements in the proactive replacement operating life scenario to total meter replacements with no proactive replacement. If meters are not proactively replaced, the average meter operating life for electronic, AMI, and AMR meters increase from 15 to 20 years, and the average meter operating life for electromechanical meters increases from 37 to 46 years. Unsurprisingly, total meter replacements over the 30-year analysis period are lower for all alternatives if meters are not proactively replaced. In the Status Quo, the impact of proactively replacing meters is greatest during the first 15 years of the analysis period as aging electromechanical meters are replaced faster than they otherwise would be replaced.

Table 14: Meter Replacement Comparison (AMR Remains Viable for 30-year Analysis Period)

Year	SQ		Full AMI / AMI+AMR_GO		Full AMR	
	Proactive Replacement	No Proactive Replacement	Proactive Replacement	No Proactive Replacement	Proactive Replacement	No Proactive Replacement
2021	47,000	25,000	26,000	13,000	26,000	13,000
2022	44,000	26,000	125,000	109,000	121,000	106,000
2023	46,000	27,000	279,000	271,000	269,000	260,000
2024	47,000	29,000	284,000	288,000	274,000	278,000
2025	52,000	30,000	293,000	305,000	284,000	295,000
2026	53,000	31,000	48,000	50,000	46,000	48,000
2027	48,000	32,000	15,000	15,000	15,000	15,000
2028	59,000	34,000	16,000	16,000	16,000	16,000
2029	53,000	35,000	17,000	17,000	17,000	17,000
2030	69,000	37,000	18,000	18,000	18,000	18,000
2031	65,000	37,000	20,000	20,000	20,000	20,000
2032	68,000	39,000	21,000	21,000	21,000	21,000
2033	62,000	40,000	23,000	23,000	23,000	23,000
2034	63,000	41,000	25,000	25,000	25,000	25,000
2035	50,000	42,000	28,000	27,000	28,000	27,000
2036	72,000	42,000	31,000	31,000	31,000	31,000
2037	73,000	43,000	38,000	35,000	38,000	35,000
2038	65,000	44,000	126,000	39,000	126,000	39,000
2039	67,000	45,000	251,000	45,000	251,000	45,000
2040	70,000	46,000	253,000	51,000	253,000	51,000
2041	73,000	47,000	253,000	57,000	253,000	57,000
2042	75,000	48,000	54,000	63,000	54,000	63,000
2043	70,000	47,000	21,000	69,000	21,000	69,000
2044	80,000	49,000	22,000	76,000	22,000	76,000
2045	74,000	47,000	24,000	82,000	24,000	82,000
2046	89,000	48,000	26,000	86,000	26,000	86,000
2047	80,000	50,000	28,000	89,000	28,000	89,000
2048	84,000	51,000	31,000	90,000	31,000	90,000
2049	77,000	52,000	35,000	87,000	35,000	87,000
2050	76,000	51,000	39,000	85,000	39,000	85,000

6.1.2. Meter Replacement Cost

Table 15 contains the weighted average meter replacement cost for each metering alternative. The cost of replacing a meter includes the cost of the meter and the cost of labor required to install the meter. Meter costs are based on the results of a recent RFP. The cost of labor is based on the Companies' current meter replacement costs and is assumed to grow at 3% per year in all alternatives. Table 15 contains the weighted average meter cost for each metering alternative because the cost per meter varies depending on the type of service for which consumption is measured. For example, the cost of an AMI meter is less for a residential customer than for a Power Service Primary customer because the residential meter requires fewer components to register the consumption of electricity.

Table 15: Replacement Meter Costs (2021 Dollars)[21]

	Status Quo	Full AMI / AMI+AMR_GO	Full AMR
Weighted Average Electric Meter Cost	[redacted]	[redacted]	[redacted]
Installation Labor Cost	42.88	42.88	42.88
Total Meter Replacement Cost	[redacted]	[redacted]	[redacted]
Weighted Average Gas AMI Module Cost	N/A	[redacted]	N/A
Installation Labor Cost	N/A	[redacted]	N/A
Total Module Replacement Cost	N/A	[redacted]	N/A
Gas ERT	[redacted]	[redacted]	[redacted]
Installation Labor Cost	[redacted]	[redacted]	[redacted]
Total Replacement Cost	[redacted]	[redacted]	[redacted]

The costs in Table 15 do not reflect any discounts that will be realized during the meter deployment period for the AMI and AMR alternatives. In the AMI alternatives, the weighted average meter cost will be approximately [redacted]% lower for all meters replaced during the meter deployment period due to negotiated discounts for the volume of meters purchased as part of the coordinated project. The same [redacted]% discount is assumed for the Full AMR alternative. The cost of labor for installing an electric meter during the coordinated meter replacement project is [redacted]% lower ($[redacted]/meter). This decrease reflects the increased economies of scale associated with this project but is not applicable to all meters replaced during the 42-month period. For example, if a new home is constructed in a neighborhood after existing meters are replaced, the meter is assumed to be replaced at the normal labor cost.

Table 16 summarizes the Companies' weighted average meter cost from their last three RFPs. The cost declined by 1.2% per year from 2012 to 2015 but increased by 2.6% per year from 2015 to 2020. From 2012 to 2020, meter costs escalated at 1.1% per year.

Table 16: Historical Meter Costs

Year RFP Issued	Weighted Average Electric Meter Cost
2012	[redacted]
2015	[redacted]
2020	[redacted]

As discussed in Section 4.3 and summarized in Appendix B – Metering RFI Summary, the Companies issued an RFI to gather information regarding the future availability and pricing for various meter types. Table

[21] Multiple models of meters exist within each form, depending upon whether the meter simply registers energy or requires additional functionality such as registering demand or time-of-use energy. Meter costs reflect a weighted average of costs based on the Companies' meter population.

17 summarizes the responses that were received regarding future meter pricing. For non-communicating electronic and AMI meters, two of three respondents said future prices would be flat or stable. No respondents said future AMI meter costs would increase. For AMR meters, two of three respondents said future prices would increase as industry support for the technology wanes.

Table 17: Meter Cost Escalation Assumptions from RFI

Respondent	Non-Communicating Electronic	AMR	AMI
[redacted]			

Based on the similar responses for non-communicating electronic and AMI meters, the Companies assumed non-communicating electronic and AMI meters would escalate at the same rate. Both meter types have the same meter platform. The only difference is that AMI meters have 2-way communications and the ability to remotely connect and disconnect service. The Companies evaluated a range of meter cost escalation from 0% to 1% with base value of 0.25%. The low end of the range is based on the RFI results. The high end of the range is the observed escalation rate over the last 3 RFP results. The base value is weighted toward RFI results and is arguably high for AMI meters and low for electronic meters. The same assumptions were used for gas AMI modules.

AMR meters have the same meter platform as AMI meters but industry support for 1-way communications is waning. As a result, Companies assumed the cost of AMR meters would escalate at the general rate of inflation, which is assumed to be 2% per year. The same escalation rate was used in all alternatives for AMR ERTs.

6.2. Non-Meter Deployment & On-Going Costs

Figure 13 provides an overview of AMI systems and the RF mesh network. The mesh network consists of multiple routers and collectors. For a given area, the need for routers and collectors depends on the topography and density of customers in that area. When an electric meter or gas module is installed, it immediately begins securely communicating via other electric meters and the mesh network with corporate IT systems.[23] Employees in the Meter Operations Center monitor the operation of the network and meters to ensure communication channels stay open, ensure meter data is delivered to the appropriate corporate IT systems, and develop processes for handling meter alarms (e.g., high

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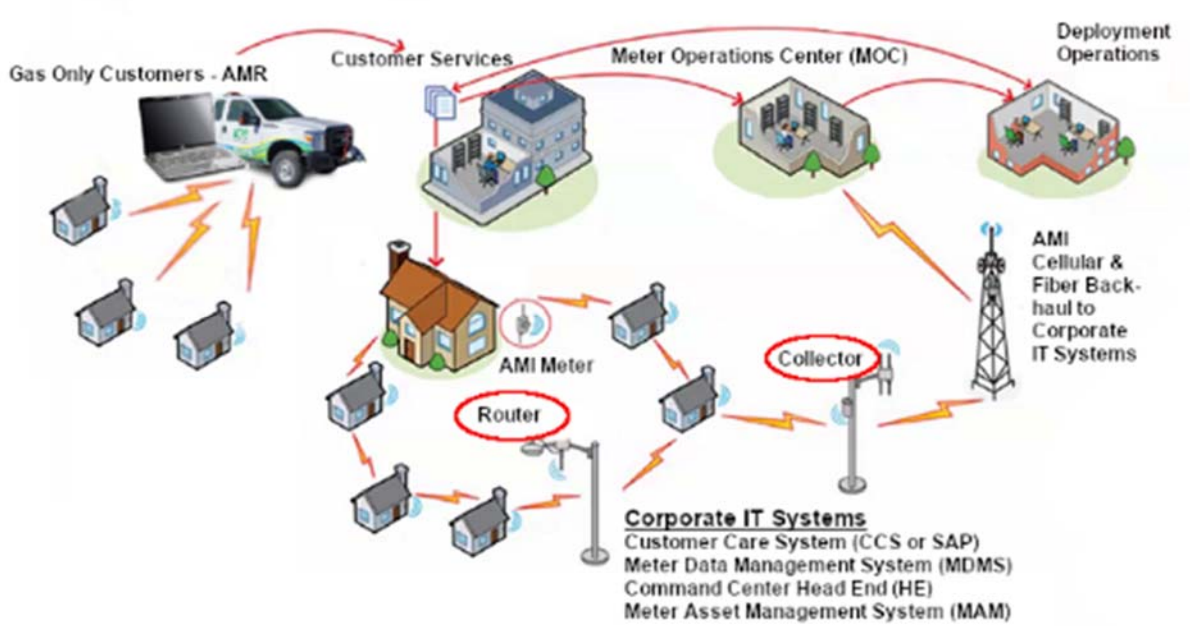
[22] [redacted] stated for all meter types that "We strive to meet a 2.5% per year cost reduction to counter CPI increase as a goal in an effort to minimize the increase in cost of our product." The Companies are defining this to mean prices will be stable.

[23] Routers transmit data from multiple electric meters and gas modules to a collector and collectors transmit data from multiple routers and electric meters to corporate IT systems.

temperature or meter tampering alarms). Network deployment must lead AMI meter deployment so that the meters can communicate properly when they are first installed.

Figure 13: AMI Systems and Network Overview



Metered interval data is stored in the MDMS and must be integrated with corporate IT systems to bill customers and remotely provide some field services. AMI systems must also be integrated with existing EDO systems to implement CVR and improve outage restoration. In the AMI alternatives, the three functionality releases that enable customer benefits are the enhanced MDMS, Remote Service Switch, and EDO integration implementations. The timing of meter reading and field services cost savings is tied to availability of systems functionality in the Meter Data Management System ("MDMS") and the Remote Service Switch, respectively. The timing of EDO savings and CVR fuel savings is tied to the integration of AMI and EDO IT systems.

Table 18 contains non-meter deployment and on-going costs for each alternative. In the Status Quo and AMR alternatives, this includes a routine upgrade to the Meter Asset Management ("MAM") system every 6 years, with a cost of $2.5 million in 2023. In the AMI alternatives, the 2023 upgrade is embedded in the overall project scope, but all future upgrades are considered as part of the on-going costs. For the AMI alternatives, the cost of systems is the same and differences in network costs pertain to the gas-only service territory. For the Full AMR alternative, in addition to the MAM upgrades, the cost of systems includes enhancements that are needed for existing systems to support additional AMR data. Program management and change management costs consist of activity and resource coordination as well as training development and delivery. Communications costs include the costs of mail campaigns and other items to inform customers about the timing of upcoming meter replacements and educate them on accessing data if applicable. The project includes 17.5% contingency on systems capital, and 5% contingency on network and meter capital. The total contingency for the Full AMI and AMI+AMR_GO alternatives is $22.5 million and $22.3 million, respectively, which equates to 7% contingency on the sum of meter and non-meter deployment costs. The total contingency for Full AMR is $8.1 million, which equates to 5% contingency on the total project.

Table 18: Non-Meter Deployment & On-Going Costs ($M, Capital and O&M, Proactive Replacement Operating Life)

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Status Quo										
Systems	0.0	0.0	2.5	0.0	0.0	0.0	0.0	0.0	3.0	0.0
Full AMI										
Systems	9.8	18.8	20.2	14.2	4.3	3.0	4.1	3.7	6.8	3.9
Network	0.0	4.2	5.4	5.8	2.5	0.6	0.6	0.8	0.9	0.9
Program Management	3.2	9.5	6.1	5.5	2.5	0.4	0.0	0.0	0.0	0.0
Change Management	0.8	4.1	4.5	2.7	0.4	0.1	0.0	0.0	0.0	0.0
Communications	0.0	0.6	1.3	1.3	1.8	0.2	0.0	0.0	0.0	0.0
Contingency	2.1	5.1	6.4	5.4	3.1	0.4	0.0	0.0	0.0	0.0
Total	15.9	42.2	43.8	34.9	14.5	4.6	4.7	4.5	7.7	4.8
AMI+AMR_GO										
Systems	9.8	18.8	20.2	14.2	4.3	3.0	4.1	3.7	6.8	3.9
Network	0.0	3.7	4.9	5.2	2.2	0.4	0.5	0.7	0.8	0.8
Program Management	3.2	9.5	6.1	5.5	2.5	0.4	0.0	0.0	0.0	0.0
Change Management	0.8	4.1	4.5	2.7	0.4	0.1	0.0	0.0	0.0	0.0
Communications	0.0	0.6	1.3	1.3	1.8	0.2	0.0	0.0	0.0	0.0
Contingency	2.1	5.1	6.3	5.4	3.0	0.4	0.0	0.0	0.0	0.0
Total	15.9	41.7	43.2	34.3	14.2	4.5	4.6	4.4	7.5	4.7
Full AMR										
Systems	1.1	1.5	2.5	0.0	0.0	0.0	0.0	0.0	3.0	0.0
Network	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Program Management	2.4	7.6	3.6	3.5	2.5	0.4	0.0	0.0	0.0	0.0
Change Management	0.5	1.9	1.9	1.9	0.6	0.1	0.0	0.0	0.0	0.0
Communications	0.0	0.5	1.1	1.2	1.8	0.2	0.0	0.0	0.0	0.0
Contingency	0.5	1.6	1.9	1.9	1.8	0.3	0.0	0.0	0.0	0.0
Total	4.6	13.2	11.1	8.5	6.8	1.0	0.0	0.0	3.0	0.0

After AMI is fully deployed in 2026, the Companies will upgrade the MDMS and replace storage hardware associated with the MDMS and other systems every six years. Ongoing network costs include labor and equipment replacement costs, the cost to upgrade backhaul hardware every six years, and annual maintenance on network equipment. For the Full AMI alternative, on-going network costs also include the cost of cellular service for network assets in the gas-only service territory.

Table 19 summarizes non-meter deployment and on-going costs under the two AMR obsolescence scenarios for 2031 to 2050. In the scenario where AMR remains viable for the entire analysis period, the costs in Table 19 simply include on-going systems and network costs. To model the impact of AMR obsolescence, the Companies assumed AMR becomes obsolete by the end of 2035. The costs for this scenario in the Status Quo reflect the cost of expanding the mesh network throughout the gas-only service territory. For the AMI+AMR_GO and Full AMI alternatives, the costs for this scenario reflect the non-meter costs associated with transitioning fully to AMI. This transition is straight-forward for the AMI+AMR_GO alternative but very costly for Full AMR alternative.

Table 19: Non-Meter Deployment Costs & On-Going Systems and Network Costs ($M, Capital and O&M, Proactive Replacement Operating Life)

	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
	AMR becomes Obsolete Midway through Analysis Period									
Status Quo	0.0	0.6	0.7	0.8	3.9	0.2	0.2	0.2	0.2	0.2
Full AMI	4.7	4.2	5.4	5.1	8.8	5.4	5.3	4.8	6.2	5.8
AMI+AMR_GO	4.6	4.6	5.9	5.7	9.0	5.4	5.3	4.8	6.2	5.8
Full AMR	20.4	53.4	55.1	43.7	21.7	5.9	5.9	5.7	9.7	6.0
	AMR Remains Viable for 30-Year Analysis Period									
Status Quo	0.0	0.0	0.0	0.0	3.6	0.0	0.0	0.0	0.0	0.0
Full AMI	4.7	4.2	5.4	5.1	8.8	5.4	5.3	4.8	6.2	5.8
AMI+AMR_GO	4.6	4.0	5.3	5.0	8.7	5.2	5.2	4.6	6.0	5.6
Full AMR	0.0	0.0	0.0	0.0	3.6	0.0	0.0	0.0	0.0	0.0
	2041	**2042**	**2043**	**2044**	**2045**	**2046**	**2047**	**2048**	**2049**	**2050**
	AMR becomes Obsolete Midway through Analysis Period									
Status Quo	4.5	0.2	0.2	0.2	0.2	0.2	5.3	0.2	0.2	0.2
Full AMI	10.2	6.1	6.1	5.5	7.1	6.6	11.9	6.9	6.9	6.4
AMI+AMR_GO	10.2	6.1	6.1	5.5	7.1	6.6	11.9	6.9	6.9	6.4
Full AMR	10.2	5.3	6.8	6.4	11.1	6.8	11.8	6.0	7.8	7.3
	AMR Remains Viable for 30-Year Analysis Period									
Status Quo	4.3	0.0	0.0	0.0	0.0	0.0	5.1	0.0	0.0	0.0
Full AMI	10.2	6.1	6.1	5.5	7.1	6.6	11.9	6.9	6.9	6.4
AMI+AMR_GO	10.0	5.9	5.9	5.3	6.9	6.4	11.7	6.7	6.7	6.2
Full AMR	4.3	0.0	0.0	0.0	0.0	0.0	5.1	0.0	0.0	0.0

6.3. Meter Reading Costs

The primary function of meter reading is to perform manual meter reads and meter safety inspections. Most meter reads are entered manually into handheld devices, but a portion are obtained by vehicle using mobile collectors for AMR-enabled meters. The Meter Reading group is also responsible for the management of keys or coordination with customers to obtain access to approximately 27,000 meters located inside customers' premises. Table 20 summarizes meter reading costs for each of the four alternatives over the next 10 years.

Table 20: Meter Reading and Inspections Costs ($M, O&M, No Opt Out, Proactive Replacement Operating Life)

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Status Quo	18.6	19.0	19.5	20.1	20.7	21.3	21.9	22.6	23.2	23.9
Full AMI	18.6	18.3	16.3	11.3	6.6	1.2	0.4	0.4	0.5	0.5
AMI+AMR_GO	18.6	18.3	16.4	11.3	6.7	1.3	0.5	0.5	0.5	0.6
Full AMR	18.6	18.4	16.6	12.2	8.0	5.5	5.3	5.4	5.6	5.7

In the AMI and AMR alternatives, the costs of manual monthly reads are phased out as AMI meters are deployed, and meter safety inspections are eventually replaced at a much smaller cost of approximately $300k/year as part of line inspections already performed by Electric Distribution Operations.[24] In the AMI alternatives, meter reading is a fully automated process with no incremental operating costs, while in the AMR alternative, monthly meter reads are transitioned from a pedestrian-based process to a vehicle-based process. While customers will be given the option to opt out of AMI, the costs in Table 20 were developed with the assumption that no customers opt-out. If any customers choose to opt-out, incremental meter reading costs associated with this group will be recovered through an opt-out fee.

Meter reading costs are primarily based on third party contracts executed with meter reading vendors in 2019. At that time, the cost per read increased by 56%, with future annual cost escalations capped at 2.5% until the end of the contract in 2024. Over the full analysis period, the cost per read is assumed to escalate between 2% per year (the general rate of inflation) and 3% per year (the Companies' assumed escalation rate for labor costs), with a base escalation of 2.5%. These costs are also growing as a function of the growth in total meters. As shown in Table 12, total meters are expected to grow by 0.3% to 0.5% per year during the 30-year analysis period.

Table 21 summarizes meter reading and inspections costs under the two AMR obsolescence scenarios for 2031 to 2050. To model the impact of AMR obsolescence, the Companies assumed AMR becomes obsolete by the end of 2035. In this scenario, after AMR meters and gas ERTs are replaced with AMI meters and gas modules, Status Quo meter reading costs are incrementally lower due to the ability to read the meters remotely. In the AMI+AMR_GO and Full AMR alternatives, meter reading and inspection costs are aligned with the Full AMI alternative by 2036 after the transition to AMI is complete.

[24] The Companies are requesting a waiver of these meter inspections due to AMI's enhanced meter monitoring capabilities, but the analysis includes this annual cost.

Table 21: Meter Reading and Inspections Costs ($M, O&M, No Opt Out, Proactive Replacement Operating Life)

	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
	AMR becomes Obsolete Midway through Analysis Period									
Status Quo	24.6	25.3	25.9	26.6	27.3	28.0	28.8	29.6	30.5	31.4
Full AMI	0.5	0.5	0.5	0.5	0.5	0.5	0.6	0.6	0.6	0.6
AMI+AMR_GO	0.6	0.6	0.6	0.6	0.6	0.5	0.6	0.6	0.6	0.6
Full AMR	5.9	5.9	5.7	5.4	4.9	1.2	0.6	0.6	0.6	0.6
	AMR Remains Viable for 30-Year Analysis Period									
Status Quo	24.6	25.3	26.1	26.8	27.6	28.4	29.2	30.1	31.0	31.8
Full AMI	0.5	0.5	0.5	0.5	0.5	0.5	0.6	0.6	0.6	0.6
AMI+AMR_GO	0.6	0.6	0.6	0.6	0.6	0.6	0.7	0.7	0.7	0.7
Full AMR	5.9	6.0	6.2	6.4	6.6	6.7	6.9	7.1	7.3	7.5
	2041	**2042**	**2043**	**2044**	**2045**	**2046**	**2047**	**2048**	**2049**	**2050**
	AMR becomes Obsolete Midway through Analysis Period									
Status Quo	32.3	33.2	34.2	35.1	36.1	37.2	38.2	39.3	40.4	41.5
Full AMI	0.6	0.6	0.6	0.7	0.7	0.7	0.7	0.7	0.8	0.8
AMI+AMR_GO	0.6	0.6	0.6	0.7	0.7	0.7	0.7	0.7	0.8	0.8
Full AMR	0.6	0.6	0.6	0.7	0.7	0.7	0.7	0.7	0.8	0.8
	AMR Remains Viable for 30-Year Analysis Period									
Status Quo	32.8	33.7	34.7	35.6	36.7	37.7	38.7	39.8	40.9	42.1
Full AMI	0.6	0.6	0.6	0.7	0.7	0.7	0.7	0.7	0.8	0.8
AMI+AMR_GO	0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.9	0.9	0.9
Full AMR	7.7	8.0	8.2	8.4	8.6	8.9	9.1	9.4	9.7	9.9

6.4. Field Services Costs

The primary function of field services is to complete customer requested orders, such as move-outs and move-ins, off-cycle meter reads and service disconnects/reconnects related to non-payment. Table 22 summarizes field service costs associated with this project for each of the four alternatives.

Table 22: Field Services Costs ($M, O&M, No Opt Out, Proactive Replacement Operating Life)

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Status Quo	14.3	14.7	15.1	15.6	16.1	16.5	17.0	17.5	18.0	18.5
Full AMI	14.3	14.7	15.1	10.8	10.1	10.0	10.2	10.5	10.8	11.1
AMI+AMR_GO	14.3	14.7	15.1	10.8	10.1	10.0	10.2	10.5	10.8	11.1
Full AMR	14.3	14.7	15.1	15.6	16.1	16.5	17.0	17.5	18.0	18.5

Costs related to off-cycle reads and service disconnects/reconnects are unchanged in the SQ and AMR alternatives. In the AMI alternatives, these costs are reduced as remote off-cycle reads and remote disconnect/reconnect capabilities are enabled. While these costs are greatly reduced in the AMI alternatives, some level of field services must be retained to complete work that cannot be performed remotely. Like meter reading costs, field services costs were developed with the assumption that no customers choose to opt out of AMI. The timing of field services cost savings is tied to the availability of the Remote Service Switch systems functionality.

A significant portion of field services costs are based on contracts executed with field services vendors in 2019. At that time, the costs increased by 22%, with future annual cost escalations capped at 2.5% until the end of the contract in 2024. Contractor field services are assumed to escalate between 2% per year (the general rate of inflation) and 3% per year (the Companies' assumed escalation rate for labor costs) during the full analysis period, with a base escalation of 2.5%. These costs are also growing as a function of the growth in total meters. As shown in Table 12, total meters are expected to grow by 0.3% to 0.5% per year during the 30-year analysis period.

Table 23 summarizes field services costs under the two AMR obsolescence scenarios for 2031 to 2050. To model the impact of AMR obsolescence, the Companies assumed AMR becomes obsolete by the end of 2035. AMR obsolescence has no impact on field services costs in the Status Quo. In the AMI+AMR_GO and Full AMR alternatives, field services costs are aligned with the Full AMI alternative by 2036 after the transition to AMI is complete.

Table 23: Field Services Costs ($M, No Opt Out, O&M, Proactive Replacement Operating Life)

	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
	AMR becomes Obsolete Midway through Analysis Period									
Status Quo	19.1	19.6	20.2	20.8	21.4	22.0	22.6	23.2	23.9	24.6
Full AMI	11.5	11.8	12.1	12.5	12.8	13.2	13.6	13.9	14.3	14.7
AMI+AMR_GO	11.5	11.8	12.1	12.5	12.8	13.2	13.6	13.9	14.3	14.7
Full AMR	19.1	19.6	20.2	14.5	13.7	13.2	13.6	13.9	14.3	14.7
	AMR Remains Viable for 30-Year Analysis Period									
Status Quo	19.1	19.6	20.2	20.8	21.4	22.0	22.6	23.2	23.9	24.6
Full AMI	11.5	11.8	12.1	12.5	12.8	13.2	13.6	13.9	14.3	14.7
AMI+AMR_GO	11.5	11.8	12.1	12.5	12.8	13.2	13.6	13.9	14.3	14.7
Full AMR	19.1	19.6	20.2	20.8	21.4	22.0	22.6	23.2	23.9	24.6
	2041	**2042**	**2043**	**2044**	**2045**	**2046**	**2047**	**2048**	**2049**	**2050**
	AMR becomes Obsolete Midway through Analysis Period									
Status Quo	25.3	26.0	26.7	27.5	28.3	29.1	29.9	30.7	31.6	32.4
Full AMI	15.2	15.6	16.0	16.5	17.0	17.4	17.9	18.4	19.0	19.5
AMI+AMR_GO	15.2	15.6	16.0	16.5	17.0	17.4	17.9	18.4	19.0	19.5
Full AMR	15.2	15.6	16.0	16.5	17.0	17.4	17.9	18.4	19.0	19.5
	AMR Remains Viable for 30-Year Analysis Period									
Status Quo	25.3	26.0	26.7	27.5	28.3	29.1	29.9	30.7	31.6	32.4
Full AMI	15.2	15.6	16.0	16.5	17.0	17.4	17.9	18.4	19.0	19.5
AMI+AMR_GO	15.2	15.6	16.0	16.5	17.0	17.4	17.9	18.4	19.0	19.5
Full AMR	25.3	26.0	26.7	27.5	28.3	29.1	29.9	30.7	31.6	32.4

6.5. Electric Distribution Operations

The Electric Distribution Operations ("EDO") group is responsible for providing safe, reliable, and low-cost operations of the electric distribution system. Some aspects of EDO operations will be impacted by AMI. For example, to reliably accommodate growth in customer-owned generation and electric vehicles, additional voltage sensing and regulating equipment will be needed along selected distribution circuits to more precisely control voltage along these circuits and prevent voltage excursions. AMI will enable the Companies to avoid the cost of these voltage sensors. In addition, AMI will enable the Companies to improve the efficiency of some of its EDO operations. Table 24 summarizes EDO costs for each metering alternative. These costs do not include the full scope of EDO's budget; EDO capital savings are computed as differences from the status quo and are related to the avoided need for voltage sensors. EDO O&M savings are computed as differences from the Status Quo and pertain to improved management of in-service assets like overloaded transformers, improved sustained outage characterization and location on circuits not outfitted from the Distribution Automation efforts, and avoided costs associated with investigation of outage reports where the service is found to be ok on arrival. The timing of EDO O&M savings is tied to the integration of AMI and EDO systems.

Table 24: EDO Costs Affected by AMI Deployment ($M, Capital and O&M, Proactive Replacement Operating Life)

	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Status Quo / Full AMR										
Voltage Sensors	0.0	1.4	1.5	1.5	1.6	1.6	1.7	1.7	1.8	1.8
Total	0.0	1.4	1.5	1.5	1.6	1.6	1.7	1.7	1.8	1.8
Full AMI / AMI+AMR_GO										
Voltage Sensors	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
EDO O&M Savings	0.0	0.0	0.0	0.0	-0.2	-0.2	-0.2	-0.2	-0.2	-0.3
Total	0.0	0.0	0.0	0.0	-0.2	-0.2	-0.2	-0.2	-0.2	-0.3

Table 25 summarizes EDO costs under the two AMR obsolescence scenarios for 2031 to 2050. To model the impact of AMR obsolescence, the Companies assumed AMR becomes obsolete by the end of 2035. AMR obsolescence has no impact on EDO costs in the Status Quo, Full AMI, or AMI+AMR_GO alternatives. In the Full AMR alternative, EDO costs are aligned with the Full AMI alternative by 2036 after the transition to AMI is complete.

Table 25: EDO Costs Affected by AMI Deployment ($M, Capital and O&M, Proactive Replacement Operating Life)

	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
	AMR becomes Obsolete Midway through Analysis Period									
Status Quo	1.9	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Full AMI	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3
AMI+AMR_GO	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3
Full AMR	1.9	0.0	0.0	0.0	-0.2	-0.3	-0.3	-0.3	-0.3	-0.3
	AMR Remains Viable for 30-Year Analysis Period									
Status Quo	1.9	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Full AMI	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3
AMI+AMR_GO	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3
Full AMR	1.9	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
	2041	**2042**	**2043**	**2044**	**2045**	**2046**	**2047**	**2048**	**2049**	**2050**
	AMR becomes Obsolete Midway through Analysis Period									
Status Quo	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Full AMI	-0.4	-0.4	-0.4	-0.4	-0.4	-0.4	-0.4	-0.4	-0.4	-0.5
AMI+AMR_GO	-0.4	-0.4	-0.4	-0.4	-0.4	-0.4	-0.4	-0.4	-0.4	-0.5
Full AMR	-0.4	-0.4	-0.4	-0.4	-0.4	-0.4	-0.4	-0.4	-0.4	-0.5
	AMR Remains Viable for 30-Year Analysis Period									
Status Quo	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Full AMI	-0.4	-0.4	-0.4	-0.4	-0.4	-0.4	-0.4	-0.4	-0.4	-0.5
AMI+AMR_GO	-0.4	-0.4	-0.4	-0.4	-0.4	-0.4	-0.4	-0.4	-0.4	-0.5
Full AMR	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2

6.6. Fuel Savings

As discussed previously, the Companies will need to be able to more precisely control voltage across a circuit to reliably accommodate continued growth in distributed generation and the number of electric vehicles. With voltage data for all customers, AMI will not only enable that control and avoid the need for additional voltage sensors but also incrementally enable the Companies to implement Conservation Voltage Reduction ("CVR"). CVR uses AMI data and more precise voltage controls to incrementally reduce grid voltage such that energy requirements are lowered. CVR cannot be reliably implemented without AMI data.

The Companies estimated the energy savings potential from CVR using voltage data from the AMS Opt-in program. The analysis focused on distribution circuits having the highest saturation of AMS Opt-in customers with meters recording voltage.[25] The analysis estimated the CVR energy savings potential over a range of voltage control thresholds (e.g., 116 to 118 volts). Based on this analysis, the Companies

[25] A summary of the CVR Potential Study is included as Appendix D – CVR Potential Study.

evaluated CVR-related energy savings ranging from 145 GWh to 270 GWh with a base value of 205 GWh. This range is 0.5% to 0.9% of total energy requirements and is consistent with other utilities' experience.

Many AMS Opt-in customers have used their interval data to gain a better understanding of their usage and have taken actions as a result to reduce their electricity consumption. Tetra Tech completed a study in 2020 to estimate incremental energy savings for AMS Opt-in customers resulting from their access to interval data through the ePortal. Tetra Tech determined that AMS Opt-In customers had 1.4% to 1.7% lower energy consumption than customers who requested an AMI meter but hadn't received one due to the limited number of meters available through the AMS Opt-in program.[26] Because the AMS Opt-in program is an opt-in program, it is difficult to extrapolate energy savings to the broader population of all customers. Therefore, the Companies have evaluated this benefit very conservatively using a range of energy savings from 0.0% to 0.70% (i.e., half of the lower level of energy savings reported by Tetra Tech for AMS Opt-in customers) with a base value of 0.35%.

These energy savings reduce the Companies' fuel expense. To compute this savings, the Companies multiplied the energy savings by its marginal cost of energy. Table 26 contains total fuel savings based on mid fuel prices from the Companies' 2021 Business Plan. As a sensitivity, the Companies also evaluated low and high fuel price scenarios for marginal fuel costs. Both categories of energy savings are phased in gradually. CVR savings don't begin until EDO integration and then are phased in gradually based on planned addition of more precise voltage controls. ePortal savings are modeled as a function of the number of AMI meters deployed.

Table 26: Fuel Savings ($M, O&M, Proactive Replacement Operating Life)

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Full AMI / AMI+AMR_GO										
CVR Savings	0.0	0.0	0.0	0.0	0.0	-0.9	-1.7	-2.6	-3.6	-4.5
ePortal Savings	0.0	-0.1	-0.3	-0.7	-1.0	-1.3	-1.3	-1.3	-1.3	-1.3
Total	0.0	-0.1	-0.3	-0.7	-1.0	-2.1	-3.1	-4.0	-4.9	-5.8

Table 27 summarizes fuel savings under the two AMR obsolescence scenarios for 2031 to 2050. To model the impact of AMR obsolescence, the Companies assumed AMR becomes obsolete by the end of 2035. AMR obsolescence has no impact on fuel savings in the Full AMI or AMI+AMR_GO alternatives. In the Full AMR alternative, fuel savings are aligned with the Full AMI alternative by 2040 after the transition to AMI is complete and CVR is fully implemented.

[26] A summary of the Tetra Tech study is included as Appendix E – Tetra Tech AMS Opt-In Study.

Table 27: Fuel Savings ($M, O&M, Proactive Replacement Operating Life)

	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
	AMR becomes Obsolete Midway through Analysis Period									
Full AMI	-6.0	-6.1	-6.3	-6.1	-6.3	-6.4	-6.1	-6.0	-6.0	-6.2
AMI+AMR_GO	-6.0	-6.1	-6.3	-6.1	-6.3	-6.4	-6.1	-6.0	-6.0	-6.2
Full AMR	0.0	-0.1	-0.4	-0.7	-1.2	-2.5	-3.3	-4.2	-5.1	-6.2
	AMR Remains Viable for 30-Year Analysis Period									
Full AMI	-6.0	-6.1	-6.3	-6.1	-6.3	-6.4	-6.1	-6.0	-6.0	-6.2
AMI+AMR_GO	-6.0	-6.1	-6.3	-6.1	-6.3	-6.4	-6.1	-6.0	-6.0	-6.2
Full AMR	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	2041	**2042**	**2043**	**2044**	**2045**	**2046**	**2047**	**2048**	**2049**	**2050**
	AMR becomes Obsolete Midway through Analysis Period									
Full AMI	-6.2	-6.3	-6.4	-6.5	-6.7	-6.8	-6.9	-7.1	-7.2	-7.3
AMI+AMR_GO	-6.2	-6.3	-6.4	-6.5	-6.7	-6.8	-6.9	-7.1	-7.2	-7.3
Full AMR	-6.2	-6.3	-6.4	-6.5	-6.7	-6.8	-6.9	-7.1	-7.2	-7.3
	AMR Remains Viable for 30-Year Analysis Period									
Full AMI	-6.2	-6.3	-6.4	-6.5	-6.7	-6.8	-6.9	-7.1	-7.2	-7.3
AMI+AMR_GO	-6.2	-6.3	-6.4	-6.5	-6.7	-6.8	-6.9	-7.1	-7.2	-7.3
Full AMR	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

6.7. Financial Assumptions

Table 28 lists the inputs used to compute capital revenue requirements in this analysis. For the AMI and AMR alternatives, capital revenue requirements during the 5-year implementation period were computed with the assumption that the Companies will record capital investments as Construction Work In Process and accrue an allowance for funds used during construction ("AFUDC"). After the 5-year implementation period, capital investments are assumed to be placed in service in the year the investments are made. In Table 28, the property tax rate is applicable to meter and network investments but not to investments in IT systems.

Table 28: Financial Assumptions

	Combined Companies
% Debt	47%
% Equity	53%
Cost of Debt	4.02%
Cost of Equity	10.00%
Tax Rate	24.95%
Property Tax Rate	1.73%
WACC (After-Tax)	6.75%

7. Appendix B – Metering RFI Summary

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Meter Life Study

PPL companies

September 2019

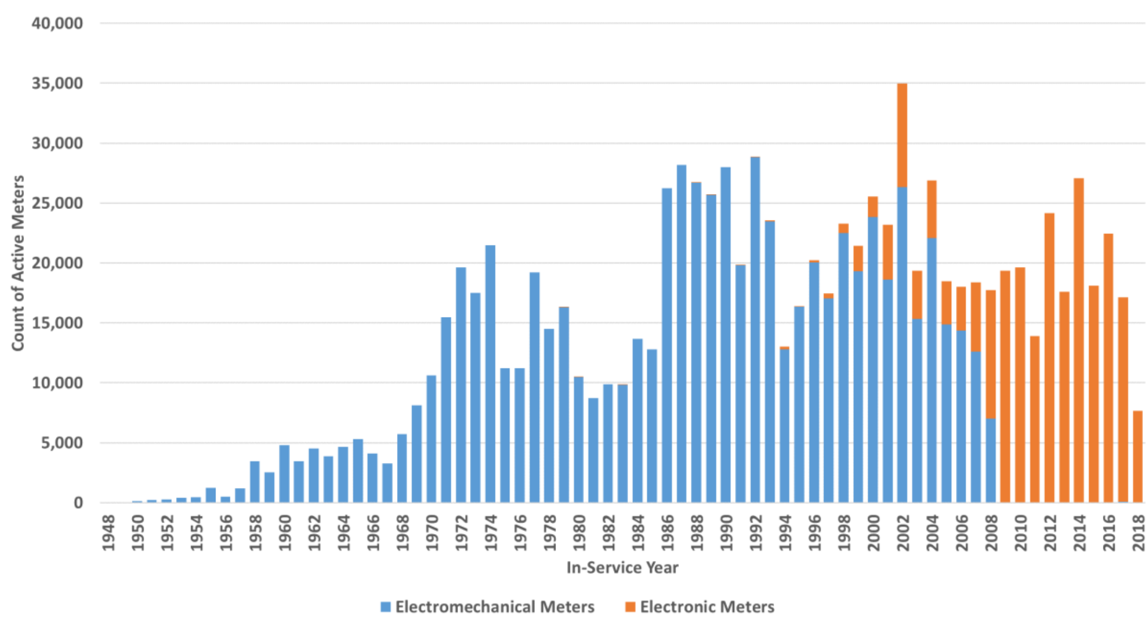
1. Background

LG&E and KU's ("The Companies'") electric meter population is aging, and meter failures are expected to increase as meters age. The use of data analytics to develop a forecast of meter failures allowed the Companies to determine how long the existing meter population will continue to be operational and also helped the Companies more effectively evaluate metering alternatives.

There are two different types of meters, each with different operating life characteristics. Electromechanical meters, or analog meters, are an older technology which measures energy by counting revolutions of a metal disc that rotates as energy flows. These meters typically had long operating lives but offered limited additional functionality and are no longer commercially available. Electronic meters, or digital meters, rely on sensors and transmit data to a digital display. These meters enable more functionality and are widely commercially available. AMI and AMR meters are subsets of electronic meters with communications, and their operating lives are expected to be functionally equivalent to that of a non-communicating electronic meter because they have the same meter platform.

Electromechanical meters were the standard technology for the Companies for most of the 20th century. The Companies began installing electronic meters in the 1990s, and electronic meters became the standard replacement meter after 2008. At the beginning of 2019, the Companies had approximately 1 million electric meters in service, with a split of 75% electromechanical and 25% electronic. Figure 1 shows a distribution of the Companies' meters by type and in-service year.[1]

Figure 1: Electric Meter Population by Type and In-Service Year



[1] This analysis excludes existing AMI meters, as well as roughly 2,000 meters that measure consumption primarily for time-of-day rates using specialized meters for many of the Companies' largest customers.

The Companies' electromechanical meter population ranges between 11 and 71 years old, with an average age of 31.4 years. The Companies' electronic meter population ranges between 0 and 28 years old, with an average age of 8.4 years.

The Companies began cataloging meter data in 2009. This includes meter failures, which for the purposes of this study includes meters that were taken out of service for any reason, including but not limited to mechanical failures. The objective of this study is to use historical failure data to create a forecast of future meter failures. To do this, the Companies evaluated historical failures over a 10-year period to develop actuarial meter failure curves for electromechanical and electronic meters, and then applied those curves to the existing meter population to develop a forecast.

2. Failure Curve Development

2.1 Electromechanical Failure Curves

The first step in developing a meter failure curve is to segment the number of meters and meter failures in each year of the historical period by age. Table 1 contains an example failure rate calculation for 40-year old meters using data from 2009 through 2018. In 2009, the meter population included 11,160 40-year old meters, and 83 of those meters were no longer active at the beginning of 2010, which implies a failure rate of 0.74%. Over the course of a 10-year period, the Companies had 169,257 meters that were 40 years old at the start of a year. During this time, annual failure rates ranged between 0.2% and 3.6%, with a weighted average failure rate of 2.1%. Based on this information, for a given population of 40-year old meters at the beginning of a year, on average 2.1% should fail, and 97.9% should remain in service and become 41-year old meters in the following year.

Table 1: Electromechanical Failures for 40-Year Old Meters

In-Service Year	Failure Year	Active Electromechanical Meters at Start of Year	Active Electromechanical Meters Retired During Year	Average Failure Rate
1969	2009	11,160	83	0.74%
1970	2010	13,787	26	0.19%
1971	2011	18,976	683	3.60%
1972	2012	22,927	532	2.32%
1973	2013	20,118	506	2.52%
1974	2014	23,604	622	2.64%
1975	2015	12,032	209	1.74%
1976	2016	11,927	228	1.91%
1977	2017	19,911	355	1.78%
1978	2018	14,815	304	2.05%
Total / Weighted Average		169,257	3,548	2.10%

Figure 2 shows the results of repeating this process for the entire range of ages across all electromechanical meters, with each dot reflecting the weighted average failure rate of a given age. Across the bulk of the age range, each dot reflects tens or hundreds of thousands of meters, though sample sizes are smaller beginning around age 60 where the electromechanical meter population is relatively sparse. The higher failure rate for 20-year old meters was the result of a high volume of a failed lot of meters in a single year from routine testing.[2] As expected, Figure 2 demonstrates that the failure rate increases as the meter ages.

[2] The Companies meter sampling process tests a wide variety of meters, and when a high failure rate is discovered among a specific model and manufacturing run, the other meters with those characteristics are declared a failed lot and will be retired. Failed lots can occur at any age, and the Companies elected not to omit or edit this data for purposes of this analysis.

Figure 2: Electromechanical Failure Rate by Age

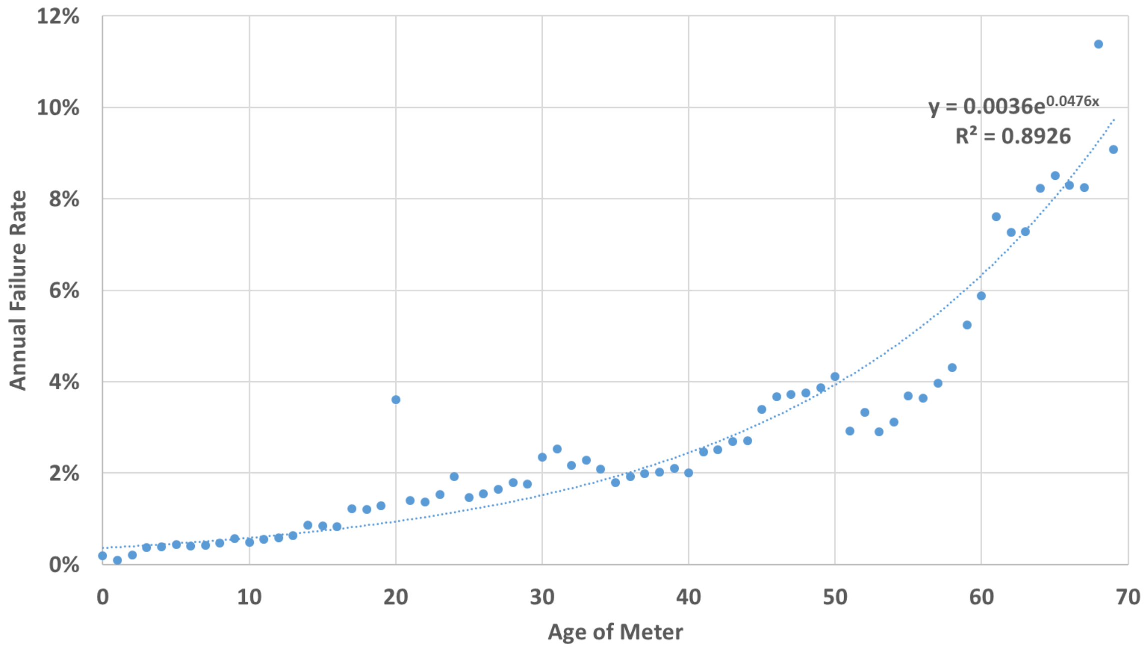


Figure 2 also shows the fitted curve and equation used to estimate meter failures.[3] An exponential curve provided the best fit and is well-suited for failure rates because it is always greater than zero, always increasing, and experiences a sharp increase in later years consistent with the Companies' data. The fitted curve yields an R^2 of 89%. Given the low number of meters greater than 70 years old in the Companies' meter population, this analysis assumes a meter failure rate of 100% after age 70.

This curve can be applied to a hypothetical meter population to determine an implied average meter life. As a demonstration, the Companies considered a population of 10,000 electromechanical meters installed in year 0 and removed from service based on the failure curves. In the first year, 35 meters are retired, and 9,965 remain in service at the end of year 0:

Meters at start of year 0:	10,000
Less failed meters in year 0 (@ 0.35%):	-35
Meters at end of year 0 / start of year 1:	9,965

During the second year, 36 of the original meters are retired, and 9,929 remain in service at the end of year 1. During the third year, 38 of the original meters are retired, and 9,891 remain in service at the end of year 2:

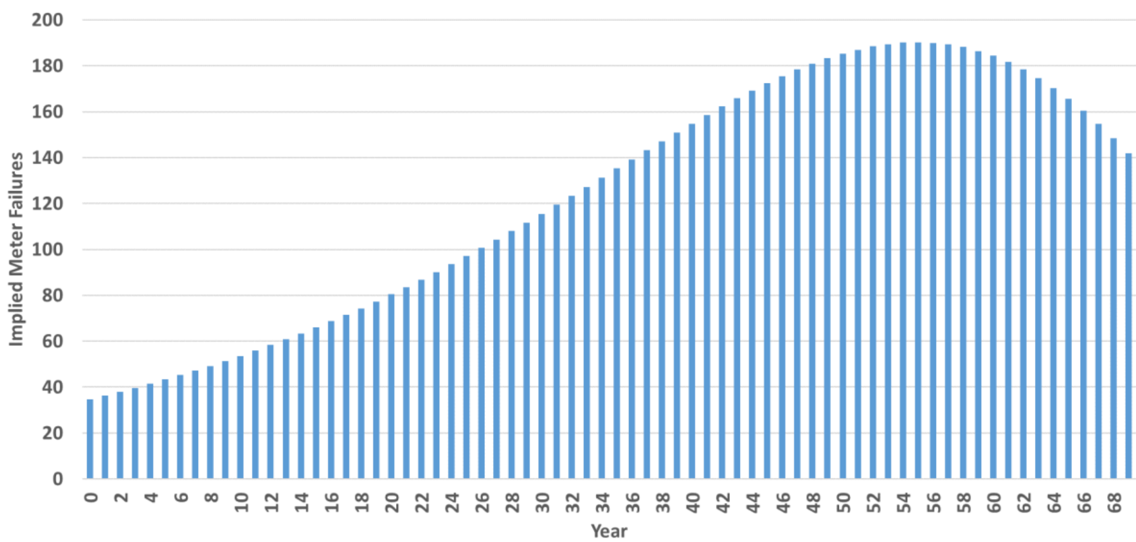
Meters at end of year 0 / start of year 1:	9,965
Less failed meters in year 1 (@ 0.36%):	-36
Meters at end of year 1 / start of year 2:	9,929

[3] See Appendix I for a complete table of failure rates by age.

Meters at end of year 1 / start of year 2:	9,929
Less failed meters in year 2 (@ 0.38%):	-38
Meters at end of year 2 / start of year 3:	9,891

Figure 3 shows the distribution of failed meter counts for this illustrative 10,000-meter population until all remaining meters are retired after age 70. Taking the weighted average of meter failures by age yields an average meter life of 46.4 years for electromechanical meters, which is to say the Companies expect an electromechanical meter to be in operation for an average of 46.4 years, but does not imply that an electromechanical meter cannot operate after 46.4 years.

Figure 3: Implied Electromechanical Meter Failures for 10,000 Meter Population



2.2 Electronic Failure Curves

Figure 4 shows the results of repeating the curve development process described in section 2.1 for electronic meters instead of electromechanical meters. Across the bulk of the age range, each dot reflects tens or hundreds of thousands of meters, though sample sizes are smaller beginning around age 20 where the electronic meter population is relatively sparse. As expected, Figure 4 demonstrates that the failure rate increases as the meter ages.

Figure 4: Electronic Meter Failure Rate by Age

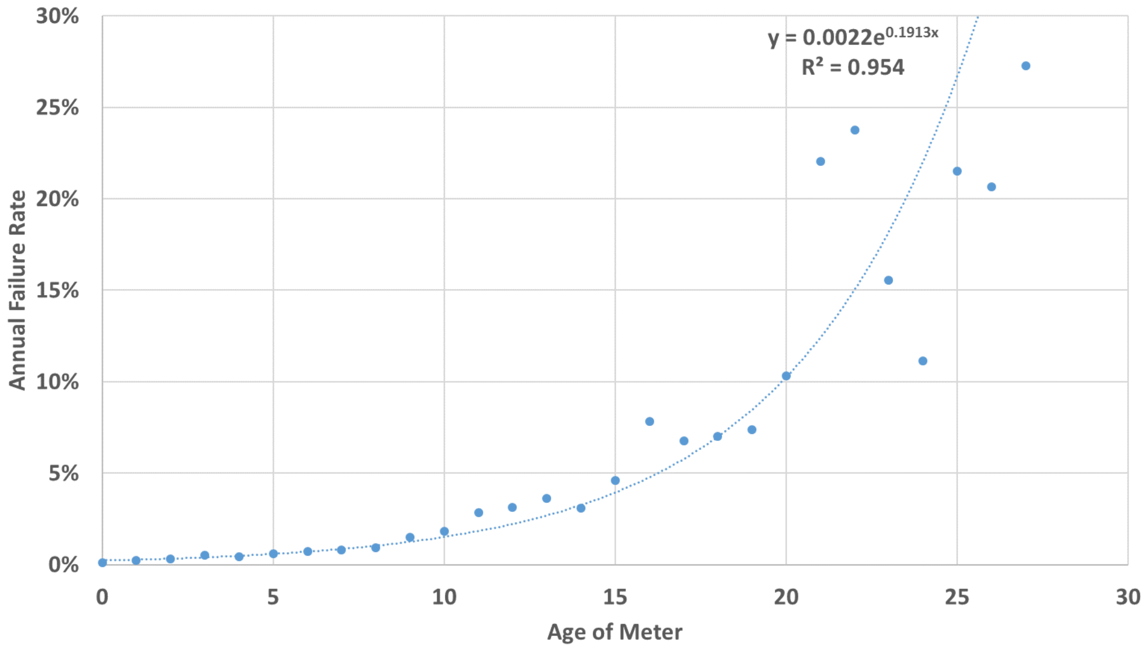


Figure 4 also shows the fitted curve and equation used to estimate meter failures.[4] Consistent with the electromechanical fitted curve, an exponential curve provided the best fit and is well-suited for failure rates because it is always greater than zero, always increasing, and experiences a sharp increase in later years consistent with the Companies' data. The fitted curve yields an R^2 of 95%. Given the low number of meters greater than 28 years old in the Companies' meter population, this analysis assumes a meter failure rate of 100% after age 28.

This curve can be applied to a hypothetical meter population to determine an implied average meter life. As a demonstration, the Companies considered a population of 10,000 electronic meters installed in year 0 and removed from service based on the failure curves. In the first year, 22 meters are retired, and 9,978 remain in service at the end of year 0:

Meters at start of year 0:	10,000
Less failed meters in year 0 (@ 0.22%):	-22
Meters at end of year 0 / start of year 1:	9,978

During the second year, 27 of the original meters are retired, and 9,951 remain in service at the end of year 1. During the third year, 33 of the original meters are retired, and 9,918 remain in service at the end of year 2:

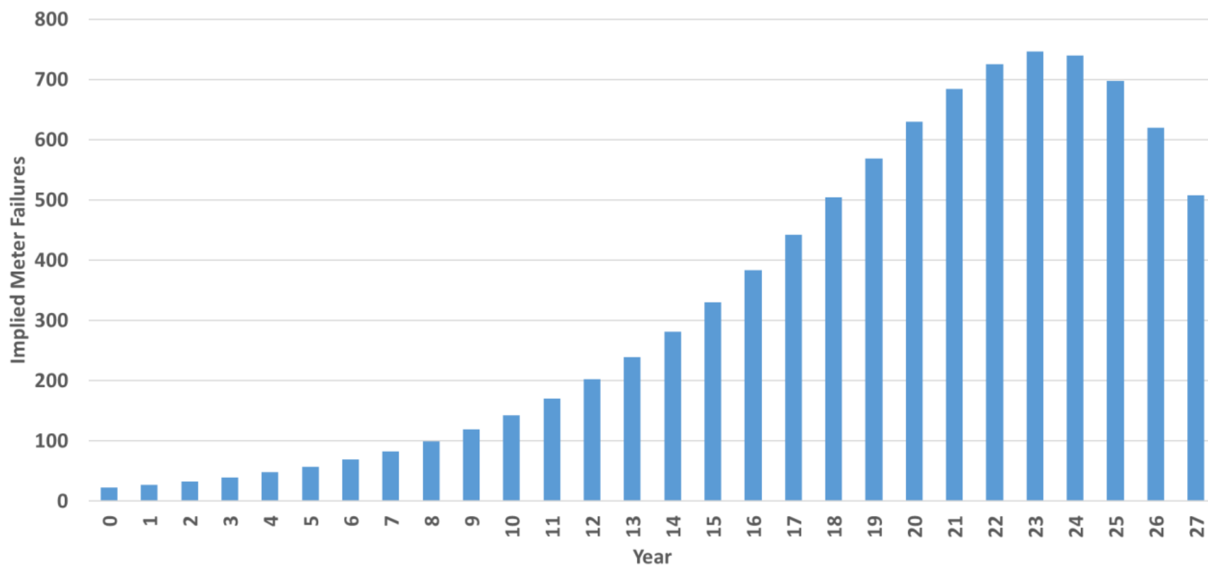
Meters at end of year 0 / start of year 1:	9,978
Less failed meters in year 1 (@ 0.27%):	-27
Meters at end of year 1 / start of year 2:	9,951

[4] See Appendix I for a complete table of failure rates by age.

Meters at end of year 1 / start of year 2:	9,951
Less failed meters in year 2 (@ 0.33%):	-33
Meters at end of year 2 / start of year 3:	9,918

Figure 5 shows the distribution of failed meter counts for this illustrative 10,000-meter population until all remaining meters are retired after age 28. Taking the weighted average of meter failures by age yields an average meter life of 20.2 years for electronic meters, which is to say the Companies expect an electronic meter to be in operation for an average of 20.2 years, but does not imply that an electronic meter cannot operate after 20.2 years.

Figure 5: Implied Electronic Meter Failures for 10,000 Meter Population



3. Forecast

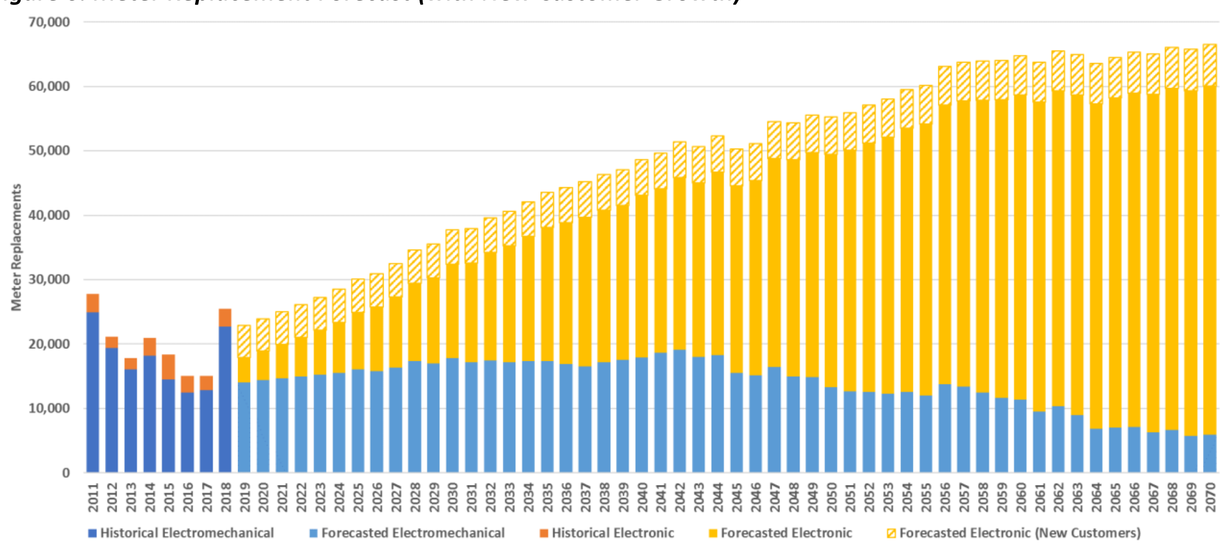
To develop the meter replacement forecast, the Companies applied the meter failure curves to the current electromechanical and electronic meter populations as of the beginning of 2019 to estimate the quantity of failed meters expected during the year. Existing electromechanical and electronic meters are assumed to be replaced with electronic meters when they fail. The calculations for forecasted meter replacements in 2019 are available in Appendix II. In each subsequent year, the remaining meters are assumed to fail at the average rate corresponding to their age, with newly-installed meters from the previous year representing the count of one-year old electronic meters in the current year.

This process was repeated through 2070 to develop a long-term forecast. Over time, electromechanical meters (with an average life of 46.4 years) would be replaced with electronic meters (with an average life of 20.2 years). Eventually, all meters would be replaced, including replacements of replacement meters, and replacements of those meters as well.

In addition to the replacement of existing meters, the Companies expect additional electronic meters and subsequent replacements will be needed for assumed growth due to the addition of new customers. The Companies' customer growth forecast is higher in earlier years – consistent with recent history – but levels off in the latter portion of the forecast period consistent with population forecasts from IHS Global Insight.

Figure 6 shows the meter replacement forecast including new customer growth. The dark blue bars reflect historical electromechanical meter failures, while the light blue bars reflect forecasted electromechanical meter failures. The orange bars reflect historical electronic meter failures, while the yellow bars reflect forecasted electronic meter failures. The hashed yellow bars reflect new customer growth.

Figure 6: Meter Replacement Forecast (with New Customer Growth)



Forecasted meter replacements in the short term are in line with recent history for both electromechanical and electronic meters. But as the proportion of longer-lived electromechanical meters decreases, the proportion of shorter-lived electronic meters increases, which results in an increasing volume of meter replacements over time.

Absent customer growth, the Companies would expect annual meter replacements to converge to a steady state given a long time horizon. For example, a meter population of 1 million electromechanical meters, which have an average life of 46.4 years, should on average experience 1 million / 46.4 annual meter replacements, or roughly 22,000 annual meter replacements. Similarly, a meter population of 1 million electronic meters, which have an average life of 20.2 years, should on average experience 1 million / 20.2 annual meter replacements, or roughly 50,000 annual meter replacements.

Since the Companies' current meter population is mostly electromechanical, but is expected to shift toward electronic over time, the Companies should expect a short-term forecast closer to 22,000 annual meter replacements, growing over time to a long-term forecast closer to 50,000 annual meter replacements. After considering additional meters for customer growth, the meter replacement forecast is consistent with these expectations.

4. Appendix I

Table 2: Expected Annual Meter Failures by Age

Age	Electromechanical Meter Failure Rate	Electronic Meter Failure Rate
0	0.35%	0.22%
1	0.36%	0.27%
2	0.38%	0.33%
3	0.40%	0.40%
4	0.42%	0.48%
5	0.44%	0.58%
6	0.46%	0.70%
7	0.49%	0.85%
8	0.51%	1.03%
9	0.53%	1.25%
10	0.56%	1.52%
11	0.59%	1.83%
12	0.62%	2.22%
13	0.65%	2.69%
14	0.68%	3.26%
15	0.71%	3.94%
16	0.74%	4.77%
17	0.78%	5.78%
18	0.82%	7.00%
19	0.86%	8.47%
20	0.90%	10.26%
21	0.94%	12.42%
22	0.99%	15.04%
23	1.04%	18.21%
24	1.09%	22.04%
25	1.14%	26.69%
26	1.20%	32.32%
27	1.26%	39.13%
28	1.32%	100.00%
29	1.38%	
30	1.45%	
31	1.52%	
32	1.59%	
33	1.67%	
34	1.75%	
35	1.84%	
36	1.93%	
37	2.02%	
38	2.12%	
39	2.22%	
40	2.33%	
41	2.45%	
42	2.57%	
43	2.69%	
44	2.82%	
45	2.96%	
46	3.10%	
47	3.26%	
48	3.41%	
49	3.58%	
50	3.75%	
51	3.94%	
52	4.13%	
53	4.33%	
54	4.54%	
55	4.76%	

Age	Electromechanical Meter Failure Rate	Electronic Meter Failure Rate
56	5.00%	
57	5.24%	
58	5.49%	
59	5.76%	
60	6.04%	
61	6.34%	
62	6.65%	
63	6.97%	
64	7.31%	
65	7.66%	
66	8.04%	
67	8.43%	
68	8.84%	
69	9.27%	
70	100.00%	

5. Appendix II

Table 3: Forecasted Electromechanical Meter Replacements in 2019

In-Service Year	Meter Age	Electromechanical Meter Failure Rate	Active Electromechanical Meters at Start of 2019	Electromechanical Meters Expected to Fail in 2019	Active Electromechanical Meters at End of 2019
1948	71	100.00%	10	10	0
1949	70	100.00%	35	35	0
1950	69	9.27%	149	14	135
1951	68	8.84%	247	22	225
1952	67	8.43%	262	22	240
1953	66	8.04%	386	31	355
1954	65	7.66%	466	36	430
1955	64	7.31%	1,231	90	1,141
1956	63	6.97%	480	33	447
1957	62	6.65%	1,178	78	1,100
1958	61	6.34%	3,440	218	3,222
1959	60	6.04%	2,531	153	2,378
1960	59	5.76%	4,820	278	4,542
1961	58	5.49%	3,448	189	3,259
1962	57	5.24%	4,502	236	4,266
1963	56	5.00%	3,887	194	3,693
1964	55	4.76%	4,669	222	4,447
1965	54	4.54%	5,316	241	5,075
1966	53	4.33%	4,090	177	3,913
1967	52	4.13%	3,252	134	3,118
1968	51	3.94%	5,744	226	5,518
1969	50	3.75%	8,146	306	7,840
1970	49	3.58%	10,640	381	10,259
1971	48	3.41%	15,495	529	14,966
1972	47	3.26%	19,617	639	18,978
1973	46	3.10%	17,508	543	16,965
1974	45	2.96%	21,498	636	20,862
1975	44	2.82%	11,202	316	10,886
1976	43	2.69%	11,212	302	10,910
1977	42	2.57%	19,212	493	18,719
1978	41	2.45%	14,511	355	14,156
1979	40	2.33%	16,301	380	15,921
1980	39	2.22%	10,499	234	10,265
1981	38	2.12%	8,723	185	8,538
1982	37	2.02%	9,904	200	9,704
1983	36	1.93%	9,849	190	9,659
1984	35	1.84%	13,659	251	13,408
1985	34	1.75%	12,777	224	12,553
1986	33	1.67%	26,233	439	25,794
1987	32	1.59%	28,181	449	27,732
1988	31	1.52%	26,706	406	26,300
1989	30	1.45%	25,667	372	25,295
1990	29	1.38%	27,977	387	27,590
1991	28	1.32%	19,811	261	19,550
1992	27	1.26%	28,813	362	28,451
1993	26	1.20%	23,483	282	23,201
1994	25	1.14%	12,809	146	12,663
1995	24	1.09%	16,370	178	16,192

In-Service Year	Meter Age	Electromechanical Meter Failure Rate	Active Electromechanical Meters at Start of 2019	Electromechanical Meters Expected to Fail in 2019	Active Electromechanical Meters at End of 2019
1996	23	1.04%	20,062	209	19,853
1997	22	0.99%	17,044	169	16,875
1998	21	0.94%	22,473	212	22,261
1999	20	0.90%	19,328	174	19,154
2000	19	0.86%	23,847	205	23,642
2001	18	0.82%	18,607	152	18,455
2002	17	0.78%	26,309	206	26,103
2003	16	0.74%	15,327	114	15,213
2004	15	0.71%	22,087	157	21,930
2005	14	0.68%	14,864	101	14,763
2006	13	0.65%	14,384	93	14,291
2007	12	0.62%	12,613	78	12,535
2008	11	0.59%	7,031	41	6,990
2009	10	0.56%	0	0	0
2010	9	0.53%	0	0	0
2011	8	0.51%	0	0	0
2012	7	0.49%	0	0	0
2013	6	0.46%	0	0	0
2014	5	0.44%	0	0	0
2015	4	0.42%	0	0	0
2016	3	0.40%	1	0	1
2017	2	0.38%	65[5]	0	65
2018	1	0.36%	0	0	0
Total	N/A	N/A	750,988	13,999	736,989

[5] Electromechanical meters are no longer manufactured; however, in 2016 and 2017, the Companies were able to procure a small volume of reconditioned electromechanical meters as a less expensive alternative to new electronic meters.

Table 4: Forecasted Electronic Meter Replacements in 2019

In-Service Year	Meter Age	Electronic Meter Failure Rate	Active Electronic Meters at Start of 2019	Electronic Meters Expected to Fail in 2019	Active Electronic Meters at End of 2019
1991	28	100.00%	24	24	0
1992	27	39.13%	6	2	4
1993	26	32.32%	70	23	47
1994	25	26.69%	197	53	144
1995	24	22.04%	20	4	16
1996	23	18.21%	183	33	150
1997	22	15.04%	415	62	353
1998	21	12.42%	810	101	709
1999	20	10.26%	2,090	214	1,876
2000	19	8.47%	1,686	143	1,543
2001	18	7.00%	4,589	321	4,268
2002	17	5.78%	8,658	500	8,158
2003	16	4.77%	4,032	192	3,840
2004	15	3.94%	4,785	189	4,596
2005	14	3.26%	3,620	118	3,502
2006	13	2.69%	3,647	98	3,549
2007	12	2.22%	5,779	128	5,651
2008	11	1.83%	10,714	197	10,517
2009	10	1.52%	19,336	293	19,043
2010	9	1.25%	19,638	246	19,392
2011	8	1.03%	13,892	144	13,748
2012	7	0.85%	24,146	206	23,940
2013	6	0.70%	17,592	124	17,468
2014	5	0.58%	28,626	167	28,459
2015	4	0.48%	20,571	99	20,472
2016	3	0.40%	26,148	104	26,044
2017	2	0.33%	17,314	57	17,257
2018	1	0.27%	9,950	27	9,923
Total	N/A	N/A	248,538	3,868	244,670

Table 5: Expected Meter Populations After First Year of Forecast

In-Service Year	Meter Age	Active Electromechanical Meters at Start of 2020	Active Electronic Meters at Start of 2020
1950	70	135	0
1951	69	225	0
1952	68	240	0
1953	67	355	0
1954	66	430	0
1955	65	1,141	0
1956	64	447	0
1957	63	1,100	0
1958	62	3,222	0
1959	61	2,378	0
1960	60	4,542	0
1961	59	3,259	0
1962	58	4,266	0
1963	57	3,693	0
1964	56	4,447	0
1965	55	5,075	0
1966	54	3,913	0
1967	53	3,118	0
1968	52	5,518	0
1969	51	7,840	0
1970	50	10,259	0
1971	49	14,966	0
1972	48	18,978	0
1973	47	16,965	0
1974	46	20,862	0
1975	45	10,886	0
1976	44	10,910	0
1977	43	18,719	0
1978	42	14,156	0
1979	41	15,921	0
1980	40	10,265	0
1981	39	8,538	0
1982	38	9,704	0
1983	37	9,659	0
1984	36	13,408	0
1985	35	12,553	0
1986	34	25,794	0
1987	33	27,732	0
1988	32	26,300	0
1989	31	25,295	0
1990	30	27,590	0
1991	29	19,550	0
1992	28	28,451	4
1993	27	23,201	47
1994	26	12,663	144
1995	25	16,192	16
1996	24	19,853	150
1997	23	16,875	353
1998	22	22,261	709
1999	21	19,154	1,876
2000	20	23,642	1,543
2001	19	18,455	4,268
2002	18	26,103	8,158
2003	17	15,213	3,840
2004	16	21,930	4,596
2005	15	14,763	3,502
2006	14	14,291	3,549
2007	13	12,535	5,651
2008	12	6,990	10,517

In-Service Year	Meter Age	Active Electromechanical Meters at Start of 2020	Active Electronic Meters at Start of 2020
2009	11	0	19,043
2010	10	0	19,392
2011	9	0	13,748
2012	8	0	23,940
2013	7	0	17,468
2014	6	0	28,459
2015	5	0	20,472
2016	4	1	26,044
2017	3	65	17,257
2018	2	0	9,923
2019	1	0	17,867[6]

[6] Sum of 13,999 electromechanical meters and 3,868 electronic meters expected to fail in the forecast, which would be replaced with new electronic meters.

LG&E and KU

CVR Potential Study

Generation Planning & Electric Distribution Planning

October 2020

Executive Summary

The continued growth of distributed energy resources and new loads such as electric vehicles are placing increasingly dynamic demands on the distribution grid. To reliably accommodate this growth, additional voltage sensing and regulating equipment will be needed along selected distribution circuits to more precisely control voltage along these circuits and prevent voltage excursions. If Advanced Metering Infrastructure ("AMI") is deployed throughout the Companies' service territories, the Companies will have voltage data for every customer. With this data, AMI will enable the Companies to implement Conservation Voltage Reduction ("CVR"), which uses AMI data and more precise voltage controls to incrementally reduce grid voltage such that energy requirements are lowered. Lower energy requirements result in avoided generation costs thus reducing revenue requirements for rate payers.

This analysis estimates the CVR energy savings potential for a subset of circuits in the LG&E and KU system using data gathered from the existing AMS Opt-In Program. 12 circuits with high saturations of AMS Opt-In voltage data were studied in detail, and the estimated CVR energy savings rates found in those 12 circuits were applied to a broader pool of 404 CVR candidate circuits. On an annual energy basis, the 404 candidate circuits represent roughly a third of LG&E and KU system. Table 1 summarizes the potential range of annualized CVR energy savings from the analysis.

Table 1: Range of Annual CVR Energy Savings

Scenario	GWh CVR Energy Savings	Percent of CVR Circuit Load	Percent of System Load
High	-270	-2.61%	-0.87%
Mid	-205	-1.99%	-0.66%
Low	-145	-1.40%	-0.47%

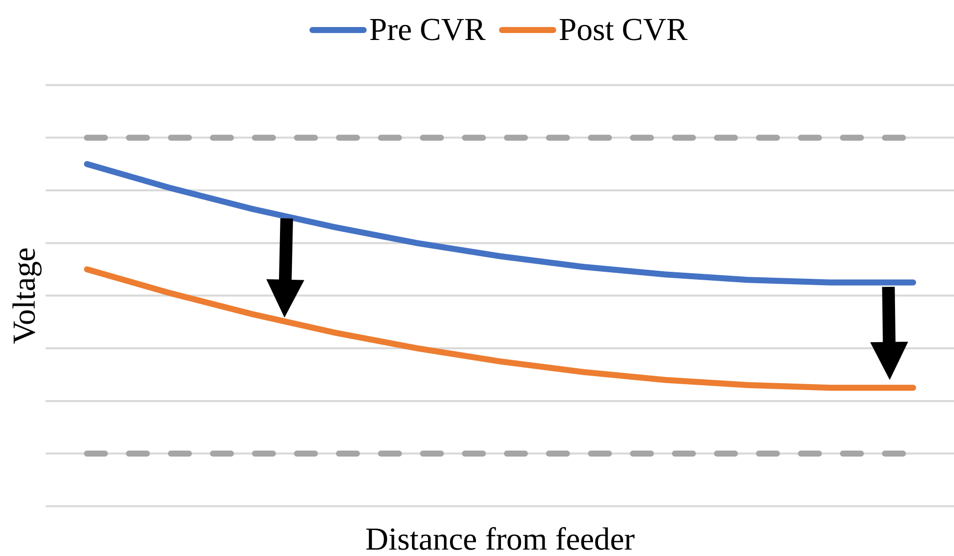
For a given circuit, CVR savings between 1 and 4 percent[1] are commonly reported in the industry. While this would be a new strategy for LG&E and KU, electric utility experience with CVR initiatives over recent years suggests any implementation risk may be substantially mitigated by industry experience and proven technology. The balance of the paper addresses the details of the methodology used to estimate the circuit-level CVR savings potential.

[1] EPA (2017)

Conservation Voltage Reduction

Conservation Voltage Reduction (CVR) is a technology that can reduce energy consumption with no change in customer behavior or the customer experience. CVR is implemented by controlling the voltage on a distribution circuit to lower portions of the tolerance band (114-126 volts as defined by ANSI C84.1) as shown in Figure 1. Conservation then occurs on the circuit when certain end-use loads draw less power.

Figure 1: Stylized CVR Voltage Reduction



Power savings is calculated using a combination of Ohm's Law and a power calculation as shown below.

Ohm's Law: $Voltage = Current * Resistance$

Power: $Power = Voltage * Current$

Since the resistance of a load typically remains constant, lowering the voltage also lowers the current. Lowering both the voltage and current results in lower power consumption. However, not all electrical loads respond the same to voltage reductions. For resistive loads with near unity power factor (e.g., incandescent lamps, heating elements), a one percent drop in voltage will result in a near one percent drop in power consumption. For reactive loads with lower power factors, the change in power consumption will be less than one percent. The "CVR factor" is the degree to which power consumption on a given circuit is sensitive to changes in voltage. CVR factors typically exist in the range of 0.5 to 1 and can vary seasonally. For the LG&E and KU system as a whole, a range of CVR factors from 0.7 to 0.8 is assumed in this analysis.[2]

AMI is critical for providing the information that is needed to reliably implement CVR. Connected loads can be damaged if voltages fall outside the upper or lower limits of the ANSI-specified tolerance band.

[2] Simms (2016)

With voltage data for every customer, AMI provides the feedback needed to control voltage to lower portions of the tolerance band without jeopardizing reliability or power quality for customers.

LG&E and KU CVR Potential Evaluation

Electric Distribution Operations ("EDO") identified 404 circuits for this analysis that would be good candidates for implementing CVR. Candidate circuits were selected based on a number of criteria including: circuit length; number of customers served; uniformity of circuits on a given substation; existing voltage control assets such as capacitors, regulators, and LTCs; and availability of communications. From within this CVR candidate circuit pool, 12 circuits were selected for a detailed analysis of the circuits' CVR energy savings potential. The data for this analysis was gathered from AMS Opt-in meters that report voltage data; the circuits selected for the detailed analysis have good coverage of these meters along the entire circuit. A range of potential energy savings for all CVR candidate circuits was developed based on the results of the detailed analysis.

Detailed Analysis of 12 Selected Circuits

Table 2 below lists each of the 12 circuits and describes several attributes including the number of AMI service points per circuit as well as the amount of energy consumed on the circuit in 2019.

Table 2: Summary of Circuits Evaluated in Detailed Analysis

Circuit Name	AMI Service Points	Total Service Points	AMI Percent	2019 Annual Energy (GWh)	Power Factor	Total Conductor Length (ft)
CF1201	12	479	2.51%	13.2	94.3%	274,210
CF1202	19	933	2.04%	21.8	93.8%	302,810
CF1205	18	752	2.39%	15.7	95.0%	144,025
CW1222	39	1657	2.35%	32.6	94.6%	280,709
CW1224	25	1281	1.95%	41.2	91.9%	260,048
CW1226	18	494	3.64%	11.5	94.1%	124,806
CW1227	15	901	1.66%	18.6	93.9%	176,144
CW1228	25	1015	2.46%	28.4	93.5%	378,221
HL1155	14	369	3.79%	7.6	94.8%	74,755
HL1156	37	1226	3.02%	30.2	93.0%	269,830
HL1157	32	1132	2.83%	22.5	94.5%	147,557
HL1158	11	368	2.99%	11.0	93.7%	168,563

For each circuit, the 5-minute data analysis is conducted independently. Cases are developed by changing two key parameters of voltage control threshold and CVR Factor. In the context of this analysis, the voltage control threshold is the voltage level to which the minimum voltage meter on the circuit is dynamically adjusted in each five-minute interval; it is not the average voltage across the circuit. The analysis further assumes that the required adjustment to the minimum voltage meter is applied across the entire circuit profile (see Table 3 and discussion for further context). The analysis contemplates three voltage control thresholds of 116, 117 and 118.

The CVR Factor relates the percent change in voltage to the percent change in power. As described in the CVR Factor section, certain loads respond differently to changes in voltage, so the CVR Factor effectively derates the intuition from the classic power formula (Watts = Volts * Amps). The analysis contemplates two CVR Factors of 0.7 and 0.8, which are typical according to a number of other utilities.[3]

For each circuit, there are a total of six cases resulting from the combination of three voltage control thresholds and two CVR factors. The procedure outlined below was evaluated independently for each circuit and case to estimate the associated CVR energy saving. For clarity of explanation, the procedure is broken out into three separate steps with sub-steps and commentary.

[3] Simms (2016)

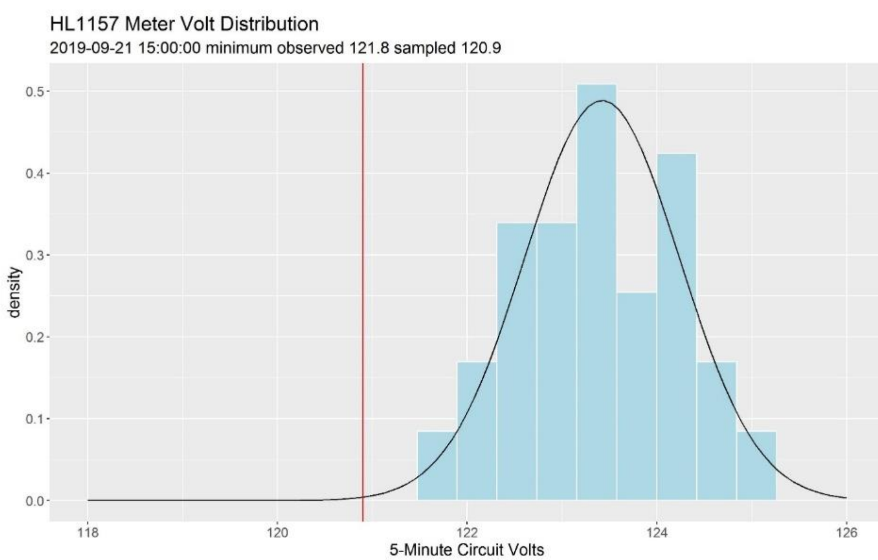
Step #1 - *Estimate* the minimum voltage on the circuit in each five-minute interval.

1. Using the 5-minute minimum line to neutral voltage data from each AMI meter on the circuit calculate the minimum, mean, and standard deviation in the five-minute interval. The minimum voltage for all meters on the circuit is the "actual minimum" voltage.
2. Use as inputs the mean and standard deviation to the normal cumulative distribution function and take the voltage level for which 99.9% of observations are expected to be greater. This is the "sampled minimum" voltage.
3. Take the minimum of the actual minimum voltage and the sampled minimum voltage as the expected minimum voltage in the given 5-minute interval. This is the step#1 result.

In "sampling" from the voltage observations to a voltage level that is oftentimes lower than the actual minimum voltage, the analysis reflects the likelihood that other meters on the circuit had lower voltage than the AMS Opt-In meters for which data is available. This would not be necessary if AMI were fully deployed.

Figure 2: represents the distribution of observed meter data with the blue histogram bars while the vertical red line at 120.9 represents the "sampled minimum" voltage from a normal distribution based on the observed voltage data. The sampled minimum voltage is 0.9 volts lower than the actual minimum voltage which is 121.8 volts

Figure 2: Voltage "Sampling" Example



Step#2 - Calculate the CVR Load Impact

Step #2 is also carried out in each 5-minute interval. Effectively, the percent difference between the voltage control threshold for the case (e.g. 118) and the expected minimum voltage on the circuit is applied to the load on the entire circuit. Table 3 illustrates the calculation given various parameter changes in columns A - D. Instances of CVR savings in Table 3 occur in the first and third row where Circuit Minimum Voltage (column C; i.e. the result of step #1 above) is greater than the Voltage Control Threshold (column B). Instances of upregulating voltage to the control threshold occur when the expected minimum voltage is less than the control threshold as in rows two and four; in these instances, Post CVR Circuit Load (column F) is greater than the original Circuit Load (column A). The CVR Factor scales the CVR Delta (column E) in that otherwise similar rows have greater effect with the 80% CVR Factor vs 70% (e.g. the -0.034 MW effect in row three is greater than -0.029 MW in row one).

Table 3: CVR Load Impact Calculation Example

A	B	C	D	E	F
				*(B/C-1)*D*A*	*A + E*
Circuit Load (MW)	**Voltage Control Threshold**	**Expected Minimum Voltage**	**CVR Factor**	**CVR Delta (MW)**	**Post CVR Circuit Load (MW)**
5	118	119	70%	-0.029	4.971
5	118	117	70%	0.030	5.030
5	118	119	80%	-0.034	4.966
5	118	117	80%	0.034	5.034

Step #3 - Aggregate the 5-minute CVR load impacts and compute annual percentage load reduction

The net energy impact of each five-minute interval is aggregated across the study period to estimate the annual net energy impact. The final aggregated results are therefore *net* avoided energy inclusive of any increased load from 5-minute intervals requiring voltage upregulation relative to the control threshold (as shown in Table 3 above).

Table 4 summarizes the results of the analysis annually by circuit for various voltage control thresholds. The 70% and 80% CVR factor cases are averaged thus reflecting a 75% CVR factor.

Table 4 CVR Annual Avoided Energy Percent by Circuit and Control Threshold

	Circuit Voltage Control Threshold		
	116	**117**	**118**
CF1201	-0.84%	-0.19%	0.00%
CF1202	-1.97%	-1.34%	-0.71%
CF1205	-2.77%	-2.14%	-1.52%
CW1222	-2.68%	-2.06%	-1.43%
CW1224	-2.51%	-1.89%	-1.26%
CW1226	-3.51%	-2.91%	-2.29%
CW1227	-2.55%	-1.92%	-1.31%
CW1228	-1.62%	-0.98%	-0.36%
HL1155	-4.10%	-3.50%	-2.87%
HL1156	-2.68%	-2.06%	-1.44%
HL1157	-3.51%	-2.89%	-2.27%
HL1158	-2.62%	-2.02%	-1.38%
Avg.	**-2.61%**	**-1.99%**	**-1.40%**

Range of CVR Energy Savings Potential

The analysis of the 12 selected circuits provides a reasonable basis for predicting what CVR energy savings may be on the remaining CVR candidate circuits. However, in recognition of the limited data and general uncertainty associated with high-level estimates of potential CVR energy savings, a set of High, Mid and Low CVR energy savings scenarios were developed.

Table 5 shows the annual avoided energy by scenario rounded to the nearest 5 GWh. The savings for each scenario are the product of the CVR candidate circuit 2019 total energy (10,384 GWh) and the CVR percent savings associated with each voltage control threshold in Table 4. The High, Mid and Low scenarios are associated with the 116, 117 and 118 voltage control threshold, respectively.

Table 5 CVR Avoided Energy Scenarios

Scenario	CVR Candidate Circuit 2019 GWh	Percent CVR Savings	CVR Avoided Energy GWh
High	10,384	-2.61%	-270
Mid	10,384	-1.99%	-205
Low	10,384	-1.40%	-145

Literature Review

Reports that many utilities find 1% to 4% savings on initial deployment.

EPA. (2017). *Conservation Voltage Reduction/Volt VAR Optimization EM&V Practices.* Retrieved from https://www.energystar.gov/sites/default/files/asset/document/Volt%20Var%20and%20CVR%20EMV%20Best%20Practice%2006-01-17clean%20-%20508%20PASSED.PDF

Presentation slides from Duke Energy to an IEEE conference in which support for a 70% CVR Factor as typical though there is significant variation.

Simms, M. (2016). *IEEE SDWG 2016: Duke Energy Production Experience with CVR.* Retrieved from http://grouper.ieee.org/groups/td/dist/da/doc/Duke%20Energy%20Production%20Experience%20with%20CVR.pdf

Pilot at Dominion Virginia Power including two circuits with average of 2.8% in savings.

IEEE. (2014). *Technologies for Advanced Volt/Var Control Implementation: Integration of Advanced Metering Data* (PowerPoint page #13). Retrieved from https://www.ieee-pes.org/presentations/gm2014/PESGM2014P-002524.pdf

To:	Jonathan Whitehouse and John Hayden, LG&E and KU
Cc:	Stacy Harvey, LG&E and KU Andrew Meyerhofer and Carrie Koenig, Tetra Tech
From:	Jonathan Hoechst and Sue Hanson, Tetra Tech
Date:	October 28, 2020
Subject:	Advanced Metering Program Evaluation – 2020 Update Executive Summary

This memo summarizes savings estimates for Louisville Gas and Electric Company and Kentucky Utilities Company's (LG&E and KU's) Advanced Metering Program (AMP), using consumption and participation data spanning from January 2014 to July 2020. We first provide an overview of our findings, and then present a summary of results in the following main topic areas:

- Analysis 1: nonparticipants and earliest adopters[1]
- Analysis 2: treatment and contrast group
- Analysis 3: participants and waitlist customers.

EXECUTIVE SUMMARY

Since 2016, Tetra Tech's analyses of LG&E and KU's AMP has indicated that electric savings occurred amongst participants in excess of naturally occurring reductions in energy usage among LG&E and KU customers that do not have advanced metering equipment. A summary of Tetra Tech's analyses is provided in Table 1, below, including the estimated energy savings associated with installing an advanced meter and the number of accounts supporting each analysis.

Table 1. AMP Savings Estimates

Year of Analysis*	Estimated Electric Savings (%)	Number of Treatment Accounts**	Number of Contrast Accounts***
October 25, 2016****	6.0%	82	199
January 3, 2018	3.8%	1,353	357
January 28, 2019	1.3%	2,635	1,094
September 22, 2020			
Analysis 2	1.7%	3,448	6,273
Analysis 3	1.4%	8,946	1,998

* The date provided is the date a memo was delivered to LG&E and KU.

** Treatment accounts are AMP participants. We use these words interchangeably throughout this memo.

*** Contrast accounts are essentially AMP nonparticipants, but how the nonparticipants were defined varied somewhat by the analysis method and timeframe. The term "control group" is avoided because households were not randomly assigned.

**** The 2016 analysis is included as a preliminary estimate, as this particular analysis included a relatively small number of accounts in both the treatment and contrast groups, increasing the potential for extreme values to unduly influence overall results.

[1] Throughout this memo, the term "earliest adopters" specifically refers to AMP participants with a meter installation that occurred in 2016.

The analyses presented in this memo support the findings that since program inception (1) LG&E and KU customers with an advanced meter installed through AMP use less electricity, on average, after installation of their meter, and (2) AMP participants have reduced their electric use by an amount greater than naturally occurring energy savings. These results are consistent across all analyses conducted by Tetra Tech for AMP.

In addition, the results of the analyses in Table 1 are similar to energy savings estimates claimed by utilities when filing dockets after AMI deployment. In particular:

- Baltimore Gas and Electric reported energy savings between 1.38 and 1.5 percent after offering advanced meters to its customers.[2]
- An evaluation of energy consumption among residential customers of Potomac Electric Power Company estimated electric savings of 1.73 percent after activation of smart meters.[3]

Tetra Tech also notes a few utilities that have filed planned energy savings estimates in support of proposed AMI deployment, but do not have actual results at this time. In particular:

- Entergy New Orleans approved filing estimated savings of 1.75 of electricity and 0.75 percent of gas consumption, and included a web portal.[4]
- Entergy Arkansas' 2016 AMI approved plan included a web portal that customers can access to see energy use and estimated electric savings of 1.75 percent across residential and commercial customers.[5]
- In Canada, BC Hydro's smart meter plan included energy savings of 2 percent from customers using their website in conjunction with new advanced meters.[6]

The more recent analysis of AMP participants was completed because AMP was fully subscribed. Tetra Tech compared electric usage among the earliest AMP participants *prior to* installation of their advanced meter to a statistically valid sample of LG&E and KU nonparticipating customers to examine whether the two groups consumed electricity at similar rates. The results indicated that, on average, AMP participants used more electricity per day before receiving their advanced meter than nonparticipating customers. This supports the notion that the general population of LG&E and KU customers *consume* electricity at different rates than program participants. However, we note that the results cannot be used to determine whether potential electric *savings* achievable through installation of an advanced meter would be different or similar between participants and current nonparticipants, as savings are relative to individuals' baseline energy usage.

[2] Navigant Consulting Inc., Smart Energy Manager Program – 2015 Evaluation Report, prepared for Baltimore Gas Electric, March 11, 2016. See also Direct Testimony of William B. Pino on behalf of Baltimore Gas & Electric Company, before the Maryland Public Service Commission – Case No. 9406, November 6, 2015.

[3] Direct Testimony of Ahmad Faruqui on behalf of Potomac Electric Power Company, Maryland Public Service Commission – Case No. 9418, April 19, 2016.

[4] New Orleans City Council Docket UD-16-04, Application of Entergy New Orleans, Inc. for Approval to Deploy Advanced Metering Infrastructure. Available at https://www.all4energy.org/uploads/1/0/5/6/105637723/2016_10_13_ud-16-04_app_for_ami_testimony_exhibits_final_public.pdf.

[5] Arkansas Public Service Commission Docket No. 16-060-U, Document 23. Available at http://www.apscservices.info/pdf/16/16-060-U_23_1.pdf.

[6] "Smart Metering & Infrastructure Program Business Case," BC Hydro. Available at https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/projects/smart-metering/smi-program-business-case.pdf.

As summarized in Table 1, AMP participants persist in decreasing their energy usage more than naturally occurring decreases in energy usage seen by the contrast accounts. Importantly, the reduction in energy use remains among AMP participants as the program continued to add participants. As participation numbers increased, the program necessarily starts to reflect the LG&E and KU population of customers more closely, a fact that supports the idea that energy savings will occur among LG&E and KU customers after installation of an advanced meter.

Using two separate methodologies to analyze electric usage, Tetra Tech's iterative modeling approach estimated savings for AMP participants to be between 1.4 and 1.7 percent greater than naturally occurring usage reductions. Put another way, Tetra Tech estimates that AMP participants reduced their electric usage by 1.4 to 1.7 percent more than nonparticipants.

SAVINGS ESTIMATION METHODOLOGY OVERVIEW

Tetra Tech conducted three distinct analyses in support of the evaluation of all AMP participants.

- First, Tetra Tech examined consumption records of program participants that installed their meter in 2016 (referred to as "earliest adopters") prior to their enrollment in the program, comparing their usage patterns to a random sample of LG&E and KU nonparticipating customers. The goal of this analysis was to examine whether participants and nonparticipants exhibited similar electric usage *before* (i.e. in 2015) any advanced meter installations for earliest adopters.
- Second, Tetra Tech updated prior analyses that estimated savings by comparing electric usage among program participants by separating participants into a treatment and a contrast group based on the date of their advanced meter installation. More recent participants were placed into the contrast group; their consumption *prior* to advanced meter installation served as a contrast period to compare to longer term program participants.
- Finally, Tetra Tech conducted an analysis of electric usage among all program participants and compared usage patterns to LG&E and KU customers currently on a waitlist to enroll in the AMP. This waitlist group of customers is available as a comparison (contrast) group because AMP is currently limited to 20,000 participants and is fully enrolled, creating the need for a waitlist for customers interested in participating in the program.

SUMMARY OF RESULTS

ANALYSIS 1. EARLIEST ADOPTERS AND NONPARTICIPANTS

The results indicate that average daily energy use was not equal between earliest adopters and nonparticipants in 2015. On average, the nonparticipants used 1.8 kWh less per day than earliest adopters, with a confidence interval of ± 0.07 kWh. Nonparticipants consumed 39.4 kWh per day, and earliest adopters used 41.1 kWh daily. The corresponding confidence interval around the estimate of ± 0.07 kWh is at 95 percent confidence. Simply put, if Tetra Tech drew 100 new random samples of nonparticipating residential contracts and conducted this exact analysis 100 times, Tetra Tech expects the resulting difference to be within 1.71 and 1.85 kWh in 95 of 100 analyses. Table 2 provides additional detail about the t-test results.

Table 2. Analysis 1: Summary Statistics for Average Daily Consumption by Group

Group	N	Mean	Std. Dev.	Lower CL[7]	Upper CL
Earliest Adopters	1,781	41.14	26.7	41.17	41.21
Nonparticipants	18,601	39.36	27.1	39.34	39.38
Difference	N/A	1.78	0.4	1.71	1.85

ANALYSIS 2: TREATMENT AND CONTRAST GROUP

The second analysis consisted of an approach to estimate savings using the consumption data of customers in the treatment and contrast groups. The contrast group for this analysis were customers who enrolled in AMP since the beginning of February 2019 and had at least 28 months of pre-period consumption data that overlapped with the treatment group pre and post-installation energy consumption data. The analysis indicated average household energy savings of approximately 2.2 percent compared with the pre-installation period among households in the treatment group. Consumption among households in the contrast group fell by approximately 0.5 percent compared to pre-installation levels during the same period. The results for each analysis group are shown in Table 3. The treatment group reduced its normalized annual consumption (NAC) between the pre- and post-periods by an average of 326 kWh, or about 2.2 percent. The contrast group, however, reduced its NAC during this time by 73 kWh, or about 0.5 percent of baseline consumption. Thus, the estimated average impact of AMP is 1.7% x 14,520 kWh = 253 kWh.

Table 3. Normalized Annual Consumption

Analysis Group	n	NAC (kWh)
Treatment – pre period	3,448	14,520
Treatment – post period	3,448	14,194
Contrast – pre period	6,273	14,626
Contrast – post period	6,273	14,554

The 90 percent confidence interval around treatment group savings is ± 19 percent of the estimated value. Thus, the lower limit to the NAC for the treatment group is 264 kWh, and the upper limit is 387 kWh. Relative uncertainty around the contrast group impact was higher, resulting in a 90 percent confidence interval around the contrast group having bounds 18 kWh and 128 kWh, with a mean of 72 kWh.

ANALYSIS 3: PARTICIPATING CUSTOMERS AND WAITLISTED CUSTOMERS

After weather normalizing the data, Tetra Tech found that AMP participants had decreased their usage more during the post period than the waitlist group. The NAC kWh savings for the participants was 1,135 kWh, while waitlisted customers reduced consumption by 1,027 kWh, leaving the participants with an additional 1.4 percent savings over the waitlist group. Full NAC for each group can be seen in Table 4. AMP participants reduced NAC between the pre and post periods by an average of 1,135 kWh, or about 7.7 percent. The waitlist group, however, reduced its NAC during this time by 1,027 kWh, or about 6.3 percent of baseline consumption. Thus, the estimated average impact of AMP is 1.4% x 14,669 kWh = 205 kWh.

[7] All confidence limits (CL) are at 95 percent.

Table 4. Normalized Annual Consumption by Analysis Group

Analysis Group	N	NAC (kWh)
Participants – pre-period	8,946	14,669
Participants – post-period	8,946	13,534
Waitlisted – pre-period	1,998	16,264
Waitlisted – post-period	1,998	15,237

Appendix F – [redacted] Meter Life Study

Smart Grid Investments
2021 BP
$000

Project	2021	2022	2023	2024	2025	Total	Nov 1, 2019 to Dec 31, 2021
LG&E							
Distribution and Customer Services:							
Advanced Metering Systems (AMS) Opt In DSM	64	67	69	71	73	344	115
Distribution Automation	9,997					9,997	20,278
Electro-Mechanical Relay Replacement	2,500	1,000	2,500	1,500	-	7,500	7,610
Fuse Savings Pilot	490					490	1,212
Scada Voltage Controller Upgrades	300	500	450	450	600	2,300	597
Transmission:							
Control Houses	-	-	984	1,667	1,954	4,605	-
Relay Panels	4,876	1,155	1,357	2,559	3,324	13,271	8,523
Remote Terminal Units	108	-	400	485	1,307	2,300	350
Switch - Auto	1,468	977	581	-	-	3,026	1,707
Switch - Motor Operated	969	-	-	447	425	1,841	4,163
Total LG&E	20,771	3,699	6,341	7,179	7,683	45,673	44,555
KU							
Distribution and Customer Services:							
Advanced Metering System (AMS) Opt In DSM	64	67	69	71	73	344	145
Distribution Automation	2,846					2,846	20,097
Electro-Mechanical Relay Replacement	2,590	1,001	2,500	1,500	-	7,591	3,205
Fuse Savings Pilot	210					210	377
Scada Voltage Controller Upgrades	300	500	450	450	600	2,301	592
VVO		500	500			1,000	-
DERMs					1,000	1,000	-
KU SCADA Expansion	5,085	999	2,500	1,000	500	10,084	10,503
Transmission:						-	
Control Houses	6,029	7,753	3,212	3,037	3,633	23,664	10,821
Relay Panels	3,118	2,925	1,024	4,980	6,611	18,658	5,332
Remote Terminal Units	538	131	756	941	2,345	4,711	1,539
Switch - Auto	2,747	2,538	1,960	2,471	2,471	12,187	4,165
Switch - Motor Operated	5,222	1,826	1,393	486	1,621	10,548	15,876
Total KU	28,748	18,240	14,365	14,936	18,854	95,143	72,652

NOTE: The information above does not include the AMI full deployment project discussed in testimony.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF	**)**	
KENTUCKY UTILITIES COMPANY FOR AN	**)**	**CASE NO. 2020-00349**
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	**)**	

In the Matter of:

ELECTRONIC APPLICATION OF	**)**	
LOUISVILLE GAS AND ELECTRIC	**)**	**CASE NO. 2020-00350**
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	**)**	

TESTIMONY OF
DAVID S. SINCLAIR
VICE PRESIDENT, ENERGY SUPPLY AND ANALYSIS
KENTUCKY UTILITIES COMPANY AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Filed: November 25, 2020

Table of Contents

<u>Section 1 – Introduction and Overview</u>

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

A. My name is David S. Sinclair. I am Vice President, Energy Supply and Analysis for Kentucky Utilities Company ("KU") and Louisville Gas and Electric Company ("LG&E") (collectively "Companies"), and an employee of LG&E and KU Services Company, which provides services to KU and LG&E. My business address is 220 West Main Street, Louisville, Kentucky 40202.

Q. Have you previously testified before the Kentucky Public Service Commission ("Commission")?

A. Yes, I have testified before the Commission numerous times in a variety of cases.[1] I testified most recently in Case No. 2020-00016, *Application of Louisville Gas and Electric Company and Kentucky Utilities Company for Approval of a Solar Power*

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[1] Among other cases, I testified before the Commission in the following cases: Case No. 2018-0294, *Application of Kentucky Utilities Company for an Adjustment of Its Electric Rates;* Case No. 2018-0295, *Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Rates;* Case No. 2016-00370, *Application of Kentucky Utilities Company for an Adjustment of Its Electric Rates and for Certificates of Public Convenience and Necessity*; Case No. 2016-00371, *Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Rates and for Certificates of Public Convenience and Necessity;* Case No. 2015-00194, *In the Matter of: Investigation of Kentucky Utilities Company's and Louisville Gas and Electric Company's Respective Need for and Cost of Multiphase Landfills at the Trimble County and Ghent Generating Stations;* Case No. 2014-00371, *Application of Kentucky Utilities Company for an Adjustment of Its Electric Rates*; Case No. 2014-00372, *Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Rates*. Case No. 2011-00161, *In the Matter of: The Application of Kentucky Utilities Company for Certificates of Public Convenience and Necessity and Approval of Its 2011 Compliance Plan for Recovery By Environmental Surcharge*; Case No. 2011-00162, *In the Matter of: The Application of Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity and Approval of Its 2011 Compliance Plan for Recovery By Environmental Surcharge*; Case No. 2011-00375, *In the Matter of: Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for a Certificate of Public Convenience and Necessity and a Site Compatibility Certificate for the Construction of a Combined Cycle Combustion Turbine at the Cane Run Generating Station and the Purchase of Existing Simple Cycle Combustion Turbine Facilities From Bluegrass Generation Company, LLC in La Grange, Kentucky*; Case No. 2014-00002, *In the Matter of: Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for a Certificate of Public Convenience and Necessity for the Construction of a Combined Cycle Combustion Turbine at the Green River Generating Station and a Solar Photovoltaic Facility at the E.W. Brown Generating Station*.

Contract and Two Renewable Power Agreements to Satisfy Customer Requests for a Renewable Energy Source Under Green Tariff Option #3.

Q. Please describe your job responsibilities.

A. I have four primary areas of responsibility: (i) fuel procurement (coal and natural gas) and coal combustion residual marketing for the Companies' generating stations, (ii) real-time dispatch optimization of the generating stations to meet the Companies' native load obligations, (iii) wholesale market activities, and (iv) sales and market analysis, generation planning, and technology research. As it pertains to this proceeding, the Sales Analysis and Forecasting group prepared the electric and gas load forecasts and the Generation Planning group prepared the generation forecast. All of this work was done under my direction and overall supervision.

Q. What are the purposes of your testimony?

A. The purposes of my testimony are to: (1) support certain exhibits required by the Commission's regulations; (2) describe the Companies' gas and electric sales forecasts including the impact of the COVID-19 induced economic recession; (3) explain the process for developing class load profiles, which are an input to the Cost of Service Study; (4) explain the Companies' forecast of generation and future resource mix; and (5) explain changes from the base period to the forecasted test period for operating revenues, sales for resale, and purchased power.

Q. Are you supporting any exhibits and schedules that are required by Commission regulation 807 KAR 5:001?

A. Yes, I am sponsoring (or co-sponsoring) the following exhibits and schedules for the corresponding filing requirements for both Companies:

• Factors Used in Forecast	Section 16(7)(c)	Tab 16
• Load Forecast Including Energy and Demand (electric)	Section 16(7)(h)5	Tab 26
• Mix of Generation (electric)	Section 16(7)(h)7	Tab 28
• Customer Forecast (gas)	Section 16(7)(h)14	Tab 35
• Sales Volume Forecast – cubic feet (gas)	Section 16(7)(h)15	Tab 36
• All commercial or in-house computer software, programs and models used to develop schedules and work papers	Section 16(7)(t)	Tab 50

Q. Please identify the documents you are sponsoring attached at Tab 16 of the Companies' Applications.

A. I am sponsoring the following documents that are among those attached at Tab 16 of the Companies' Applications and relate to the Companies' forecasts:

Item B – Electric Sales & Demand Forecast Process;

Item C – 2021 Business Plan Electric Sales Forecast;

Item D – Annual Natural Gas Volume Forecast Process;

Item E – Class Load Profile Forecast Process;

Item F – 2021 Business Plan Gas Volume Forecast;

Item G – Annual Generation Forecast Process;

Item H – 2021 Business Plan Generation and OSS Forecast.

Q. Are you sponsoring any exhibits to your testimony?

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

Exhibit DSS-1 Comparison of KU Electric Customers, Billing Demand, and Energy: Base Period vs. Forecasted Test Period

Exhibit DSS-2	Comparison of LG&E Electric Customers, Billing Demand, and Energy: Base Period vs. Forecasted Test Period
Exhibit DSS-3	Comparison of LG&E Gas Customers, Billing Demand, and Volume: Base Period vs. Forecasted Test Period
Exhibit DSS-4	Economic Inputs to Electric and Gas Forecasts
Exhibit DSS-5	Comparison of Generation Volume by Unit, Base Period vs. Forecasted Test Period

Section 2 – Overview of Electric Load Forecast

Q. Please describe the Companies' electric load forecast process.

A. Each year, the Companies prepare a 30-year demand and energy forecast with the first six years used in the Companies' business plan. The electric load forecast created for the most recent business plan that I will be discussing is referred to as the "2021 Load Forecast." The electric load forecast process is essentially the same for both KU and LG&E and is described in the document at Tab 16 to the Companies' Applications entitled "Electric Sales & Demand Forecast Process." Basically, the forecast process involves:

- Using historical data to develop models that relate the Companies' electricity usage, demand, sales, and number of customers by rate classes to exogenous factors such as economic activity, appliance efficiencies and adaptation, demographic trends, and weather conditions; and
- Using the models in combination with forecasts of the exogenous factors to forecast the Companies' electricity usage, demand, sales, and number of customers for the various rate classes.

Q. Have the Companies materially changed their approach to electric load forecasting since their 2018 rate cases?

A. No. While each year we try to improve our models, these changes are typically incremental and do not depart from methods that have been utilized for decades. The 2021 Load Forecast reflects information that has become available since the 2018 rate cases such as updated actual load and customer data, updated national and regional economic forecasts, and updated model parameters. Additionally, the impact of the economic shutdowns in response to COVID-19 created a forecasting challenge that required additional analysis to ensure the reasonableness of the 2021 Load Forecast.

Q. Have the Companies filed an integrated resource plan with the Commission since the 2018 rate cases?

A. Yes. The 2018 Integrated Resource Plan ("2018 IRP") was filed on October 19, 2018.[2] The methods used to forecast load in the 2021 Load Forecast are not materially different from those discussed in Section 5.(2) of Volume I of the 2018 IRP as well as the Energy & Demand Forecast Process document of Volume II of the 2018 IRP. In the 2018 IRP case, Commission Staff stated:

> Staff is generally satisfied with the Companies' analysis of the many uncertainties and risks LG&E/KU will be facing over the planning period. The improvements in its load forecasting analysis, reserve margin analysis, and its supply-side screening and optimization plan have produced an optimal plan that is cost-effective.[3]

Q. Does the Companies' load forecast capture how economic activity may vary across the state?

A. Yes. The Companies use economic inputs to specifically capture economic conditions appropriate to the parts of the state being served. Factors such as household formation and population growth, which have a strong correlation with the number of customers the Companies serve, can vary significantly within the service territory. Recent trends show continued steady growth in customers in the urban centers of Louisville and

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[2] *The 2018 Joint Integrated Resource Plan of Kentucky Utilities Company and Louisville Gas and Electric Company*, Case No. 2018-00348, Companies' Integrated Resource Plan (Ky. P.S.C. Oct. 19, 2018).
[3] Case No. 2018-00348, Commission Staff's Report at 46 (Ky. P.S.C. July 20, 2020).

Lexington, while the rural areas are either experiencing little growth or declining sales and customers, primarily driven by ongoing challenges facing the coal industry and limited success at attracting new businesses.

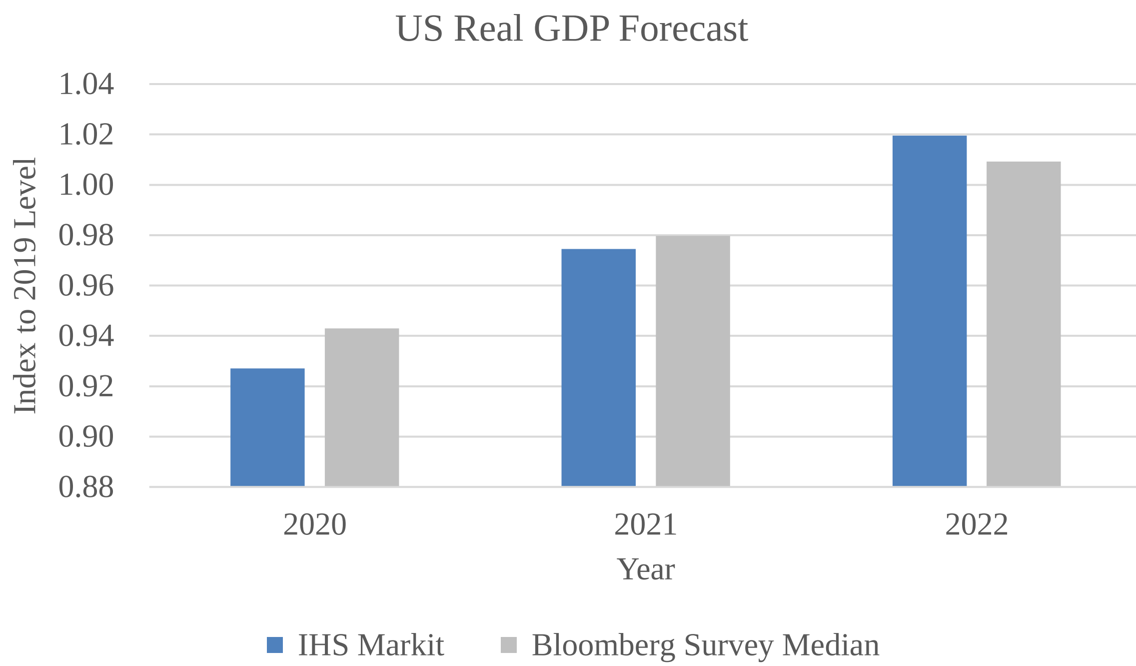
Q. Does the 2021 Load Forecast specifically reflect the effect of COVID-19 on the national and Kentucky economies?

A. Yes. The 2021 Load Forecast specifically reflects the effect of COVID-19 on the national and Kentucky economies. The most severe reductions in load due to the pandemic were due to mandatory business shutdowns that began in March. Load has recovered in subsequent months but remains below pre-pandemic levels. The economic recovery is forecasted to remain weak in the industrial and commercial sectors as the absolute level of economic growth remains depressed. IHS Markit is projecting real Kentucky economic output to return to 2019 levels by 2022.

Q. How does IHS Markit's projection of the national economic recovery, which underpins the 2021 Load Forecast, compare to the projections of others?

A. Figure 1 below compares the forecast of US Real GDP from IHS Markit to the median of Bloomberg's survey of approximately 85 economic forecasting organizations at the time the 2021 Load Forecast was developed. To facilitate the comparison, their forecasted growth rates are indexed to the 2019 US Real GDP level. While IHS Markit was slightly more pessimistic than the median value in 2020, IHS Markit was similar to others in 2021 and slightly more optimistic by 2022.

Figure 1: US Real GDP Forecast



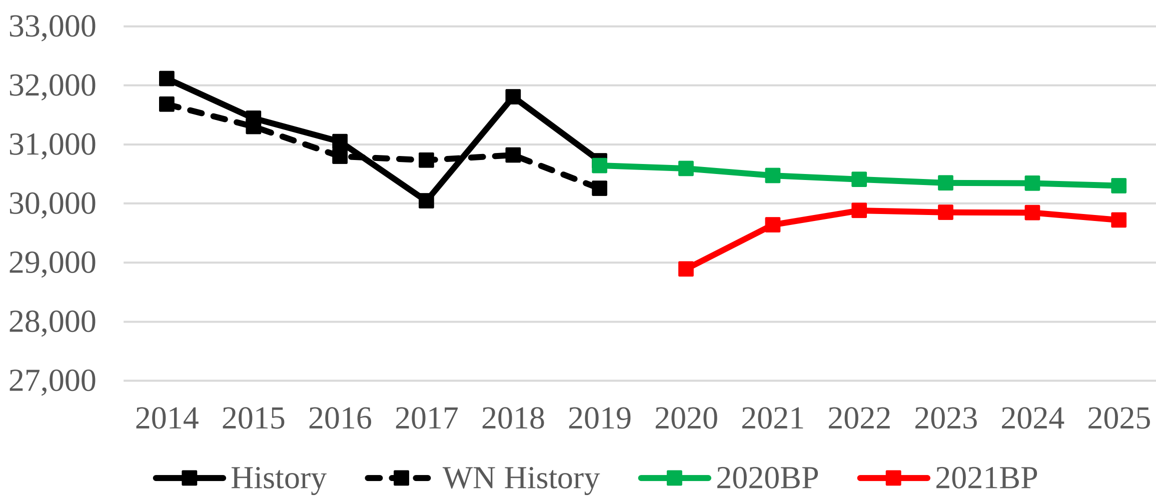
Q. In Appendix A, you state that since 2013 you have been a member of the Consensus Forecasting Group ("CFG") that sets the state's revenue forecasts. Does the CFG rely on any third party national or state economic forecasts in the preparation of their forecasts?

A. Yes. The CFG also uses IHS Markit for their economic forecasts of the U.S. and Kentucky economies.

Q. In a general sense, what is the effect of COVID-19 on the 2021 Load Forecast?

A. As Figure 2 shows below, sales are forecasted to recover through 2022 as the economy is forecasted to recover. At the time the forecast was prepared, it was assumed that the economy would begin opening up by the fall of 2020 and that working from home would largely be over. Therefore, COVID-19 had no material impact on the residential forecast. However, commercial and industrial energy and billed demands are forecasted to remain well below pre-pandemic levels as lingering weakness in the economy is expected to be a drag on sales to these sectors throughout the Plan period. Commercial and industrial sales are forecasted to remain below 2019 weather-normalized levels through the end of planning period (2025). While still reduced from previous plan levels, billed demands are not as impacted by COVID-19 as energy sales for the commercial and industrial rates. Many large customers in the service territory are operating the same equipment, but with reduced operating time. This type of change in operations changes energy sales (kWh) more than billed demands (kW or kVA). Additionally, the peak and intermediate billed demand periods are impacted more similarly to energy sales than the base billed demand period. The base billed demand period covers all hours of every day and has rate provisions that cause it to be more stable.

Figure 2: Historical and Forecasted Billed Sales (GWh)[4]



Q. How did you ensure that the forecasts for the large customers reflected their expected operations and the impacts of the COVID-19 recession?

[4] Data shown for 2020 in the 2021BP represents 5 months of actual billed sales data and 7 months of forecast data. Also, data shown for all years does not include sales data for departed municipal customers.

A. While we always survey approximately 30 of our major accounts as part of our annual sales forecast process, this year we put additional emphasis on our communications with them to make sure our forecast had the best and latest data possible. My team prepared monthly forecasts of both total energy and measured demands for these large customers based on information they provided regarding their future operations. These forecasts were sent to the customers for review so that any feedback could be incorporated in the 2021 Load Forecast. Base, intermediate, and peak demand forecasts, which are key components of the revenue forecast for these customers, were developed based on the measured demand forecasts to reflect applicable tariff provisions. By explicitly focusing each of our major account customers on a monthly forecast of their energy and demands, we were able to reflect their best views of the impact of the COVID-19 recession on their operations and when, and to what extent, they expected a recovery to take place.

Q. Does the Companies' load forecast reflect the impact of the Companies' demand side management and energy efficiency ("DSM-EE") programs?

A. Yes. The load forecast reflects the demand and energy impacts of the Companies' past and future demand side management programs.

Q. In addition to the Companies' DSM-EE programs, does the electric load forecast reflect other changes in end-use energy efficiency?

A. Yes. For example, the Companies incorporate specific end-use assumptions covering base load, heating, and cooling components into residential and small commercial forecasts. These end-use assumptions incorporate forecasts of both consumer adaptation and technology efficiency that are impacted by legislation and regulations of the energy efficiency of specific technologies. Absent these assumed improvements in energy efficiency by our customers, sales would be 1.9 percent (approximately 577 GWh) greater by 2025 than currently forecasted in the 2021 Load Forecast.

Q. Does the electric forecast reflect the impact of distributed solar generation and electric vehicles?

A. Yes, but the impact is negligible in the near term as the incidence of both technologies remains small but growing in the combined Companies' service area. In addition to being small, there remains a great deal of uncertainty about how these technologies might grow, or not grow, in the future. According to the Electric Power Research Institute ("EPRI"), as of March 2020 there were 3,088 plug-in electric vehicles ("EVs") in Kentucky counties served by the Companies. Assuming the average EV is driven 10,000 miles a year and that it requires 30 kWh per 100 miles of charge, this amounts to 7.67 GWh and 9.16 GWh of sales in the forecasted test period for KU and LG&E, respectively, or less than 0.1 percent of each Company's sales. Similarly, existing distributed generation resources are estimated to be around 6.7 MW at KU and 6.0 MW at LG&E of summer capacity as of March 2020, with almost all of that in the form of solar generation. Assuming an annual capacity factor near 15 percent results in a reduction of energy sales in the forecasted test period of 9 GWh and 10 GWh for KU and LG&E, respectively. Again, these volumes represent less than 0.1 percent of forecasted test year sales for each Company.

Q. Please explain how weather is reflected in the electric load forecast.

A. Outside air temperature impacts customers' demand for heating and air conditioning in order to maintain a comfortable indoor living environment. Therefore, the forecasting process includes information that reflects historical monthly temperatures and projected normal temperatures. As discussed in Electric Sales & Demand Forecast Process at Tab 16, the Companies assume that future weather will be the average of the weather experienced over the last 20 years. The Companies have used this approach for many years in IRP filings.[5] It is also consistent with a standard electric utility industry practice of using the average of historical weather as the basis for determining the "normal" weather when preparing a load forecast. This helps ensure there is an approximately equal chance that actual weather will be warmer or cooler than the "normal" period, thereby avoiding weather bias in the forecast.

Q. You stated that the Companies prepare a 30-year load forecast each year. When was the load forecast prepared that was used in preparing the 2021 business plan?

A. The 2021 Load Forecast that was used in preparing the 2021 Business Plan was completed in the summer of 2020. The electric load forecasts the Companies used in their 2021 Business Plan are attached at Tab 26 to the Applications.

Q. How was the 2021 Load Forecast used to develop class load shapes for the cost of service study?

[5] *See, e.g.*, Case No. 2018-00348, Integrated Resource Plan at 5-26 (Ky. P.S.C. Oct. 19, 2018) ("The Companies develop their long-term energy requirements forecast with the assumption that weather will be average or 'normal' in every year. The Companies use 20 years of historical weather data to develop their normal weather forecast."); *The 2014 Joint Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company*, Case No. 2014-00131, Integrated Resource Plan at 5-19 (Ky. P.S.C. Apr. 21, 2014) ("In addition, all forecasts of energy sales/requirements, peak demand, and use per customer assume normal weather – based on the 20-year period (through 2012) average of daily temperatures in each month."); *The 2011 Joint Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company*, Case No. 2011-00140, Integrated Resource Plan at 6-19 (Ky. P.S.C. Apr. 21, 2011) ("For both KU and LG&E, the most recent 20-year average of heating degree days ('HDDs') and cooling degree days ('CDDs') is used to represent the weather conditions that are likely to be experienced on average over the forecast horizon. 'Normal' weather in the 2011 IRP forecast is based on the weather in the 20-year period ending in 2009; the weather in the 2008 IRP was based on the weather in the 20-year period ending in 2006.").

A. The Companies utilize historical hourly load data by customer class to develop forecasted energy sales by class on an hourly basis. This process is essentially the same for both KU and LG&E and is described in detail in the document at Tab 16 to the Companies' Applications entitled "Class Load Profile Forecast Process." Part of this process includes various quality control and data integrity checks to ensure that the resulting forecasts of class profiles are reasonable.

Section 3 – KU Electric Load Forecast

Q. How are KU's customer count and electricity sales expected to change in the forecasted test period as compared to the base period?

A. As shown in Exhibit DSS-1, from the base period (March 2020 through February 2021) to the forecasted test period (July 2021 through June 2022), total retail KU calendar-adjusted electric sales increase by 612 GWh (3.6 percent) and total customers increase by 1,977 (0.4 percent). The customer growth is consistent with what one would expect given historical growth trends, as well as economic and other assumptions underlying the forecast.[6] Economic growth in Lexington and the areas around Louisville served by KU is partially offset by the impact of slower growth in the rural areas that KU serves, which have been heavily impacted by depressed mining activity. The "growth" in sales from the base period to the forecasted test period is primarily a result of the negative impacts of COVID-19 on commercial and industrial base period actual sales (March 2020 through August 2020) as opposed to economic growth that would have happened absent the virus-driven recession.

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[6] See Exhibit DSS-4 for detailed assumptions for the Forecasted Test Period.

Q. Please discuss the difference in sales and customers between the base period and the forecasted test period.

A. As I mentioned, commercial and industrial sales are forecasted to recover through the forecasted test period. As can be seen in Exhibit DSS-1, sales to the classes with the largest sales volumes except residential are forecasted to increase from the base period to the forecasted test period. The RTS, TOD-Primary, and TOD-Secondary rate classes are the biggest sources of the retail sales increase between the base period and the forecasted test period.

As usual, the majority of KU's customer growth is coming from the residential class. The residential class has experienced unanticipated sales growth in the summer of 2020, likely as a result of a good portion of the workforce worked from home due to COVID-19 restrictions. This temporary COVID-19-related growth in actual sales in the base period is forecasted to dissipate in the forecasted test period. RS sales are forecasted to decrease by 144 GWh (2.4 percent) in the forecasted test period compared to the COVID-19 inflated base period as continued energy efficiency gains related to lighting and general appliance replacement leads to lower forecasted residential sales.

Q. In Exhibit DSS-1, why are GS sales forecasted to increase by 67 GWh in the forecasted test period while the average number of GS customers are forecasted to decrease by a relatively small 246?

A. The number of customers and sales are forecasted using separate models with different variables. GS customers are forecasted based on Lexington Non-Farm Employment, which was forecasted to decline each month from April 2020 through March 2021. GS sales are forecasted based on heating, cooling, and non-weather-sensitive end-use intensities, of which one component is Kentucky Real Gross State Product (RGSP) excluding Louisville. Kentucky RGSP excluding Louisville was forecasted to decline in the first half of 2020 and then rebound. COVID-19 has had a much greater negative impact on sales than on the number of customers thus far, which is why sales are forecasted to rebound in the forecasted test year despite a forecast of slightly fewer customers.

Q. In Exhibit DSS-1, why are PS-Secondary sales forecasted to increase by 85 GWh in the forecasted test period while the average number of PS-Secondary customers is forecasted to decrease by 29?

A. The number of PS-Secondary customers is forecasted by utilizing the average growth rate from 2012 to 2019. PS-Secondary sales are forecasted based on degree days and non-weather-sensitive end-use intensities, of which one component is Kentucky RGSP excluding Louisville. Kentucky RGSP excluding Louisville was forecasted to decline in the first half of 2020 and then rebound. PS-Secondary sales and customers have been slowly declining over the past decade and are forecasted to continue this trend longer term, but the relatively large decrease in RGSP in the base period leads to an increase in sales in the forecasted test period as the economy recovers.

Q. Is there a difference in the weather between the base period and the forecasted test period?

A. Yes, but only a slight difference. The base period consists of actual billed data for the first six months and therefore reflects the actual weather during that time. On the other hand, sales in the last six months of the base period and the entire forecasted test period are based on 20-year normal weather for the KU service area as described in Annual

Electric Sales & Demand Forecast Process at Tab 16. Table 1 compares the actual monthly heating degree days ("HDDs") and cooling degree days ("CDDs") to their 20-year normal values. Actual degree days are lower in most months except for April, which did not materially deviate from the 20-year average HDDs. The net result is that weather sensitive load should be somewhat lower in the base period as compared to the forecasted test period.

Table 1: Comparison of Actual and 20-year Average Weather for KU

	Actual	Average	Difference
March (HDD)	658	695	-37
April (HDD)	428	418	10
May (CDD)	28	64	-36
June (CDD)	182	196	-14
July (CDD)	329	327	2
August (CDD)	326	343	-17

Q. Please describe the primary differences in billing demands between the base period and the forecasted test period.

A. As shown in Exhibit DSS-1, billing demands in total are increasing from the base period to the forecasted test period. Furthermore, as with energy, the RTS, TOD-Primary, and TOD-Secondary rate classes are the biggest sources of the increase. As discussed in Section 2, the increase is primarily the result of COVID-19 impacts during the base period, which particularly reduced billing demands in the intermediate and peak demand periods.

Q. Why are TOD-Primary base demands declining from the base period to the forecasted test period, whereas TOD-Primary peak and intermediate demands are increasing?

A. The loss of a large customer in July 2020, which was known when the forecast was completed, caused the base period actuals to come in above the same months in the forecasted test period. The variance between periods becomes positive when removing this customer from the base period actuals. Although this customer's peak and intermediate demands are also absent from the forecasted test period, the projected COVID-19 recovery that occurs in the peak and intermediate periods exceeds this customer's lost load.

Q. Do you believe the forecasted billing determinants for the forecasted test period are a reasonable basis for developing revenue forecasts?

A. Yes. The forecast process is one that has been employed for many years and has been reviewed by the Commission in the context of IRPs, certificates of public convenience and necessity ("CPCNs"), environmental cost recovery ("ECR") filings, and the Companies' base-rate cases. It reflects the best data available at the time it was prepared, and the output is reasonable both in a historical context and given the underlying input assumptions. Furthermore, the Companies have taken extra care to ensure that the impacts of COVID-19 have been incorporated into the forecast.

Section 4 – LG&E Electric Load Forecast

Q. How are LG&E's customer count and electricity sales forecasted to change in the forecasted test period as compared to the base period?

A. As can be seen in Exhibit DSS-2, from the base period (March 2020 through February 2021) to the forecasted test period (July 2021 through June 2022), total LG&E calendar-adjusted electric sales increase by 367 GWh (3.3 percent) and total customers increase by an average of 1,324 (0.3 percent). Higher sales in the forecasted test period to RTS, TOD-Primary, and TOD-Secondary customers are offset somewhat by lower sales to residential customers. The customer growth forecast is consistent with what one would expect given the economic and other assumptions underlying the forecast, namely that, as shown in Exhibit DSS-4, projected growth in Kentucky population is approximately 0.3 percent annually.

Q. In Exhibit DSS-2, why are GS sales forecasted to increase by 84 GWh in the forecasted test period while the average number of GS customers are forecasted to decrease by 399?

A. The number of customers and sales are forecasted using separate models with different variables. GS customers are forecasted based on Louisville Non-Farm Employment, which is forecasted to decline each month from April 2020 through March 2021. GS sales are forecasted based on heating, cooling, and non-weather-sensitive end-use intensities, of which one component is Louisville Real Gross Metro Product (RGMP). Louisville RGMP is forecasted to decline in the first half of 2020 and then rebound as the national economy recovers. The COVID-19 driven recession is forecasted to have a negative impact on sales in 2020 before recovering in the forecasted test year, whereas it is forecasted to have little impact on customer growth.

Q. In Exhibit DSS-2, why are PS-Secondary sales forecasted to increase by 120 GWh in the forecasted test period while the average number of PS-Secondary customers are forecasted to decrease by 17?

A. The number of PS-Secondary customers is forecasted by utilizing the average growth rate from approximately 2010 to 2019. PS-Secondary sales are forecasted based on degree days and non-weather-sensitive end-use intensities, of which one component is Louisville RGMP. Louisville RGMP was forecasted to decline in the first half of 2020 and then rebound. PS-Secondary sales and customers have been slowly declining over the past decade and are forecasted to continue this trend longer term, but the relatively large decrease in RGMP in the base period makes for an increase in sales when looking at the forecasted test period.

Q. Is there a difference in the weather between the base period and the forecasted test period?

A. Yes, the actual months in the base period are generally milder than the normal forecasted test period except July. The base period consists of actual billed data for the first six months and, therefore, reflects the actual weather during that time. Table 2 compares the actual monthly HDDs and CDDs to their 20-year normal values used in the forecast period. The net result is that weather sensitive load should be somewhat lower in the base period as compared to the forecasted test period.

Table 2: Comparison of Actual and 20-year Average Weather for LG&E

	Actual	Average	Difference
March (HDD)	578	652	-74
April (HDD)	342	372	-30
May (CDD)	43	87	-44
June (CDD)	236	249	-13
July (CDD)	419	392	27
August (CDD)	396	404	-9

Q. Please describe the primary differences in billing demands between the base period and the forecasted test period.

A. Exhibit DSS-2 shows that billing demands in total are forecasted to increase from the base period to the forecasted test period. Furthermore, as with energy, this increase is primarily in the RTS, TOD-Primary, and TOD-Secondary rate classes. As discussed in Section 2, the increase is primarily the result of COVID-19 impacts during the base period, which reduced billing demands in the intermediate and peak demand periods.

Q. Do you believe the forecasted billing determinants for the forecasted test period are a reasonable basis for developing revenue forecasts?

A. Yes. As I said before, the forecast process is one that has been employed for many years and has been reviewed by the Commission in the context of IRPs, CPCNs, ECR filings, and the Companies' base-rate cases. It reflects the best data available at the time it was prepared, and the output is reasonable both in a historical context and given the underlying input assumptions. Furthermore, the Companies have taken extra care to ensure that the impacts of COVID-19 have been incorporated into the forecast.

<u>Section 5 – LG&E Natural Gas Forecast</u>

Q. Please provide an overview of the 2021 Load Forecast of natural gas volumes for LG&E.

A. As discussed in document entitled "Annual Natural Gas Volume Forecast Process" at Tab 16 of LG&E's Application, the natural gas volume forecast consists of two broad types of customers: i) sales to consumers and ii) transportation for customers who procure their own natural gas. As shown in Exhibit DSS-3, from the base period (March 2020 through February 2021) to the forecasted test period (July 2021 through June 2022), natural gas sales are forecasted to increase by 809,309 Mcf (2.7 percent) and total customers on sales rates are forecasted to increase by 913 (0.3 percent). Comparing the same time periods, volumes for transportation customers are forecasted to increase by 467,815 Mcf (3.9 percent).

Q. In Exhibit DSS-3, how do the unbilled adjustments impact the comparison of the base period and forecasted test period?

A. The unbilled adjustments mostly impact the residential and commercial rate classes. The residential unbilled adjustment shown in Exhibit DSS-3 impacts residential rate class sales, and the other unbilled adjustment mostly impacts commercial rate class sales. Both of these unbilled adjustments should be added into the variances shown in their respective rate classes to get the most accurate comparison of the two periods.

Q. In Exhibit DSS-3, what are the major reasons for changes in Firm Transport (FT) volumes from the base period to the forecasted test period?

A. As shown in Exhibit DSS-3, the "Gas Transport Service, FT" rate class FT is forecasted to increase by 467,672 Mcf (4.1 percent) in the forecasted test period. There are two main reasons for this change. First, three existing customers with a total annual consumption of approximately 100,000 MCF will switch to the FT rate beginning November 2020. These customers will switch from the As-Available Gas Service (AAGS) and Firm Industrial Gas Service (IGS) rates to the FT rate, which causes the forecasted increase in customers seen in Exhibit DSS-3 in the FT rate and the decreases in AAGS (commercial) and IGS. The balance of growth from the base period in the forecasted test period is primarily due to the negative impacts of COVID-19 on commercial and industrial base period actual volumes (March 2020 through August 2020) as opposed to economic growth that would have happened absent the virus-driven recession.

Q. What explains the decrease in the forecasted test period of TS-2 AAGS volumes in Exhibit DSS-3?

A. The lone customer on rate TS-2 (AAGS) has experienced a large increase in actual volumes during the base period, but the customer anticipates dropping back to levels seen prior to 2020 in the forecasted test period. Table 3 below contains monthly volumes for this customer for the base and forecasted test periods.

Table 3: TS-2 AAGS Volumes (MCF)

Base Period Month	Base Period Actuals & Forecast		Test Period Month	Test Period Forecast
March 2020	8,602		July 2021	2,883
April 2020	17,339		August 2021	8,221
May 2020	8,815		September 2021	12,457
June 2020	18,966		October 2021	13,372
July 2020	19[7]		November 2021	13,842
August 2020	20,677		December 2021	8,836
September 2020	12,457		January 2022	6,890
October 2020	13,372		February 2022	5,839
November 2020	13,842		March 2022	5,534
December 2020	8,836		April 2022	6,264
January 2021	6,890		May 2022	4,769
February 2021	5,839		June 2022	6,922
Total	135,654		Total	95,829

Q. Although the volumes are very small, what explains the decrease in Distributed Generation Gas Service (DGGS) volumes in Exhibit DSS-3?

A. Upon completion of the gas forecast, a new customer began taking service on the DGGS rate in May 2020, which increased the base period actual volume.

Q. Do you believe the forecasted billing determinants for the forecasted test period are a reasonable basis for developing revenue forecasts?

A. Yes. The forecast process is one that has been employed for many years, reflects the best data available, and the output is reasonable both in a historical context and given

[7] The July 2020 figure is low because the customer was shut down for the majority of the month.

the underlying input assumptions. The natural gas forecast process uses many of the same methodologies and forecasting techniques as the electric forecast which has been reviewed by the Commission in the context of IRPs, CPCNs, ECR filings, and in LG&E's gas base-rate cases. Furthermore, the Companies have taken extra care to ensure that the impacts of COVID-19 have been incorporated into the forecast.

Section 6 – Electric and Gas Forecast Summary

Q. How do the Companies ensure their electric and gas load forecasts are reasonable?

A. The Companies seek to ensure their load forecasts are prepared using sound methods by people who are qualified professionals. There are three practices that the Companies employ to help produce the most reasonable forecast possible:

1. Build and rigorously test statistically and economically sound mathematical models of the load forecast variables;
2. Use quality forecasts of future macroeconomic events, both nationally and in the service territory, that influence the load forecast variables; and
3. Thoroughly review and analyze the model outputs to ensure the results make sense based on historical trends and the forecaster's own sense and understanding of long-term trends in electricity and natural gas usage.

The end result is the best forecast that can be produced by experienced professionals using the best available methods, models, and data.

Q. Please summarize your opinions on the 2021 electric and natural gas forecasts.

A. As I have stated, both the electric and natural gas forecasts were prepared using methods that have been in place for many years. These are the same methods that have been used to prepare forecasts that have been presented by the Companies in numerous proceedings at this Commission. The 2021 electric and natural gas forecasts were prepared using updated models and the latest information, and the resulting forecasts are reasonable. Furthermore, throughout the development of the 2021 Load Forecast, the actual and potential impacts from the COVID-19 recession and recovery were evaluated and reflected to the best of our knowledge.

Q. In your professional opinion, is the 2021 Load Forecast a reasonable forecast that can be relied upon in the development of the 2021 Business Plan?

A. Yes. I have been involved in economic forecasting for 37 years and first began performing utility load forecasts in 1986, so I have prepared and reviewed many forecasts in my career. It is my opinion that the 2021 Load Forecast fully meets the criteria I just described and is a reasonable forecast upon which to base the 2021 Business Plan.

<u>Section 7 – Generation Forecast</u>

Q. Please describe how the generation forecast is prepared.

A. A software program called PROSYM is used to simulate the dispatch of the Companies' generation fleet. The model uses a forecast of hourly energy requirements for the combined KU and LG&E system (including load in Virginia and wholesale requirements contracts) along with information on the Companies' generation fleet (unit capacity, heat rate, fuel cost, variable operations and maintenance, emissions, maintenance schedules, forced outage rate, etc.) and market conditions (spot wholesale electricity prices, transmission availability) to first optimize the cost of serving native load via self-generation and market energy purchases and then to sell any economic generation into the market. This process is described in detail in the document entitled "Generation Forecast Process" attached at Tab 16 of the Companies' Applications.

Q. Why is the Companies' generation system jointly planned and dispatched?

A. Generation units are jointly dispatched by KU and LG&E to achieve operational efficiencies associated with serving their combined loads. Pursuant to the Companies' *Power Supply System Agreement* filed with the Federal Energy Regulatory Commission, the Companies' joint planning objectives are to maximize the economy, efficiency, and reliability of their combined systems as a whole. Dispatch of generation, whether from the Companies' own generating resources or from purchased power, is determined by lowest variable operating cost, regardless of ownership, that is required to maintain system reliability. Therefore, it is reasonable to view the Companies' generation systems from the perspective of the combined KU and LG&E system.

Q. What are the primary reasons for differences in the generation volumes in the forecasted test period compared to the base period?

A. Exhibit DSS-5 shows generation volumes in the forecasted test period compared to the base period. The differences are most notable with simple-cycle combustion turbines ("SCCTs"), which show a 73 percent increase in generation from the base period. This difference is primarily due to the dampening effect of the COVID-19 recession on load in 2020. One exception is the decrease in generation volume at Trimble County 8, which is due to a planned outage in fall of 2021. Coal generation overall is relatively unchanged; however, some individual units show differences, which is to be expected given differences in maintenance schedules, other outages, load, weather, fuel costs, etc. Generation volumes at Mill Creek 1, Mill Creek 3, and Mill Creek 4 increase in the forecasted test period because the generation volumes in the base period are lower due to the effect of the COVID-19 recession on load in 2020. Mill Creek 3 and Mill Creek 4 were on reserve shutdown for much of April and May 2020 because of decreased load. During those months, because fewer units were online, Brown 3's generation increased, which explains why generation volume at Brown 3 decreases by 20 percent in the forecasted test period. Generation volumes at Ghent 1, Ghent 4, Trimble County 1, and Trimble County 2 all show differences due to their planned outages. Other unit-by-unit differences are primarily attributable to the timing and duration of planned and forced outages.

Q. Have there been or will there be other changes to the Companies' generation fleet since the Companies' last rate case in 2018?

A. Yes. KU retired the 106 MW Unit 1 and the 166 MW Unit 2 at the E.W. Brown Station in February 2019. LG&E retired the 14 MW Unit 11 SCCT at the Cane Run Station in November 2019. Additionally, LG&E plans to retire the 50+ year old 14 MW Zorn SCCT by the end of 2021, and it is assumed that the remaining similarly sized and aged SCCTs will retire by 2025. As discussed in Mr. Bellar's testimony and Exhibit LEB-2, the Companies also expect to retire Mill Creek Unit 1 by the end of 2024 and Mill Creek Unit 2 and Brown Unit 3 by the end of 2028. Finally, because of the ongoing ozone issues in Jefferson County, it is assumed that daily NO_x emissions will continue to be limited to 15 tons per day during the months of April through October at the Mill Creek Station. This will limit the ability to simultaneously operate Mill Creek Unit 1 and Unit 2, which has the impact of reducing the summer capacity rating of the Mill Creek Station by 300 MW.

Q. What is the Companies' forecasted summer reserve margin through 2025?

A. Based on the 2021 Load Forecast, the reduction in Mill Creek Station summer capacity, and the expected retirements of the small SCCTs, the Companies' forecasted summer reserve margin is as follows:

Table 4 - Forecasted Summer Reserve Margin

	2021	2022	2023	2024	2025
Summer Reserve Margin	24.4%	23.6%	23.8%	23.9%	24.1%

Q. You stated that the Companies expect to retire the SCCTs that are similar in size and age to Zorn by 2025. Please describe these units.

A. LG&E has Paddy's Run Units 11 and 12 that have a summer rating of 12 MW and 23 MW, respectively. Both units became operational in 1968. KU has Haefling Units 1 and 2 that have a summer rating of 12 MW each and became operational in 1970.

Q. Why are the Companies expecting to retire these units by 2025?

A. The Companies will continue to operate these units until they have major mechanical issues, which could occur at any time as we have experienced with similar SCCTs. When such major mechanical issues arise, these units will likely be retired because they will likely be too costly to repair given their age, high variable cost of operation, and low contribution to system reliability. Past catastrophic failures led to the retirements of Haefling Unit 3 and Cane Run Unit 11 and could occur any time the Companies try to operate the remaining older SCCTs. For purposes of preparing the 2021 Business Plan, it was assumed that all of these units would be retired by the end of 2025.

Q. You indicated that the Companies are likely to retire the 300 MW Mill Creek Unit 1 by December 31, 2024. Do the Companies plan to replace this capacity?

A. No. As demonstrated in the Companies' 2018 IRP, the target summer reserve margin range is between 17 percent and 25 percent. As shown in Table 4, when Mill Creek

Unit 1 is retired at the end of 2024, the summer reserve margin in 2025 is within the target reserve margin range.

Q. In your professional opinion, is the 2021 generation forecast reasonable and can it be relied upon in the development of the 2021 Business Plan?

A. Yes. The forecast was developed using the best data available and with processes and software the Companies have used for many years and have been the basis for information provided to the Commission in numerous IRP, CPCN, and ECR cases. The processes and software were also reviewed in the Companies' 2018 base-rate cases. Using sound models and assumptions produces reasonable forecasts.

Section 8 – Schedule D-1 Support

Q. Does your testimony support the Jurisdictional Adjustments to the base period for Operating Revenues from Sales of Electricity in Schedule D-1?

A. Yes. For the reasons I have stated, the volumetric differences in both KU's and LG&E's electric and gas load forecasts are the major reason for the differences in Operating Revenues from Sales of Electricity (Account Nos. 440, 442.2, 442.3, 444, and 445) between the base period and the forecasted test period.

Q. In Schedule D-1, what revenues and expenses are included in Sales for Resale (Account No. 447) and Purchased Power (Account No. 555)?

A. Sales for Resale contains intercompany sales revenue. Purchased Power contains intercompany purchased power expense, market economy purchased power expense, and Ohio Valley Electric Corporation ("OVEC") purchase power expense. Intercompany sales revenue for one company in Account No. 447 equals the intercompany purchased power expense for the other company in Account No. 555. Off-System Sales ("OSS") revenues recorded to Account No. 447 and OSS-related purchased power expenses recorded to Account No. 555 have been removed with a pro forma adjustment.

Q. What are the differences in Sales for Resale and Purchased Power between the base period and the forecasted test period?

A. Compared to the base period, KU's Sales for Resale in the forecasted test period are expected to decrease by $8 million, from $17.5 million to $9.5 million; LG&E's Sales for Resale in the forecasted test period are expected to increase by $15.5 million, from $21.3 million to $36.8 million. The primary causes of KU's decrease and LG&E's increase are the planned maintenance periods of Ghent Units 1 and 2 (owned by KU), Brown Unit 3 (owned by KU) and Trimble County Unit 2 (81 percent owned by KU).

Compared to the base period, KU's Purchased Power is expected to be higher by $14.3 million; LG&E's Purchased Power in the forecasted test period is expected to be lower by $8.4 million. These changes are also primarily explained by the changes in intercompany transactions associated with the aforementioned planned maintenance of Ghent Units 1 and 2, Brown Unit 3, and Trimble County Unit 2.

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

The undersigned, **David S. Sinclair**, being duly sworn, deposes and says that he is Vice President, Energy Supply and Analysis for Kentucky Utilities Company and Louisville Gas and Electric Company and an employee of LG&E and KU Services Company, and 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.

David S. Sinclair

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 20th day of November 2020.

Notary Public

Notary Public, ID No. 603967

My Commission Expires:

July 11, 2022

APPENDIX A

David S. Sinclair

Vice President, Energy Supply and Analysis
Kentucky Utilities Company
Louisville Gas and Electric Company
220 West Main Street
Louisville, Kentucky 40202
(502) 627-4653

Education
Arizona State University, M.B.A. -1991
Arizona State University, M.S. in Economics – 1984
University of Missouri, Kansas City, B.A. in Economics - 1982

Professional Experience
LG&E and KU Energy, LLC
2008-present – Vice President, Energy Supply and Analysis
2000-2008 – Director, Energy Planning, Analysis and Forecasting

LG&E Energy Marketing, Louisville, Kentucky
1997-1999 – Director, Product Management
1997-1997 (4th Quarter) – Product Development Manager
1996-1996 – Risk Manager

LG&E Power Development, Fairfax Virginia
1994-1995 – Business Developer

Salt River Project, Tempe, Arizona
1992-1994 – Analyst, Corporate Planning Department

Arizona Public Service, Phoenix, Arizona
1989-1992 – Analyst, Financial Planning Department
1986-1989 – Analyst, Forecasts Department

State of Arizona, Phoenix, Arizona
1983-1986 – Economist, Arizona Department of Economic Security

Affiliations
Consensus Forecasting Group (2013-present) - nonpartisan group of economists that sets Kentucky's official revenue budget on behalf of the governor and legislature.

Civic Activities
Serve on the Board of Junior Achievement of Kentuckiana
Graduate of Leadership Louisville (2008) and Bingham Fellows (2011)

Comparison of KU Electric Customers, Billing Demand, and Energy by Rate Classes: Base Period vs Test Period

Rate	Category	Values		Period	Base Period Billed Actual (Mar '20 - Aug '20)*	Base Period Calendar Forecasted (Sept '20 - Feb '21)	Base Period Total (Mar '20 - Feb '21)	Forecasted Test Period (Jul '21 - Jun '22)	Difference	% Difference
KU RETAIL										
AES	Customers	Avg Number of Customers			424	426	425	424	(1)	-0.2%
	Energy	Sum of Volume	GWh		50	70	120	129	9	7.5%
EV_Charge	Customers	Avg Number of Customers			7	10	9	10	1	11.1%
	Energy	Sum of Volume	GWh		-	-	-	-	-	0.0%
FLS	Customers	Avg Number of Customers			1	1	1	1	-	0.0%
	Demand	Sum of Volume	MVA	Base	1,276	1,263	2,539	2,438	(101)	-4.0%
	Demand	Sum of Volume	MVA	Intermediate	1,238	1,206	2,444	2,402	(42)	-1.7%
	Demand	Sum of Volume	MVA	Peak	823	825	1,648	1,647	(1)	-0.1%
	Energy	Sum of Volume			260	276	536	606	70	13.1%
GS	Customers	Avg Number of Customers			83,640	82,423	83,032	82,786	(246)	-0.3%
	Energy	Sum of Volume	GWh		791	820	1,611	1,678	67	4.2%
OSL	Customers	Avg Number of Customers			4	4	4	4	-	0.0%
	Demand	Sum of Volume	MW	Base	4	4	8	8	-	0.0%
	Demand	Sum of Volume	MW	Peak	1	1	2	3	1	50.0%
	Energy	Sum of Volume	GWh		-	-	-	-	-	0.0%
PS-Pri	Customers	Avg Number of Customers			205	204	205	204	(1)	-0.5%
	Demand	Sum of Volume	MW	Base	173	143	316	302	(14)	-4.4%
	Energy	Sum of Volume	GWh		51	37	88	79	(9)	-10.2%
PS-Sec	Customers	Avg Number of Customers			4,456	4,483	4,470	4,441	(29)	-0.6%
	Demand	Sum of Volume	MW	Base	2,583	2,592	5,175	5,273	98	1.9%
	Energy	Sum of Volume	GWh		810	804	1,614	1,699	85	5.3%
RS	Customers	Avg Number of Customers			440,124	439,838	439,981	442,208	2,227	0.5%
	Energy	Sum of Volume	GWh		2,887	3,200	6,087	5,943	(144)	-2.4%
RTOD	Customers	Avg Number of Customers			104	116	110	134	24	21.8%
	Demand	Sum of Volume	MW	Base	-	-	-	-	-	0.0%
	Demand	Sum of Volume	MW	Peak	-	-	-	-	-	0.0%
	Energy	Sum of Volume	GWh		1	1	2	2	-	0.0%
RTS	Customers	Avg Number of Customers			19	20	20	20	-	0.0%
	Demand	Sum of Volume	MVA	Base	1,584	1,543	3,127	3,201	74	2.4%
	Demand	Sum of Volume	MVA	Intermediate	1,341	1,390	2,731	2,938	207	7.6%
	Demand	Sum of Volume	MVA	Peak	1,331	1,369	2,700	2,903	203	7.5%
	Energy	Sum of Volume	GWh		627	673	1,300	1,405	105	8.1%
TOD-Pri	Customers	Avg Number of Customers			257	255	256	256	-	0.0%
	Demand	Sum of Volume	MVA	Base	5,344	5,311	10,655	10,620	(35)	-0.3%
	Demand	Sum of Volume	MVA	Intermediate	4,173	4,166	8,339	8,647	308	3.7%
	Demand	Sum of Volume	MVA	Peak	4,107	4,109	8,216	8,522	306	3.7%
	Energy	Sum of Volume			1,798	1,855	3,653	3,952	299	8.2%
TOD-Sec	Customers	Avg Number of Customers			746	744	745	766	21	2.8%
	Demand	Sum of Volume	MVA	Base	3,035	3,041	6,076	6,217	141	2.3%
	Demand	Sum of Volume	MVA	Intermediate	2,244	2,296	4,540	4,865	325	7.2%
	Demand	Sum of Volume	MVA	Peak	2,191	2,238	4,429	4,745	316	7.1%
	Energy	Sum of Volume	GWh		810	821	1,631	1,784	153	9.4%
Lighting	Customers	Avg Number of Customers			1,477	1,439	1,458	1,439	(19)	-1.3%
	Energy	Sum of Volume	GWh		56	71	127	127	-	0.0%
KU Unbilled Adjustment**										
Residential	Energy	Sum of Volume	GWh		14	-	14	-	(14)	-100.0%
Other	Energy	Sum of Volume	GWh		9	-	9	-	(9)	-100.0%
Total KU Unbilled	Energy	Sum of Volume	GWh		23	-	23	-	(23)	-100.0%
KU WHOLESALE										
Municipal - Remaining	Customers	Avg Number of Customers			2	2	2	2	-	0.0%
	Demand	Sum of Volume	MW	Base	364	384	748	803	55	7.4%
	Energy	Sum of Volume	GWh		189	192	381	401	20	5.2%

Total KU KY Retail Energy - Calendar Adjusted	Energy	Sum of Volume	GWh		8,164	8,628	16,792	17,404	612	3.6%
Total KU KY Energy - Calendar Adjusted	Energy	Sum of Volume	GWh		8,353	8,820	17,173	17,805	632	3.7%
Total KU Customers	Customers	Avg Number of Customers			531,464	529,963	530,716	532,693	1,977	0.4%

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Comparison of LG&E Electric Customers, Billing Demand, and Energy by Rate Classes: Base Period vs Test Period

					Base Period			Forecasted Test		
Rate	**Category**	**Values**		**Period**	**Billed Actual (Mar '20 - Aug '20)***	**Calendar Forecasted (Sept '20 - Feb '21)**	**Total (Mar '20 - Feb '21)**	**Period (Jul '21 - Jun '22)**	**Difference**	**% Difference**
PS-Pri	Customers	Avg Number of Customers			68	70	69	70	1	1.4%
	Demand	Sum of Volume	MW	Base	129	165	294	340	46	15.6%
	Energy	Sum of Volume	GWh		43	47	90	104	14	15.6%
PS-Sec	Customers	Avg Number of Customers			2,800	2,797	2,799	2,782	(17)	-0.6%
	Demand	Sum of Volume	MW	Base	2,048	2,038	4,086	4,277	191	4.7%
	Energy	Sum of Volume	GWh		704	685	1,389	1,509	120	8.6%
TOD-Pri	Customers	Avg Number of Customers			128	131	130	132	2	1.5%
	Demand	Sum of Volume	MVA	Base	2,641	2,676	5,317	5,355	38	0.7%
	Demand	Sum of Volume	MVA	Intermediate	2,125	2,055	4,180	4,410	230	5.5%
	Demand	Sum of Volume	MVA	Peak	2,085	2,008	4,093	4,306	213	5.2%
	Energy	Sum of Volume	GWh		948	919	1,867	1,993	126	6.7%
TOD-Sec	Customers	Avg Number of Customers			504	498	501	505	4	0.8%
	Demand	Sum of Volume	MVA	Base	2,089	2,160	4,249	4,406	157	3.7%
	Demand	Sum of Volume	MVA	Intermediate	1,546	1,586	3,132	3,268	136	4.3%
	Demand	Sum of Volume	MVA	Peak	1,508	1,544	3,052	3,184	132	4.3%
	Energy	Sum of Volume	GWh		604	607	1,211	1,288	77	6.4%
Special Contract #1	Customers	Avg Number of Customers			2	2	2	2	-	0.0%
	Demand	Sum of Volume	MW	Base	59	56	115	113	(2)	-1.7%
	Energy	Sum of Volume	GWh		27	29	56	56	-	0.0%
GS	Customers	Avg Number of Customers			46,311	45,209	45,760	45,361	(399)	-0.9%
	Energy	Sum of Volume	GWh		569	544	1,113	1,197	84	7.5%
EV Charge	Customers	Avg Number of Customers			10	10	10	10	-	0.0%
	Energy	Sum of Volume	GWh		-	-	-	-	-	0.0%
OSL	Customers	Avg Number of Customers			1	1	1	1	-	0.0%
	Demand	Sum of Volume	MW	Base	-	-	-	1	1	0.0%
	Demand	Sum of Volume	MW	Peak	-	-	-	-	-	0.0%
	Energy	Sum of Volume	GWh		-	-	-	-	-	0.0%
RS	Customers	Avg Number of Customers			375,985	375,434	375,710	377,436	1,726	0.5%
	Energy	Sum of Volume	GWh		2,180	1,889	4,069	4,048	(21)	-0.5%
RTOD	Customers	Avg Number of Customers			133	142	138	164	26	18.8%
	Demand	Sum of Volume	MW	Base	-	-	-	-	-	0.0%
	Demand	Sum of Volume	MW	Peak	-	-	-	-	-	0.0%
	Energy	Sum of Volume	GWh		1	1	2	2	-	0.0%
RTS	Customers	Avg Number of Customers			13	13	13	13	-	0.0%
	Demand	Sum of Volume	MVA	Base	1,203	1,184	2,387	2,400	13	0.5%
	Demand	Sum of Volume	MVA	Intermediate	1,008	1,057	2,065	2,132	67	3.2%
	Demand	Sum of Volume	MVA	Peak	906	1,035	1,941	2,085	144	7.4%
	Energy	Sum of Volume	GWh		500	507	1,007	1,051	44	4.4%
Lighting	Customers	Avg Number of Customers			1,198	1,161	1,180	1,161	(19)	-1.6%
	Energy	Sum of Volume	GWh		47	59	106	106	-	0.0%
LG&E Unbilled Adjustment**										
Residential	Energy	Sum of Volume	GWh		94	-	94	-	(94)	-100.0%
Other	Energy	Sum of Volume	GWh		(17)	-	(17)	-	17	-100.0%
Total LG&E Unbilled	Energy	Sum of Volume	GWh		77		77		(77)	-100.0%
Total LG&E Energy - Calendar Adjusted	Energy	Sum of Volume	GWh		5,700	5,287	10,987	11,354	367	3.3%
Total LGE Customers	Customers	Avg Number of Customers			427,153	425,468	426,313	427,637	1,324	0.3%

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Comparison of LG&E Gas Customers, and Volumes by Rate Classes: Base Period vs Test Period

				Base Period					
Rate	Category	Volume Type	Values	Billed Actual (Mar '20 - Aug '20)*	Calendar Forecasted (Sept '20 - Feb '21)	Total (Mar '20 - Feb '21)	Forecasted Test Period (Jul '21 - Jun '22)	Difference	% Difference
As-Available Gas Service, Commercial	Customers	Sales	Average Number of Customers	2	1	2	1	(1)	-50.0%
	Gas Volumes	Sales	Volume (Mcf)	32,918	20,539	53,457	24,383	(29,074)	-54.4%
As-Available Gas Service, Industrial	Customers	Sales	Average Number of Customers	1	1	1	1	-	0.0%
	Gas Volumes	Sales	Volume (Mcf)	18,474	12,351	30,825	29,446	(1,379)	-4.5%
Distributed Generation Gas Service	Customers	Sales	Average Number of Customers	3	2	3	2	(1)	-33.3%
	Demand	Sales	Billed Demand (Mcf)	680	600	1,280	1,200	(80)	-6.3%
	Gas Volumes	Sales	Volume (Mcf)	22	4	26	8	(18)	-69.2%
Firm Commercial Gas Service	Customers	Sales	Average Number of Customers	25,148	25,699	25,424	25,739	315	1.2%
	Gas Volumes	Sales	Volume (Mcf)	3,315,557	7,417,938	10,733,495	10,409,092	(324,403)	-3.0%
Firm Industrial Gas Service	Customers	Sales	Average Number of Customers	223	206	215	200	(15)	-7.0%
	Gas Volumes	Sales	Volume (Mcf)	510,855	491,120	1,001,975	994,578	(7,397)	-0.7%
Gas Special Contracts - LG&E Generation	Customers	Generation	Average Number of Customers	1	1	1	1	-	0.0%
	Gas Volumes	Generation	Volume (Mcf)	88,878	168,775	257,653	290,883	33,230	12.9%
Gas Transport Service, FT	Customers	Transport	Average Number of Customers	75	77	76	78	2	2.6%
	Demand	Transport	Billed Demand (Mcf)	460,756	462,232	922,988	938,972	15,984	1.7%
	Gas Volumes	Transport	Volume (Mcf)	5,166,832	6,272,899	11,439,731	11,907,403	467,672	4.1%
Residential Gas Service	Customers	Sales	Average Number of Customers	301,283	300,805	301,044	301,659	615	0.2%
	Gas Volumes	Sales	Volume (Mcf)	6,465,924	14,376,605	20,842,529	19,501,502	(1,341,027)	-6.4%
Substitute Gas Sales Service	Customers	Sales	Average Number of Customers	1	1	1	1	-	0.0%
	Demand	Sales	Billed Demand (Mcf)	14,509	13,672	28,181	24,000	(4,181)	-14.8%
	Gas Volumes	Sales	Volume (Mcf)	78	1,200	1,278	1,500	222	17.4%
TS-2: Gas Trans/Firm Balancing (AAGS In)	Customers	Transport	Average Number of Customers	1	1	1	1	-	0.0%
	Gas Volumes	Transport	Volume (Mcf)	74,417	61,235	135,652	95,828	(39,824)	-29.4%
TS-2: Gas Transport/Firm Balancing (IGS)	Customers	Transport	Average Number of Customers	8	8	8	8	-	0.0%
	Gas Volumes	Transport	Volume (Mcf)	167,204	191,424	358,628	398,595	39,967	11.1%
LG&E Gas Unbilled Adjustment**						-			
Residential	Gas Volumes	Sales	Volume (Mcf)	(1,695,395)	-	(1,695,395)	-	1,695,395	-100.0%
Other	Gas Volumes	Sales	Volume (Mcf)	(816,990)	-	(816,990)	-	816,990	-100.0%
Total LGE Gas Unbilled	Gas Volumes	Sales	Volume (Mcf)	(2,512,385)		(2,512,385)		2,512,385	-100.0%

Total Volumes - Calendar Adjusted	Gas Volumes	Total	Volume (Mcf)	13,328,774	29,014,090	42,342,864	43,653,218	1,310,354	3.1%
Total Customers	Customers	Total	Average Number of Customers	326,746	326,802	326,776	327,691	915	0.3%
Total Sales Volumes - Calendar Adjusted	Gas Volumes	Sales	Volume (Mcf)	7,831,443	22,319,757	30,151,200	30,960,509	809,309	2.7%
Total Customers	Customers	Sales	Average Number of Customers	326,661	326,715	326,690	327,603	913	0.3%
Total Transport Volumes	Gas Volumes	Transport	Volume (Mcf)	5,408,453	6,525,558	11,934,011	12,401,826	467,815	3.9%
Total Customers	Customers	Transport	Average Number of Customers	84	86	85	87	2	2.4%
Total Generation Volumes	Gas Volumes	Generation	Volume (Mcf)	88,878	168,775	257,653	290,883	33,230	12.9%
Total Customers	Customers	Generation	Average Number of Customers	1	1	1	1	-	0.0%

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	US Real Gross Domestic Product Billions of Chained 2012 Dollars, SAAR	KY Real Gross State Product (GSP) Millions of 2012 US$, SAAR	KY Employment, Retail Trade (NAICS 44-45) Thousand	KY Employment, Wholesale Trade (NAICS 42) Thousand	KY Industrial Production Index, Total (2012=100)
2007 Q1	15,493.33	170,130.50	214.07	76.03	103.43
2007 Q2	15,582.09	171,246.30	214.23	76.07	105.09
2007 Q3	15,666.74	171,697.80	213.47	75.87	104.16
2007 Q4	15,761.97	174,402.80	212.80	75.63	104.51
2008 Q1	15,671.38	174,039.00	212.93	75.80	104.69
2008 Q2	15,752.31	175,553.10	211.50	75.37	103.30
2008 Q3	15,667.03	171,782.00	210.80	75.13	98.75
2008 Q4	15,328.03	167,229.20	207.47	74.63	94.94
2009 Q1	15,155.94	164,664.00	203.30	72.50	88.77
2009 Q2	15,134.12	163,115.80	202.20	71.37	86.75
2009 Q3	15,189.22	164,385.00	201.30	70.73	87.84
2009 Q4	15,356.06	167,894.90	200.33	70.90	89.33
2010 Q1	15,415.15	167,219.40	200.07	70.63	90.57
2010 Q2	15,557.28	171,638.50	200.47	70.53	92.94
2010 Q3	15,671.97	174,627.70	200.43	70.67	94.06
2010 Q4	15,750.63	174,693.30	201.20	70.87	94.84
2011 Q1	15,712.75	172,092.40	201.03	70.80	94.70
2011 Q2	15,825.10	173,176.70	201.17	70.60	94.88
2011 Q3	15,820.70	173,758.00	200.97	71.30	95.80
2011 Q4	16,004.11	177,517.10	201.80	71.20	97.65
2012 Q1	16,129.42	176,814.90	202.40	71.17	98.76
2012 Q2	16,198.81	177,328.10	203.13	71.33	99.83
2012 Q3	16,220.67	176,364.50	202.87	71.63	100.28
2012 Q4	16,239.14	174,701.80	202.93	71.90	101.13
2013 Q1	16,382.96	180,559.90	202.53	72.47	101.69
2013 Q2	16,403.18	178,872.80	202.50	72.47	102.13
2013 Q3	16,531.69	179,355.20	203.60	72.57	102.02
2013 Q4	16,663.65	178,771.90	204.67	72.47	103.18
2014 Q1	16,616.54	178,473.10	203.70	72.70	104.11
2014 Q2	16,841.48	180,514.00	204.80	72.67	105.93
2014 Q3	17,047.10	180,717.50	205.57	72.60	106.77
2014 Q4	17,143.04	180,252.50	207.07	72.70	107.44
2015 Q1	17,277.58	179,806.40	208.63	72.37	106.89
2015 Q2	17,405.67	181,902.80	209.60	72.50	105.47
2015 Q3	17,463.22	181,690.00	210.53	72.90	105.89
2015 Q4	17,468.90	181,893.40	211.13	73.37	105.40
2016 Q1	17,556.84	180,182.40	213.13	73.37	105.42
2016 Q2	17,639.42	182,305.90	213.83	73.43	105.68
2016 Q3	17,735.07	183,946.60	215.30	73.27	106.74
2016 Q4	17,824.23	184,039.50	215.53	73.17	107.14
2017 Q1	17,925.26	183,808.30	214.73	73.43	107.83
2017 Q2	18,021.05	183,804.10	214.13	74.27	109.09
2017 Q3	18,163.56	184,522.20	214.23	74.13	108.17
2017 Q4	18,322.46	186,029.00	214.53	74.37	109.75
2018 Q1	18,438.25	185,815.50	214.33	74.77	109.75
2018 Q2	18,598.14	187,036.00	214.67	74.67	110.53
2018 Q3	18,732.72	187,660.80	213.87	74.93	111.40
2018 Q4	18,783.55	188,349.90	212.33	75.50	112.56
2019 Q1	18,927.28	188,393.50	211.97	75.70	111.88
2019 Q2	19,021.86	188,863.30	210.13	75.83	110.76
2019 Q3	19,121.11	189,569.40	209.53	75.97	110.99
2019 Q4	19,221.97	190,636.10	207.13	75.03	109.97
2020 Q1	18,987.88	188,417.01	207.60	75.23	108.42
2020 Q2	16,947.04	167,399.34	162.30	61.78	85.72
2020 Q3	17,199.64	169,601.84	162.05	50.95	88.91
2020 Q4	17,589.34	173,690.69	161.97	52.71	90.83
2021 Q1	18,101.72	178,666.56	172.50	54.22	93.95
2021 Q2	18,512.76	182,596.00	182.79	54.66	96.45
2021 Q3	18,774.81	184,996.89	188.73	55.48	98.09
2021 Q4	18,955.04	186,473.78	193.00	56.94	99.16
2022 Q1	19,130.44	187,865.16	196.41	58.39	100.15
2022 Q2	19,336.91	189,530.32	196.47	59.37	101.33
2022 Q3	19,555.37	191,362.76	194.49	61.79	103.06
2022 Q4	19,757.06	193,127.99	189.47	63.34	104.61
2023 Q1	19,946.17	194,734.18	183.05	64.41	106.08
2023 Q3	20,121.76	196,155.51	184.88	65.06	107.22
2023 Q4	20,292.97	197,619.68	186.35	65.66	108.29
2023 Q1	20,469.42	199,028.47	187.02	66.13	109.45
2024 Q2	20,638.73	200,436.42	186.96	66.69	110.57
2024 Q3	20,802.51	201,640.09	186.31	67.22	111.70
2024 Q4	20,959.49	202,931.20	187.93	67.58	112.75
2024 Q1	21,113.62	204,051.81	189.45	67.88	113.74
2025 Q3	21,263.14	205,306.64	190.21	68.27	114.68
2025 Q4	21,406.32	206,422.26	191.07	68.53	115.58

	KY Industrial Production Index, Fabricated Metal Products (2012=100)	KY Real Personal Income Millions of 2012 US$, SAAR	KY Population Thousand	KY Households, Total Thousand	KY Household Average Size Persons
2007 Q1	112.84	165,579.27	4,247.31	1,660.22	2.56
2007 Q2	114.31	166,234.20	4,256.67	1,661.38	2.56
2007 Q3	116.86	165,872.39	4,264.97	1,669.17	2.56
2007 Q4	117.22	166,135.21	4,273.28	1,677.01	2.55
2008 Q1	118.10	167,120.96	4,281.58	1,684.88	2.54
2008 Q2	115.11	172,318.50	4,289.88	1,692.78	2.53
2008 Q3	109.36	166,095.69	4,296.68	1,694.96	2.53
2008 Q4	102.15	167,636.79	4,303.48	1,697.15	2.54
2009 Q1	88.20	165,875.61	4,310.28	1,699.33	2.54
2009 Q2	80.59	167,770.35	4,317.07	1,701.52	2.54
2009 Q3	80.42	166,511.66	4,324.49	1,707.50	2.53
2009 Q4	81.75	167,255.44	4,331.91	1,713.64	2.53
2010 Q1	83.56	167,246.06	4,339.33	1,719.97	2.52
2010 Q2	87.25	170,102.43	4,348.18	1,722.13	2.52
2010 Q3	91.04	171,992.18	4,353.59	1,719.08	2.53
2010 Q4	93.07	171,980.29	4,359.00	1,716.02	2.54
2011 Q1	93.89	173,609.10	4,364.41	1,712.97	2.55
2011 Q2	95.70	173,482.70	4,369.82	1,709.92	2.56
2011 Q3	96.89	174,752.95	4,373.95	1,718.64	2.55
2011 Q4	97.77	176,168.77	4,378.08	1,727.36	2.53
2012 Q1	98.30	176,445.42	4,382.21	1,736.07	2.52
2012 Q2	99.92	177,479.96	4,386.35	1,744.79	2.51
2012 Q3	100.88	175,756.22	4,390.92	1,744.44	2.52
2012 Q4	100.89	177,539.78	4,395.50	1,744.09	2.52
2013 Q1	102.86	175,076.45	4,400.08	1,743.74	2.52
2013 Q2	101.57	175,038.13	4,404.66	1,743.39	2.53
2013 Q3	101.46	175,252.76	4,407.08	1,745.01	2.53
2013 Q4	104.55	175,488.04	4,409.50	1,746.63	2.52
2014 Q1	105.91	179,713.12	4,411.93	1,748.24	2.52
2014 Q2	106.86	182,465.99	4,414.35	1,749.86	2.52
2014 Q3	106.92	183,995.49	4,417.26	1,750.88	2.52
2014 Q4	106.30	186,326.46	4,420.16	1,751.90	2.52
2015 Q1	105.08	187,789.52	4,423.07	1,752.92	2.52
2015 Q2	105.29	189,149.31	4,425.98	1,753.94	2.52
2015 Q3	106.13	190,001.96	4,429.03	1,754.32	2.52
2015 Q4	104.53	191,931.90	4,432.08	1,754.70	2.53
2016 Q1	104.39	191,285.30	4,435.13	1,755.09	2.53
2016 Q2	104.24	192,070.84	4,438.18	1,755.47	2.53
2016 Q3	104.35	194,022.33	4,441.70	1,757.31	2.53
2016 Q4	104.87	194,187.90	4,445.23	1,759.14	2.53
2017 Q1	106.32	195,612.88	4,448.75	1,760.97	2.53
2017 Q2	106.26	196,226.61	4,452.27	1,762.80	2.53
2017 Q3	106.29	196,932.07	4,454.49	1,764.72	2.52
2017 Q4	108.19	198,295.46	4,456.71	1,766.64	2.52
2018 Q1	109.61	198,982.39	4,458.93	1,768.56	2.52
2018 Q2	111.38	199,955.97	4,461.15	1,770.48	2.52
2018 Q3	113.49	200,154.82	4,462.78	1,771.64	2.52
2018 Q4	115.92	201,090.73	4,464.41	1,772.82	2.52
2019 Q1	116.92	203,446.78	4,466.04	1,774.03	2.52
2019 Q2	115.55	203,670.79	4,467.67	1,775.27	2.52
2019 Q3	114.65	204,615.06	4,469.44	1,776.70	2.52
2019 Q4	115.09	205,975.97	4,471.35	1,778.42	2.51
2020 Q1	112.41	206,118.50	4,473.32	1,780.68	2.51
2020 Q2	97.56	206,612.29	4,475.18	1,781.44	2.51
2020 Q3	92.80	210,484.39	4,477.21	1,781.22	2.51
2020 Q4	91.75	205,009.87	4,479.44	1,781.79	2.51
2021 Q1	93.89	203,508.66	4,481.89	1,782.54	2.51
2021 Q2	97.27	205,738.60	4,484.56	1,783.89	2.51
2021 Q3	100.08	207,301.97	4,487.46	1,787.26	2.51
2021 Q4	102.03	208,250.46	4,490.60	1,791.61	2.51
2022 Q1	103.12	209,041.98	4,494.03	1,795.56	2.50
2022 Q2	103.78	209,724.67	4,497.75	1,799.65	2.50
2022 Q3	104.31	211,034.41	4,501.77	1,803.43	2.50
2022 Q4	104.79	212,433.37	4,506.12	1,807.02	2.49
2023 Q1	105.28	214,359.94	4,510.69	1,810.67	2.49
2023 Q3	105.74	216,064.57	4,515.34	1,814.23	2.49
2023 Q4	106.18	217,679.02	4,519.94	1,817.51	2.49
2023 Q1	106.72	219,274.83	4,524.66	1,820.96	2.48
2024 Q2	107.14	220,756.24	4,529.35	1,824.30	2.48
2024 Q3	107.51	222,146.90	4,534.02	1,827.36	2.48
2024 Q4	107.83	223,515.80	4,538.67	1,830.32	2.48
2024 Q1	108.08	224,876.76	4,543.28	1,833.18	2.48
2025 Q3	108.34	226,364.92	4,547.88	1,836.31	2.48
2025 Q4	108.60	227,642.55	4,552.45	1,839.59	2.47

Generation Differences by Unit, Base Period vs. Forecasted Test Period, KU[1]

GWh	**Base Period**	**Forecasted Test Period**	**Difference**	**% Difference**
Coal				
Brown 3	938	754	(183)	-20%
Ghent 1	2,915	2,595	(320)	-11%
Ghent 2	2,713	2,702	(11)	0%
Ghent 3	2,467	2,502	34	1%
Ghent 4	1,997	2,311	315	16%
Mill Creek 1	N/A	N/A		
Mill Creek 2	N/A	N/A		
Mill Creek 3	N/A	N/A		
Mill Creek 4	N/A	N/A		
OVEC	185	163	(21)	-12%
Trimble County 1	N/A	N/A		
Trimble County 2	2,970	2,357	(613)	-21%
SCCT				
Brown 5	17	46	29	167%
Brown 6	35	70	35	100%
Brown 7	26	39	13	48%
Brown 8	5	8	3	68%
Brown 9	11	18	7	59%
Brown 10	18	17	(2)	-8%
Brown 11	5	6	0	9%
Haefling	0	0	0	0%
Paddy's Run 11	N/A	N/A		
Paddy's Run 12	N/A	N/A		
Paddy's Run 13	18	34	17	93%
Trimble County 05	135	307	172	128%
Trimble County 06	98	238	140	144%
Trimble County 07	94	124	30	32%
Trimble County 08	38	25	(14)	-36%
Trimble County 09	101	108	7	7%
Trimble County 10	7	14	7	94%
Zorn 1	N/A	N/A		
NGCC				
Cane Run 7	3,825	3,848	23	1%
Hydro				
Dix Dam	109	89	(20)	-18%
Ohio Falls	N/A	N/A		
Solar				
Brown Solar	10	11	0	3%
Total Coal	14,185	13,385	(800)	-6%
Total SCCT	608	1,052	444	73%
Total NGCC	3,825	3,848	23	1%
Total Hydro	109	89	(20)	-18%
Total Solar	10	11	0	3%
Grand Total	18,737	18,386	(352)	-2%

[1] Generation volumes reflect KU's ownership share of the unit. "N/A" is shown for units with no KU ownership share.

Generation Differences by Unit, Base Period vs. Forecasted Test Period, LG&E[2]

GWh	Base Period	Forecasted Test Period	Difference	% Difference
Coal				
Brown 3	N/A	N/A		
Ghent 1	N/A	N/A		
Ghent 2	N/A	N/A		
Ghent 3	N/A	N/A		
Ghent 4	N/A	N/A		
Mill Creek 1	1,741	2,012	271	16%
Mill Creek 2	820	804	(17)	-2%
Mill Creek 3	1,785	2,297	512	29%
Mill Creek 4	2,442	3,156	714	29%
OVEC	422	386	(36)	-9%
Trimble County 1	2,578	2,400	(178)	-7%
Trimble County 2	697	553	(144)	-21%
SCCT				
Brown 5	19	52	32	167%
Brown 6	21	43	21	100%
Brown 7	16	24	8	48%
Brown 8	N/A	N/A		
Brown 9	N/A	N/A		
Brown 10	N/A	N/A		
Brown 11	N/A	N/A		
Haefling	N/A	N/A		
Paddy's Run 11	0	0	0	0%
Paddy's Run 12	0	0	0	0%
Paddy's Run 13	20	39	19	93%
Trimble County 05	55	125	70	128%
Trimble County 06	40	97	57	144%
Trimble County 07	55	73	18	32%
Trimble County 08	23	15	(8)	-36%
Trimble County 09	59	63	4	7%
Trimble County 10	4	8	4	94%
Zorn 1	0	0	0	0%
NGCC				
Cane Run 7	1,079	1,085	7	1%
Hydro				
Dix Dam	N/A	N/A		
Ohio Falls	264	300	37	14%
Solar				
Brown Solar	7	7	0	3%
Total Coal	10,484	11,607	1,123	11%
Total SCCT	313	539	226	72%
Total NGCC	1,079	1,085	7	1%
Total Hydro	264	300	37	14%
Total Solar	7	7	0	3%
Grand Total	12,146	13,538	1,392	11%

[2] Generation volumes reflect LG&E's ownership share of the unit. "N/A" is shown for units with no LG&E ownership share.

Generation Differences by Unit, Base Period vs. Forecasted Test Period, Combined Company[3]

GWh	Base Period	Forecasted Test Period	Difference	% Difference
Coal				
Brown 3	938	754	(183)	-20%
Ghent 1	2,915	2,595	(320)	-11%
Ghent 2	2,713	2,702	(11)	0%
Ghent 3	2,467	2,502	34	1%
Ghent 4	1,997	2,311	315	16%
Mill Creek 1	1,741	2,012	271	16%
Mill Creek 2	820	804	(17)	-2%
Mill Creek 3	1,785	2,297	512	29%
Mill Creek 4	2,442	3,156	714	29%
OVEC	607	549	(58)	-10%
Trimble County 1	2,578	2,400	(178)	-7%
Trimble County 2	3,667	2,910	(757)	-21%
SCCT				
Brown 5	36	97	61	167%
Brown 6	57	113	56	100%
Brown 7	42	63	20	48%
Brown 8	5	8	3	68%
Brown 9	11	18	7	59%
Brown 10	18	17	(2)	-8%
Brown 11	5	6	0	9%
Haefling	0	0	0	0%
Paddy's Run 11	0	0	0	0%
Paddy's Run 12	0	0	0	0%
Paddy's Run 13	38	73	35	93%
Trimble County 05	190	432	242	128%
Trimble County 06	137	335	198	144%
Trimble County 07	149	197	48	32%
Trimble County 08	61	39	(22)	-36%
Trimble County 09	160	171	11	7%
Trimble County 10	11	22	11	94%
Zorn 1	0	0	0	0%
NGCC				
Cane Run 7	4,904	4,933	30	1%
Hydro				
Dix Dam	109	89	(20)	-18%
Ohio Falls	264	300	37	14%
Solar				
Brown Solar	17	18	1	3%
Total Coal	24,670	24,992	323	1%
Total SCCT	921	1,591	670	73%
Total NGCC	4,904	4,933	30	1%
Total Hydro	373	390	17	5%
Total Solar	17	18	1	3%
Grand Total	30,884	31,924	1,040	3%

[3] Generation volumes reflect the Companies' ownership share of the unit.

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, 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**

In the Matter of:

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. 2020-0000350**

TESTIMONY OF
JOHN K. WOLFE
VICE PRESIDENT, ELECTRIC DISTRIBUTION
KENTUCKY UTILITIES COMPANY AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Filed: November 25, 2020

TABLE OF CONTENTS

I. BACKGROUND

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

A. My name is John K. Wolfe. I am Vice President of Electric Distribution 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, which provides services to the Companies. My business address is 220 West Main Street, Louisville, Kentucky 40202.

Q. Please describe your educational and professional background.

A. I was hired by LG&E and KU Services Company in 1991 as a gas operations engineer. Since that time, I have held various technical and management responsibilities with the Companies in both gas and electric distribution operations, as well as other areas of the Companies. I have held my current position as Vice President – Electric Distribution since 2016. A complete statement of my work experience and education is contained in Appendix A.

Q. Have you previously testified before the Kentucky Public Service Commission ("Commission")?

A. Yes. I have testified in numerous proceedings before the Commission. Most recently, I provided rebuttal testimony in KU's and LG&E's 2018 base rate cases.[1]

Q. What is the purpose of your testimony?

A. I will describe the performance of the Companies' electric distribution operations, including the ways in which operational success is measured for the safety, reliability,

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[1] *Electronic Application of Kentucky Utilities Company for an Adjustment of Its Electric Rates*, Case No. 2018-00294, Rebuttal Testimony of John K. Wolfe (Ky. PSC Feb. 21, 2019); *Electronic Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Rates,* Case No. 2018-00295, Rebuttal Testimony of John K. Wolfe (Ky. PSC Feb. 21, 2019).

customer satisfaction, and cost containment for distribution operations. I will describe the Companies' portfolio of programs for distribution reliability and resiliency and outline the strategy for centralized grid operations and advancements toward the grid of the future. I will also provide a summary of distribution operations' capital planning process and outline key capital investments being made in electric distribution systems. I will discuss areas where the Companies are seeing steadily rising operational costs and while simultaneously pursuing operational efficiency programs to contain those costs. And finally, I will support the Companies' plan for full deployment of Advanced Metering Infrastructure ("AMI") and describe how AMI adds immense operational value to electric distribution for the benefit of customers.

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring the following exhibits, which are attached to my testimony:

Exhibit JKW-1 Distribution Reliability and Resiliency Plan

Exhibit JKW-2 Operational Benefits of AMI

II. DISTRIBUTION OPERATIONS

Distribution System Overview

Q. Please describe the Companies' electric distribution system.

A. The Companies' electric distribution system is jointly operated, planned, and maintained to achieve efficiencies and maximize resource allocation. The electric distribution system serves a total of approximately 948,000 customers in 79 Kentucky counties. The Companies' electric service area covers approximately 5,200 square miles. Electric distribution facilities in Kentucky include a total of 521 substations (88 of which are shared with transmission), 16,771 miles of overhead electric lines, and

5,211 miles of underground electric lines. The net book value of the Companies' distribution plant in Kentucky is approximately $2.4 billion.

Distribution System Performance

Q. What key indicators do LG&E and KU track to measure the performance of Distribution Operations?

A. The Companies' key performance indicators for Distribution Operations include metrics for safety, system reliability, customer satisfaction, and cost management.

Q. Are Distribution Operations performing safely?

A. Yes. Distribution Operations' principal safety performance metrics include recordable injury incident rate ("RIIR") and days away, restricted, or transferred ("DART") rates based on Occupational Health and Safety Administration definitions. Distribution Operations' average annual RIIR over the period 2015 through 2019 was 1.67. This rate compares very favorably to Bureau of Labor Statistics data which indicates an average rate of 2.30 for electric transmission, control, and distribution workers for the five-year period ending in 2018 (most recent available data). More importantly, Distribution Operations' average annual DART rate between 2015 and 2019 was 0.75. This rate also compared very favorably to BLS data, which indicates an average annual DART rate of 1.22 for the five-year period ending in 2018. The Companies' performance under these metrics reflects the cultural importance of safe work and adherence to safe work practices throughout distribution operations.

Q. How do LG&E and KU measure and monitor performance in distribution system reliability?

A. The Companies track reliability of their distribution facilities using performance metrics such as distribution System Average Interruption Duration Index ("SAIDI") and distribution System Average Interruption Frequency Index ("SAIFI"). Distribution SAIDI measures the average electric service interruption duration in minutes per customer for the specified period and distribution system. SAIFI measures the average electric service interruption frequency per customer for the specified period and distribution system. Both are established and widely used reliability metrics in the industry.

Q. How is the distribution system performing according to these metrics?

A. The reliability of the distribution system continues to improve. For the five-year period ending 2019, the Companies average annual adjusted distribution SAIDI (excluding major event days) was 82.6 minutes. This performance ranked upper second quartile against peer utilities and resulted in a 10% improvement in average annual SAIDI compared to the five-year period ending 2014. Similarly, the average annual adjusted distribution SAIFI for the Companies was 0.850 over the five-year period ending 2019, an 11.6% improvement over the previous five-year period. SAIFI performance represented mid second quartile ranking against peer utility performance. Furthermore, the Companies' combined transmission and distribution adjusted SAIDI and SAIFI ranked in the first quartile compared to industry peers between 2015 and 2019.

2020 adjusted distribution SAIDI and SAIFI are trending toward record low levels (more reliable performance) for the combined Companies. The Companies have achieved record performance for adjusted SAIFI – lowest average outage frequency – in three of the past four years.

Q. How is Distribution Operations performing in Customer Satisfaction?

A. LG&E and KU participate in multiple industry accepted customer satisfaction surveys, the most recognizable of which is administered by J.D. Power, which evaluates several key indices. Power quality and reliability consistently rank as the most important component of customer satisfaction and have the greatest influence on the relative value of other key utility customer satisfaction indices in the J.D. Power customer studies. LG&E and KU residential customer satisfaction ratings for power quality and reliability ranked upper third and first quartile respectively in the 2019 study. The ratings achieved by LG&E and KU improved by 6.2% and 5.8% respectively between the 2016 and 2019 J.D. Power Electric Residential Satisfaction studies, despite the Companies' experiencing four extreme outage events during 2018 and a very active weather season during 2019.

Q. What key cost metrics do LG&E and KU monitor to indicate cost performance for Distribution Operations?

A. The Companies monitor and measure cost performance for Distribution Operations by total cash costs per megawatt hour served against publicly available FERC (Federal Energy Regulatory Commission) Form 1 annual reports for major public utilities. These reports are filed annually by major utilities subject to the jurisdiction of the FERC and contain standard financial and operations information.

Q. How do Distribution Operations' costs compare to the industry?

A. For the five-year period ending 2019, the Companies total combined cash costs per megawatt hour served for Distribution Operations ranked in the first quartile for cost containment against all other major investor owned utilities in the United States.

Operations and Maintenance expenses ranked twenty-first (second quartile), and capital investments ranked tenth (first quartile), out of fifty-four benchmarked utilities.

Distribution Reliability and Resiliency

Q. How do LG&E and KU monitor and react to trends in distribution system reliability and resiliency?

A. The Companies benchmark peer utilities to identify and implement proven industry standards and best practices for planning, designing, constructing, operating, and maintaining the electric distribution system. The Companies also routinely monitor and assesses system outage data against peer utilities and historical results, and leverage customer satisfaction survey results, to help drive short- and long-term investment strategies and system maintenance practices. Further, the Companies regularly assess and reengineer business processes that support outage management, emergency preparedness and response, and mutual assistance, to assure efficient restoration of outages when they occur. Finally, the Companies closely monitor evolving technologies to develop key asset management strategies which assure sustained deliverability of safe and reliable service to customers. Information on key investment and maintenance programs and historical reliability performance is presented in the Companies' 2020 Distribution Reliability and Resiliency Plan (DRRP), attached as Exhibit JKW-1 to my testimony.

Q. Please describe the status of the Companies' Distribution Automation Program which was authorized by the Commission as part of the Companies' 2016 base rate case proceedings.

A. The three primary components of the Distribution Automation ("DA") program include: (1) installation of supervisory control and data acquisition ("SCADA") capable electronic reclosers[2]; (2) implementation of distributed SCADA ("DSCADA") software to monitor and communicate with those reclosers; and (3) deployment of a Distribution Management System ("DMS") that interfaces with the DSCADA system to provide intelligent control over the electronic reclosers.

Since receiving approval for the Distribution Automation project from the Commission in July 2017, the Companies have installed more than 1,300 SCADA capable electronic reclosers on its electric distribution grid as of September 2020. The reclosers have been strategically placed to reduce customer exposure to fault conditions on the system through greater division of customer counts between protective devices. This reduces the number of customers who experience momentary or extended service interruptions due to fault conditions.

During January 2019, the Companies deployed distribution SCADA software as part of the Distribution Automation project. Since its deployment and through September 2020, project members connected more than 1,900 reclosers to the new software, enabling centralized monitoring and control through the Companies' Distribution Control Center. Roughly 600 of the reclosers connected to SCADA were installed on the electric distribution system through reliability investment programs outside of the Distribution Automation program.

Full deployment of DMS software functionality is now scheduled to be completed in 2021. This phase of the project will provide for automatic fault locating and isolation, and service restoration, which is the self-healing component of an advanced DMS. Following full deployment of this functionality, the Companies will

[2] A SCADA system for electric distribution consists of hardware and software that work together to collect data from system resources, monitor performance, and automate control functions, including switching.

work to integrate the software with all Distribution Automation capable circuits. This phase of the Distribution Automation project is targeted for completion by the end of 2022.

Q. Has Distribution Automation enhanced the reliability of electric service to the Companies' customers?

A. Yes, Distribution Automation has significantly improved overall reliability and the full benefits of the program are still yet to be realized. As of September 2020, the reclosers installed as part of Distribution Automation have resulted in a total of 31,342,644 avoided outage minutes and 180,013 avoided outage interruptions. These avoided outages have translated to 10.43 minutes of avoided SAIDI from project inception to date, with over 4.2 minutes of avoided SAIDI year to date through September 2020 alone. Likewise, Distribution Automation enhancements have reduced SAIFI by 0.134 from project inception to date, with a SAIFI avoidance of 0.050 for 2020 year to date through September. Once full DMS implementation is complete, even greater reliability benefits are expected through intelligent control of connected reclosers.

Q. Please provide an update on the Distribution Operation's Pole Inspection and Treatment Program.

A. Distribution Operations initiated the Pole Inspection and Treatment Program in 2010 following the 2008 Ike Windstorm and the 2009 Kentucky Ice Storm events, which resulted in the two largest outage events in the combined Companies' history. Through September 2020, the program has achieved inspection of 575,000 of 673,000 poles on which the Companies' equipment is installed, treatment of approximately 182,000 poles to extend their service life, and replacement of more than 23,100 poles. This program continues to contribute significantly to the resiliency and reliability of the electric distribution system with pole related outages dropping by approximately 14% on completed circuits since the inception of the program.

Q. Please provide an update on Distribution Operations' CEMI Program.

A. The Customers Experiencing Multiple Interruptions ("CEMI") program was initiated during 2010. The program provides for targeted investments in system assets serving customers who have experienced repeated service interruptions. Between 2010 and 2019, the Companies reduced the number of customers experiencing more than five interruptions annually by 21%. The Companies' CEMI performance consistently ranks upper first quartile in industry reliability surveys of peer utilities, indicating effective business processes and controls for monitoring and mitigating repetitive customer outages.

Q. Please provide an update on Distribution Operation's Substation Transformer Contingency Program.

A. Distribution Operations' substation transformer contingency program was initiated during 2014 and was originally planned to be a 15-year program. The program was established to address substation transformers on the LG&E and KU distribution system which cannot be adequately backed up in the event of an outage or failure involving the transformer. Since inception of the program, contingency has been added for 108 transformers, representing a 22% improvement in substation transformer-related long-term outage exposure to the electric distribution system. The Companies plan to continue investing in the substation contingency program through 2029.

Q. Please briefly describe Distribution Operations' vegetation management program.

A. Distribution Operations categorizes vegetation management into two distinct programs: routine line clearing and hazard tree mitigation. These programs account for roughly a third of Distribution Operations' operations and maintenance expenses annually.

The Companies' routine clearing program provides for scheduled trimming or treatment of vegetation on distribution circuits on a 5-year average cycle frequency and in accordance with the American National Standards Institute ("ANSI") A300 standards. Some parts of the distribution system also receive mid-cycle/out-of-cycle maintenance as dictated by higher tree related interruptions due to vegetation growth patterns, system construction standards, and tree density.

The Companies' hazard tree program addresses trees which are predisposed to failure due to disease, structure, death or declining condition, lean or soil conditions, and which could contact a conductor if the tree or a limb from the tree falls. Hazard trees near the Companies' lines are separately inspected and, where necessary, addressed by trimming limbs or complete tree removal if they pose a threat to the safe operation of distribution lines. For trees that are outside of the utility easement, customer authorization is required before mitigation activities are performed.

Q. Please briefly describe the effects of vegetation on distribution system reliability.

A. Over the five-year period ending 2019, known tree related outages have contributed an average of 26% to adjusted (excluding major event days) SAIDI, 46% to total SAIDI, 17% to adjusted SAIFI, and 23% to total SAIFI on an annual basis. The average contribution of tree growth to adjusted SAIDI over the five-year period ending 2019 was only slightly over 2%, indicating effective routine cycle program management and execution. Risks associated with downed trees and limbs are much more difficult to manage and predict due to the causes of tree decay and defects, and the contribution of weather.

Q. How do the Companies plan to approach Vegetation Management in the coming years?

A. The Companies will continue to manage vegetation through its existing routine cycle and hazard tree programs. However, the Companies expect to achieve greater efficiency in addressing vegetation management going forward due to two key developments.

First, the Companies recently built an advanced data analytics model designed to help perform system wide vegetation risk assessments and enable optimization of line clearing timing, scope, resource utilization, and costs. Inputs into the associated analytics model include power infrastructure, weather, environment, satellite imagery, and historic vegetation maintenance practices.

Second, the Companies anticipate reduced unit costs for mitigating hazard trees compared to recent year unit costs due to a recent decline in at-risk ash trees on the electric distribution system. Distribution Operations commenced its hazard tree mitigation efforts during 2010 to improve overall system resiliency to falling trees, strong winds, and severe weather. Starting in 2009 Kentucky's ash trees were subject to widespread invasion by emerald ash borers (a beetle species not native to this region), and by 2014 the rates of decay and death of ash trees had grown exponentially as a result. Unit costs for trimming or removing diseased trees rose significantly because they could not safely be climbed and often required mechanized equipment or cranes to mitigate their threat to the electric distribution system. Most ash trees posing a risk to the distribution system were addressed by the end of 2019, thereby helping to contain unit costs for trimming or removing hazard trees going forward.

<u>Centralized Grid Operations</u>

Q. What are Centralized Grid Operations?

A. Centralized Grid Operations defines Distribution Operations' organizational structure, business processes, technologies, and decisional hierarchy for monitoring, controlling, planning, and operating the electric distribution system. This operational approach is enabled and advanced by the Companies' recent and planned investments in operations, information, and communications technologies, including those technologies being deployed in the Distribution Automation, SCADA expansion, substation relay modernization, and crew technology mobilization capital programs. These technologies equip responsible personnel with more granular and near immediate monitoring and awareness of the electric grid, further enabling critical decision-making regarding system operations during normal, abnormal, or emergency conditions. As part of the centralized operational approach, advanced technologies are also providing for a holistic view of the electric distribution system, field technicians, and work volumes, facilitating more efficient and effective alignment of human resources and equipment with system priorities. Finally, communications between field technicians, office personnel, and customers are being enhanced though accelerated availability and conveyance of essential system information, enabling safer and more reliable electric service to customers.

Q. What other key investment has contributed to Distribution Operations' Centralized Grid Operations strategy?

A. In the 2018 rate cases, Mr. Bellar reported that construction of a new distribution control center located in Simpsonville was underway. Construction of that facility was completed in April 2019. Construction of a modern control center enabled the Companies to centralize their distribution system operations centers from two locations into one and facilitated refinement of existing business processes to assure consistent system operations and safety business processes across the LG&E and KU service areas.

Q. Does the Distribution Control Center assist the Companies with more reliable and efficient operations?

A. Yes. The centralized Distribution Control Center supports the Companies' efforts to implement centralized grid operations by enhancing control uptime through redundant electrical and mechanical systems. The facility is designed around 12-hour shift employees and provides added space for headcount associated with the migration of SCADA functions from the Transmission Control Center to the Distribution Control Center. The control center also improves overall technology and communications infrastructure needed to support the Companies' existing and planned system investments in operations and communications technologies and information systems.

Q. Have the Companies been recognized for the innovations brought on by the Distribution Control Center?

A. Yes, the Companies' Distribution Control Center received a 2020 Industry Excellence Award for Distribution from the Southeastern Electric Exchange. In recognizing the Companies for the benefits achieved by the control center, Southeastern Electric Exchange noted that the facility "has resulted in a number of improvements, such as increased operational efficiencies, adaptability for the changing workforce and grid of the future, enhanced distribution system reliability, technological advancement bringing distribution operations to the cutting edge of available technology, and increased safety for customers . . . ."[3]

Q. How do Centralized Grid Operations strategy better prepare the Companies for future grid and customer challenges?

A. Distributed Energy Resources, expanded electrification of transportation, and grid-interactive customer assets all pose new challenges to operation and performance of the electric grid. Distributed Energy Resources include small and decentralized customer-owned electric generation resources or other "behind the meter" technology which is connected to the grid at the distribution level. These systems rely on two-way power flow, insofar as customers with Distributed Energy Resources both provide to and take power from the electric distribution system. These added system challenges will expand the need for visibility and control to support advanced system planning and ensure high levels of reliability and power quality for customers.

[3]Southeastern Electric Exchange, Industry Excellence Awards, https://theexchange.org/IEAwardVideos/IEAwards_DistributionWinner_LGEKU.mp4 (last visited Sept. 28, 2020).

The Companies' Centralized Grid Operations strategy includes investments in additional connected field devices, through Distribution Automation and substation SCADA expansion, and enhancements to the Companies' SCADA technology platform that allow visibility into grid operations. These investments ensure that the Distribution Control Center can monitor and manage system disturbances quickly. Enhanced field devices will make certain that our protection and control information management systems are resilient and designed to quickly manage outages and minimize system impacts now and into the future, when more dynamic operating conditions and challenges will exist. These connected devices also increase data availability across all levels of the grid, enhancing our overall system planning processes to account for two-way power flow.

Capital Investment Planning

Q. Please describe the process by which the Companies plan capital investments for Distribution Operations.

A. Since 2011, Distribution Operations has been using an Asset Investment Strategy ("AIS") decision-support model and supporting business processes to help evaluate and prioritize distribution investment programs. The model and processes enable Distribution Operations to evaluate and prioritize proposed investments based on 1) a set of custom benefit criteria defined by subject matter experts; and 2) estimated costs of proposed projects. The AIS prioritization algorithm sorts proposed investments based on a benefit/cost ratio, which in turn allows the Companies to determine the best allocation of capital spending. Distribution Operations management team then applies other criteria, such as resource availability and seasonality of work, to determine the ultimate set of investment projects to include in Distribution Operations Business Plan.

Q. What key capital investments will the Companies make in their distribution system?

A. Key capital investments for the period November 1, 2019 to December 31, 2021 include $40.4 million in Distribution Automation, $27.0 million in substation transformer contingency, $26.9 million in the pole inspection and treatment program, $23.2 million in Paper Insulated Lead Covered cable replacement, $13.7 million in Substation SCADA Expansion, and $10.8 million in Electro-mechanical Relay Replacements. These investments are targeted to achieve one or more of the goals and strategy discussed above – namely – grid modernization, centralized system operations, and system reliability and resiliency.

Q. Please summarize the total capital investment the Companies plan to make in their distribution operation business.

A. The following chart summarizes distribution capital expenditures by company from November 1, 2019 to December 31, 2021 (in millions):

	KU	**LG&E**	**Total**
Connect New Customers	$99	$67	$166
Enhance the Network	$110	$77	$187
Maintain the Network	$90	$119	$209
Repair the Network	$17	$22	$39
Miscellaneous	$2	$2	$4
Total	$318	$287	$605

<u>Increase in Operational Costs</u>

Q. Are the Companies facing rising operational costs to maintain the electric distribution system?

A. Yes. Electric Distribution Operations forecasts an increase of $7.0 million in operation and maintenance costs for the forward-looking test period, as compared to the forward-looking test period in the Companies' previous base rate cases. The primary contributors to this increase are $2.6 million increase in line clearance contract labor, $2.1 million increase in operation technology security, $0.5 million increase in trouble order costs, and $1.0 million increase in the 5-year average storm costs.

Q. Why are line clearance contract labor costs increasing?

A. Recent contract negotiations with the Companies' line clearance service providers resulted in higher base wage rates due to tighter labor markets locally and across the country. Demands for vegetation management resources have increased as electric utilities across the industry continue to place increased emphasis on their line clearance programs to improve system reliability performance and as California and other wildfire prone states look to establish and maintain greater line clearance from vegetation to reduce associated fire risks. Also, as competition for line clearance workers and general laborers has grown, worker turnover has increased for all vegetation management contractors. Resulting higher turnover rates have produced higher overhead costs associated with training, recruiting, and retaining line clearance workers. Many of these added costs for impacted contractors were negotiated into their contracts during 2019.

Q. Why are costs associated with tree trouble activity increasing?

A. 2018 and 2019 weather was significantly above normal for precipitation. For example, 2018 was the wettest year on record for Louisville with 68.83" of precipitation versus an average of 44.91" and Lexington with 72" versus an average of 45.2". This amount of rainfall accelerates vegetation growth as well as saturates the ground creating more issues with tree falls inside and outside the right-of-way. Additionally, the Companies' systems experienced two Level IV and Level III severe weather events in 2018 creating ongoing issues with tree related outages. 2019 rainfall amounts were lower, but still above the average with 53.3" of rain for Louisville and 56.1" for Lexington. The combination of these wet conditions with higher than normal wind gusts and wind events in 2018 and 2019 led to an increase in tree fall and tree limb outages of more than 45% and 40% respectively when compared to the previous five-year average ending 2017. Tree related SAIDI performance and outages for those two years were the highest since 2012. This increased outage activity due to weather and tree related events increases costs associated with identifying and responding to outages to restore power to customers.

Q. Why are costs associated with threats to physical and cybersecurity increasing?

A. In recent years there has been an increase in cyber security incidents across all industries. The number of Electric Sector Threat Reports that have been reviewed by LG&E and KU in 2020 have more than doubled compared to the same time last year. Attackers are becoming more sophisticated in their targets, intent and impacts. Within electric distribution networks, attackers could potentially operate field equipment or cause loss of visibility by distribution system operators resulting in customer impact. Increased reliance on technology and the transition to more centralized grid operations presents new cybersecurity threats that must be managed.

As a result of these increased threats, and as described in Mr. Bellar's testimony, the Companies have undertaken a comprehensive review of the security of their Operational Technology (OT) systems and measures required to minimize threats. Security enhancements include continuous monitoring of connected devices to detect abnormal activity, installation of security gateways that control data transfer to and from field devices and enhanced business continuity planning. For the electric distribution business, these security measures will result in an additional $1.5 million in O&M costs from the last rate case forecast test period to the current forecast test period.

Operational Efficiencies

Q. What key initiatives are the Companies pursuing to reduce costs and increase the efficiency of distribution operations?

A. I have already described three projects in my testimony that enable more efficient operations, enhance customer experience, and reduce costs: distribution automation, data analytics for vegetation management, and consolidation of distribution control operations in the Distribution Control Center. Several other key Distribution Operations initiatives will contribute to improved operational efficiency: enhanced data analytics modeling for investment planning, use of fault circuit indicators on distribution circuits, and advancement of SCADA and relay upgrades in distribution substations.

As part of its 2020 Capital Planning process, Distribution Operations started using the advanced data analytics modeling used for line clearing processes to enable more effective assessment and prioritization of proposed reliability investment projects on distribution circuits. By leveraging historical data on outages, number of customers interrupted, and outage duration by circuit, the Companies plan to quickly assess outage risks and customer outage exposure on particular circuits using a simple risk score, which will then be used to help identify, prioritize and analyze alternatives for reliability investments.

The Companies initiated a program in 2019 to deploy underground faulted circuit indicators (UG FCIs) on approximately 40,000 distribution padmount transformers between 2019 and 2021. UG FCIs provide restoration crews with a visual indication (blinking LED) on the exterior of padmount transformers allowing crews to quickly identify the location of underground faults and immediately begin switching to restore customers. UG FCIs do not prevent outages, rather, they reduce the time required to restore underground outages. It is estimated that the average underground outage will be reduced by more than fifty minutes where UG FCIs are installed.

Distribution Operations' Electromechanical Relay Replacement and KU SCADA Expansion programs both offer greater operational efficiencies with the installation of modern microprocessor-based relays in distribution substations. Microprocessor-based relays emulate the system detection and operational functionality of electromechanical relays, but also offer advanced features such as fault locating, event logging and alarming, control capability, and advanced metering functionality. These advanced features provide opportunity to improve system reliability, enhance worker and public safety, and contribute to greater operational efficiencies. They also enable connectivity with the DMS and DSCADA applications deployed as part of the Distribution Automation program, providing greater centralized operability, monitoring, and control of the distribution grid.

III. ADVANCED METERING

Q. Are the Companies requesting the Commission's approval of their proposed investment in Advanced Metering Infrastructure ("AMI")?

A. Yes. Several of the Companies' witnesses in these cases describe various aspects and benefits of the Companies' proposal to move forward with full deployment of AMI. I will explain the significant benefits AMI creates for the Companies' electric distribution operations.

Q. How can AMI meters enhance distribution operational capabilities?

A. AMI meters can do much more than just provide usage and billing data. They act as a coordinated group of sensors throughout the service area. In that capacity, they can be used to provide various types of information the Companies can use to prevent and handle outages, validate restoration, manage voltage, and determine asset loading.

Q. Will AMI work in conjunction with the Companies' ongoing distribution automation program?

A. Yes. In fact, AMI will complement the distribution automation program in significant ways. As described above, at its core, Distribution Automation currently consists of approximately 1,900 SCADA system-connected reclosers on distribution circuits, but more system-connected reclosers will be added as part of Distribution Automation and other reliability programs. The Distribution Automation Management System allows for the intelligent management and operation of reclosers, capacitor banks, load tap changes, and voltage regulators. Using AMI meters as sensors, we can enhance our management of those devices to achieve greater overall distribution benefits to better serve customers.

Q. Will AMI enable the Companies to implement Conservation Voltage Reduction ("CVR")?

A. Yes. CVR can be achieved with AMI by enabling regulation of voltages at a very granular level. AMI allows us to know a very specific voltage profile of a circuit down to individual customers. The Companies are required to deliver voltage within a specific range for the safe and reliable operation of customers' electric consuming devices. AMI allows us to manage the voltage delivered at the low end of that range while still providing safe and reliable service.

Q. Will AMI help the Companies manage outages?

A. Yes. Important aspects of managing outages are identifying the outage area, isolating it, and then restoring service. First, AMI enables the Companies to know of an outage down to the individual customer as soon as it occurs without the customer having to take any action. Without AMI outage reporting, the Companies are dependent on information coming from SCADA monitored equipment and customer notifications. An AMI system reports outages quickly and greatly reduces the time to accurately determine the outage location. When notifications from the customers become unnecessary, the Companies can change the way outage information is processed and provide information to the customer in a manner that is not possible without AMI. With earlier detection and outage location, we can achieve a faster and more effective restoration effort. Faster, more targeted restoration activity translates into decreased crew time, overtime savings, reduced fleet costs, and lower contractor expenditures.

Q. Will AMI assist the Companies in diagnosing momentary and sustained customer outages?

A. Yes. For distribution operations, there is a major difference between a momentary outage and sustained outage. Momentary outages occur when the system's protection schemes work as designed and either clear temporary faults or isolate permanent faults to the smallest number of customers. A sustained outage is an event that requires the utility to perform a manual task to restore service. When we cannot distinguish between a momentary and a sustained outage, our ability to manage it is hindered and can result in false outage events which must be investigated and cleared by system operators.

AMI meters can determine if an outage is momentary or sustained in the meter itself. These meters are designed to allow them to continue to analyze loss of voltage events during service interruptions. Loss of voltage events that exceed a specified period of time are considered sustained and knowing that will allow us to handle it accordingly. It is also useful to know about the existence of momentary outages because it helps us to prevent larger problems from occurring. We can use momentary outage information to investigate and evaluate why it occurred and learn whether there are problems with the distribution system such as intermittent contact from vegetation. Other issues such as loose or damaged connections can cause momentary outages that can be corrected prior to a sustained outage occurring.

Q. Will AMI help the Companies manage nested and tail outages?

A. Yes. A nested outage is a small outage associated, or contained, within a much larger outage. An example is a blown fuse on a circuit that is de-energized for a different event. When the circuit is restored, the customers behind the fuse will remain out. AMI will help us to quickly know whether nested outages still exist after a circuit is restored. Tail outages occur at the end of major outage event. They are the last outages to be investigated, restored, or confirmed to already be energized due to the Companies' restoration priorities for major outages. Critical customers and the largest numbers of customers are assigned highest priority. AMI expedites knowing which of these last outages remain and which have been previously restored, thus increasing the efficiency and speed of concluding storm restorations, which can result in reduced call backs and truck rolls after a major event.

Q. Will AMI help the Companies reduce "OK on arrival" events?

A. Yes. AMI technology will reduce the number of instances in which a crew is dispatched to a reported outage but arrives on-site to find utility-responsible services operating properly. AMI can alert dispatchers that an experienced outage has elapsed or that outages are "behind the meter" and would better be resolved by a customer's electrician. Frequently, a customer will contact the Companies and request assistance with a problem they are having, so the Companies will send a technician to investigate only to learn that the problem is on the customer's side of the meter, in the customer's premise, or even resolved by the time the technician arrives. This results in the technician deeming it to be "OK-on-arrival." The Companies expect to eliminate 4,500 per year "OK-on-Arrival" instances, reducing fleet and crew time, which represents a significant savings.

Procedures for single customer outages reported only through the AMI system can save unnecessary expense. If a customer calls in to report an outage but the customer's account does not match an existing outage, the system informs the customer that the utility's analytics do not indicate that the customer is experiencing an outage and requests them to check their main breaker. Many customer calls are associated with internal breaker issues and can be easily addressed by checking the breaker. If that does not solve the problem, the system can give the customer the opportunity to have their meter interrogated or "pinged." The associated meter is then "pinged" for health and voltage. If the ping is successful, the customer would again get the message directing them to check their breaker. If the ping was unsuccessful, the customer would hear a message confirming their outage and the system creates an outage ticket and a follow up work order is created. If the customer decides to forgo the automated process and talk directly to a CSR, the CSRs also knows what the AMI system is reporting for that customer's meter.

Q. Will AMI help the Companies' manage in-service distribution assets such as transformers and hydraulic reclosers?

A. Yes. Some distribution transformer failures may be predicted prior to failure using AMI data for transformer load management. This earlier identification allows the Companies to move from time-based maintenance to condition-based preemptive repair or replacement of the failing transformer before it fully fails, thereby reducing the outage duration and avoiding any additional cost of an "emergency" replacement. This capability is especially important as more load is placed on the system by electrical vehicle charging which can stress transformer capacity especially during extreme heat or cold periods.

AMI data can also be used to diagnose momentary outages, described earlier, related to overloaded hydraulic reclosers which are not SCADA-connected. Following weather events that cause an increase in demand, momentary outages can be plotted on a map to identify hydraulic reclosers that are operating due to load. Pockets of momentary outages that appear on the map behind hydraulic reclosers indicate a recloser that was probably operating due to load. Although we have been installing intelligent reclosers since 2016 to identify these kinds of issues, there are more than 900 circuits that do not have an intelligent recloser and will benefit from the information AMI will provide. Without AMI, these operations may go unnoticed until the recloser fails altogether.

Q. Please explain how AMI provides for better management of voltage on the distribution system.

A. Certainly. AMI can provide data for voltage management. If the average voltage of a meter is outside of the normal band, but not low enough to be considered an outage, the meter can send the voltage reading to the system operator for analysis and response. These voltage excursions will help us identify where there may be issues in the system and can also be used to enable more advanced voltage management solutions on the distribution system.

Q. Can the data from AMI help the Companies manage shorts in transformer windings and regulators not operating properly?

A. Yes. Utilities have experienced good success at identifying failed or failing equipment based upon information from AMI meters. Average voltage information can be used to identify transformers with windings shorted and can also identify regulators and switched capacitors that are not operating properly. When voltage information is combined with circuit data, the type of problem identified can be scripted which allows repair orders to be automatically created and dispatched. Voltages that are out of range on a single meter indicate a bad meter and a work order is issued. Voltages out of range for multiple meters on a transformer create a repair order to swap the transformer. Voltages out of range for multiple transformers are investigated for regulator or capacitor problems.

AMI usage and demand data will be used to identify over or underutilized transformers. Obviously, the larger the transformer the more value there is in keeping it from failing from overload or replacing it with a smaller transformer. The process is very straightforward for transformers with only one customer served from the transformer. The same process can be applied to smaller transformers by summing the load from all the AMI meters that are connected to the transformer. This process will identify overloaded transformers and may also identify transformers that have mis-linked meters. Additionally, this can help identify distribution losses or theft.

Q. Will AMI be used to improve the Companies' mapping of meters to transformers?

A. The connection between the meter and the transformer is critical to accurately predicting failed devices and the customers impacted from an outage. The service from a meter may be rerouted to a different transformer for several reasons. When this occurs, it is important that the rerouting is correctly mapped in the Companies' mapping system. Voltage signatures from AMI meters can be used to determine what meters are connected to a transformer and make any necessary adjustments. Thus, AMI provides very precise and current mapping of meter-to-transformer pairings.

Q. Will the full deployment of AMI provide other operational benefits to distribution operations beyond those already mentioned?

A. Yes. AMI technology provides a foundation that extends well beyond meter reading. I have already discussed how AMI meters act as a sensor network that will be used to compliment Distribution Automation and other reliability programs by providing unprecedented line of sight where the distribution system meets the customer. This is where the benefit of AMI starts for Distribution Operations but it is not where it ends.

Across the industry, additional use cases for the data supplied by AMI technology are being identified each year as utilities get more and more experience with the technology and data analytics. Additional opportunities that the Companies' are already exploring include:

- AMI meters can enhance fault locating and isolation, and service restoration capabilities once the final phase of the advanced distribution management system is deployed. Using the existing, Company-owned, radio frequency mesh network could provide cost savings not possible without that network.
- Meters that have a remote service switch ("RSS"), which provides the ability to disconnect or reconnect a meter from service remotely, might one day be utilized to mitigate temporary overloads that might occur during restoration activities. An overload condition can be a result of cold load or it might be the result of distributed energy resources (such as rooftop solar) not being available. The meters with RSS ability can be programmed to disconnect the service following any outage lasting more than a predetermined amount of time. Once power is restored, meters are programmed to close the RSS in such a way that restoration is done in a safe and reliable way and avoid such temporary overloads.
- RSS can also be used mitigate generation shortfalls by automatically disconnecting when there is an under-frequency event on the system. Today, the Companies have systems designed to address under-frequency events by automatically de-energizing entire circuits across the service territory. These systems are only used in extreme emergency situations, but

by utilizing AMI meters as the disconnect, the circuit can remain in service to serve critical loads along the same circuit. Upon activation for under frequency, the meters report an alarm and must receive a close command from the AMI system before restoring load.

- System Operators can utilize the near real-time data from AMI to identify service breaks in the distribution system that don't exist at designed segmentation point such as a recloser or fuse. Coupling this use with advanced system protection technologies being deployed across the system, the Companies will be better suited to identify and respond to energized downed conductors that pose a huge public safety concern.
- Usage data from AMI meters will improve customer load modeling capabilities, allowing the Companies to better identify electric vehicles adoption and penetration rates across the system. This is important for the Companies in order to ensure the safe and reliable operation of the distribution system to meet customer demands. Additionally, usage data from AMI meters where customers have distributed generation installed can provide the data needed for advanced planning methods to better forecast actual customer loads and customer-owned generation output.

Q. Do the Companies have a study that discusses many of the benefits described above?

A. Yes. The Companies asked the Electric Power Research Institute ("EPRI") to research and review the types of operational benefits that AMI can facilitate. EPRI is a widely recognized and respected entity that conducts research, development, and demonstration projects in the United States and internationally. Through its work, it assists electric utilities by providing expertise and collaborative value on a wide range of issues.[4] At the Companies' request, EPRI researched and prepared the report attached as Exhibit JKW-2 entitled Operational Benefits of Advanced Metering Infrastructure. It discusses and confirms that many of the operational benefits described above are achievable.

Q. In sum, what are the major benefits AMI will create for the distribution system?

A. AMI meters will provide excellent visibility into the distribution system. With that visibility, the Companies 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, most importantly, a better customer experience.

IV. CONCLUSION

Q. Does this conclude your testimony?

A. Yes, it does.

[4] www.epri.com

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

The undersigned, **John K. Wolfe**, being duly sworn, deposes and says that he is Vice President, Electric Distribution for Kentucky Utilities Company and Louisville Gas and Electric Company and an employee of LG&E and KU Services Company, and 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.

John K. Wolfe

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 20th day of November 2020.

Notary Public

Notary Public, ID No. 603967

My Commission Expires:

July 11, 2022

APPENDIX A

John K. Wolfe
Vice President, Electric Distribution
Kentucky Utilities Company
Louisville Gas and Electric Company
220 West Main Street
Louisville, Kentucky 40202
Telephone: (502) 627-4312

Education

Bachelors in Mechanical Engineering, University of Louisville, May 1991
Graduate work in Mechanical Engineering, University of Louisville, 1991
Gas Distribution Engineering, Institute of Gas Technology, 1993
Graduate work in Business Administration, Bellarmine College, 1994-1995
E.ON Emerging Leaders Program, London Business School, 2003-2004

Professional Experience

LG&E and KU Services Company

Vice President, Electric Distribution Jan. 2015 – Present
Director, Electric Sys. Restoration and Dist. Feb. 2013 – Jan. 2015
Director, Operations Nov. 2010 – Feb. 2013

E.ON U.S. LLC

Director, Operations Mar. 2010 – Nov. 2010

Louisville Utilities Company

Manager, Operations Center Feb. 2000 – Mar. 2010
Manager, Gas Service Center Sep. 1997 – Feb. 2000
Group Leader Engineering and Planning Jan. 1997 – Sep. 1997
Mechanical Engineer II Sep. 1993 – Jan. 1997
    Main Replacement Program Manager May 1996 – Jan. 1997
    Operations Auditor Dec. 1994 – May 1996
    Distribution Engineering Sep. 1993 – Dec. 1994
Mechanical Engineer I Jul. 1991 – Sep. 1993
Co-Op Student Aug. 1989 - May 1991

Professional Memberships

American Society of Heating, Refrigerating and Air-Conditioning Engineers - 1991-1994
American Society of Mechanical Engineers - 1991-1994
Great Lakes Mutual Assistance Group Officer - 2013-2016
Southeastern Electric Exchange Mutual Assistance Officer - 2014-2016

National Mutual Assistance Resource Allocation Team Officer – 2015-2019
American Edison Illuminating Companies Power Delivery Committee – 2016-present
EEI Emergency Preparedness and Mutual Assistance Executive Committee – 2015-present
Southeastern Electric Exchange Board Member - 2016-Present

Civic Activities

Juvenile Diabetes Research Foundation Board of Directors - 2005-2008
Leadership Kentucky - Class of 2010
High School Athletics Coach - 2007-2018
American Red Cross Board Member - 2016-Present
American Red Cross Executive Board Member – 2019-present
Juvenile Diabetes Corporate Chair of Kentucky One Walk - 2020

2021 – 2025 Distribution Reliability and Resiliency Plan

PPL companies

Electric Distribution Operations
November 2020

Contents

1. Introduction

LG&E and KU are responsible for providing safe, reliable, resilient, high quality and valuable electric service to customers. Acting upon this responsibility, Electric Distribution Operations (EDO) manages distribution system reliability and resiliency through effective execution of operations, maintenance, inspection, and construction programs which align with industry trends and best practices.

EDO's annual distribution reliability and resiliency planning places emphasis on reliability data collection and analytics, identification of unacceptable performance, prioritization of improvement opportunities, and preservation of investment strategies, organizational structure, and business processes which provide for control and reduction of outage frequencies and durations.

To meet evolving customer expectations and better prepare the grid for future challenges, EDO has earmarked $312 million in capital investments and $146 million in operations and maintenance expenses in its 2021 Business Plan for specific system reliability and resiliency programs. The allocated funding provides for:

- Trimming, treatment, or removal of vegetation which presents a risk to electric infrastructure;
- Routine inspection of electric system components, vegetation and third-party pole attachments to identify issues which present a risk to system reliability and resiliency;
- Continued advancement of operations, information, and communications technologies on the grid to further enable and enhance centralized grid operations;
- Prudent replacement of aging infrastructure to reduce the frequency of equipment failure outages;
- Hardening of targeted system components to build resiliency to extreme weather, natural disasters, and other physical interference;
- Repairing or rebuilding system components which experience outage frequencies and durations which do not meet service standards; and,
- Building contingency for substation transformers.

Consistent with the industry, EDO has gradually increased capital investments in circuit hardening, critical asset contingency, aging infrastructure replacement, and grid intelligence technologies. These investment initiatives, coupled with more robust inspection and maintenance programs, and improved construction standards and outage restoration procedures, have produced significant improvements in recent reliability performance when compared to historical results. Improvements in reliability have improved customer satisfaction ratings and enabled enhanced operational efficiencies.

2. Background

The LG&E and KU electric distribution systems collectively serve more than 976,000 customers in Kentucky and Virginia. LG&E services more than 418,000 customers in Louisville and 16 surrounding counties. KU serves 558,000 electric customers in 79 Kentucky counties and five Virginia counties.

Key components of the combined LG&E and KU electric distribution systems include:

- Geographical area – 7,700 square miles
- Circuit miles – 23,000 (Overhead – 77%, Underground – 23%)
- Substations – 576
- Circuits - 1,826
- Company Owned Poles – 519,000
- Foreign Attached Poles – 152,000

2.1 Distribution Reliability Performance

EDO regularly monitors and assesses system reliability metrics and infrastructure data to identify opportunities for improving system reliability and resiliency. Benchmarks and standards established for EDO key system performance indicators are based on metrics defined by the Institute of Electrical and Electronics Engineers (IEEE). Key metrics calculated and trended by EDO include:

- SAIFI – system average interruption frequency index
- SAIDI – system average interruption index
- CAIDI – customer average interruption duration index
- $CEMI_n$ – customers experiencing multiple interruptions, where **n** equals number of interruptions

Distribution system and customer reliability data is collected from outage history obtained in EDO's Network Management System (NMS), and is primarily viewed from a circuit level basis for holistic reliability performance assessment and investment planning. More granular views of performance are also conducted to enable identification and mitigation of pockets of poor performance, recurring outage devices, and customers experiencing multiple interruptions.

For the purposes of these measurements, interruptions are defined as any electric service disruption which lasts five minutes or longer.

1. **Major Event and Gray Sky Days**

   In order to analyze and set goals for reliability performance, and enable benchmarking with the electric industry, the above referenced reliability metrics are "adjusted" to exclude Major Event Days (MEDs). MEDs are calculated using a statistics-based methodology developed by IEEE to identify outlying reliability performance. The method is known as the "Beta Method" because of its use of the naturally occurring log normal distribution that best describes reliability performance data. It identifies the occurrence of abnormal conditions that grossly affect the reliability of an electric system.

Events that typically result in exclusion from "normal" or unadjusted reliability metrics include major weather events or natural disasters. These major events are excluded because they typically present risks to the electric system which are beyond the design or operational limits of a utility's electric system.

Building on MED concepts, EDO also uses a Gray Sky Day (GSD) measurement to help normalize weather and other events which create an abnormal number of outage activity on the system. GSD thresholds are calculated by multiplying the MED threshold for outage activity by one-third. The GSD metric is used primarily for internal reporting and discussion.

Figure 1 displays calculated MEDs and GSDs for electric distribution reliability between 2010 and 2019.

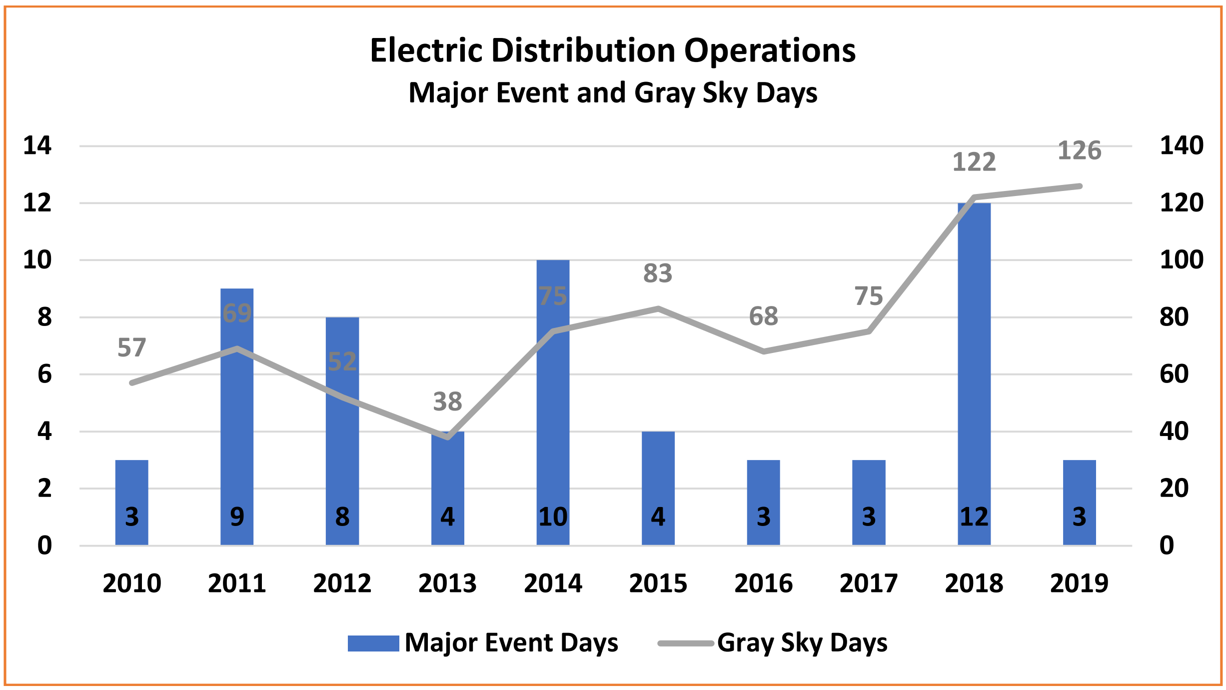

Figure 1. Electric Distribution Operations Major Event Days and Gray Sky Day Trends

Explanations for the steep increase in gray sky days for 2018 and 2019 appear to tie primarily to weather. In 2018, the Companies experienced two Level III and IV events. Data provided by EDO's weather service indicates that the number of days where wind speeds greater than 35 mph were experienced in representative weather stations in the LG&E and KU service areas increased by 12% from the ten-year norm during 2018. Amazingly, the number of days where wind speeds greater than 35 mph were experienced during 2019 increased by 52% from the ten-year norm.

2. System Outages

Electric distribution system outages trends are monitored and tracked using outage data from EDO's NMS and can be viewed in Figure 2.

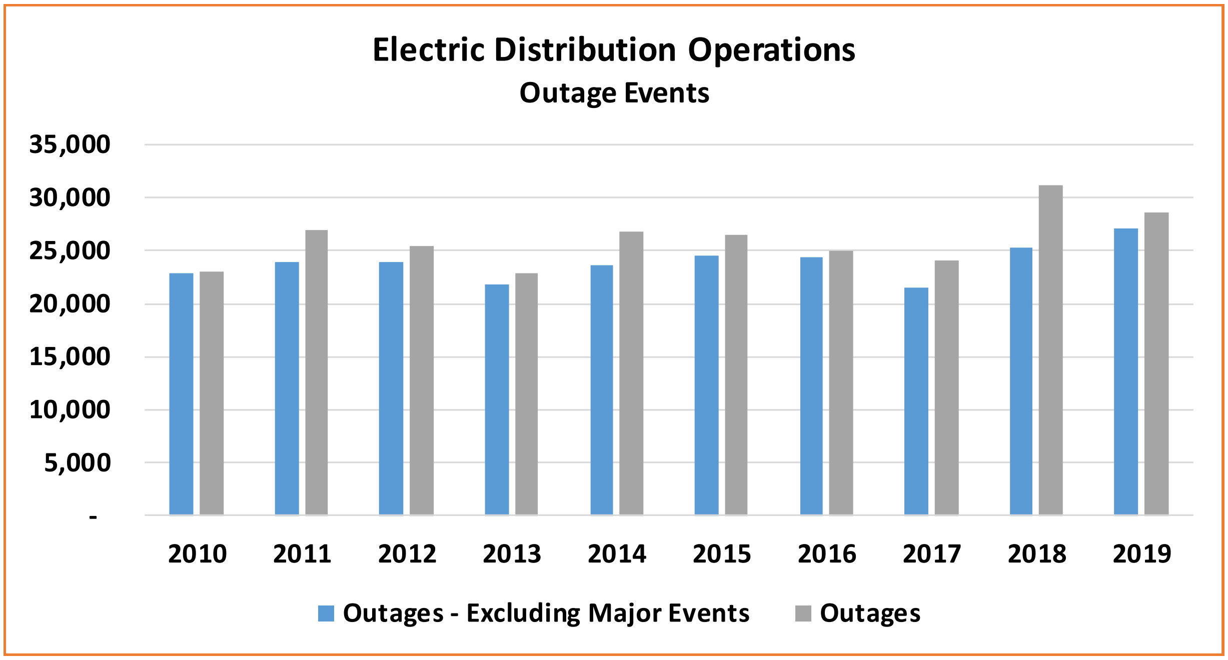

Figure 2. Electric Distribution Operations Outage Event Trends

Total outages experienced on the distribution system during 2019 ranked second highest over the past ten years for the combined companies. When excluding MED outages, distribution's adjusted outage count for 2019 ranked highest over the last ten years. The average number of outages per year has increased by 5.7% and 8.2% respectively for adjusted and total outages respectively when comparing the most recent five-year results to the five-year period ending in 2014.

Contribution of individual outages to total and adjusted SAIDI has decreased over the last ten years, indicating EDO's efforts to segment customers and reduce outage durations through improved outage management processes, focused hardening efforts on mainline segments, and advancement of operations technology are providing positive results. For the five-year period ending 2014, individual outages contributed 0.0040 minutes on average to adjusted system SAIDI annually. For the most recent five-year period, the average annual contribution of individual outages to adjusted system SAIDI reduced by 14.8%.

3. System Average Interruption Frequency Index

The purpose of EDO's system reliability and resiliency capital investments is to reduce the frequency and duration of electric service interruptions. Figure 3 displays the average outage frequency LG&E and KU customers experienced over the last ten years.

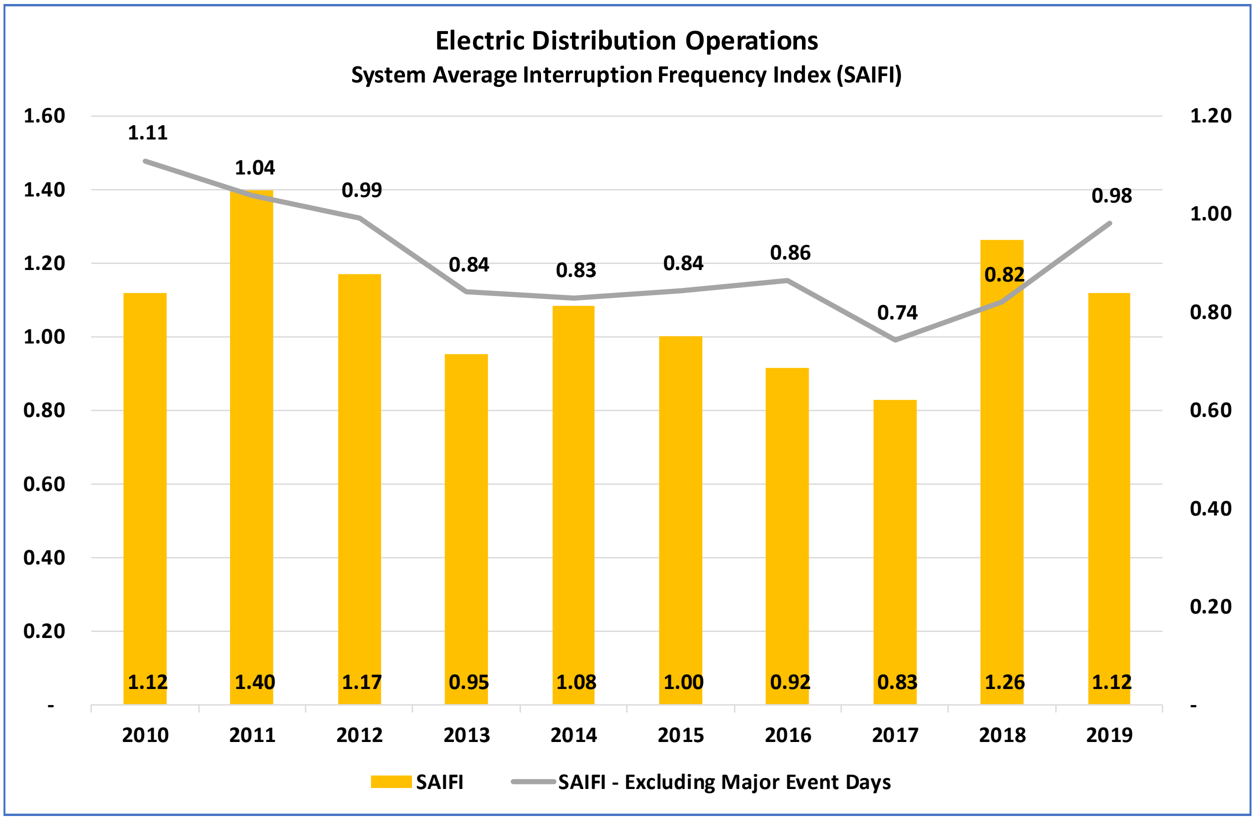

Figure 3. Electric Distribution Average Frequency Index Trends

Between 2010 and 2018, the frequency of outages experienced by customers showed progressive improvement. In fact, customers experienced fewer outages (excluding major event days) during 2017 and 2018 than at any time over the previous ten-year period. Unfortunately, adjusted SAIFI in 2019 was the highest of the last seven years. Weather was the leading contributor to decreased performance during 2019. Despite documented increases in weather contributions during 2018 and 2019, the average annual total and adjusted SAIFI over the five-year period ending 2019 reduced by 10.4% and 11.6% respectively when compared to SAIFI performance for the five-year period ending 2014.

4. System Average Interruption Duration Index

EDO's system reliability and resiliency capital investments have reduced outages and thus reduced the time that customers experience loss of electric service. Focus on outage management preparedness and response, coupled with continued investments and improvements in communications, information, and operations technologies also help to reduce the time customers experience a loss in electric service. Figure 4 displays the average outage duration LG&E and KU customers experienced over the last ten years.

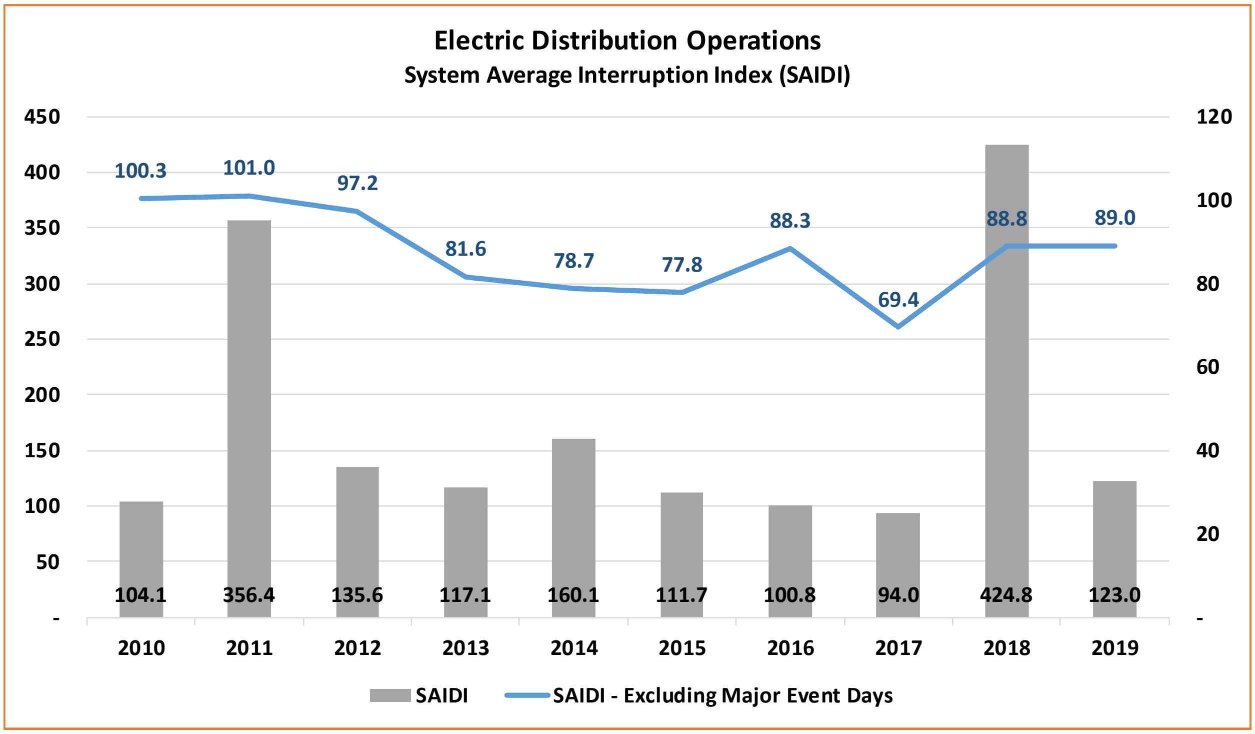

Figure 4. Electric Distribution System Average Interruption Index Trends

For the five-year period ending 2019, LG&E and KU customers experienced an average of 82.6 (adjusted) and 170.1 (total) minutes of electric service interruption, representing a 10.1% improvement over the five-year period ending 2014 for adjusted SAIDI, and a 2.2% reduction in outage minutes when including major event days.

5. Outage Causes Trends

Evaluation of outage causation trends is used in both strategic and tactical planning and in responses for reducing the frequency and duration of service interruptions. Table 1 displays recent trends of more frequent causes of customer outages.

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2010-2019 Average
Adjusted SAIFI	**1.08**	**1.02**	**0.96**	**0.82**	**0.82**	**0.83**	**0.85**	**0.74**	**0.80**	**0.96**	**0.89**
Performance Rank	**10**	**9**	**7**	**3**	**3**	**5**	**6**	**1**	**2**	**7**	
Equipment Failure	0.26	0.24	0.20	0.22	0.22	0.21	0.20	0.24	0.22	**0.25**	**0.23**
Tree Related	0.13	0.20	0.14	0.11	0.13	0.12	0.15	0.11	0.16	**0.18**	**0.14**
Unknown	0.18	0.14	0.19	0.15	0.12	0.13	0.15	0.09	0.12	**0.15**	**0.14**
Lightning	0.14	0.12	0.11	0.08	0.07	0.07	0.09	0.05	0.04	**0.03**	**0.08**
Pulled Off	0.10	0.12	0.09	0.05	0.07	0.09	0.06	0.06	0.06	**0.07**	**0.08**
Animal	0.07	0.06	0.06	0.06	0.05	0.08	0.07	0.05	0.04	**0.06**	**0.06**
Vehicle	0.06	0.06	0.04	0.04	0.04	0.07	0.06	0.06	0.07	**0.05**	**0.06**

Table 1. Leading contributions to electric distribution customer outages (2010-2019).

Table 2 displays the EDO's leading contributions to annual customer outage minutes.

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2010-2019 Average
Adjusted SAIDI	**99.40**	**99.15**	**94.03**	**79.74**	**76.86**	**76.95**	**87.02**	**68.48**	**86.06**	**87.30**	**85.50**
Performance Rank	**11**	**10**	**9**	**5**	**2**	**3**	**7**	**1**	**6**	**8**	
Equipment Failure	21.78	20.87	18.20	19.44	19.67	17.58	19.66	19.62	22.04	**24.80**	**20.37**
Tree Related	18.51	29.75	24.93	18.25	16.56	18.05	22.97	16.68	26.91	**24.77**	**21.74**
Unknown	12.82	10.15	13.12	11.21	8.18	9.46	11.89	7.17	8.89	**10.08**	**10.30**
Lightning	15.20	12.57	12.40	8.87	9.26	7.40	9.20	5.10	3.92	**3.40**	**8.73**
Vehicle	6.27	5.45	4.65	5.05	4.85	5.75	5.90	5.93	7.68	**5.39**	**5.69**
Pulled Off	7.63	4.32	3.44	4.51	5.92	6.15	5.92	5.49	5.86	**7.39**	**5.66**

Table 2. Leading contributions to electric distribution customer outage durations (2010-2019).

Over the last ten years, equipment failures and tree-related interference have consistently been the leading causes of customer service outage frequency and duration. Unknown contributions have also consistently ranked third in causation and are believed to be primarily tree related. To effect additional step improvements in or maintenance of reliability performance, or both, EDO strategies must continue to place emphasis on reducing outages caused by equipment failures and trees. Investments in aging infrastructure and system hardening are necessary, as equipment failures contributing to adjusted SAIDI for the five-year period ending 2019 increased by 3.7% over the five-year period ending 2014. While trees and unknown causes contributed to nearly 40% of customer outage durations during 2019, the average contribution of trees and unknown causes for the five-year period ending in 2019 was reduced by approximately 4.1% compared to the five-year period ending in 2014.

6. Momentary Interruptions

Momentary interruptions are defined as electric distribution service interruptions which are restored within minutes. Advances in electric grid technology and intelligence in the industry is enabling greater ability to identify, monitor, and report on momentary interruptions. Advanced Metering Infrastructure (AMI) provides the most comprehensive and accurate tool, followed by SCADA connected relay equipment. EDO has not yet instituted key performance indicators around momentary interruptions because AMI has not been deployed on the LG&E and KU systems. Starting in 2020, however, various departments in EDO have been tasked with developing reporting tools and enhanced business processes around identifying, monitoring, and reducing momentary interruptions on the electric distribution system. Recently deployed and integrated SCADA capable electronic reclosers have substantially enhanced EDO ability to monitor and act on momentary interruptions. Further development and refinement of reliability reporting and business processes are planned moving forward, as operations, information, and communications technologies continue to advance.

2.2 Customer Satisfaction

LG&E and KU participate in multiple industry accepted customer satisfaction surveys, the most recognizable of which is administered by J.D. Power (JDP). For 2019, KU and LG&E placed first and fifth respectively in JDP's Electric Residential Customer Satisfaction Study and first and third respectively in their 2019 Electric Business Customer Satisfaction Study, among Midwest midsize utilities. Nationally, KU's overall customer satisfaction performance ranked in the first quartile and LG&E's performance ranked in the second quartile. (See Figure 5)

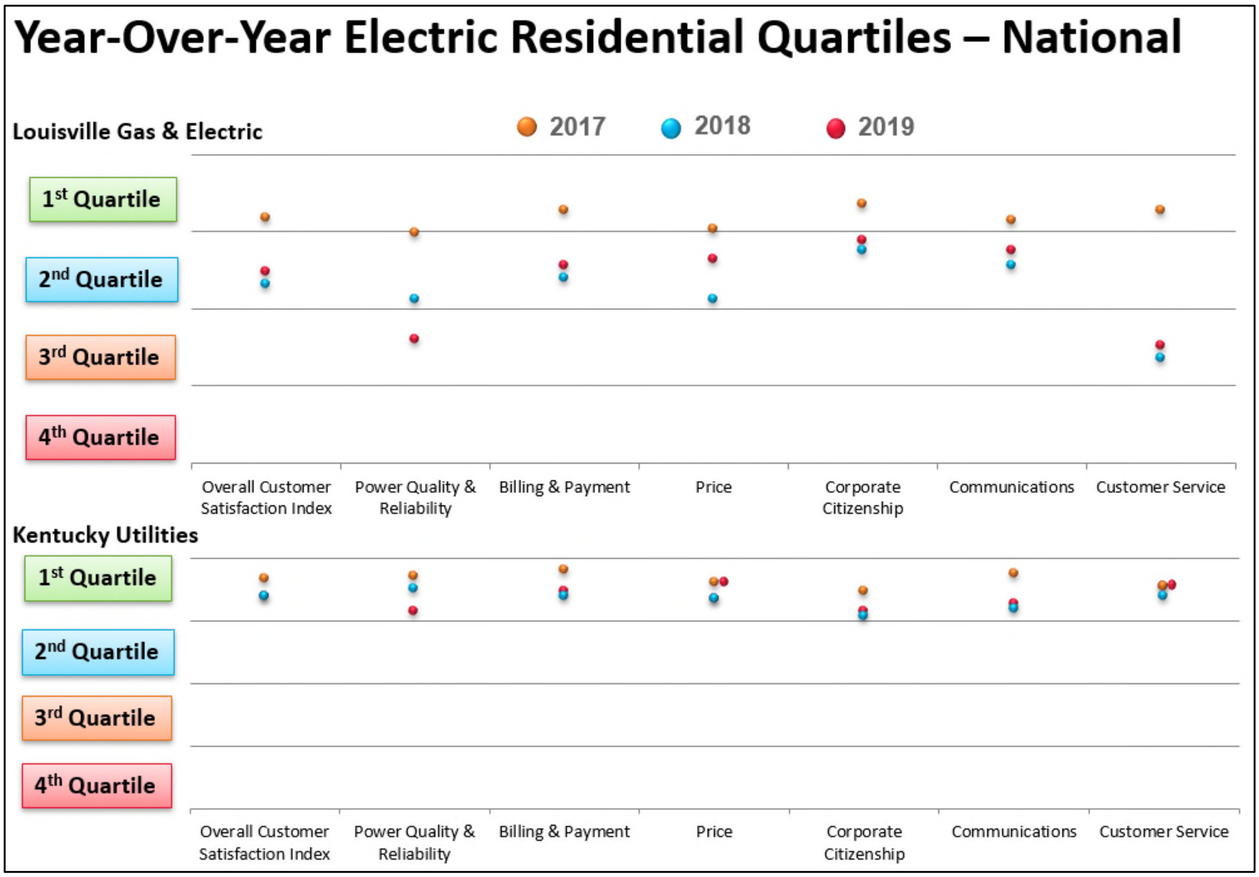

Figure 5. J.D. Power 2019 Electric Utility Residential Customer Satisfaction Study

Power quality and reliability (PQR) consistently rank as the most important component of customer satisfaction and have the greatest influence on the relative value of other key utility customer satisfaction indices in JDP customer studies of electric utilities. When assessing the Companies' 2019 customer satisfaction against 2017 results, across all indices, it's important to note that during 2017, KU and LG&E experienced their best reliability performance in history. During 2018, the Companies experienced two-Level III and two-Level IV events. The residual effects of these storms contributed to increased trouble on the system in subsequent months.

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Reliability during 2019 was also greatly influenced by an abnormally high number of strong wind events. As stated previously, the number of strong wind (Wind speeds > 35 mph) event days was approximately 52% higher than the ten-year norm, based on representative weather stations monitored by EDO's primary weather service. Despite these factors, KU residential customers continued to rank KU's PQR performance in the first quartile nationally. LG&E customers ranked LG&E's PQR in the third quartile nationally, dropping from first quartile performance in 2017.

2.3 Industry Perspective

EDO participates in industry reliability studies and surveys to enable benchmarking of Company reliability performance against the electric industry, particularly peer utilities. Figures 6 and 7 display adjusted SAIDI and SAIFI results [redacted] for the period 2010 through 2019, with LG&E and KU combined results overlaid.

When comparing Company reliability results to other investor owned utilities, consideration is always given to factors which might influence data accuracy or relevance. For example, Companies in the south that deal with hurricanes and frequent thunderstorms should not be compared to utilities that do not. Differences in the average length of feeders and customer densities on circuits contributes to significant differences in physical risks between utilities. It is not recommended or fair to compare the performance of a rural utility system to a metropolitan system which might have substantially more redundancy. Another key driver of difference between utilities is the level of grid intelligence and automation. Grid technology undoubtedly creates opportunities for utilities to reduce outage durations and frequencies through automated monitoring, control, and operations of connected field devices.

[redacted]

Figure 6. [redacted] "Adjusted" Distribution SAIDI Survey Results (2010-2019)

[redacted]

Figure 7. [redacted] Distribution "Adjusted" SAIFI Survey Results (2010-2019)

[redacted]

[redacted]. Advanced metering infrastructure and increased SCADA connected devices on the grid have contributed to improved real time reporting and record keeping of outage initiation, momentary interruptions, and outage restoration. [redacted]

[redacted]

[redacted]

In addition to participating in electric industry reliability and customer satisfaction performance benchmarking studies, EDO also routinely benchmarks the electric industry to identify emerging and advancing technologies for improving distribution resiliency and reliability. Over the past decade, most leading electric utilities have focused on improving distribution reliability by increasing capital investments in circuit hardening and critical asset contingency. More recent trends point to accelerated investment strategies in and deployment of grid intelligence technologies, in response to increasing customer expectations for reliable power, and the proliferation of distributed energy resources (DER) and electrification of transportation.

During EEI's February 5, 2020 Wall Street Briefing, EEI shared the Industry Capital Expenditures and Projected Functional Capital Expenditures presentation as seen in Figures 8 and 9 below. Based on EEI's analysis, annual capital investments in U.S. investor owned electric utilities increased by 54% over the last ten years and are projected to remain above $100 billion through 2021 (Figure 8).

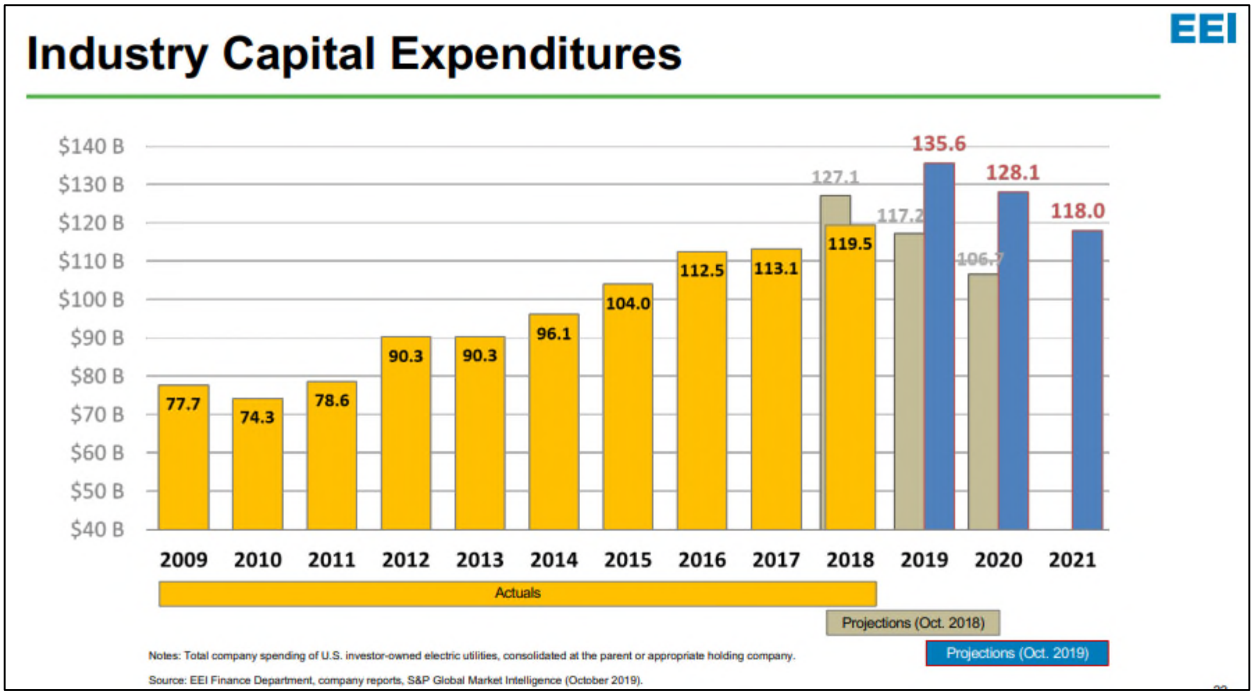

Figure 8. EEI Electric Industry Investment Trends

Further, EEI pointed out that capital investments across the industry continue to be shifted from generation to power delivery (i.e., transmission and distribution). In 2019, the percent of investor owned utility capital investments in distribution and transmission remained at 48% when compared to 2018 (Figure 9), significantly higher than 2019 generation spend of 28%.

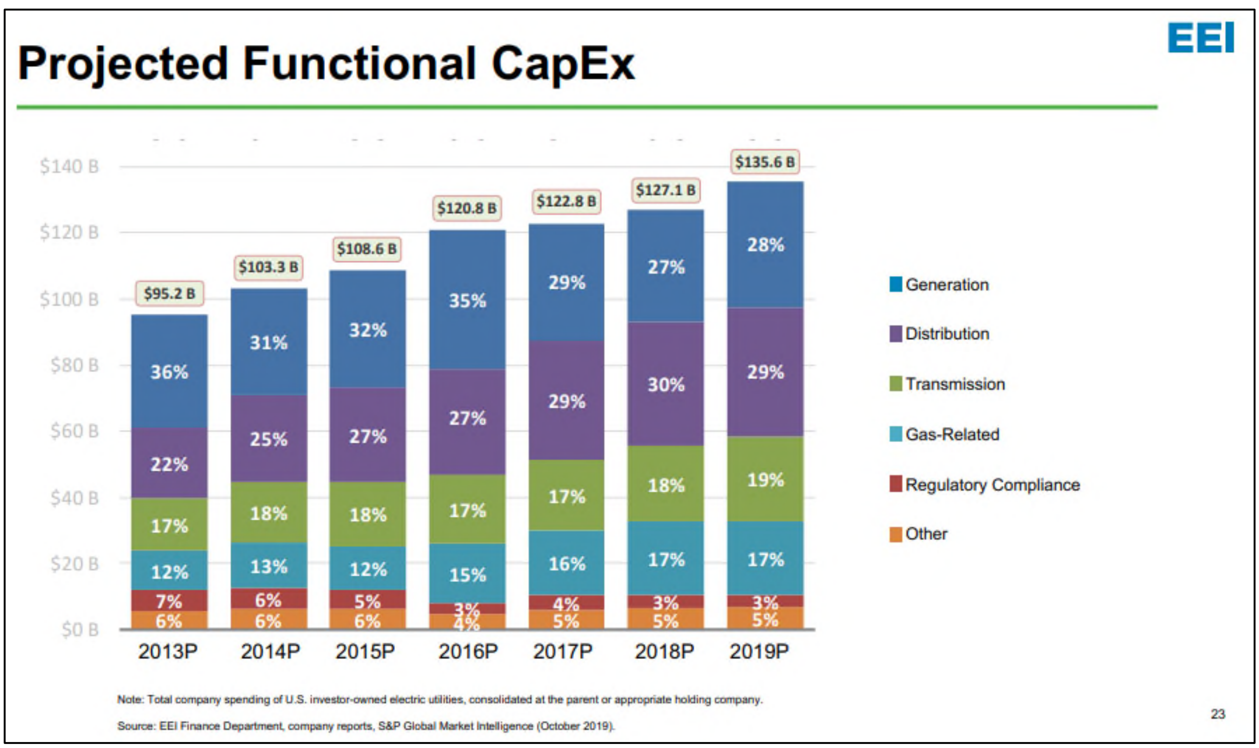

Figure 9. EEI Projected Distribution of Capital Funding by Electric Utility Functional Area

3. Distribution Reliability and Resiliency Strategy

In 2011, EDO began using an Asset Investment Strategy (AIS) decision-support model and supporting business processes to help evaluate and prioritize distribution investment programs. The model and processes enable EDO to evaluate and prioritize proposed investments based on 1) a set of custom benefit criteria defined by EDO subject matter experts; and 2) estimated costs of proposed projects. The AIS prioritization algorithm sorts proposed investments based on a benefit/cost ratio, which in turn allows EDO to determine the best allocation of capital spending. EDO's management team then applies other criteria, such as resource availability and seasonality of work, to determine the ultimate set of investment projects to include in EDO's Business Plan.

Using this AIS decision-support model along with emphasis on centralized grid operations, the EDO 2021 Business Plan delivers a prudent system reliability and resiliency strategy that capitalizes on past and current investments in the distribution system.

The following assumptions adopted in the plan are founded on customer satisfaction surveys and industry intelligence.

- Customer reliance on electricity will continue to increase, with advancement of end use technologies and electrification of nearly everything. Accordingly, customer expectations respective to electric service safety, reliability, and quality will continue to evolve.
- Expectations for system resiliency and outage responsiveness will continue to grow in the face of increased grid vulnerabilities linked to severe and extreme weather, threats of cyber and physical attacks, and interference from wildlife and vegetation and continued Work from Home (WFH) options provided to a large number of office employees across the commonwealth.
- Across the industry, customers, regulators, and community leaders will continue to push for modernization of the electric grid, effective interconnection of distributed energy resources, increased operational flexibility, and enhanced customer communications

In accordance with its 2021 Business Plan, EDO will address these ongoing issues and continue to deliver increasing value to its customers via the following initiatives:

- Invest in system reliability and contingency to meet increasing customer expectations respective to service availability
- Investment in aging infrastructure to continue long term service reliability
- Advance grid intelligence to meet evolving customer expectations and align with industry trends
- Respond to outage events in an efficient and effective manner, and continue to improve on the accuracy, timeliness, and provision of estimated restoration times

- Invest in and deploy technology which enhances business processes, reduces cycle times, and expands communications with customers.

3.1 System Reliability and Resiliency Investment Programs

1. Distribution Automation

Distribution Automation (DA) takes advantage of converging and evolving operations, information, and communications systems technologies that enable extension of intelligent control over the electric distribution system. Intelligent control of distribution equipment facilitates remote monitoring of connected field devices in real time, and enablement of device control and operations equipment. Operations of this equipment can also be automated, eliminating the need for human intervention on some key monitoring, analysis, and operations of distribution line equipment.

The Companies received Certificate of Public Convenience and Necessity (CPCN) authority for advancing DA on the electric distribution system in July 2017. The three primary components of the Companies' approved $112M, seven-year, DA program include:

1. Installation of supervisory control and data acquisition ("SCADA")-capable electronic reclosers;
2. Implementation of distributed SCADA ("DSCADA") software to monitor and communicate with those reclosers; and
3. Deployment of a Distribution Management System ("DMS") that interfaces with the DSCADA system to provide intelligent control over the electronic reclosers.

Through the end of 2019, the Companies had installed more than 1,066 SCADA capable electronic reclosers on its electric distribution grid. The reclosers have been strategically placed to reduce customer exposure to fault conditions on the system which create momentary or extended service interruptions, through greater division of customer counts between protective devices. Funding budgeted in 2020 is projected to provide for the installation of an additional 330 reclosers during the year. At the conclusion of the program, more than 1,538 reclosers will be installed on the distribution system. This will provide greater customer segmentation and integration with the new DMS for approximately 45% of the Companies distribution circuits, directly affecting 81% of customers.

During January 2019, the Companies deployed distribution SCADA (D-SCADA) software as part of the DA project. Since its deployment and through December 2019, project members connected more than 1,600 reclosers to the new software, enabling centralized monitoring and control through the Companies' Distribution Control Center (DCC). Roughly 600 of the reclosers connected to D-SCADA were installed on the electric distribution system through reliability investment programs outside of the DA program. During 2020, the DA project team will continue to work on connecting added reclosers to D-SCADA.

Full deployment of DMS software functionality is tentatively scheduled to be completed during 2020. (The ongoing coronavirus pandemic will likely necessitate pushing deployment to January 2021 due to physical controls put in place to prevent spread of the virus.) The added DMS functionality is designed to provide for automatic fault locating and isolation, and service restoration, which is the self-healing component of an advanced DMS. Following full deployment of this functionality, the Companies will work to integrate the software with all DA capable circuits. This phase of the DA project is targeted for completion by the end of 2022. (Integration of all DA capable circuits will also likely be delayed because of the pandemic.)

Capital funding allocated in the 2021 Business Plan:

Program Description	2021	2022	2023	2024	2025
Distribution Automation	$ 12,843	$ -	$ -	$ -	$ -

2. **Circuit Hardening**

EDO's system hardening program focuses on rear easement hardening, conductor upgrades, and circuit relocations. Generally, rear easement hardening involves the rehabilitation or relocation of older, storm sensitive overhead lines in difficult to maintain rear easements where they have demonstrated poor reliability or storm performance. Aspects of this program include replacement of undersized and/or defective small wire, stronger and/or taller poles, selective undergrounding, storm guying, elimination of secondary, replacement of aged and defective equipment, and/or relocations of lines to less problematic areas. System hardening projects are prioritized based on AIS rankings.

System hardening efforts on the distribution system increased in 2010, in the aftermath of the 2008 Hurricane Ike Windstorm and 2009 Kentucky Ice Storm. These two storms caused the most significant system damage in the company's history and created residual impacts to system reliability which prompted a more aggressive system hardening approach. System hardening investments are targeted for circuits with high customer interruptions and pockets of poor performance.

Capital funding allocated in the 2021 Business Plan:

Program Description	2021	2022	2023	2024	2025
System Hardening	$ 3,652	$ 7,090	$ 8,241	$ 7,674	$ 7,734

3. **Customers Experiencing Multiple Interruptions**

EDO's CEMI (Customers Experiencing Multiple Interruptions) Program consists of an annually reoccurring initiative to address system components which caused customers to experience more than a predesignated number of outages in in the previous year. As part of this investment category, reliability engineers across the organization address recurring outage devices (ROD) and unfused tap lines. Targeted investments of these devices have consistently and effectively reduced the number of LG&E and KU customers experiencing multiple outages each year, and the number of recurring outages of distribution equipment.

For 2019, the number of customers experiencing multiple interruptions was 86,377, roughly 8.85%. This number compares favorably to the number of customers who experienced multiple outages during 2018. CEMI customers in 2019:

- $CEMI_1$ – 246,021
- $CEMI_2$ – 86,377
- $CEMI_3$ – 33,339
- $CEMI_4$ – 11,557
- $CEMI_{5+}$ – 4,844

[redacted]

Capital funding allocated in the 2021 Business Plan:

Program Description	2021	2022	2023	2024	2025
Customers Experiencing Multiple Interruptions	$ 2,431	$ 2,492	$ 2,554	$ 2,618	$ 2,683

4. **Reliability Improvement Blankets**

Reliability improvement blankets provide for local investment in distribution components experiencing new reliability or power quality issues. Allocated funding is distributed to Operations Center engineers and managers to enable timely response and mitigation of reliability or power quality issues raised by customers throughout the year.

Capital funding allocated in the 2021 Business Plan:

Program Description	2021	2022	2023	2024	2025
Reliability Improvement Blankets	$ 1,825	$ 1,888	$ 1,892	$ 1,951	$ 2,011

5. **Circuits Identified for Improvement**

This initiative covers reactive reliability improvement work on circuits that are prioritized based on each circuit's 5-year average SAIFI performance. CIFI circuit improvements include updating line protective coordination and targeted aging asset replacements where reliability is negatively impacted. Annual funding allocations vary based on the number of circuits targeted, scope of investments needed for targeted circuits, and relative circuit performance across both utilities. Reliability performance of circuits targeted and addressed by the program since inception consistently show improvements. In fact, addressed circuits have shown an average reduction in controllable outages of 53% for the five-year period following program completion. Candidate circuits are evaluated against other proposed investments.

Capital funding allocated in the 2021 Business Plan:

Program Description	2021	2022	2023	2024	2025
Circuits Identified for Improvement	$ 2,751	$ 2,820	$ 2,891	$ 2,963	$ 3,037

6. **Substation Wildlife Protection**

Since 2012, wildlife has been the single largest contributor to distribution substation level outages at KU, representing 36% of all SAIDI (System Average Interruption Duration Interval) at KU substations. Wildlife protection is included in the design and construction of new and expanded distribution substations. However, EDO's current design practice was only formalized as of 2012, and numerous previously constructed KU distribution substations continue to utilize legacy standards that are sometimes less than adequate in providing the highest level of station protection. Primary wildlife threats to these stations include raccoons, squirrels, birds and snakes.

There are 467 KU substations with distribution facilities. As of the end of 2019, 355 of KU substations had some degree of wildlife protection and 112 had no wildlife protection. As previously noted, even those substations that have some level of existing wildlife protection are not secured at a standard necessary to provide enough protection to substantially impact the number and duration of interruptions. During 2020, approximately 20 KU substations will be addressed, leaving approximately 107 substations remaining to be addressed.

Priorities for addressing KU substations targeted by this project include history of past interruptions or repetitive interruptions, amount of load served, and SAIDI impact.

Capital funding allocated in the 2021 Business Plan:

Program Description	2021	2022	2023	2024	2025
Substation Wildlife Protection	$ 1,974	$ 1,280	$ 1,288	$ 295	$ 302

7. **Underground Fault Current Indicators**

During 2019, EDO initiated a three-year program to install underground faulted circuit indicators (UG FCIs) on approximately 40,000 padmount transformers across the LG&E and KU electric distribution systems. UG FCIs provide field technicians with a visual indication (blinking LED) on the exterior of padmount transformers to more expediently identify the location of underground faults and enable swifter restoration of customer outages.

In the five years leading up to the project, more than 4,200 underground outage events were experienced on the LG&E and KU systems. Electric Reliability estimates that the installation of UG FCIs as proposed under the program will reduce the average duration of underground outages by 53 minutes. Annual benefits are estimated at 0.76 SAIDI minutes and $31.5k of operating costs.

Capital funding allocated in the 2021 Business Plan:

Program Description	2021	2022	2023	2024	2025
Underground Fault Current Indicators	$ 5,702	$ -	$ -	$ -	$ -

8. **Aging Infrastructure Replacement**

Annually, EDO's Asset Management organization performs a high-level study to evaluate all electric distribution asset classes to determine if current asset replacement strategies adequately mitigate and align with asset failure rates. This evaluation considers overall condition, age, and reliability of each asset class to predict future failure trends. Further, consideration is given to distribution system criticality and potential customer impact of each asset class to infer consequences associated with asset failure. Asset condition for key assets is evaluated via technologies such as infrared scans, dissolved gas analysis, power factor testing and internal inspection results where necessary. Asset reliability and performance is also evaluated through review of maintenance history and failure rates. Assessment of asset class probabilities of failure and associated consequences enable development of an overall risk profile identifying asset classes at greatest risk for failure and in most need of modified investment rates. The resulting replacement priority is compared to existing asset replacement programs to identify potential need for acceleration or slowing of current programs and to establish new programs where needed.

Recent year studies revealed need for increased investments and accelerated replacement of oil filled substation breakers, electromechanical relays, copper and copper-clad overhead conductor. The studies also support continuation of key aging asset replacement programs such as the pole inspection and treatment, cable rejuvenation, paper insulated lead cable replacement, and substation breaker replacement programs.

Capital funding allocated in the 2021 Business Plan:

Program Description	2021	2022	2023	2024	2025
Total Aging Infrastructure	$ 29,034	$ 14,524	$ 16,705	$ 13,507	$ 10,742

Descriptions of EDO's key aging infrastructure categories are provided below:

a. Pole Inspection and Treatment Program (PITP)

The LG&E and KU electric distribution grid contains more than 517,000 Company owned wood poles with an estimated average age of 30 years. Additionally, the grid is comprised of more than 155,000 foreign-owned wood poles which contain LG&E and KU equipment attachments.

Wood poles used in the electric industry are initially treated with a preservative during processing to extend the life of poles. The effectiveness of initial preservative treatment declines with age. As the effectiveness of treatment reduces, in-service wood poles become more susceptible to deterioration from fungal decay and insect damage. In most cases, decay is difficult to detect because it occurs out of sight just below the ground-line where conditions of moisture, temperature and air are most favorable for growth of fungi. Ground-line is also the point of maximum loading stress for a pole.

Before 2010, EDO's distribution poles only received an inspection every two years in accordance with Kentucky Public Service Commission (KPSC) requirements. KPSC mandated biennial inspections of the electric distribution system help to identify obvious physical defects and unsafe conditions of distribution equipment. However, the Commission's inspection requirements do not focus singularly on poles, nor provide for life extending preservative retreatment of poles, pole loading calculations or below grade inspection for ground line rot.

During 2010, EDO's implemented a pole inspection, treatment, and replacement program (PITP) to provide for improved distribution system resiliency and reliability. The PITP provides a systematic and focused approach to prolonging the service life of poles through a pole-by-pole inspection and assessment, and execution of condition based corrective actions where deficiencies are identified. Potential corrective actions include preservative retreatment, pole reinforcement, or pole replacement. Preservative retreatment arrests any decay present and can significantly increase the useful life of the pole at a very small cost relative to replacement costs. One industry study indicates the predicted pole life with no remedial treatment is 32.5 years compared to a predicted pole life of greater than 50 years for poles with remedial treatment.

Under the PITP, EDO had inspected more 542,000 poles, and treated nearly 172,000 poles or replaced more than 21,000 poles by the end of 2019. Pole replacement and reinforcement had been required on approximately 3.9% and 0.3% respectively of poles inspected.

Original 2020 funding provided for inspection of 36,000 additional poles during 2020.

Capital funding allocated in the 2021 Business Plan:

Program Description	2021	2022	2023	2024	2025
Pole Inspection and Treatment Program	$ 13,026	$ 13,416	$ 13,818	$ 14,173	$ 14,528

b. Substation Circuit Breaker Replacement

LG&E and KU substations contain approximately 2,200 circuit breakers of varying designs and vintages. Many of these in-service breakers are greater than 40 years old, well exceeding their design life. The substation circuit breaker replacement strategy focuses on all oil-filled circuit breakers, as well as air-magnetic and vacuum circuit breakers with a history of poor reliability and highest cost of ownership across the system. Starting in 2018, incremental funding has been allocated in EDO's capital budget to provide for accelerated replacement of targeted legacy breakers, with emphasis being placed on oil breakers. Prior to 2018, oil filled breakers were being placed at a rate of less than 1% per year.

Capital funding allocated in the 2021 Business Plan:

Program Description	2021	2022	2023	2024	2025
Legacy Substation Breaker Replacements	$ 3,659	$ 3,224	$ 3,510	$ 2,315	$ 2,373

c. Legacy Relay Replacement

LG&E and KU distribution substations contain more than 4,000 electromechanical and legacy solid-state relays. Many of these relays have far exceeded their designed in-service life, increasing the likelihood for failure. In addition to risks associated with failure, electromechanical relays are simple in design and limit the companies' ability to advance distribution system operations to meet future grid challenges. As part of EDO's strategy to move to a more centralized, smarter distribution system, a program to accelerate replacement of electromechanical relays with more advanced microprocessor relays was initiated during 2018.

Microprocessor based relays are engineered to provide additional information needed to better leverage evolving information, operations, and communications technologies that have been or are being deployed on the LG&E and KU distribution systems. Microprocessor based relays will allow system operators and field technicians to more quickly locate faults and restore electric service following an outage.

EDO's electromechanical relay replacement program targets replacement of approximately 350 relays annually through 2023. Through the end of 2019, 520 electromechanical relays had been replaced.

Capital funding allocated in the 2021 Business Plan:

Program Description	2021	2022	2023	2024	2025
Legacy Substation Relay Replacements	$ 5,318	$ 2,234	$ 5,240	$ 3,245	$ 252

d. Underground Substation Exit Cable Replacement Program

Overall, the electric distribution system contains roughly 320 miles of underground exit cables. The underground substation exit cable replacement program was initiated by EDO during 2015 to more aggressively address aging paper insulated lead covered cable which exits distribution substations, has exceeded designed in-service life, and is indicating higher propensity to failure. Cables targeted for replacement are prioritized based on failure history and inability to repair due to legacy technology. During 2019, 104 sections (10,143 feet) of targeted cable were replaced. An additional 91 sections (11,599 feet) are budgeted for replacement during 2020.

Capital funding allocated in the 2021 Business Plan:

Program Description	2021	2022	2023	2024	2025
Underground Substation Exit Cable Replacement	$ 1,660	$ 1,720	$ 1,500	$ 1,538	$ 1,576

e. URD Cable Replacement Program

Electric Distribution Operations' proactive cable replacement program targets LG&E/KU Underground Residential Development (URD) direct buried cables installed between the mid-1960s and mid-1980s. Over 95% of failures occurred on 1st and 2nd generation solid dielectric cables installed in underground residential subdivisions between the mid-1960's and mid-1980's. Failure rates on these 30-year design life systems have been steadily increasing over the past 35 years. The replacement of LG&E/KU's oldest and poorest performing URD direct buried cable will help increase system reliability, minimize customer disruptions, and reduce the likelihood of accelerated reactive URD cable replacement costs in future years. The program prioritizes selected assets by age, failure history, customer impact, and URD circuits identified for improvement (CIFI).

Capital funding allocated in the 2021 Business Plan:

Program Description	2021	2022	2023	2024	2025
Underground Residential Development Cable Replacement	$ 3,058	$ 3,067	$ 2,408	$ 2,449	$ 2,482

f. Paper Insulated Lead Covered (PILC) Cable Replacement Program

During 2013, Louisville Operations initiated a program to accelerated replacement of bare (unjacketed), paper insulated, lead covered (PILC) low voltage secondary and medium voltage primary cables operating in the downtown Louisville network distribution system. The downtown network consists of five separate network systems with 27 circuits within the core downtown Louisville business and medical districts, roughly bounded by the Ohio River (north), Floyd Street (east), York Street (south), and 8th Street (west). At the start of the program, three of the five network systems, served by the Waterside, Magazine, and Madison Substations, contained bare PILC cables.

At the beginning of this program, an estimated 70 miles of bare primary and secondary PILC cables, ranging in age from 48 to 100 years old, were in service in the downtown Louisville network distribution system. Early PILC primary cables and all PILC secondary cables utilized bare lead sheaths that have experienced varying degrees of surface corrosion over their service lives. Corrosion and/or mechanical damage allow the insulating oil to leak from the insulation and allow water to enter the cable, ultimately leading to a cable failure. Insulating oils in the older bare PILC cables are also reportedly much drier than when newly manufactured, indicating the degree of insulation aging and degradation.

Leading up to 2013, PILC cable in the downtown network has shown increasing failure rates over the previous fifteen years and were failing at twice the average rate per mile as the rest of the LG&E and KU underground systems. Primary cable failures over three consecutive five-year periods preceding program initiation increased from an average of 3.2 (1999-2003), to 5.6 (2004-2008), to 8.2 (2009-2013). Known secondary failures averaged approximately two each year and had significantly greater consequences than primary failures due to high fault currents, and because secondary cables are not protected against faults and must burn in the clear before a fault is extinguished. The increase in secondary cable burnouts, the documented primary cable failure incidence rate, and the risk posed to adjacent cables in the duct and manhole system highlighted the need to accelerate replacement of secondary and primary PILC cables.

Under this program, PILC cables are replaced with the latest generation of solid dielectric cables using either rubber or crosslinked polyethylene insulation. The new cables are not subject to corrosion under wet conditions and are more resistant to water ingress with aging. Current generation cables have a life expectancy of more than 50 years.

Since program initiation, through the end of 2019, 62.94 miles of PILC cable had been replaced, leaving approximately 19 miles to be replaced. In addition, 76,333 feet of duct had been installed. The 2020 Business Plan provided for replacement of 10 additional miles of cable.

Capital funding allocated in the 2021 Business Plan:

Program Description	2021	2022	2023	2024	2025
Paper Insulated Lead Covered Cable Replacement	$ 11,163	$ -	$ -	$ -	$ -

9. **KU SCADA Expansion**

During 2018, EDO elected to accelerate expansion of SCADA capabilities to KU substations. At that time, only approximately 20% of circuits in the KU service territory were equipped with SCADA connectivity - accounting for approximately 30% of KU customers (including ODP). Lack of SCADA capabilities to monitor and control substation facilities prevents remote and central monitoring, control, and operations of line equipment, adding time to circuit restoration following an outage event. The expansion of SCADA capabilities in KU substations allows distribution system operations to have the necessary information to identify outages and take remedial measures in those substations in real time.

Under the SCADA expansion program, approximately 570 KU circuits – not currently connected to SCADA - were targeted for upgrade and connection to D-SCADA by 2024. At program conclusion, over 150 legacy breakers and 300 electromechanical relay packages will be upgraded to modern technology – serving as a further enabler for EDO's overall centralized grid operations strategy. Under this program, more than 85% of all KU and ODP customers will be served from a SCADA connected circuit by 2024.

At the conclusion of 2019, SCADA capabilities had been enabled on an additional 175 circuits. Planned funding will provide for upgrade and connection of 145 additional circuits during 2020. At the conclusion of 2020, this will represent 46% of circuits and 60% of customers in the KU service territory with SCADA capability.

Capital funding allocated in the 2021 Business Plan:

Program Description	2021	2022	2023	2024	2025
KU Substation SCADA Expansion	$ 5,085	$ 999	$ 2,500	$ 1,000	$ 500

10. **Substation Transformer Contingency Program**

EDO's substation transformer contingency program was introduced by Substation Construction and Maintenance in the 2014 BP to address distribution substation transformers that cannot be fully restored in the event of an outage or failure. During associated outages, some customers could experience service interruption periods greater than 24 hours until failed equipment can be replaced or until a portable transformer can be installed. Through 2017, annual funding allocated for the program targeted designing, engineering, and constructing contingency solutions for two substations transformers annually. During the 2017 business planning process, EDO increased funding levels to roughly $11.7M annually for fifteen years ($175M program) to provide for a systematic and more aggressive approach to provide for necessary backup of targeted distribution substation transformers.

EDO's substation transformer contingency program targets large, high impact substations in a priority rank order and includes substation/circuit upgrades, capacity additions and enhancements at critical substations for the purpose of adding contingency for substation transformer failures and outages. Targeted substations are stations where large numbers of customers or critical loads will be without service for extended periods of time during transformer failures/outages due to lack of contingency from area stations. This initiative is separate from capacity additions to serve existing customers although it also often addresses near term loading issues in addition to contingency. It also provides additional capacity necessary to support long-term goals of EDO's DA initiative. Projects are prioritized using a project assessment model which considers benefit to cost in a methodology consistent with AIS project prioritization and evaluation processes. Projects are assessed based on factors such as the number of transformers a project will remove from the substation transformer contingency list, load at risk, percent of year the load is at risk, customers served (by type), age of the power transformer, availability of property and other factors.

After initial inception, revisions were made to the original program strategy. First, all new major capacity enhancements are now evaluated to also include a contingency provision for substation transformer failures. Where the incremental cost to gain contingency has high benefit/cost value and scores highly in the transformer contingency prioritization model, the incremental cost component for contingency can be funded with a reallocation of N1DT funding. This process has funded the contingency portion of multiple projects.

A second revision to the program was made during 2016 to focus on reducing outage durations at more rural KU stations not originally targeted under this program. A Spares and Portables project, completed in 2017, provided for two new, midsize portable transformers to be purchased and staged in Earlington and Pineville to better address transformer failures (At the time KU's two available portable transformers were stationed in Lexington.) and expedite service restorations involving substation transformer failures. The project also included purchase of additional spare transformers, and transformer components to speed restoration response in more rural KU areas.

LG&E/KU power transformers are all sizes – some small – less than 3750kVA, all the way up to 67MVA and several sizes and configurations in between. There are a significant number of power transformers in the LG&E/KU system where service cannot be fully restored in the event of a transformer failure during heavy load periods without direct transformer replacement or the installation of a portable transformer, both of which leave customers without service for extended periods of time. If one of these transformers fails during peak periods customers are impacted 18-48 hours while the failed transformer is replaced or portable is installed; depending on the location of the transformer and the resulting damage it could take longer.

Since inception of the substation transformer contingency program, the number of transformers considered “at risk” has been reduced from 484 to 376 across KU and LG&E. This reduction of 108 transformers results in a 22% outage exposure reduction to electric distribution substation transformers.

Capital funding allocated in the 2021 Business Plan:

Program Description	2021	2022	2023	2024	2025
Substation Transformer Contingency Program	$ 12,001	$ 9,703	$ 11,301	$ 7,500	$ 7,900

11. Volt/VAR Optimization (VVO)

Starting in 2021, EDO plans to begin deploying Volt/VAR Optimization (VVO) technologies and business processes which enable greater capabilities to manage system-wide voltage levels and reactive power flow on the electric distribution grid. An effective VVO solution enables distribution system operators to reduce system losses, peak demand or energy consumption using Conservation Voltage Reduction techniques. VVO control is an advanced system operations function that determines the best set of control actions for voltage regulating devices and VAR control devices on the electric distribution grid to achieve a one or more specified operating objectives without violating any fundamental operating constraints (high/low voltage limits, load limits, etc.). Associated functionality and capabilities are partially enabled by ongoing technology advancements on the distribution grid and will be needed with greater proliferation of distributed energy interconnections on the distribution system.

EDO’s planned VVO program provides for phased integration of VVO capabilities on the LG&E and KU electric distribution system. The Companies have conducted a pilot to demonstrate VVO capabilities in the past, however this demonstration was performed with a third party and integration with the centralized ADMS platform was not evaluated. A phased approach will allow LG&E and KU to optimally design VVO operations while building the core organization, internal skills, business processes, and controls for effective implementation and integration with EDO’s new DMS.

VVO provides distribution system operators:

- Higher level of visibility into system status and a greater degree of control capabilities to optimize energy efficiency and system reliability.
- Expanded accesses to more granular system information to support improved operating decisions by engineers, field personnel, and themselves.

- Greater ability to monitor and control voltage, limiting potential for voltage issues caused by higher penetrations of intermittent renewable generation resources and increasingly diverse and variable loads while increasing hosting capacity of such sources and loads.
- Ability to optimize within operating parameters especially when running at the system capability limits.
- Optimization of power factor such that less power generation is required to satisfy the demand of customers thereby reducing environmental impacts.
- Ability to “flatten” voltage profiles on distribution circuits allowing lower distribution system voltages when needed while minimizing risks associated with such actions.

VVO tools also enhance the ability to attain energy efficiency targets, require no change in customer behavior, require no customer purchases or incentives, and benefit all customer classes.

Capital funding allocated in the 2021 Business Plan:

Program Description	2021	2022	2023	2024	2025
Volt/VAR Optimization	$ 600	$ 1,500	$ 1,400	$ 900	$ 1,200

3.2 System Reliability and Resiliency Expense Programs

1. **Line Clearing**
   a. **Tree Related Reliability Impacts**
   Tree related outages continue to increase year over year. Data supports that decreases in annual hazard trees addressed (see part C. Hazard Tree Program, below), coupled with increased severe weather and strong wind events, particularly during 2018 and 2019, have likely contributed to higher tree related outages.

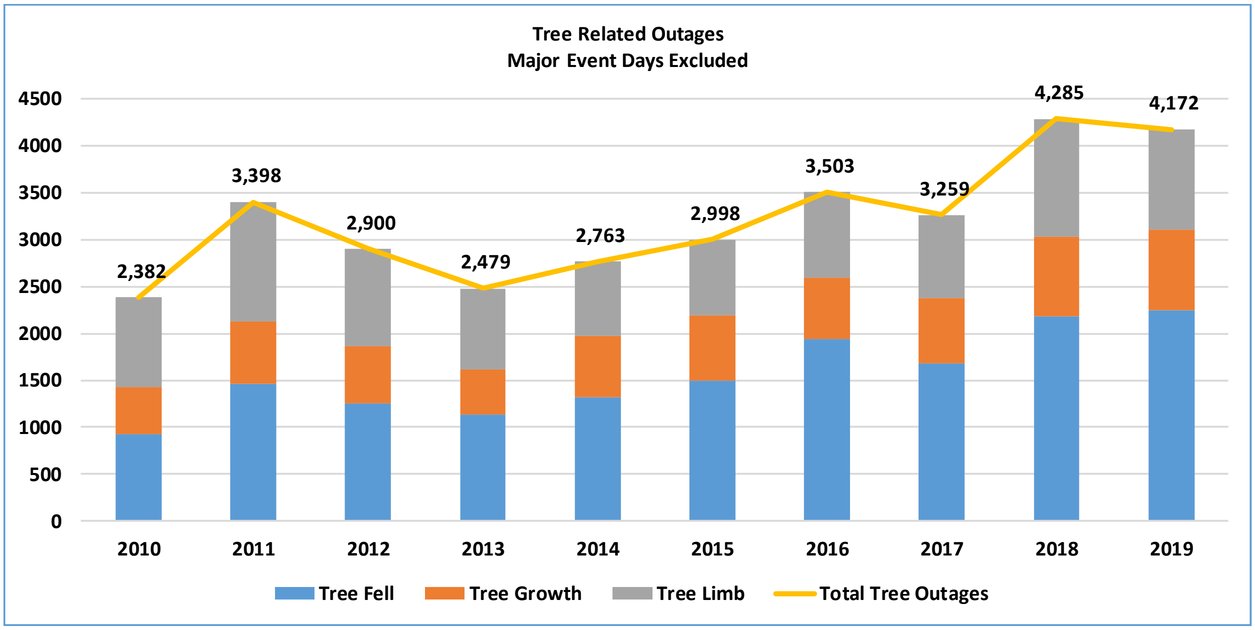

Figure 11. Tree Related Outages – Excluding Major Event Days

Average tree related adjusted SAIFI (see Figure 12) and SAIDI (see Figure 13) for the five-year period ending 2019 was virtually equal to the average tree related SAIFI and SAIDI for the five-year period ending 2014, despite the average number of tree related outages increasing by 30% when comparing the two referenced time periods. Advances in line clearance planning, coupled with increased deployment of sectionalizing and protective devices on the grid, have reduced the impacts of individual tree falls on outage duration and frequency.

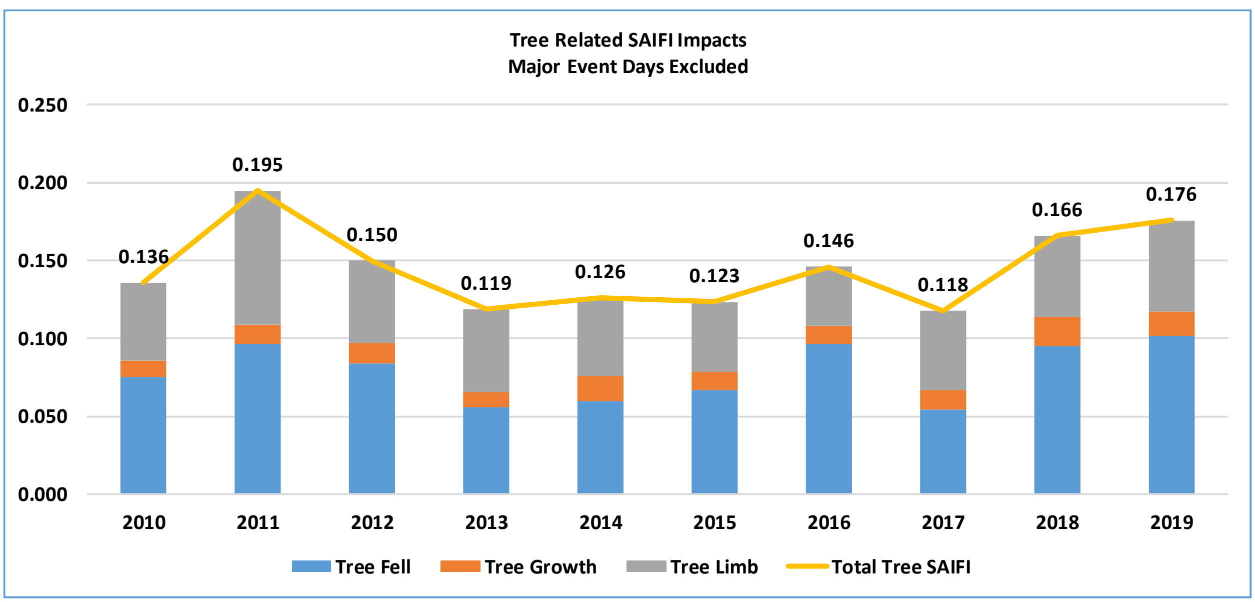

Figure 12. Tree Related Outages – Excluding Major Event Days

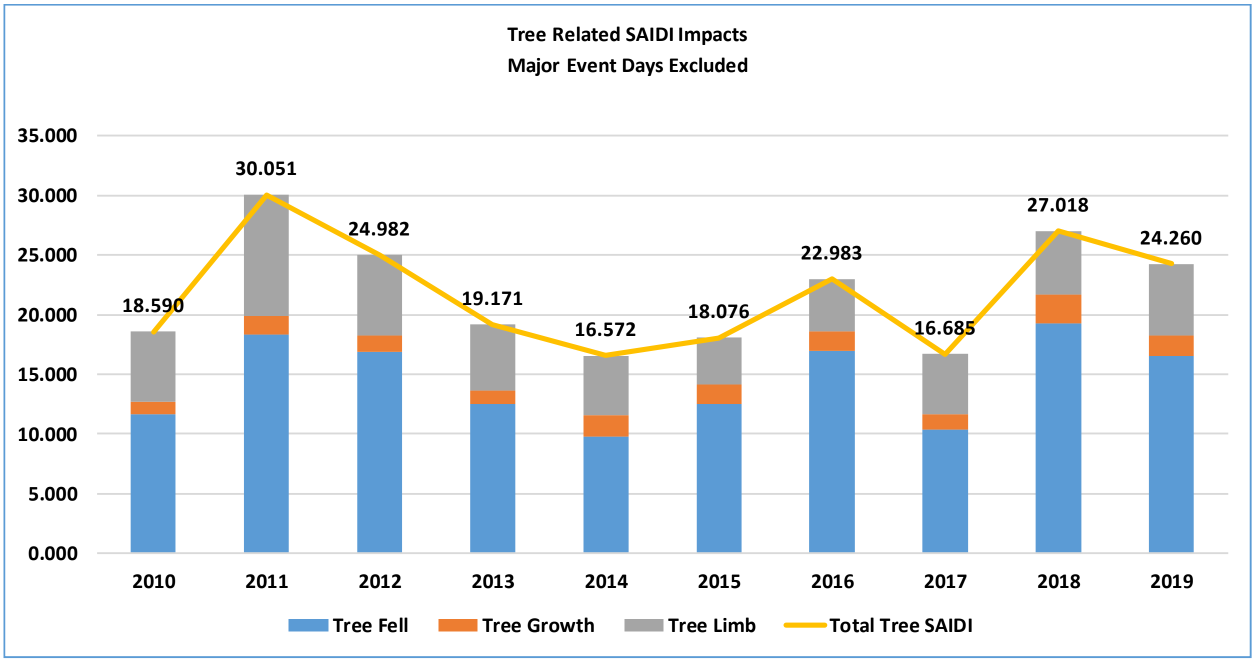

Figure 13. Tree Related SAIDI – Excluding Major Event Days

b. Routine Cycle Program

EDO employs an integrated vegetation management plan which incorporates use of manual, mechanical or chemical techniques to control undesirable vegetation and includes natural or directional pruning, tree removal, or application of environmentally safe herbicides. The program includes flexibility to operate and maintain variable easement widths as dictated by applicable ordinances or codes and need to coexist with property owners and local communities and their jurisdictional leadership.

EDO's routine cycle program (RCP) includes use of a flexible multi-cycle strategy to address tree growth and density which varies across service areas, tree populations, and tree types. The RCP provides for maintenance of a scheduled proactive circuit cycle – on a five-year or less average - in harmony with reactively addressing circuits where tree related outages and reliability performance do not meet customer expectations.

All line clearance is performed in accordance with principles of modern arboriculture and adhere to International Society of Arboriculture (ISA) standards. EDO's RCP also adheres to ANSI A300 standards and applicable National Electric Safety Code (NESC) and Occupational Safety and Health Administration (OSHA) 1910.269 regulations.

Forestry Arborists prepare annual RCP Work plans by circuit based on vegetation growth, cycle-last trim date, reliability data, and visual inspections by Company arborists. Individual circuit plans include details on trees targeted to be trimmed, removed, or chemically treated. Flexibility also exists for arborists to schedule out of cycle vegetation management to deal with reliability issues or touch up high growth areas.

As part of the comprehensive plan development, arborists assess the worst performing circuits as identified by each reliability index. These circuits are evaluated to determine root causes of outages. If tree trimming is a contributor to the poor performance, the arborists will visually inspect the circuit and determine a vegetation management plan which targets reduction/elimination of tree related outages.

Detailed assessment of tree related outage data provides that the contribution of tree growth to annual SAIDI has averaged 1.71 minutes over the last five years.

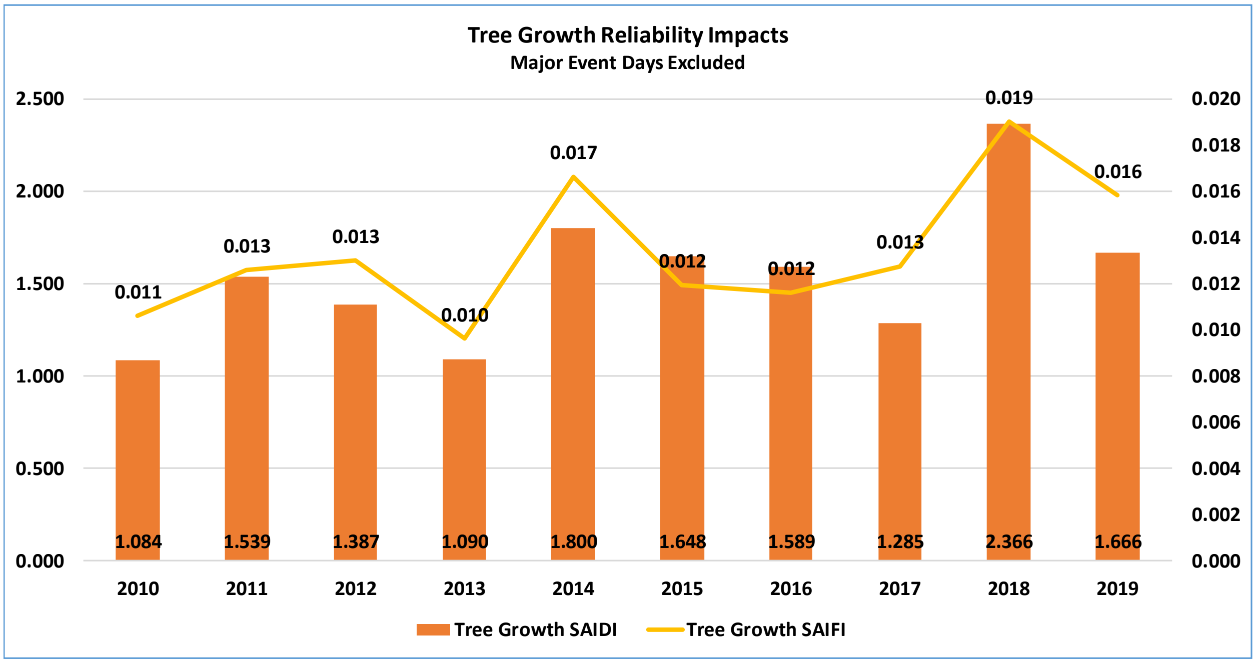

Figure 14. Tree Growth Impacts - Reliability Trends

c. Hazard Tree Program

EDO's hazard tree program (HTP) addresses trees which are predisposed to failure due to disease, structure, death or declining condition, lean or soil conditions, and which could contact a distribution conductor if the tree or a limb from the tree falls. Hazard trees near the Companies' lines are separately inspected by Company arborists and, where necessary, addressed by trimming limbs or complete tree removal if they pose a threat to the safe operation of distribution lines. For trees that are outside of the utility easement, customer authorization is required before they can be addressed.

Between 2010 and 2019, the HTP addressed nearly 141,000 hazard trees. During the first five years of the program, approximately 18,400 trees were addressed annually. Over the last five years, the average number of hazard trees addressed reduced to 9,700 annually. A primary contributor to this annual reduction related to the impacts of Emerald Ash Borer (EAB) infestation of Ash trees in proximity to distribution lines, which necessitated increased focus on aggressive trimming or complete removal of at-risk trees. More than 55% of all hazard trees addressed over the last five years were EAB trees. Because many diseased EAB trees could not be safely climbed and required heavy equipment to mitigate, significantly higher unit costs to address hazard trees were experienced over the last five years, thereby reducing the number of total hazard trees that could be addressed annually.

The contribution of tree and limb fall outages continue to trend higher (see Figure 15) despite the focus of the HTP. In fact, tree fall and limb related outages during 2019 ranked highest over the past ten-year period, with weather and wind having the biggest impacts.

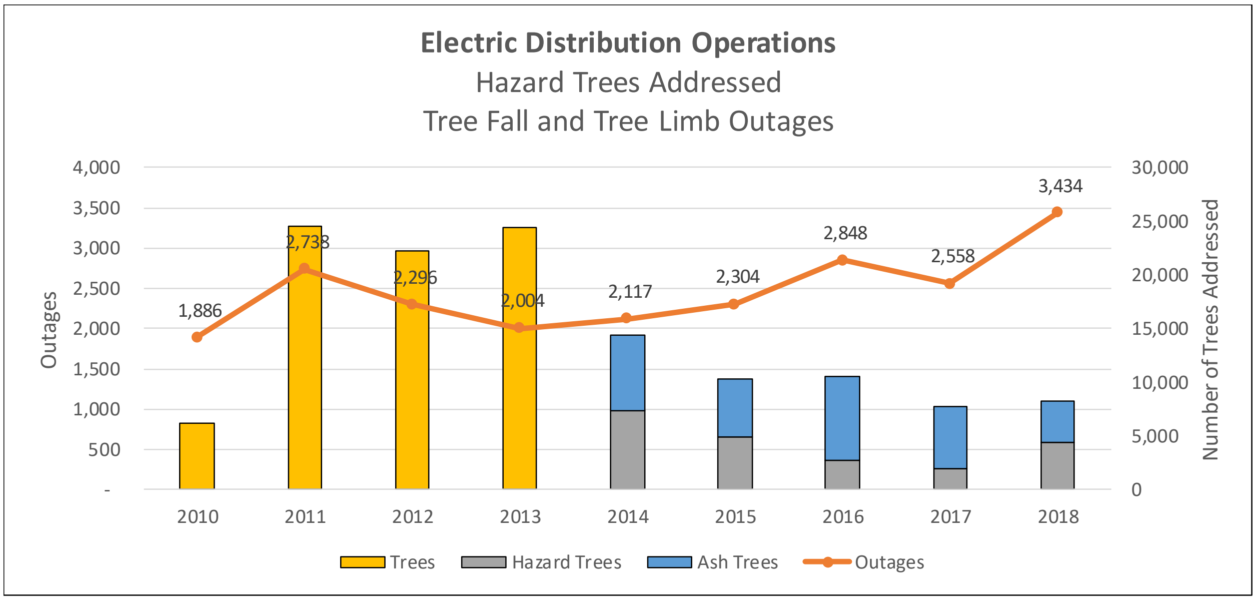

Figure 15. Electric Distribution Tree Fall and Limb Outage History

The contribution of tree and limb fall outages to average customer durations are shown in Figure 16.

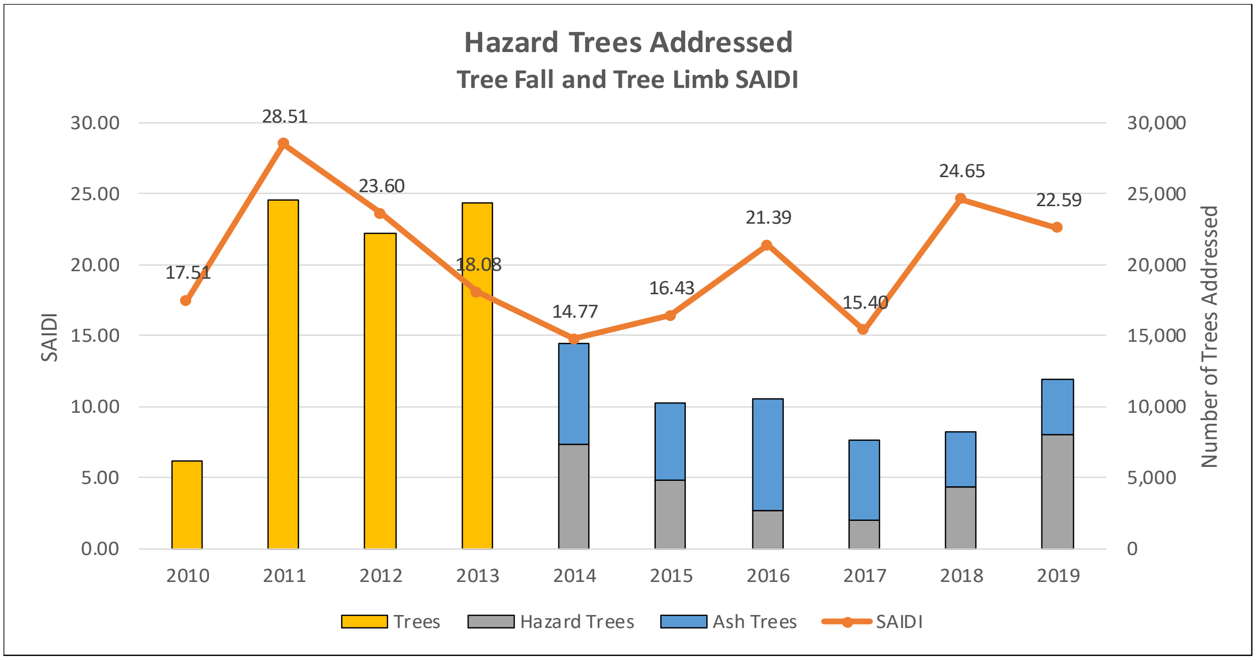

Figure 16. Electric Distribution Tree Fall and Limb SAIDI History

As shown, the annual contribution to SAIDI reduced during the early years of the HTP, where more than 20,000 trees were addressed annually between 2011 and 2013. As the number of EAB trees started to increase on the system and the number of hazard trees addressed annually decreased, the contribution of tree and limb falls to SAIDI trended higher. The five-year average contribution of tree falls for the five-year period ending 2019 was just under 2% lower than the five-year period ending 2014.

d. Vegetation Management Funding

Figure 17 displays annual line clearance expenses incurred for the Routine Cycle Program and Hazard Tree Program over the last ten years.

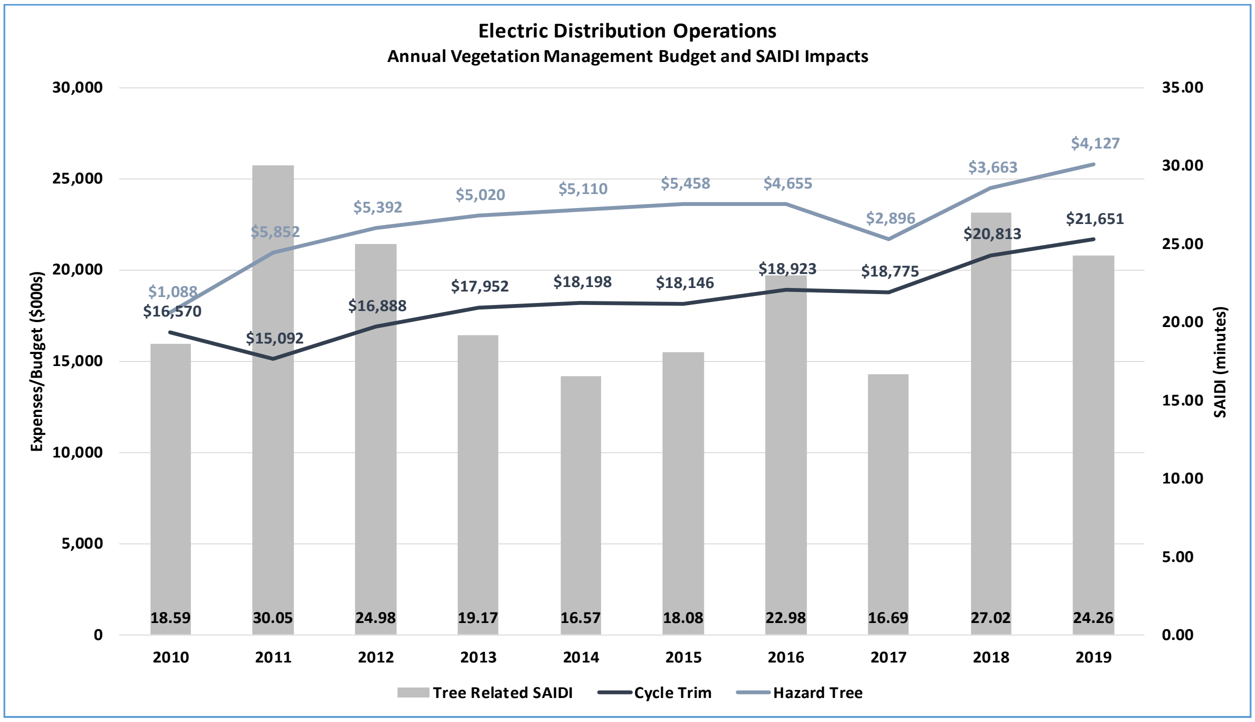

Figure 17. EDO annual tree trimming expenses overlaid on tree and limb fall SAIDI.

Funding budgeted for 2020 totaled $24.6M, including $19.7M for the Routine Cycle Program and $4.9M for the Hazard Tree Program.

Expenses budgeted in the 2021 Business Plan:

Program Description	2021	2022	2023	2024	2025
Routine Cycle Program	$ 22,515	$ 23,179	$ 23,861	$ 24,565	$ 25,291
Routine Cycle Program	$ 4,637	$ 4,775	$ 4,915	$ 5,060	$ 5,210
Total Vegeatation Management	**$ 27,152**	**$ 27,954**	**$ 28,776**	**$ 29,625**	**$ 30,501**

2. Joint Use Pole Attachment Processes

EDO manages and monitors third party pole attachments on its distribution poles to protect the integrity, resiliency, and reliability of the electric distribution system. Key programs which help to assure electric grid integrity include:

a. Standardized Pole Attachment Application Process - Since May 2019, the Companies have established the Katapult pole attachment application portal as the only acceptable form for pole attachment applications by third party entities. One consequence of this move has been more effective management of proposed attachments and more accurate record keeping. A less obvious consequence is that LKE is receiving enhanced information regarding proposed attachments, enabling engineers and design technicians to better evaluate the burden those attachments create on the electric distribution system.

- **b.** Clearance Violation Prevention – For several years, LG&E has conducted post-construction inspections of third-party attachments to identify and influence mitigation of any attachments which violate horizontal or vertical clearance codes. EDO plans to implement similar inspection procedures across all KU service areas during 2021.
- **c.** Pole Loading Studies – EDO now requires pole load modeling/testing for third party attachment applications where deemed necessary by the Company to prevent overloading of existing in-service poles targeted for attachments. Where loading issues might exist by proposed attachments, third party attaching entities are required to complete necessary "make ready" work before the proposed attachments can be completed.
- **d.** Pole Attachment Audit - During 2018, LKE initiated a system-wide third-party pole attachment audit. The audit consisted of three primary objectives: 1) verify pole ownership, 2) count and identify third party attachments, and 3) identify locations where stub pole remains after pole replacement ("double wood"). A secondary benefit of this program was to assure that any unauthorized attachment on the electric distribution system did not jeopardize the reliability or resiliency of the electric distribution system.

  Audit of the system is expected to be concluded early this summer (2020) and cost nearly $2.7M. Data collected from the audit will be assessed for quality control and ultimately be loaded into the Company's designated asset management and mapping data bases and be shared with attaching entities. The next audit of the electric distribution system is scheduled to begin approximately five years post completion of the audit initiated in 2018. Future system audit costs for third party attachments will be the responsibility of cost causers.

4. Distribution Reliability and Resiliency Summary

Customer expectations regarding electric service reliability and power quality continue to increase commensurate with their growing dependence on electric service. The reliability and resiliency capital and maintenance programs described herein advance grid intelligence and system automation, concentrate on underperforming system components, and provide for prudent and consistent replacement of aging infrastructure to support sustained delivery of safe and reliable electric service to customers. Table 3 below provides a summary of funding allocated to specific reliability and resiliency programs in the 2021 Business Plan.

	Electric Distribution Operations Primary System Reliability and Resiliency Programs										
		2021 Business Plan ($000)									
	Program Description	2021		2022		2023		2024		2025	
Capital	Distribution Automation	$	12,843	$	-	$	-	$	-	$	-
Capital	System Hardening	$	3,652	$	7,090	$	8,241	$	7,674	$	7,734
Capital	Customers Experiencing Multiple Interruptions	$	2,431	$	2,492	$	2,554	$	2,618	$	2,683
Capital	Reliability Improvement Blankets	$	1,825	$	1,888	$	1,892	$	1,951	$	2,011
Capital	Circuits Identified for Improvement	$	2,751	$	2,820	$	2,891	$	2,963	$	3,037
Capital	Substation Wildlife Protection	$	1,974	$	1,280	$	1,288	$	295	$	302
Capital	Underground Fault Current Indicators	$	5,702	$	-	$	-	$	-	$	-
Capital	Pole Inspection and Treatment Program	$	13,026	$	13,416	$	13,818	$	14,173	$	14,528
Capital	Legacy Substation Breaker Replacements	$	3,659	$	3,224	$	3,510	$	2,315	$	2,373
Capital	Legacy Substation Relay Replacements	$	5,318	$	2,234	$	5,240	$	3,245	$	252
Capital	Underground Substation Exit Cable Replacement	$	1,660	$	1,720	$	1,500	$	1,538	$	1,576
Capital	Underground Residential Development Cable Replacement	$	3,058	$	3,067	$	2,408	$	2,449	$	2,482
Capital	Paper Insulated Lead Covered Cable Replacement	$	11,163	$	-	$	-	$	-	$	-
Capital	KU Substation SCADA Expansion	$	5,085	$	999	$	2,500	$	1,000	$	500
Capital	Substation Transformer Contingency Program	$	12,001	$	9,703	$	11,301	$	7,500	$	7,900
Capital	Volt/VAR Optimization	$	600	$	1,500	$	1,400	$	900	$	1,200
Capital	Distributed Energy Resource Management System	$	-	$	-	$	-	$	-	$	1,000
Capital	Miscellaneous Aging Infastructure/Reliability Projects	$	4,840	$	4,886	$	3,908	$	2,742	$	2,761
	Total Capital	**$**	**91,588**	**$**	**56,319**	**$**	**62,451**	**$**	**51,363**	**$**	**50,339**
Expense	**Routine Cycle Program**	$	22,515	$	23,179	$	23,861	$	24,565	$	25,291
Expense	**Hazard Tree Program**	$	4,637	$	4,775	$	4,915	$	5,060	$	5,210
Expense	**Joint Use Pole Attachment Audit**	$	-	$	-	$	-	$	-	$	-
Expense	**Pole Inspection and Treatment Program**	$	536	$	552	$	568	$	586	$	604
	Total Expenses	**$**	**27,688**	**$**	**28,506**	**$**	**29,344**	**$**	**30,211**	**$**	**31,105**

Table 3. 2021 Business Plan – System Reliability and Resiliency Investments and Expenses

As displayed, capital allocated for distribution reliability and resiliency investments will decline sharply after 2021 but remain relatively steady throughout the remainder of the 2021 Business Plan period, as key capital programs – Distribution Automation, Paper Insulated Lead Covered cable replacement, Underground Faulted Circuit Indicators, etc. - implemented over the last decade are completed.

Annually, Reliability Engineering attempts to predict system reliability performance, taking into consideration planned investment and maintenance programs, historical reliability performance, and any weather or natural disaster events which might negatively impact system performance going forward. Table 17 represents forecasted reliability performance for the 2021 Business Plan period.

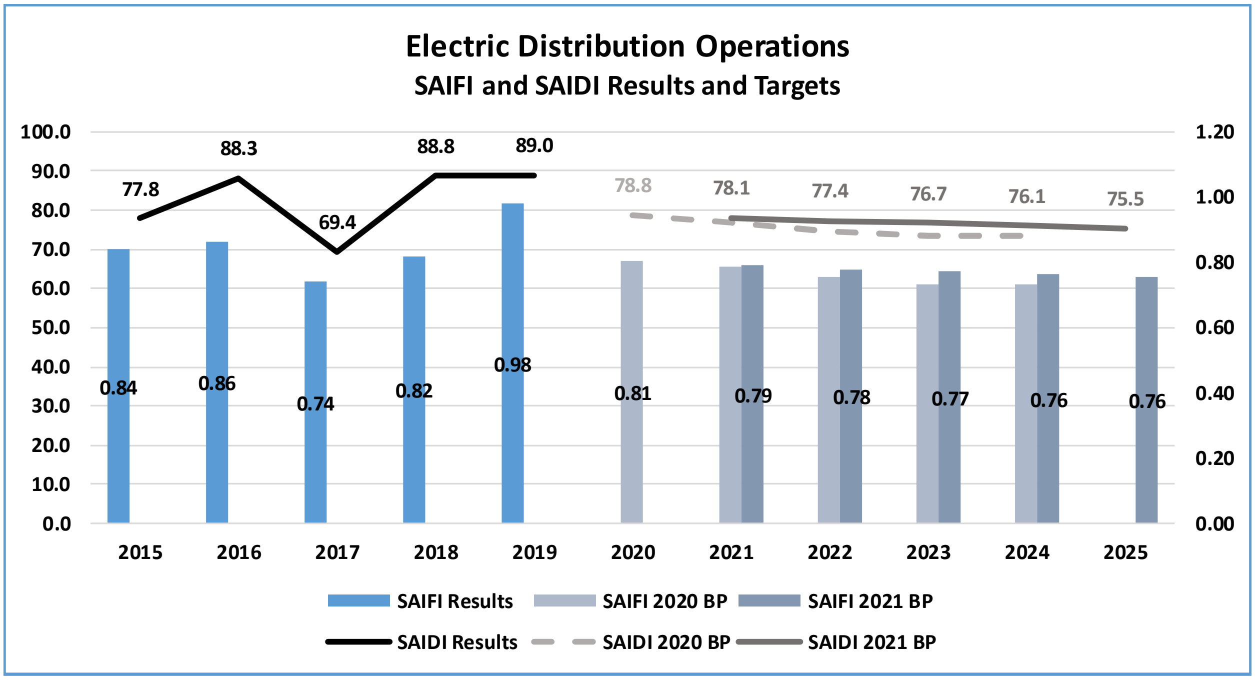

Figure 17. Reliability Engineering adjusted SAIDI and SAIFI forecasts for 2020-2025.

Operational Benefits of Advanced Metering Infrastructure

Louisville Gas & Electric – Kentucky Utilities Use Cases

3002019487

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EXECUTIVE SUMMARY

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Product Title: Operational Benefits of Advanced Metering Infrastructure: Louisville Gas & Electric – Kentucky Utilities Use Cases

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PRIMARY AUDIENCE: Distribution operations managers

SECONDARY AUDIENCE: System integration managers

KEY RESEARCH QUESTION

Advance Metering Infrastructure (AMI) systems have been deployed throughout the electric utility industry with capabilities to accurately record and transmit the metered usage of electricity. However, these AMI systems have different capabilities associated with supporting use cases related to operations.

RESEARCH OVERVIEW

This research explores the operations-based use cases supported by the AMI technology planned for deployment at LGE-KU. The document also describes the integration of the AMI system with other distribution systems to enable the use cases deemed valuable.

KEY FINDINGS

- The uses cases that do not require additional development have been proven at multiple utilities.
- The determination of sustained outages can be performed within the meter if properly tuned to the operation of the distribution system.
- Customer Communication systems can deliver quick and accurate outage information based upon AMI reports.
- The utilization of AMI pinging has proven the ability to identify outages that also have an associated down energized conductor hazard.

WHY THIS MATTERS

Understanding how to properly tune the AMI system with other distribution operations data sources enables the realization of many operation benefits.

HOW TO APPLY RESULTS

The use cases listed in the document should be further analyzed by the utility to determine the associated systems capabilities required, the expected value and the development cost for each. Based upon the specific utility's analysis, a development roadmap can be created that outlines the resources need for each use case and a timeline for development and deployment.

LEARNING AND ENGAGEMENT OPPORTUNITIES

- AMI based operational beneficial use cases in production or being considered are often discussed in the Distribution Operations Interest Group (DOIG).

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PROGRAM: Distribution Planning and Operations, Program 200

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ABSTRACT

Timely and accurate readings of customers' electricity usage have been the primary basis for the business case that has seen millions of advanced metering infrastructure (AMI) meters deployed, but there are other valuable uses for AMI systems and data. Some utilities have since realized great operational benefits, whereas others have kept the focus on consumption readings.

The utilities that have realized operational benefits have tuned their AMI system to be in sync with their distribution system. The operational benefits have rivaled those provided by supervisory control and data acquisition (SCADA) and the outage management systems. In a short time, distribution system operators have come to rely on the information generated by AMI meters to efficiently process outages, and they use its other operational information. In addition to measuring consumption, the meters have become a valuable sensor located at each customer premise.

The first two sections of this report summarize use cases that have been demonstrated by utility deployments of AMI meters. The first section is dedicated to the many use cases enabled by the simple process of the meter detecting a sustained outage at its point of connection. The second section uses data in addition to outages collected by the AMI meter. The third section describes use cases that require further development from the AMI vendors or vendors of auxiliary systems before the use case can be demonstrated.

Keywords
Advanced metering infrastructure (AMI)
Kentucky Utilities
Louisville Gas and Electric
Outage management system
Outage messages

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SERVICE RESTORATION BENEFITS FROM ADVANCED METERING INFRASTRUCTURE OUTAGE MESSAGES

Outage messages from advanced metering infrastructure (AMI) meters can create many efficiency managing tasks associated with service restoration. The ability to fully realize the efficiency is dependent on the design of outage determinations to be in sync with the operation of the distribution system and tuning the outage management system (OMS) to work in harmony with the AMI outage messages. A well-designed system can supersede customer calls as the primary method for identifying outages.

Engineering the Outage Reporting System

Although AMI meters' primary goal is to provide individual customer consumption data, the main goal for operations is to accurately distinguish between a momentary outage and a sustained outage. The utility should take great effort to ensure that inaccurate outage determinations do not create an outage prediction within the OMS. The most straightforward and accurate method for accurately distinguishing between a temporary and sustained outage is to program the meters to delay coding an outage as sustained until after the utility's protection system completes all its attempts to reenergize the system. This can be accomplished by adjusting the protection philosophy or by adjusting the outage threshold timer in the AMI meter.

Momentary outages occur when the system's protection and restoration schemes work as designed and either reenergize the system following a temporary fault or isolate permanent faults to the smallest number of customers through protection and restoration systems. The length of a momentary outage depends on the reclose times programmed into protective devices and the time required for automation systems to restore customers from alternative sources. A sustained outage occurs for the customers who lose power and must remain out until the utility acts to enable the customer to have their service restored.

Knowing about momentary outages is beneficial, and the data associated with them are employed in many use cases. But none of the use cases associated with momentary outages requires an immediate response by the distribution system operator (DSO) or a first responder. Thus, collecting data associated with momentary outages can occur with normal meter reading schedules. Sustained outages require the immediate attention of the DSO to manage the restoration of the customers. If the AMI, OMS, and supervisory control and data acquisition (SCADA) systems are designed to work together to identify sustained outages, restoration processes and customer outage communication can be greatly improved.

Outage Identification

The process to determine that an outage occurred is the same for most communication technologies, with just a few variables. The first variable is the **outage threshold** in the meter metrology portion of the meter. The outage threshold is the dip in voltage that will cause the power supply to the communication module to drop out. The outage threshold is usually expressed as a percentage of nominal voltage. Table 1-1 displays outage thresholds for Georgia Powers' deployed meters. The second variable is the **sustained outage threshold**. The sustained outage threshold is the duration for which the communication card experiences a loss of power from the meter before the meter transmits an outage event message. The outage threshold varies by meter manufacturer.

Table 1-1
Georgia Power outage threshold table for meters deployed

Form	Nominal Voltage	Sensus Gen2		L+G Focus AX		Elster A3	
		Detection Voltage	%	Detection Voltage	%	Detection Voltage	%
1S	120	–	–	84	70	–	–
2S	240	36	15	168	70	48	20
4S	240	48	20	–	–	–	–
9S	120	–	–	84	70	48	40
12S	120	–	–	84	70	–	–
16S	120	–	–	84	70	36	30

Notes:
All meters programmed with a six-cycle (minimum) delay when voltage drops to levels shown in table.
Nominal voltages selected based on meters primarily in use on our system.

In many meters, the outage threshold is a function of the design of the power supply, located in the metrology portion of the meter, and is a variable that cannot be changed. But the sustained outage threshold is calculated by the software. In many systems, the sustained outage threshold is configurable within the limits of the stored energy within the meter.

For early models of AMI, the capability of the stored energy to power the communication module was just a few seconds. Modern AMI meters have an internal capacitor or batteries that can keep the meter operating for a couple of minutes to many minutes. For AMI systems with a couple of minutes of stored energy, the sustained outage timer is a variable that can be manipulated to match the operation of the distribution system.

Determining Sustained Outage Threshold

Because the meter reset voltage is not maintained during the reclose attempts, the reclose times must be added together to get the total time to lockout. For example, a feeder breaker with a 3-second, 15-second, and 30-second reclose time could have a successful restoration 48 seconds after the start of the event. For this example, to be conservative, the sustained outage threshold should be set greater than 48 seconds so that only outages lasting longer than 48 seconds will be coded by the AMI system as sustained. Setting this wait time too low will result in some momentary outages being reported as sustained outages. Setting the sustained outage threshold too long will reduce the amount of time that the AMI system has to send data packets. For large outages, the reduction in transmit time might result in fewer outage events making it to the OMS. If reclosing times are consistently applied throughout the utility, the wait time can be set close to the sum of the reclose times.

The balance between accuracy and speed is of great concern. If a momentary outage is reported by the AMI system as a sustained outage, the DSOs will process the outage as sustained without any benefit.

Undesired Outage Message Filters

An effective outage reporting system should filter undesired sustained outages before they are passed to the OMS or filter the messages within the OMS. Filtering is often performed outside of the OMS and meter management system by a standalone application. This application will need to access data from multiple systems to identify messages that should be blocked from entering the OMS or identifying messages that might need to be differentiated within the OMS.

Meters with Active Work Orders for Their Location

Blocking the outage message for meters that have an active work order prevents outages from being reported on meters that are experiencing an outage due to normal work activities. This filter works very well for meter orders. Work that involves deenergizing a transformer is usually associated only with one of the many meters attached to the transformer. Thus, a crew will need to contact operations before deenergizing a transformer that is serving multiple customers because only one meter can be filtered out. Active work orders can also be scripted to block outages from all the customers connected to the same transformer as the meter identified by the work order. Because knowing a crew's work location benefits the DSO, having crews call before deenergizing a transformer is a good practice. If the DSO's workload allows, the DSO can allow the outages to migrate into the OMS and then verify that only the transformer involved is predicted and that all the meters associated with the transformer report an outage. Based on the outage information, the DSO can then take action to correct the model of any misassociated meters.

Inactive Meters

Meters that are inactive might have a filter that blocks their message, or the outage in the OMS might be marked as inactive. When responding to a single meter outage associated with an inactive meter, the inactive flag allows the operator to inform the first responders that the service is inactive. There have been cases where a crew responding to an inactive meter outage arrives to find unauthorized individuals removing the service conductors. There is also the option to completely filter out events associated with inactive meters. However, completely filtering them out could leave a hazardous situation for the public, such as an energized overhead service that has been torn from the house of an inactive account.

Meters with an Active Tamper Alert

Some meters report both an outage and a tamper alert together when the meter is removed. Outage events associated with a tamper event are generally blocked from the outage process. The tamper message is still sent through the tamper response process.

Meters That Do Not Reliably Distinguish Between Sustained and Momentary Outages

If a utility has a mixture of meters where some (usually an early vintage) do not accurately distinguish between sustained and momentary outages, that utility might choose to pass outage information only from the meters that can distinguish between the different outages. Filtering the early-vintage meters reduces the need for more complicated filtering applications.

Meter Ranges

When a filtering system is designed, it is a common practice to have a filter based solely on the meter number or a range of meter numbers. This allows the utility to filter out a vintage of meters or meters that are used for alternative purposes.

Single Customer Outages

Single customer outages are often filtered out in areas that have electricians who are permitted to remove meters to work on customer's facilities. Although this practice reduces truck rolls to planned customer outages, filtering these outages also keeps single customer outages from being reported. Some utilities have applied this filter only during normal business hours. During hours when electrician work is not common, the single customer outage events pass to the OMS.

Single customer outages inherently have different investigation techniques. Many events will require the first responder to enter the customer's property. To protect the first responder from startling a homeowner, utilities have initiated additional work processes for dispatching single AMI-only events (customer does not call). The business rule may include the requirement that the customer be contacted to make them aware that a crew will be investigating. Another option is to dispatch someone to inspect the transformer and service from the street without trespassing on the customer's premises until contact is established.

Picking the Meter with the Desired Outage Threshold Voltage

In many meters, the voltage threshold is a function of the hardware and is not a variable that can be changed. Depending on the segment of the distribution system to which the meter is connected, a higher dropout voltage might be desired. In particular, identifying blown fuses on delta-wye transformers and outages associated with ungrounded systems is best supported by a high dropout voltage. For meters with a programmable voltage threshold, the voltage threshold can also be manipulated to provide the optimum outage detection. Following are two scenarios that will be reported as an outage for meters with a high threshold voltage but will not be reported as an outage if the voltage threshold is low. It should also be noted that many polyphase meters monitor the voltage on only one phase and will not report an outage for some single-phase conditions.

Identifying Blown Substation High-Side Transformer Fuses

Many substations use fuses to provide transformer protection. If the transformer is also a delta-wye configuration, a single blown high-side fuse will cause low voltage on two phases of the distribution system. The phaser diagram is shown in Figure 1-1. A blown fuse on Phase 2 of the substation transformer will affect the voltage on phase B and C of the distribution system. Because Va + Vb + Vc = 0 and Va is nominal, the voltage at the meter for customers connected to phase B or phase C will be nearly 50% of nominal.

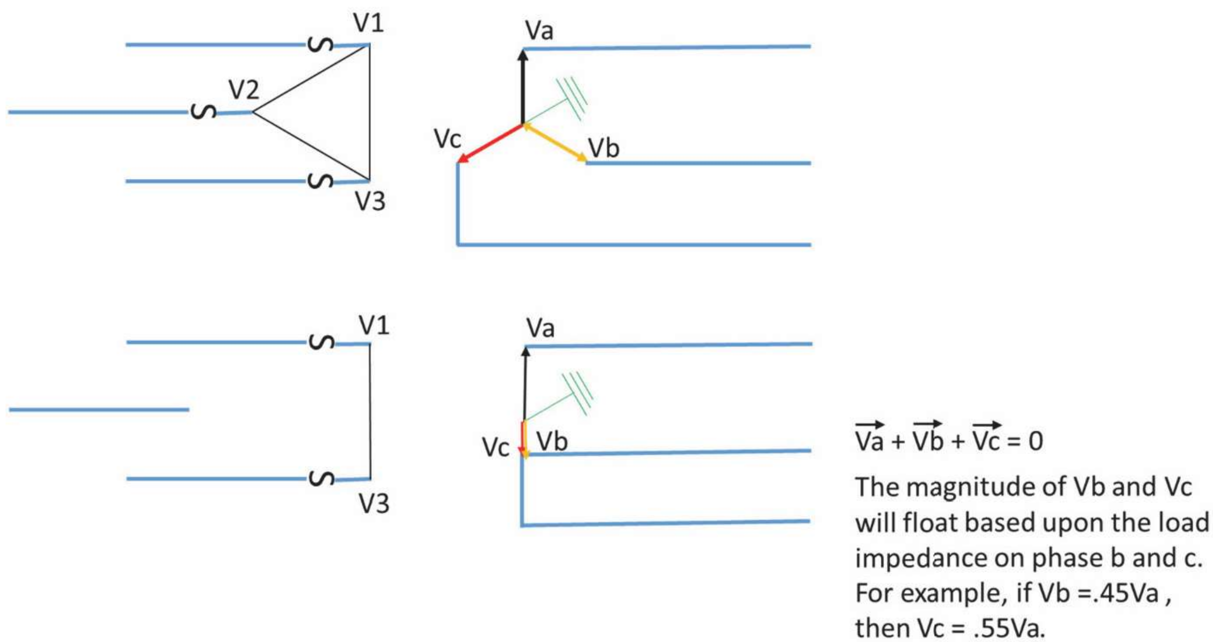

Figure 1-1
Vector representation of high-side transformer fuse open

Because the outage threshold for meters is different for different makes and models of meters, some meters might report an outage while other meters report on a low-voltage alarm. If outages are reported, the OMS will create a predicted outage on the feeder breaker. The DSO will be prompted to investigate.

If low-voltage AMI alarms are not imported into the OMS, the distribution system operator might not know about the condition until customers call. If customers report dim lights to a customer service agent, the agent might create a power quality report instead of an outage report.

Identifying Outages on Ungrounded Distribution Systems

Ungrounded distribution systems might also have a reduced voltage instead of a complete voltage collapse. By selecting meters with a high outage voltage threshold, the meters will report an outage for phases that are being back-fed through transformer windings from the unfaulted phases.

OMS Impacts

The OMS functions by using many prediction rules. Although these rules were created to use a small number of customer calls to create an outage association, the same rules can be used with mass outage reports from AMI meters. But there is some additional functionality created by the predictable speed at which AMI can report outages.

Identifying Nested Outages by Locking Outage Predictions

AMI has the potential to identify nested outages. As AMI outage reporting continues to get faster and more accurate, OMS prediction rules can be adjusted to take advantage of the speed and quantity of outage reporting. One such OMS rule is the time in which outages are locked and prevented from being associated with a larger outage. For example, if the time to lock the outage is set at 5 minutes, a fuse outage that occurs at least 5 minutes prior to an upstream recloser lockout would be locked in as a nested outage. Events that are locked will be identified to system operations as a separate event from the larger event.

In severe weather events when multiple faults are occurring near each other, AMI meters could be reporting outages within proximity of time. Although it is possible to compare the outage start times of AMI outage messages to identify nested outages, this computation is not commonly pursued because field crews are expecting multiple cases of trouble and require a manual inspection of the entire line before energizing. These inspections include the reporting and modeling of open protective devices before closing source devices to restore service.

Outages Restored by FLISR Systems

Outages restored by FLISR (*FLISR* stands for *fault location, isolation, and service restoration*) systems pose an additional challenge for AMI systems. Figure 1-2 illustrates an outage associated with a FLISR restore. In this example, an outage threshold of 60 seconds would report an outage to the OMS, and an outage threshold of 120 seconds would accurately report the outage as a temporary outage.

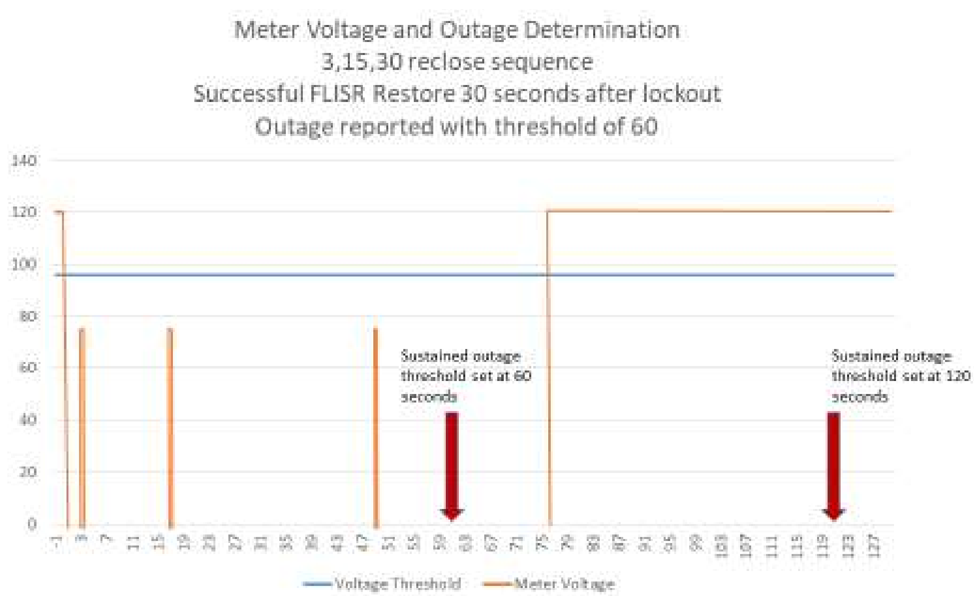

Figure 1-2
Determining outages restored by FLISR systems

Because many AMI systems will have a shorter outage threshold than the total restoration time of most automated FLISR systems, this type of outage will be reported by the AMI meters as sustained. As long as the actions taken by the automatic FLISR application are modeled in the OMS in the correct order, the OMS should predict an outage, create a nested outage, and then close the outage event for the areas restored by the FLISR actions.

Because the FLISR action could occur very close in time to the meters reporting their outage, the AMI outage messages might impact the outage management system by creating a prediction to an area that has just been restored. Prior to AMI, buffered messages from voice response systems created the same issue within the OMS. To prevent restored areas from being predicted out, OMSs have a time delay setting that will group outage messages with restoration activities. For example, in Figure 1-3, within 5 minutes of restoration occurring, any outage messages from customers or meters that come in from the restored area will be auto-closed.

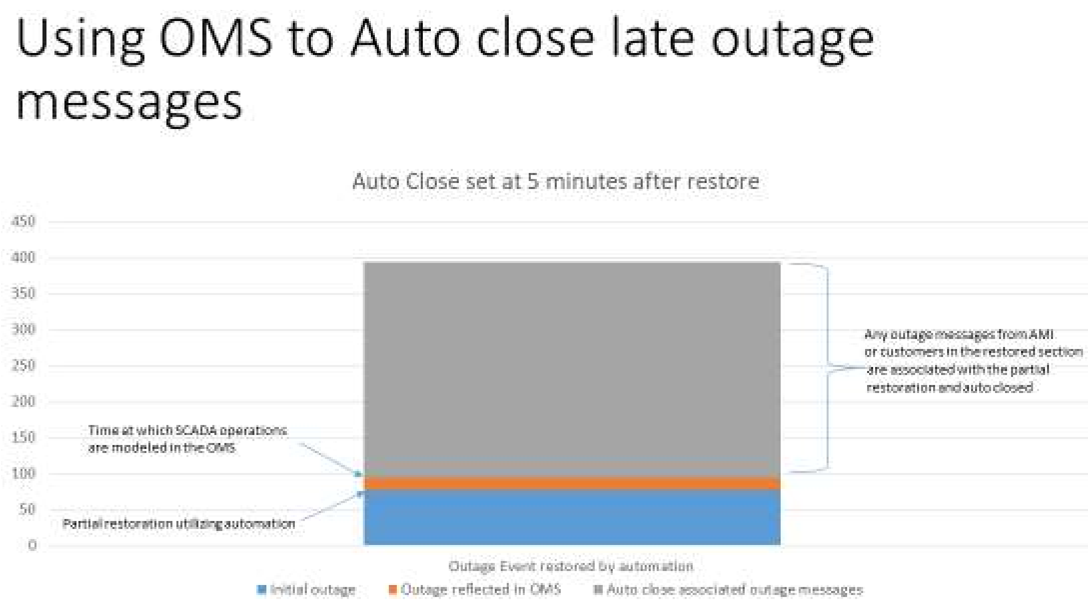

Figure 1-3
Using OMS to close FLISR restored outages

Linking Meters to a Transformer and Capturing the Latitude and Longitude

When the geographic information system (GIS) became the source of information driving the OMS to create predictions, a relationship between the meter account and the premise ID was created. When an AMI meter is installed, it will inherit the premise ID association. The relationship between the meter and the premise ID is the primary linkage for outage messages to be used by the OMS. If past OMS experience has proven the linkage to the premise ID to be a constant source of misinformation, the cost associated with training meter installers to read GIS maps and verify the correct premise ID association might be warranted. Whereas verifying the premise ID association could require additional training and cost, capturing the meter's global positioning system (GPS) coordinates requires little training and can be built into the tools used by the AMI installers. The association of the AMI meter to its physical location enables many use cases that depend on a visual representation of the data. Depending on the meter, the GPS coordinates can be stored in the meter (ANSI C12.19 standard, Table 6) and transmitted with certain messages. If the meter does not support the storage of GPS data, the GPS data can be stored in a back-office association table and added to various messages during processing.

Visually Showing Customer Calls and AMI Outages in the OMS Map

The OMS will receive both customers' reported outage calls and AMI meter outage messages. The OMS can be configured to distinguish between the different outage messages. The OMS can distinguish the outage type by deploying different icons or using the same icon with different colors. The visualization of outages on the OMS outage map provides the operator with a tool to further analyze the current state of the distribution system. Visually representing outages also enables the operator to look for patterns associated with outage events.

AMI Outage Visualizations Outside of the OMS

In addition to showing AMI outages in the OMS maps, utilities can realize other benefits from displaying AMI-related data on a map using the GPS coordinates of the AMI meter. Some AMI vendors have visualization packages, or the utility can design its own visualization to meet their particular use case.

Business Continuity for a Loss of the OMS

If outages are shown on a map that overlays the distribution system, operators can use the outage information to manually perform the function of an OMS. Ideally, the outages would be removed from the map once AMI restore messages are received from the same meters. This is a very effective backup to the loss of the OMS.

High-Level Storm Management

AMI outage and restore messages overlaid on a distribution system map can be used by distribution executives to monitor the outages and the associated restoration efforts during major events. Outages are typically shown in one color, and restorations are shown in a different color. Although the number of AMI outages does not have a direct correlation to the amount of damage to the distribution system, seeing the restorations in near-real-time will show the progress being made by restoration efforts.

Enhanced Customer Outage Information

Many customers expect today's utility to know about their outage and communicate information to them about it without the customer taking any action. Without AMI outage reporting, utilities are able to meet this expectation for outages only behind SCADA-monitored equipment. Without AMI meters sending outage messages, outages behind devices, such as hydraulic reclosers and fuses, will depend on customers notifying the utility about the outage. An AMI system can report outages quickly and greatly reduce the time it takes to accurately determine the open protective device. When notifications from the customers become unnecessary, the utility can change the way it processes outage information and provide information to the customer in a manner that was not possible before an AMI deployment.

Proactive Customer Communication of an Outage Using an AMI-Driven OMS

Customers desire information about their outage. Once a sustained outage occurs, the customer would like to receive a notification from the utility confirming that the utility is aware of the outage. Utilities with an AMI system that accurately distinguishes between a sustained and momentary outage can meet the customer's expectations by quickly (usually within 90 seconds) communicating with the customer that the utility is aware of their outage. For some, this might be a text message or an automated phone call. Customers who do call the utility can be greeted with recorded messages confirming that the utility is aware of the outage as part of the automated voice response system. Customer service agents will also know that the OMS is already aware of their outage. The notification messages can also include account information, such as the address associated with the outage. This allows customers to know the power status at remote locations, such as vacation properties or vacant rentals.

Customer Main Breaker Issues

If outages from your AMI meters consistently create a prediction in your OMS system before customer calls, your customer communication systems can be designed to give customers messages that accurately reflect the state of their service. If the customer's account does not match an existing outage prediction, the system informs the customer that the utility's analytics does not indicate that the customer is experiencing an outage and that they should check their main breaker or contact the maintenance department if the meter is associated with a multifamily account. Many customer calls are associated with internal breaker issues. The system can be further advanced by giving the customer the opportunity to have their meter interrogated. The associated meter is pinged for health and voltage. If the ping is successful, the customer would again get the message directing them to check their breaker. If the ping was unsuccessful, the customer would hear a message confirming their outage, and the system would create an outage ticket and a follow-up work order to determine why the meter did not report the outage. If the customer decides to forgo the automated process and talk directly to a customer service representative, the representative has the same information, including instructions on how to reset a breaker.

Outages for Customers with Multiple Accounts

An outage report by phone from a customer with multiple accounts can be difficult to accurately process. Many customers might not know the identifying attributes of their service, such as account number, meter number, or even the address the utility has on file. Once the customer has linked their phone or email to an account, they will receive outage communications for all accounts.

Outages for Large Commercial and Industrial Accounts

Many commercial and industrial (C&I) accounts have advanced meters that have a different communication medium than the standard AMI meter. Many C&I meters were not designed to report power outages. Utilities have found that it is beneficial for large C&I meters to also report outages, even if the meter uses a different communication system or involves a process separate from standard AMI meter outages. The utility might have to invest in a separate metering monitoring system to proactively report outages associated with their larger customers.

Intermittent Service Problems

Many utilities develop special procedures for single customer outages reported only through the AMI system. One step in the process might be to immediately ping the meter. Occasionally, operations will ping a meter associated with a single meter outage that was reported by the AMI meter and receive a ping response that shows that the meter is energized and has good voltage. Meters that ping on are taken out of the outage process and are dispatched to someone who is equipped to study the service to determine what caused the sustained outage determination. Examples include a bad meter, connection issues, or cable degradation. This allows problems to be corrected before they result in an extended outage or equipment damage.

Enhanced Reliability Indices

If the meter adheres to the ANSI C12.19 standard and implements both the outage and restoration events and the history table and/or profile tables, the meter will have a record of every outage and restoration event. Because the record includes a time stamp, the data within the tables can be used to create very accurate reliability indices. The data within the tables can be collected with normal usage data packets. By calculating indices outside of the OMS, the indices are not impacted by erroneous predictions or human error associated with manually entering outage start and restore times. Utilities have successfully transitioned from reliability indices calculated from the OMS, which are dependent on accurate modeling and data entry, to indices calculated from the start and stop times from the AMI meters. Note that although not all outage messages from AMI meters make it to the OMS systems, all outage events are kept within the outage tables.

Down Energized Conductor Identification

When an energized conductor breaks and falls to the ground, there is the potential for the impedance of the fault to limit the fault current associated with the event. Because most protective devices detect a fault condition by measuring or reacting to the elevated level of current, faults that have limited fault current might go unrecognized by protective devices and remain energized. The occurrence of conductors that remain energized creates a hazard that has been difficult to mitigate. The Electric Power Research Institute (EPRI) has researched multiple options to identify these hazardous conditions (see, for example, the 2018 EPRI report *Modern Approaches to High-Impedance Fault Detection* [3002012882]). One option is to analyze data from an AMI system to help identify broken energized conductors before a visual inspection occurs.

AMI, Outage Management System, and SCADA Data

The process of identifying down conductors with AMI data was first proven by correlating data from advanced metering infrastructure, OMS, and SCADA. Outages within the OMS are either "predicted" or "confirmed." For confirmed outages, SCADA or an operator acknowledges that the outage is real. When SCADA data from a recloser indicate that the recloser is open, the OMS system will create a confirmed outage and aggregate all outage reports downstream of the recloser into the outage event. If the SCADA system indicates that a recloser is closed but the OMS collects advanced metering infrastructure outages that exceed the prediction setting, the OMS will create a predicted outage at the recloser. The predicted outage must be analyzed by an operator to determine if SCADA or the prediction engine is incorrect.

Through experience, outage events with a SCADA and an OMS conflict were found to be the result of multiple fuse outages or from having an unintended break in the system. A visual review of the outages proved useful in determining which type of event caused the conflict.

Multiple Fuse Outages

If the number of fuse outages behind the recloser exceeded the prediction rules, the fuses' outages would be combined into one outage event behind the recloser. For these events, the operator would determine which fuses were opened based on their associated outage notifications and create confirmed fused outages within the OMS. The predicted recloser outage would be cleared and transformed into multiple fuse outages.

An Open Point in the Main Line

There are times when a jumper or switch might burn open or a conductor breaks to create an open point in the line. Because manual switches, jumpers, and line segments are not predictable devices within the OMS, the outages behind the open point would be grouped and predicted at the recloser. When these events are visually viewed by the operator, a pattern occurs that is easily recognizable. Because all these events create a type of hazard, the operator is prompted to act. Figure 1-4 is a representation of the visualization tool.

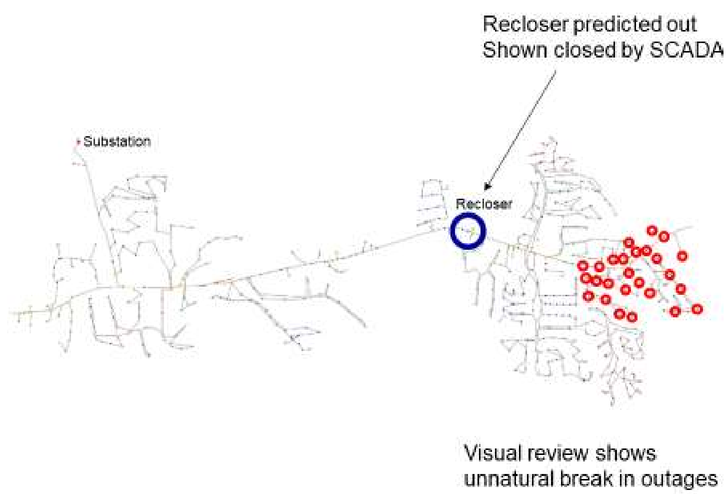

Figure 1-4
Outage pattern of an open point

AMI and OMS Data

The success of identifying down conductors behind SCADA reclosers prompted the investigation of creating an application to identify when AMI data might conflict with an OMS prediction for protective devices without SCADA data. This application is used to identify AMI and outage management system conflicts for outages predicted behind non-SCADA reclosers and fused taps. The process begins by identifying and pinging a meter close to the protective device, known as the *bellwether meter* (see Figure 1-5). Pinging is the act of communicating to the meter with a short, quick message. If the meter does not respond to the ping, the bellwether meter is considered deenergized, indicating that the protective device is open. If the meter does respond to the ping, the meter is known to be energized, indicating that the protective device is closed and in conflict with the OMS prediction. Conflicts between AMI and OMS should be presented to the operator for a review to determine the proper action. Figure 1-6 is a process diagram used by the application that identifies AMI and OMS conflicts.

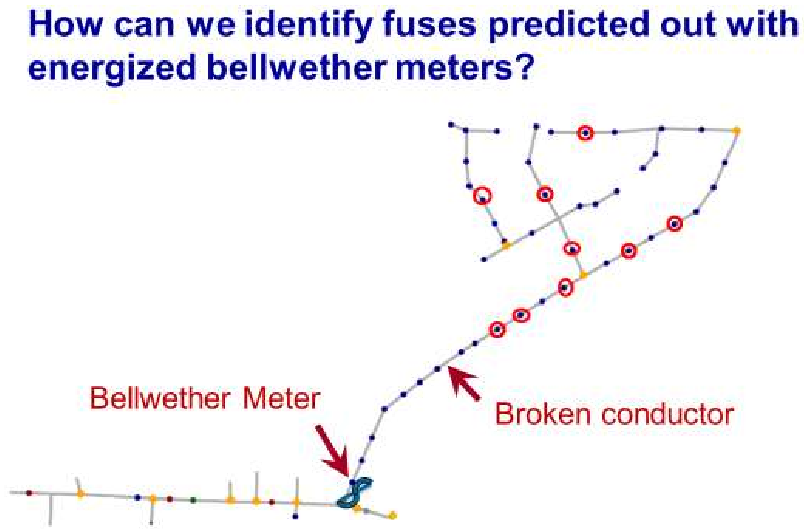

Figure 1-5
Bellwether meters

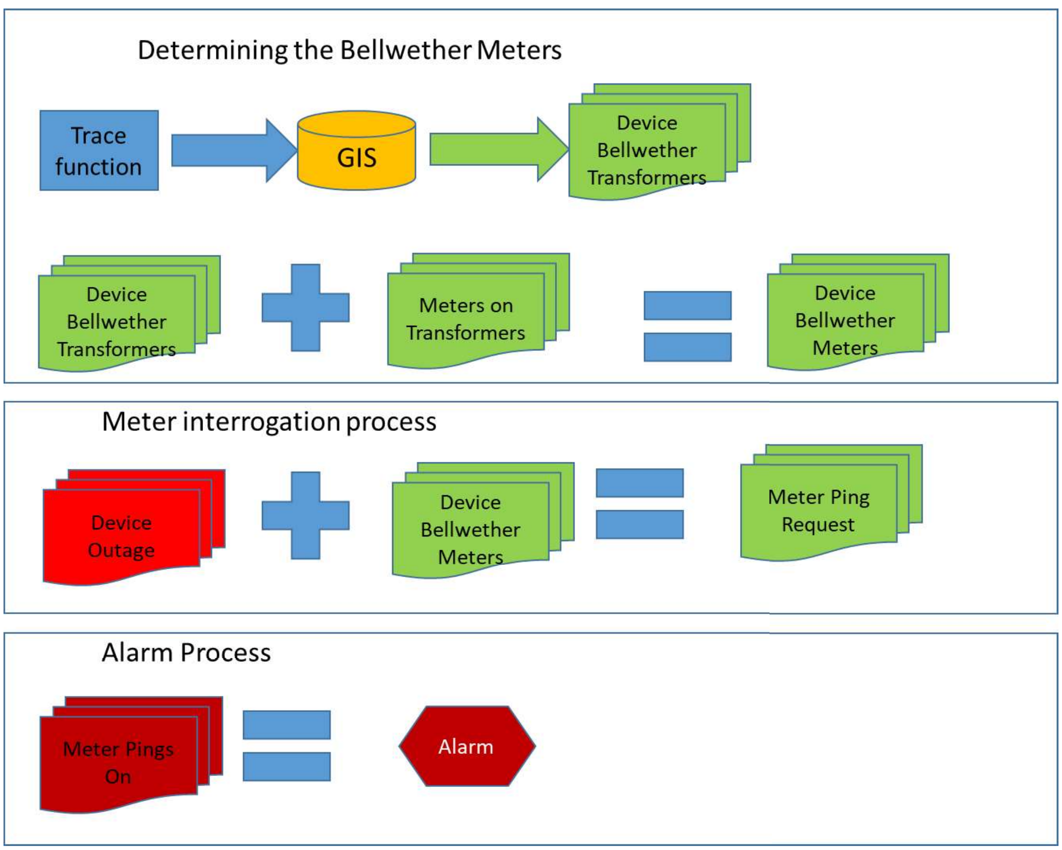

Figure 1-6
Process chart for AMI/OMS conflict identification

Challenges of Delta Systems

Some utilities operate portions of the distribution system without a ground reference. Numerous outages were analyzed on ungrounded systems to determine if the same application could create a visualization of events with a broken conductor. The results were promising. Although events on the three-phase portion of the system can mask the outages, the events associated with only two phases (considered single-phase) could be identified with the same AMI pinging logic (see Figures 1-7 and 1-8). There is a potential to analyze the voltage sags to try to identify a back-feed condition.

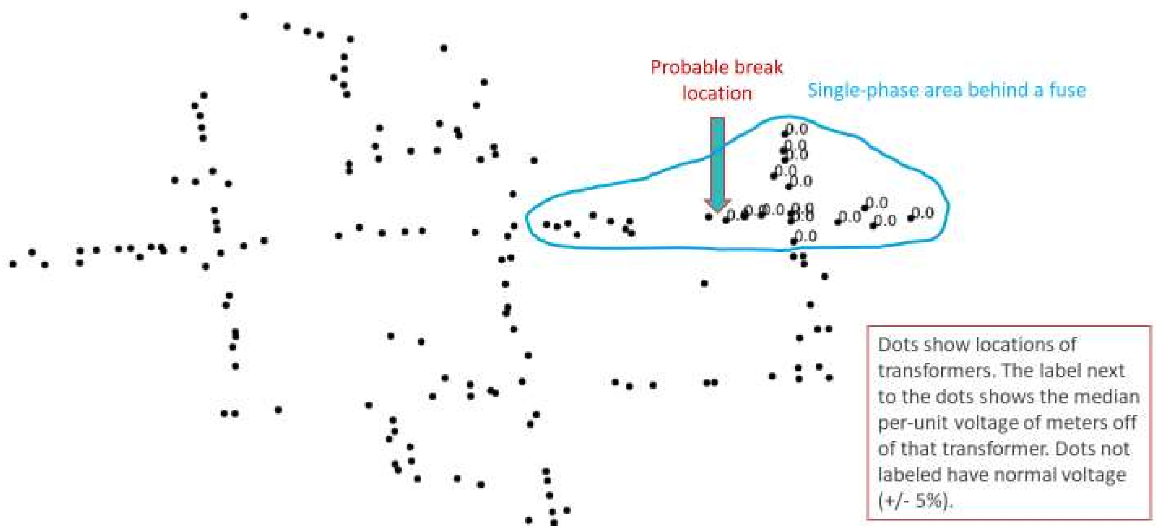

Figure 1-7
Outage event on single-phase delta system

Figure 1-8
Outage event on three-phase delta system

2

USE CASES SUPPORTED BY ANALYZING AMI DATA

A large volume of data within AMI meters is available to operations. Some of these data are used in near-real-time, whereas other data might be collected during normal data collection schedules. In 2012, EPRI tabulated the data captured from a few AMI meters. Table 2-1 lists some of the data available, which vary by meter manufacturer. The data available also vary by the communication module used. In general, using a meter manufacturer that is not the same as your AMI system provider will result in fewer features available. Also noted in Table 2-1 are the intervals available. The interval figure gives the user the range at which other values can be averaged. For example, if you desired 1-minute average voltage, you would not pick meter B1 or E1, which would be able to return only 15-minute averages.

Table 2-1
Parameters provided by sample meters

METER										
Designator	A1	B1	C1	D1	E1	A3	B3	C3	D3	E3
STEADY-STATE PARAMETERS										
Voltage	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Current	✓		✓	✓		✓	✓	✓	✓	✓
Real (kW)	✓	✓	✓	✓		✓	✓	✓	✓	✓
Reactive (kVAR)	✓		✓			✓	✓	✓	✓	✓
Apparent (kVA)	✓					✓	✓	✓	✓	✓
Displacement Pwr Factor	✓			✓		✓	✓	✓	✓	
Total Power Factor			✓				✓	✓	✓	✓
Frequency	✓			✓		✓	✓	✓	✓	✓
Phasors	✓			✓		✓	✓	✓	✓	✓
THD	✓					✓	✓	✓		✓
TDD	✓					✓		✓		✓
Harmonic Quantities	2nd Hrm					✓	Up to 24th	2nd Hrm		Up to 127
Interharmonics										✓
Harmonic Phase Angle										✓
K Factor										✓
Crest Factor										
+/-/0 Sequence										
Flicker										✓
Imbalance						✓				✓
DEMAND										
Real (kW)	✓	✓	✓	✓		✓	✓	✓	✓	✓
Reactive (kVAR)	✓		✓			✓	✓	✓	✓	✓
Apparent (kVA)	✓		✓			✓	✓	✓	✓	✓
Current	✓			✓		✓	✓	✓	✓	
ENERGY										
Watt-hours	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Var-hours	✓		✓			✓	✓	✓	✓	✓
VA- hours	✓		✓			✓	✓	✓	✓	✓
CONTINUOUS TRENDING / DEMAND INTERVALS										
Intervals	1 to 60 Min	15	1 to 60 Min	1 to 60 Min	15	1 to 60 Min	1 to 60 Min	1 to 60 Min	1 to 60 Min	1 second +
Trend Calculations	Max/Min/Avg	Min	Max/Min/Avg	Max/Min/Avg	Min	Max/Min/Avg	Max/Min/Avg	Max/Min/Avg	Max/Min/Avg	Max/Min/Avg
EVENT RECORDINGS										
Text Based	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Oscillograph										✓
Samples per Cycle										Up to 512
TRIGGERS / ALERTS										
Outage					✓		✓		✓	✓
Thresh. Limits (V, I, Harm)					✓		✓		✓	✓
Transients										✓

Transformer Windings Shorts and Regulator Misoperation Identification

Utilities have shown success in identifying failed or failing equipment based on information from AMI meters. Average voltage information can be used to identify transformers with windings shorted and can identify regulators and switched capacitors that are not operating properly. If voltage information is combined with circuit data, the type of problem identified can be scripted, which allows repair orders to be automatically created and dispatched. Voltages that are out of range on a single meter are dispatched as a bad meter. Voltages out of range for multiple meters on a transformer create a repair order to swap the transformer. Voltages out of range for multiple transformers are investigated for regulator or capacitor problems.

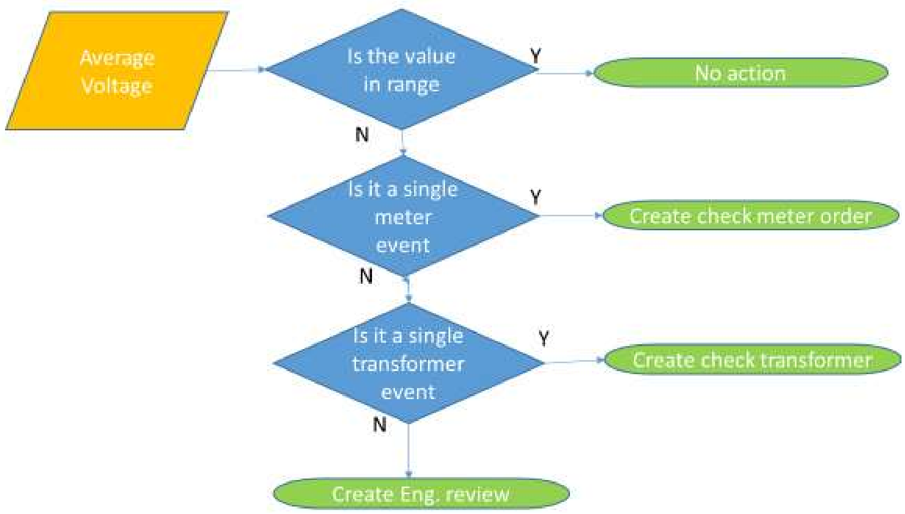

Figure 2-1
Flow chart for sustained voltage out of range

Near-Real-Time Voltage Visualization

If the average voltage of a meter is outside of the normal band but is not low enough to be considered an outage, the meter can be programmed to send the voltage reading to a visualization system. The visualization system resembles a heat map with both high and low voltage readings shown. Once the average voltage is within the acceptable voltage band, the meter again sends its voltage reading and is removed from the heat map. Some meters might be able to perform 1-minute averages, but others are limited to 4-hour averages. The length of time over which the meter averages the voltage depends on the capabilities of the metrology portion of the meter.

Voltage Feedback for CVR Systems

Voltage data from AMI meters can provide feedback to CVR systems. By identifying bellwether meters, the CVR system can ping the bellwether meters after each step-in voltage reduction. If the ping indicates that the voltage is close to the established limit, the CVR system does not perform another step reduction. By using AMI, additional CVR reductions can be realized. Systems that depend on planning studies to determine the amount of reduction are inherently conservative to not create voltage events below the standard limits. AMI meters also account for actual secondary voltage drop. Many planning models estimated a secondary voltage drop. In lieu of selecting bellwether meters, low-voltage alarms can also be monitored by the CVR system to create the low limit of reduction.

Analyzing Feeder Voltage Profile

AMI meters generally report an average voltage, a maximum voltage, and a minimum voltage. The rate at which the data are collected is independent of the time over which the meter calculates the average. The average readings may be minute averages to hour(s) averages. Figure 2-2 presents the voltages reported from a circuit analyzed by Arizona Public Service. Their meters were collecting 1-hour averages; the data are presented each hour over the course of 24 hours. The distance between the data sets in each hour illustrates the range for the meter average voltage across the feeder. Each series represents a group of similarly located meters. The graph in Figure 2-2 highlights the following:

- The series with the lowest voltage becomes the series with the highest voltage during solar generation hours. This might indicate small service wire or undersized transformers at the solar installations.
- Almost all the meters on the feeder exceed the high-voltage threshold when solar panels are generating.
- This feeder does not have substation regulation. To create additional hosting capacity, adding feeder regulation along with capacitor management is being considered.
- Figure 2-2 can also identify areas where the transmission voltage might be high, or the substation transformer could be set on the wrong tap to deliver nominal voltage.
- The data are consistent enough to have a back-office application evaluate the data to identify circuits that are approaching or exceeding voltage limits. The same process would identify circuits with low voltage.
- AMI voltage data alone might be enough to identify individual solar installations.

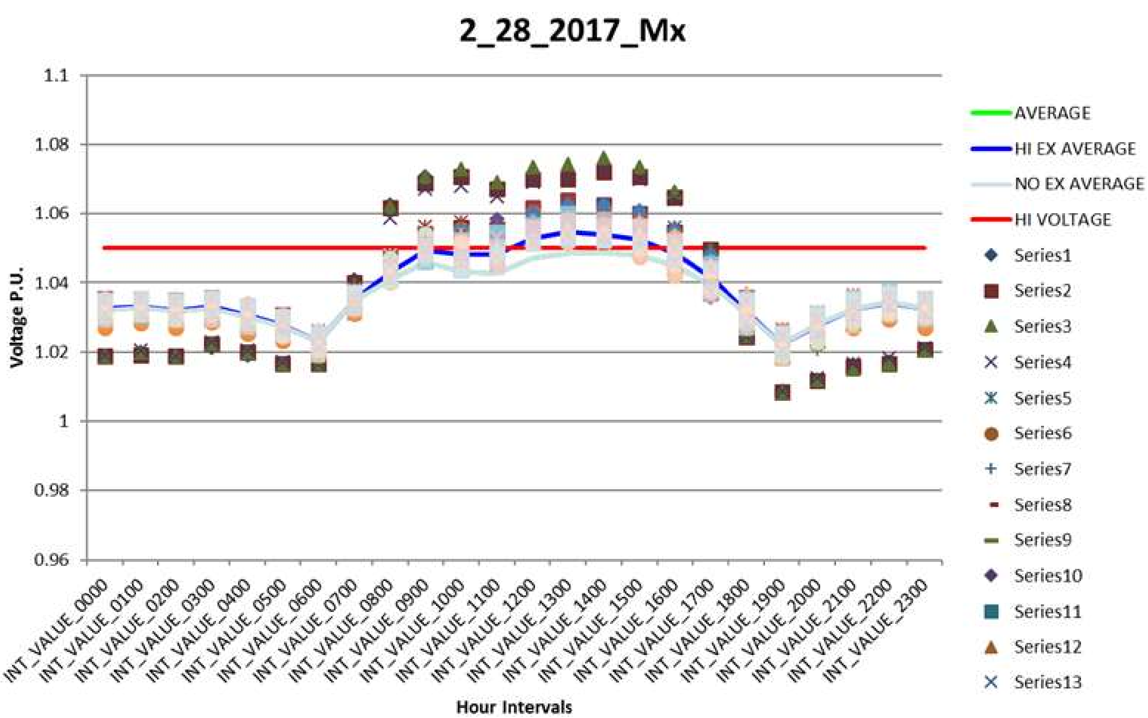

Figure 2-2
Arizona Public Service plot of voltage profiles

Capacitor Health and Control

By adapting a meter socket, the neutral current of a capacitor bank can be monitored using a standard 120-V residential AMI meter. This arrangement can be used on both fixed and switched capacitors. Voltage and kVA data are returned from the meter daily. Based on these data, failed capacitor cans, capacitors with blown fuses, and capacitors with misoperating switches are identified.

Figure 2-3 represents how the AMI meter is connected through a current transformer (CT) to the capacitor. A CT is used to connect to the neutral to keep surges through the neutral from damaging the meter.

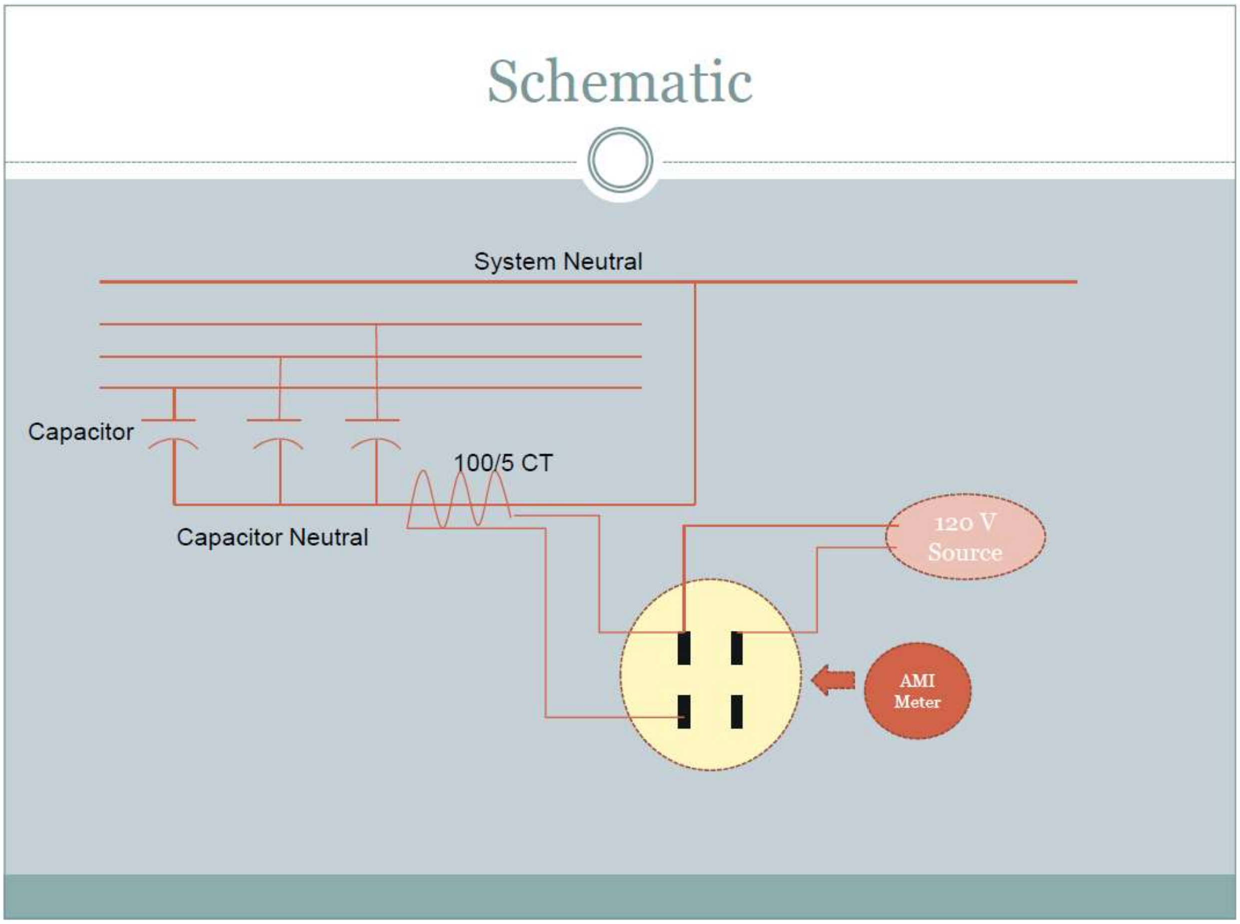

Figure 2-3
AMI capacitor monitor

Following the success of the AMI-based capacitor monitor to identify health issues, a second meter adapter was created that has electronics to monitor and control a switched capacitor based on the status of an AMI meter with connect and disconnect capabilities (see Figure 2-4). The electronics in the adapter monitors the load spade of the AMI meter. If the load spade is energized, after a delay, the electronics send a close pulse to the capacitor switches. If the load spade becomes deenergized, after a delay, the electronics send an open pulse to the capacitor switches. The AMI meter becomes the monitor and the controller and completely replaces the capacitor control. This type of monitor and control are dependent on a centralized volt-var system to control the position of the AMI meter, which, in turn, controls the position of the capacitor switches. A more detailed article about this process can be found in the February 2013 issue of *T&D World* magazine.

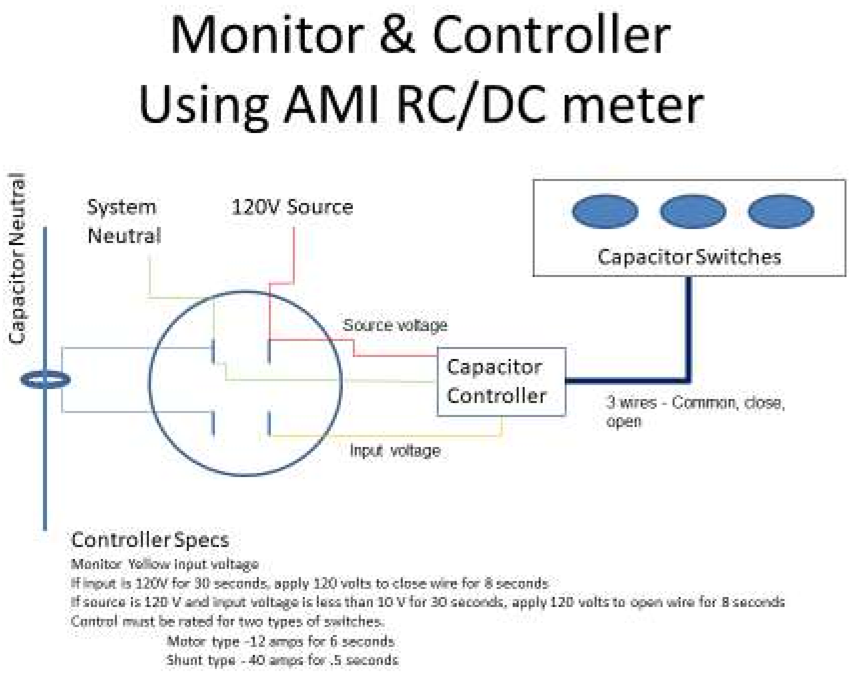

Figure 2-4
AMI capacitor monitor with control module

Identify Mapping Errors

Customers are increasingly interested in more information associated with their service, especially proactive communication from the utility with information about their outages. The relationships between the customer's meter, the service transformer, the phase to which the transformer is connected, and the protective devices are critical in allowing utilities to provide accurate information. AMI offers several opportunities to identify mapping errors.

Using Outages

For single-phase faults and transformer faults, mislinked AMI outage notifications create predicted outages on uninvolved transformers or phases. The outages are identified by the system operators. Many OMSs allow the system operator to move the AMI meter to a different transformer. This move is then incorporated into the database that links the meter to the new transformer for all future events. When multiple meters are mislinked, utilities have created processes for the operator to request a map change. Because every mislinkage meter creates an outage event that the operators must manage, it is in the operator's interest to correct the map whenever practical.

Using Momentary Outages

Following a successful single-phase reclosing event, AMI momentary data can be compared to AMI phase linkage to identify mismatches. In addition to the reliability benefits of single-phase reclosing, feeder breakers that have single-phase reclosing can be used to correct meter linking on the entire feeder. Every single-phase fault can be used to update the map.

Using Voltage Data

Feeders with single-phase regulation have had their voltage data analyzed to determine if sufficient grouping can be done to identify phases. EPRI published a report in 2018 [1] with the following key findings:

- Correlation and regression models performed reasonably well for the six feeders evaluated using only voltage measurements.
- A method to reduce the amount of data needed for phase identification was to intentionally create a change in voltage on one phase. With individually regulated phases, this was easy, quick, and almost foolproof.
- Prediction accuracy rates were higher in cases when both the voltage and consumption data were included in the regression analysis.

Overutilized and Underutilized Transformers

Many utilities have used AMI usage and demand data to identify overutilized or underutilized transformers. Obviously, the larger the transformer, the more value there is in keeping it from failing from overload or replacing it with a smaller transformer. The process is very straightforward for transformers with only one customer served from the transformer. Each utility has its own criteria for what percentage above or below nameplate they are willing to accept. The same process can be applied to smaller transformers by summing the AMI meters that are linked. This process will identify overloaded transformers and can identify transformers that have many mislinked meters.

Past 24-Hour Transformer Loading for Replacements

Extreme weather events associated with extreme heat or cold can create many transformer outages. Having the past 24-hour loading data for transformers enables operations to make an informed decision as to whether a transformer should be replaced or simply refused. Because refusing a transformer is many times quicker than changing the transformer out for a larger size, having loading information readily available can dramatically impact the restoration time.

Individual Solar Distributed Energy Resources Identification

By looking for changes in voltage, interval load, and power factor, a standard residential AMI meter can identify the presence of solar photovoltaics so that the utility can properly model and plan the distribution system. The addition of radiance and/or wind data can further enhance identification and establish baseload projections that can be used to approximate the generation size. The data points required and the specific algorithms are being determined. If successful, customers with rooftop solar who did not register their installation with the utility can be identified.

Individual Electric Vehicle Charging Identification

By looking for changes in voltage, load, and power factor, a standard residential AMI meter might be able to identify the presence of an electric vehicle (EV) charging system so that the utility can properly model and plan the distribution system. The data points required and the specific algorithms are being determined. If successful, customers with EV chargers who did not register their installation with the utility can be identified, planned for, and educated about any rates that would encourage off-peak charging.

Feeder Solar Distributed Energy Resources Identification

By plotting average voltage on a feeder, feeders with high voltage away from the substations are being used to identify the feeders that have enough solar penetration to impact the voltage profile. This can also be accomplished by comparing average voltage readings between meters close to the substation (V1) with those further down the line (V2). Circuits are flagged when the differential (V1-V2) exceeds a preset negative number.

Customer Heating Method Identification

After a high number of transformer failures during a period of abnormally cold weather, a Dominion Energy investigation proved that many of the failures could be contributed to customers changing their home heating source from gas to electric. If Dominion could use AMI to determine the heat source for each customer, the transformers serving those customers could be identified and resized before failures occur. Dominion began an AMI analytics effort to identify the heating method of each customer.

In 2017, Dominion installed a data repository designed to capture and store the vast amount of data that AMI can generate. Using the interval data from their residential meters, Dominion was able to successfully group customers by their heating method by grouping customers based on their sensitivity to temperature. Although AMI provided 30-minute usage resolution, Dominion is performing the same analytics on monthly data to determine if the resolution provided by AMI is critical for successful heating determination.

Reliability Indices Audits

Many utilities have kept the calculation of reliability indices within the OMS and used the time stamps within AMI meters as a tool for validating or correcting outage records to increase accuracy.

Single-Phase Outages Modeled As Three-Phase

AMI reported outages can be analyzed to highlight reclosers that were modeled as all three phases open when only one or two phases were involved in the outage event. Changing a three-phase recloser outage to a single-phase outage can dramatically reduce the number of SAIDI minutes reported. These instances can be found by sorting three-phase outages by the number of AMI reported outages per phase. Outages with one or two phases with low representation should be studied. The process will also help correct mapping errors.

Outage Associations

The outage start times of all the meters associated to an outage should be close to the same time. Having a process to identify outages with meter start times outside of an acceptable band can identify separate outages that have been associated by the OMS. An OMS will use the earliest prediction as the start time of the outage. For example, a transformer outage with four customers occurs at noon and is predicted in the OMS but not confirmed by an operator. At 2:00 PM, the feeder serving the transformer opens, creating an outage for an additional 2000 customers. The feeder outage is restored at 3:00 PM. At 4:00 PM, customers on the transformer call back and are re-predicted out. The transformer is restored at 5:00 PM.

Equation 2-1
Reported versus actual customer minutes of interruption (CMI)

Reported CMI = 2004 x (15-12)hrs + 4 x (17-15)hrs = 361,200 customer minutes
Actual CMI = 2000 x (15-14)hrs + 4 x (17-12)hrs = 121,200 customer minutes

Overloaded Hydraulic Reclosers Identification

Momentary outages can confuse an outage management system. However, they are useful at identifying overloaded hydraulic reclosers. Hydraulic reclosers trip when the current approaches two times the rated current. When the recloser operates, some of the load does not immediately come back. After a short period, though, the load will return and make the recloser trip again. In a high-load weather event, the trip and reclose sequence can happen many times. Following weather events that cause an increase in demand, momentary outages can be plotted on a map (using map coordinates) to identify hydraulic reclosers that are operating due to load. The map plots customers with greater than X momentary outages within the weather period. Pockets of outages that appear on the map behind hydraulic reclosers indicate a recloser that was probably operating due to load. Without AMI, these operations might go unnoticed until the recloser fails or customers complain.

Nested Outage Predictions

A nested outage is a small outage associated with a much larger outage. A good example is a blown fuse on a feeder that is deenergized for a different fault event. After the feeder is restored, the customers behind the fuse will remain out. Unless the outage is associated with a major weather event, first responders might not assume that there are multiple fault events. After clearing the fault on the recloser or breaker, the first responder might leave the area unaware of the fault behind the fuse. The outage must be identified later and because the AMI meters will have already used all of their stored energy, the nested outage is dependent on customer calls to re-predict. If the customers behind the fuse have already called, they might not realize that they need to call again, until their frustration increases. The customer's initial call will be associated with the larger outage by the OMS and completed. Sending power on messages will prompt customers to call sooner. But notifying a customer that their power is on when it is still off can also create a negative customer experience.

OMS Association Rules

AMI has the potential to identify nested outages. As AMI outage reporting continues to get faster and more accurate, OMS prediction rules can be adjusted to take advantage of the speed and quantity of outage reporting. One such OMS rule is the time in which outages are locked and prevented from being associated with a larger outage. For example, if the time to lock the outage is set at 5 minutes, a fuse outage that occurs at least 5 minutes prior to an upstream recloser lockout would be locked in as a nested outage. Events that are locked will be identified to system operations as a separate event from the larger event. Locking the event as a nested outage also keeps customers associated with the nested outage from getting a power restore message when the larger outage is restored. Care should be taken when reducing the time waited before an outage is locked. If the time is set below what the AMI outage reporting can support, a large single event might be predicted as many smaller events.

In severe weather events, utilities expect multiple cases of trouble and require field crews to inspect the entire line before energizing. These inspections include the reporting and modeling of open protective devices before closing source devices to restore service. By modeling the nested outages, utilities prevent customers from getting erroneous restore messages.

SCADA Alternative

Before pad-mount transformers were available, some large customers would be served from a small substation connected to the distribution system. For example, a large plant might have a 12/4-kV ground-type substation served from the 12-kV distribution system. This type of installation might require the call-out of a first responder with a different skill set than those responding to a standard distribution customer. The same type of customer might have difficulty reporting an outage through the normal outage process. To monitor the service, standard substation SCADA could be installed. However, adding SCADA to old substation-based equipment that usually has electromechanical relays can become very expensive.

As an alternative to installing SCADA, utilities have turned to monitoring the C&I three-phase meter located at these facilities to identify outages. The process might not be able to use the same processes as other AMI meters due to the different construction of C&I meters. As indicated in Table 2-1, meters A3 and C3 do not have indication for either outages or low voltage. Meters without either indication must have the data collected from normal polling analyzed by a back-office application to identify low voltage and create an outage event. Some C&I meters stop communicating any data when the power is lost (they do not have an internal stored energy source). For meters that stop communicating, utilities have put in place back-office systems that will convert multiple failed communication attempts into an outage. If the communication is known to have numerous failures, the system might have to wait several minutes before converting failed communication attempts into an outage message. Meters B3, D3, and E3 all report outages and low voltage, but, typically, only one phase will be monitored for outages. If the substation can experience single-phase outages, an alternative process must be developed. The processes to monitor these installations can be repurposed to monitor all C&I meters.

3
USE CASES THAT REQUIRE ADDITIONAL DEVELOPMENT

Identifying Nested Outages with Reverse OMS Predictions

OMSs and AMI restoration messages can also be used to identify nested outages. The OMS uses the AMI restore message to "predict restorations." OMSs have the topology required to predict nested outages based on the absence of restore messages sent from the AMI meters. Following a restore event (closing a protective device in the model), protective devices that are not already confirmed open are predicted open using restore prediction rules similar to outage prediction rules (protective devices without X number of restore messages within a defined period) to identify nested outages. To further enhance the accuracy of the prediction, the system can ping a subset of the meters behind a protective device that does not have any restore messages before creating a nested outage. In a large event, this system would be very helpful at identifying transformer outages that were missed by the line inspection. For mesh systems, a time delay to allow the network to reestablish itself will be required.

Step Restoration with Reconnect/Disconnect Meters

If meters with a built-in disconnect have a stored energy source that can open the disconnect without ac present, the disconnect switch can be used to mitigate temporary overloads that might occur during restoration activities. The temporary overload condition might be a result of cold load, or it might be the result of distributed energy resources (DER) disconnecting during the disturbance. The logic to disconnect could include a temperature variable so that the disconnect occurs only during high or low temperatures. This function would extend an outage, but the extension would be minimal and occur only during high-load periods. A wait time of 2 minutes would be sufficient. If all the residential meters have disconnect ability, the reconnect wait time can be a random number within a range to keep all the meters from reconnecting at the same time.

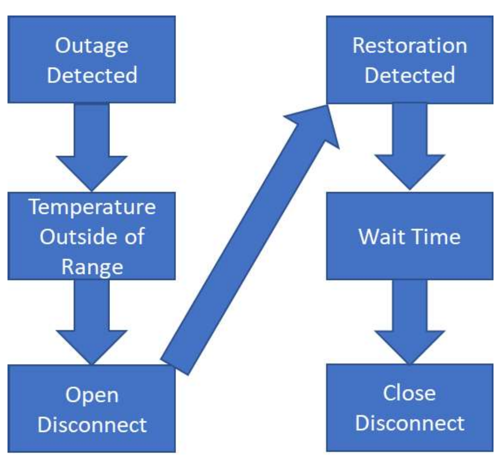

Figure 3-1
Step restoration using internal meter disconnect

Under-Frequency Load Shed with Reconnect/Disconnect Meters

Meters that have a built-in disconnect switch can be used to mitigate generation disturbances by opening for under-frequency. The under-frequency pickup of the meter is set to have the meter open before the substation-based under-frequency relays open the feeder breaker. By using AMI meters as the disconnect, the circuit can remain in service to serve critical loads and important services, such as traffic lights, gas stations, and some businesses. Upon disconnecting for under-frequency, the meters must receive a close command from the AMI system before reconnecting the load. Having AMI-based under-frequency does not mean that substation-based under-frequency is eliminated. AMI under-frequency can be designed to operate first, faster than substation-based relays. But by keeping substation-based under-frequency in place, the substation relays are the only devices that would be periodically tested to meet reliability requirements. The system developed to close the meters once the generation stabilizes would need to include a feedback loop to identify meters that did not respond to the close command and block the close of meters that were disconnected for auxiliary reasons.

Targeted Load Shed with Reconnect/Disconnect Meters

Meters that have a built-in disconnect switch can be used to mitigate generation shortfalls by opening from a command originating in a load shed application. The load shed application could either select the number of meters based on the desired kW reduction or select meters by feeder. By using AMI meters as the disconnect, the circuit can remain in service to serve critical loads and important services, such as traffic lights, gas stations, and businesses. Upon activation, the meters must receive a close command from the AMI system before restoring load. Because load shed events often result in a rolling blackout, the meters selected must be organized in a manner that facilitates reconnection. If there were not enough self-contained meter load to allow a second block of disconnects, the utility could decide to leave the initial group out for an extended period or move to feeder-level disconnection. Ideally, the decision to establish the AMI-based load shed approach would include the mass deployment of capable meters.

Neutral Problems

In general, single-phase self-contained meters do not have a neutral reference. This limits the meter’s ability to identify voltage swings between the phase conductors and the neutral and in turn limits its ability to identify neutral problems. However, three-phase meters do have a neutral connection and have proven very effective at identifying phase-to-neutral voltage swings that identify corroded or loose neutral connections. Utilities have successfully written applications that look for loose neutral conditions associated with C&I meters.

CT Issues (Three-Phase Meters)

The data from three-phase meters can be analyzed to identify CT problems as well as any wiring errors associated with potential or current transformers. Because these errors are normally associated with large customers, not identifying these issues can cause large loss of revenue due to inaccurate metering. Utilities have established unmonitored processes to identify data abnormalities that indicate onsite construction or materials issues.

4
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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, 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**

In the Matter of:

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**

TESTIMONY OF
EILEEN L. SAUNDERS
VICE PRESIDENT - CUSTOMER SERVICES
KENTUCKY UTILITIES COMPANY AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Filed: November 25, 2020

TABLE OF CONTENTS

I. BACKGROUND

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

A. My name is Eileen L. Saunders. I am Vice President – Customer Services 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, which provides services to the Companies. My business address is 220 West Main Street, Louisville, Kentucky 40202.

Q. Please describe your educational and professional background.

A. I have been employed with LG&E and KU Services Company for the past twenty-six years. I was first hired as a manager of Organizational Development to oversee leadership training for employees. In the ensuing years, I accepted management roles with increasing responsibility and diversity in generation station maintenance, project engineering, and generation services. Most recently before my current position, I served as director for Safety and Technical Training. In January of this year, I was promoted to my current position of Vice President – Customer Services. A complete statement of my work experience and education is contained in Appendix A.

Q. Have you previously testified before the Commission?

A. Yes, I testified on behalf of KU and LG&E before the Commission earlier this year in a formal conference proceeding in the Commission's Investigation of Home Energy Assistance Programs.[1]

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[1] *Electronic Investigation of Home Energy Assistance Programs Offered by Investor-Owned Utilities Pursuant to KRS 278.285(4)*, Case No. 2019-00366, Hearing (Feb. 25, 2020).

Q. Please describe your responsibilities as Vice President - Customer Services.

A. My team and I are leaders of the customer experience at our company. In that light, I am responsible for oversight of a broad range of customer relationship functions. These include electric and gas metering, contact center and customer support operations, marketing, billing and revenue collection, economic development initiatives, renewable energy offerings like the solar share and business solar programs and green tariff, as well as facilities services, corporate security, and energy efficiency operations. Additionally, I work to make sure that those activities are conducted safely and in an efficient manner that enhances the overall experience for the customer.

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring the following exhibits, which are attached to my testimony:

Exhibit ELS-1	Tools Available Today to AMS Opt-In and Solar Share Program Participants
Exhibit ELS-2	Advanced Metering Infrastructure Customer Engagement and Communication Plan

Q. What is the purpose of your testimony?

A. I will provide information and background about the Companies' customer services operations, including customer services values, objective performance metrics, recognitions, and efforts to assist low-income customers. I will describe investments the Companies are making in Customer Services operations, why they are facing rising operational costs, and efficiency programs implemented to manage those costs. I will describe how the Companies' proposed advanced metering infrastructure ("AMI") initiative will provide innovative and helpful tools for our customers as well as greatly enhance the Companies' customer services operations. It is important for our customers to understand how AMI will look from their perspective so I will describe how the Customer Services team will roll out components of the AMI plan and communicate those plans to customers. Finally, I will report on two programs within my area of responsibility: the HomeServe protection plan and electric vehicle charging stations.

II. CUSTOMER SERVICES OPERATIONS

Q. How do the Companies demonstrate the value they place on customer service?

A. Customer focus is at the very heart of the Companies' vision, mission, and values. Our employees are dedicated to providing the highest quality, safe, reasonably-priced service to all our customers, and improving quality of life in the areas we serve. We live these values by refusing to compromise on safety and health, and by listening to customers, treating them with respect, and seeking their input to better serve their needs. We serve customers by providing them with timely and useful information about energy usage and billing, and by creating and maintaining programs tailored to their expressed needs. We also demonstrate the value we place on our customers by continuously seeking and implementing ways to serve them more effectively. I will describe many of these programs and process improvements throughout my testimony.

Performance and Recognition

Q. Describe Customer Services' safety performance.

A. We do not compromise on safety at our company. Because the safety of the public, employees, and contractors is a company-wide cultural value and responsibility, safety is paramount in every aspect of our business, including customer services. This dedication to safety is demonstrated by Customer Services' recent safety performance, as measured by the rate of Occupational Safety and Health Administration ("OSHA") recordable injury incidents ("RIIR") per 200,000 hours worked and the rate of injury resulting in days away/restricted/transferred ("DART") per 200,000 hours worked. In 2019, for example, Customer Services had a RIIR of just 0.49 for employees compared to a target of 0.71, and had zero DART incidents all year compared to a target rate of 0.38. In 2020 through September, Customer Services has continued excellent safety performance, with only a single recordable/DART injury among employees, and a RIIR for contractors of just 1.66 compared to the Companies' target of 1.73 for the year. We are proud how our employees and contractors have performed safely, especially during the pandemic. This performance is a testament to the Companies' commitment to safe work through culture, training, and accountability by everyone in the organization.

Q. How do the Companies measure customer satisfaction?

A. The Companies strive to make every interaction with their customers a positive one. The Companies measure customer satisfaction through collection of objective data generated in part through customer feedback. For example, customers are offered the opportunity to take a survey through a third-party to rate their satisfaction with contact center interactions they have with the Companies. Using a scale of 1 to 10 (1 being Not Satisfied at all and 10 being Completely Satisfied), the scores from these surveys are averaged and designated as the Combined Customer Experience Rating. This "CE" rating gives the Companies critical information on service experience by contact channel (i.e., phone, in person, online, chat). The Companies regularly monitor this data and J.D. Power survey data to respond and adjust to ensure we continue to meet and exceed customer's expectation.

The Companies also measure "service level" for customer interactions, which tracks the amount of time it takes to respond to a customer through various channels. The Companies further track customer experiences through inquiries filed with the Kentucky Public Service Commission ("Commission"), and the resolution of those inquiries.

Q. How have the Companies performed under these metrics in 2020?

A. The Companies are proud that their 2020 CE scores and service levels have exceeded targets, despite the disruptions caused by the COVID-19 pandemic. For example, all of the Companies' business office lobbies were closed in March 2020 due to the pandemic, reducing the ability of the Companies to respond to customer needs in person. Nevertheless, average CE ratings have improved year to date through September 2020, with the average CE rating exceeding 9.0 for business and residential phone interactions and business office transactions, and achieving 8.87 for email interactions. All these figures represent an improvement over full year 2019. These results highlight the dedication our employees have to serving the needs of our customers. It was important to our employees to be responsive and consistent during interactions with our customers during a time of uncertainty.

The Companies began tracking CE and service level for the "Live Chat" feature on their website starting in June 2019, and the results have been very positive. Average CE for live chat has exceeded 9.0 in most months since tracking began, with service level (percentage of inquiries answered within 30 seconds) approximately 95 percent for calendar year 2020 through September.

Finally, ninety-nine percent (99%) of Commission customer service inquiries were resolved within three business days for calendar year 2020 through September.

Q. Have the Companies been recognized recently for excellence in customer satisfaction?

A. Yes. In December 2019, LG&E was ranked first by J.D. Power in gas business customer satisfaction among its peers for the Midwest region. The national survey measures overall business customer satisfaction for utility safety and reliability, billing and payment, corporate citizenship, customer service, price, and communications. KU earned top honors in both the 2019 J.D. Power Electric Utility Business Customer Satisfaction Study for the Midwest mid-size region and 2019 Electric Utility Residential Customer Satisfaction Study for the Midwest mid-size region while LG&E finished third and fifth in these surveys, respectively. KU also earned top honors in the 2020 J.D. Power Electric Utility Business Customer Satisfaction Study for the Midwest mid-size region, while LG&E ranked fourth in the same study. These recognitions reflect the high level of commitment and resources the Companies have consistently dedicated to customer satisfaction.

Q. How have the Companies demonstrated their commitment to increasing economic development activity in Kentucky?

A. In late 2018, the Companies created a new position, Director – Business and Economic Development, to lead the Companies' economic development efforts, which are now under my direction. We filled the position with John Bevington, a former Commissioner for the Kentucky Cabinet for Economic Development with extensive experience in promoting business and economic growth in the Commonwealth. The

Companies work closely with state and local government and other partners to provide support to existing and new business seeking to relocate to Kentucky or grow operations here. This includes assistance with building and site identification, infrastructure development, economic incentives, and project management. Furthermore, in November 2020, the Companies finalized implementation of a new customer relationship management software platform called Cloud for Customer, which helps us better organize and document our interactions with customers and prospects, and identify trends and indicators to drive performance. These recent developments reflect the Companies' increasing role and commitment to promoting economic growth for the benefit of all Kentuckians.

Q. Have the Companies been recognized for promoting economic development?

A. Yes, as Paul W. Thompson notes in his testimony, the Companies were named in an elite group of the Top 20 utilities in the United States for corporate facility investment and job creation in 2019 by Site Selection Magazine, an international publication focused on economic development.[2] The Companies were selected from approximately 3,300 utilities across the country evaluated for the honor. The publication noted that 10 of Kentucky's 21 top new and expanding business are LG&E and KU customers, including four of the top five announcements. This achievement highlights the breadth and depth of the Companies' customer service offerings, including an economic development team to assist with new business investments in Kentucky and an attentive customer service team to ensure customers stay and grow here.

[2] https://siteselection.com/issues/2020/sep/2020-top-utilities-in-economic-development.cfm#gsc.tab=0 (last visited Nov. 13, 2020).

Q. What other recognitions have the Companies received for their customer services offerings?

A. In addition to being honored for overall customer satisfaction and economic development initiatives, specific customer services programs have been recognized for excellence in the past two years. The Companies' Interactive Voice Response call system won "Balanced Company" awards for top quartile ratings in functionality, usability, and aesthetics in both 2019 and 2020 at the Interactive Voice Response Doctors and Market Strategies Conference. The Companies also received Silver and Bronze awards for their energy efficiency customer communications campaigns and advertising at the 2019 Better Communications Competition hosted by Utility Communicators International.

COVID-19 Response

Q. How have the Companies responded to assist customers struggling with the impact of the COVID-19 pandemic?

A. Like nearly all businesses, the Companies had to respond quickly and decisively to change their business practices in response to the pandemic and resulting effects on economic conditions. The Companies did so with public safety, reliable service, and customer assistance at the forefront of their decision-making. Starting in mid-March 2020, and in accordance with the Commission's moratorium, the Companies suspended customer disconnects for non-payment and waived new late payment fees.

Efforts to assist customers and provide relief from economic hardship did not stop with suspension of disconnects for non-payment. From April 1, 2020 through June 30, 2020, the Companies not only waived but absorbed over $1 million in convenience fees on behalf of Kentucky ratepayers paying utility bills through their authorized third-party payment providers.

Furthermore, while business office lobbies closed in March, for customers who preferred to do business in person, the Companies continued to staff and operate business office drive-throughs where available. Customers were able to continue to utilize the payment drop boxes available at all offices. The Companies continue to educate customers on assistance program resources including funds from the Low-Income Home Energy Assistance Program ("LIHEAP") and Team Kentucky[3] funds to assist customers who cannot pay utility bills during the crisis. Information on efficiency programs and energy saving tips have also been distributed as more customers have been at home throughout the pandemic.

Throughout the pandemic we maintained communications via our website, social media, emails and letters designed to let customers know we were here to help. We directed them to agencies that could assist them and encouraged them to pay what they could so their bills would ultimately be more manageable when the moratorium was lifted.

Q. How do the Companies plan to handle customer service disconnects and communication about disconnects now that recent Commission Orders have lifted to moratorium on disconnects for nonpayment?

[3] The Team Kentucky Fund was established by Governor Beshear in March 2020 to provide help to Kentuckians experiencing employment-related financial hardship related to the COVID-19 health emergency. See https://www.capky.org/team-kentucky-fund-2/ (last visited Nov. 13, 2020).

A. The moratorium on customer disconnects for nonpayment was lifted by Commission Order effective October 20, 2020.[4] As the Companies recently reported to the Commission, they will offer default payment plans of 12-months to customers with arrearages and will offer customers several other alternatives, including repayment plans up to 24 months.[5] The Commission has commented that the Companies' proposal for offering payment plans complies with the requirements of the Order lifting the moratorium.[6]

The Companies have worked to develop payment plans that are flexible and offer customers choice. Customers behind on payments have new COVID-19 payment arrangements available to them to avoid disconnection. The process to sign up is simple, as customers will select a payment plan that best fits their situation by extending the due date a few more days or spreading a past-due amount evenly over 6- or 12-month installments. These options are available anytime through self-service online or by using our automated phone system.

The Companies are helping residential customers who do not select a payment arrangement by automatically rolling past due balances into a 12-month payment plan, one time, and sending those customers a separate letter outlining the terms of that plan. While on a payment plan, customers have been advised that they must pay the current balance and the payment arrangement monthly installment amount by the due date to avoid disconnection. If the payment plan and monthly bill are not paid on time, customers will receive a disconnection notice that clearly indicates disconnections have

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[4] *Electronic Emergency Docket Related to the Novel Coronavirus COVID-19*, Case No. 2020-00085, Order (Ky. PSC Sep. 21, 2020), as clarified by Order (Ky. PSC Oct. 28, 2020).
[5] Case No. 2020-00085, Order (Ky. PSC Oct. 22, 2020).
[6] *Id.* at 3.

resumed and will provide customers time up through the final payment date listed on the notice to contact us before service is disconnected.

Assistance programs such as Team Kentucky Fund and LIHEAP Low-Income Assistance may also be available to eligible customers. For additional information on assistance programs or locating their local Community Action Kentucky ("CAK") office, customers can visit our website at lge-ku.com/assistance-programs.

The Companies have noted the Commission's emphasis on customer communication about arrearages, payment terms, customer disconnects, and resources to help utility customers pay their bills. The Companies will make every effort to engage with customers on these issues. Communications were sent to customers eligible for disconnection in late October and early November. These communications along with social media posts and updates to our corporate website provide customers with information on how to avoid service disconnection, including payment plan options available and touchless ways to make payments or contact us. In addition, customer service representatives are available by phone or in the lobbies of our reopened business offices to assist.[7] The Companies have notified CAK of the resumed disconnection process and payment arrangement options available. CAK will share this information with its action agencies. We will work in partnership with the community agencies and our customers during the coming months and will use disconnection of service only as a last resort in addressing COVID-19 related arrearages.

[7] Case No. 2020-00085, *Louisville Gas and Electric Company and Kentucky Utilities Company's Petition for Clarification and Deviation and Request for Expedited Treatment*, at 3 (Oct. 2, 2020).

Low-Income Customer Assistance

Q. Describe the Companies' efforts to support low-income customers.

A. As Mr. Thompson discusses in his testimony, support of low-income customers is an integral part of the Companies' overall strategy and culture to support the communities we serve. Support for low-income customers takes many forms, and includes the Companies' long-standing, close relationships with community assistance organizations like Community Action Council ("CAC") and Association of Community Ministries ("ACM"), communications and information targeted to low-income and fixed-income customers, shareholder contributions, employee volunteerism, and a portfolio of programs to provide assistance to low-income customers. Additionally, we meet with representatives from the agencies on a regular basis to share information and maintain communication.

Q. What programs are designed to assist customers who are struggling economically?

A. WeCare ("Weatherization, Conservation Advice and Recycling Energy") is an existing voluntary program designed to create savings through weatherization and energy education to help income-eligible customers in need. This program assists approximately 4,000 eligible customers each year, with each customer receiving an average of approximately $1,500 in energy efficiency upgrades per home. These upgrades may include air and duct sealing, attic and wall insulation, energy efficient water devices, basic HVAC tune-ups, and energy efficient lighting and appliances. WeCare customers are also given advice on energy conservation and installation of other energy efficient devices that are not included in the upgrades.

Q. Which customers are eligible for the WeCare program?

A. Eligible customers must have nine months of continuous service through the Companies in order to apply. The home must not have received WeCare benefits for the past three years, and the customer's income must meet the guidelines set forth in LIHEAP at the 200 percent poverty level.

Q. How are the Companies working to provide WeCare support to even more families?

A. Through their membership with the Midwest Energy Efficiency Alliance ("MEEA")[8], the Companies seek to leverage Federal Home Loan Bank ("FHLB") funds to enhance the WeCare Program with a new initiative called WeCare Plus. The Plus enhancements would focus on income-eligible customers who are homeowners, with a median household income at or below 50 percent of area median income, and who are 60 years of age and older. With additional eligible funding from FHLB, the Companies can provide even greater assistance in some cases, up to and including replacement of HVAC equipment and installation of ventilation equipment.

After identifying and screening eligible customers who are enrolled in WeCare, the Companies' chosen contractor would perform a home energy audit and propose energy efficiency improvements to the home. The WeCare Plus application will be submitted to MEEA for approval prior to installing the suggested retrofits or improvements. If the application meets all program criteria and is approved by MEEA, the work would be performed by the contractor and the cost would be reimbursed to

[8] The Midwest Energy Efficiency Alliance is a membership-based network of utilities, nonprofits, universities, manufacturers, state and local governments and other stakeholders, organized to promote energy efficiency in the Midwest.

the contractor using FHLB funds. It is the Companies' goal that the WeCare Plus enhancements provide even more support to eligible customers in need of assistance than the current WeCare program can accommodate.

Q. Do the Companies have other assistance programs for low-income customers?

A. Yes. In addition to the WeCare program, the Companies maintain relationships with a number of organizations engaged in community-assistance programs and efforts, including the Community Action Council for Lexington-Fayette, Bourbon, Harrison, and Nicholas Counties, Inc. and the Association of Community Ministries. The Companies meet and communicate with these groups on a regular basis to understand low-income customers' needs, how community organizations are working to meet those needs, and how the Companies can help.

Recently, in accordance with the Commission's final order in Case No. 2019-00366, the Companies engaged Community Action Kentucky to administer their Home Energy Assistance ("HEA") programs.[9] The Companies have worked well with CAK in the past and look forward to coordinating with and learning from CAK as the Companies, CAK, and CAK's subcontracting community action agencies work together to help meet the needs of some of the Companies' most vulnerable customers.

The Companies have used the experience and knowledge gained from these interactions as they have worked on their own and in conjunction with community groups to provide various forms of assistance to low-income customers over the years. For example, KU matches customer donations to the WinterCare Energy Assistance Fund, which assists low-income customers with their utility bills during winter months.

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[9] *Electronic Investigation of Home Energy Assistance Programs Offered by Investor-Owned Utilities Pursuant to KRS 278.285(4)*, Case No. 2019-00366, Order (Ky. PSC May 4, 2020).

In 2019, KU's shareholders contributed $100,000 to WinterCare. Since 2010, customer donations and matching funds from the Companies have raised over $4.2 million for WinterCare and LG&E's Winterhelp. For the 2020-2021 heating season, KU's shareholders will once again match $1.00 for every $1.00 donated by KU's residential customers to WinterCare. Prior to a COVID year, KU's employees participated in Winterblitz, an annual weatherization effort performed in conjunction with CAC. Each November, employees join volunteers and community organizations to weatherize the homes of low-income senior citizens and the disabled. KU provides the weatherization materials for Winterblitz, and in 2019, KU employees assisted in weatherizing approximately 50 homes through their participation and donations.

Similarly, LG&E matches customer donations to the Winterhelp Energy Assistance Fund, which assists low-income customers with their utility bills during winter months. In 2019, LG&E's shareholders contributed over $111,000 to Winterhelp. As noted above, since 2010, customer donations and matching funds from the Companies have raised over $4.2 million for Winterhelp and KU's WinterCare. For the 2020-2021 heating season, LG&E's shareholders will once again match $1.00 for every $1.00 donated by LG&E's residential customers to Winterhelp. Moreover, LG&E has been a proud partner of Project Warm since its inception in 1982. Project Warm is a non-profit organization that provides weatherization assistance for the low-income elderly and disabled. Prior to a COVID year, LG&E's employees work with Project Warm in the annual Project Warm Blitz, a program whereby employees join volunteers and community organizations to weatherize the homes of low-income senior citizens and the disabled. LG&E provides the weatherization materials for Project

Warm Blitz, and in 2019, LG&E employees assisted in weatherizing approximately 150 homes through their participation and donations.

In addition, through the LG&E and KU Foundation, KU is currently making annual shareholder contributions of $570,000, made up of a $100,000 contribution to WinterCare and a $470,000 contribution to KU's HEA program. Likewise, LG&E through the Foundation is currently making annual shareholder contributions of $880,000, made up of a $700,000 contribution to ACM for its utility assistance programs and an $180,000 contribution to LG&E's HEA program.

Q. In addition to the Companies' shareholder contributions and the support the HEA programs provide to low-income customers, have the Companies implemented policy measures to assist fixed- and low-income customers?

A. Yes. The Companies provide all customers at least 22 calendar days to pay their bills after the issuance date, but the Companies go even further to assist fixed- and low-income customers. First, the Companies' Fixed and Limited Income Extension ("FLEX") Program allows residential customers with limited incomes to pay their bill 28 days from issuance. This helps prevent the fixed- and low-income customers from incurring late payment charges, increases the time in which such customers may seek financial aid, and helps reduce the issuance of disconnection notices to these customers. The popularity of the FLEX Program indicates it is achieving its intended aims: since the Companies implemented the program in December 2009 through August 2020, over 31,000 unique customers have used it.

Second, since October 1, 2010, a residential customer who has received a pledge or notice of low-income assistance from an authorized agency is not assessed or required to pay a late-payment charge for the bill for which the pledge or notice is received. Moreover, the customer will not be assessed or required to pay a late-payment charge in any of the 11 months following receipt of the pledge or notice. This waiver of the late-payment charge has provided significant benefits to low-income customers. From May 2019 through February 2020, the Companies waived approximately $740,000 in late-payment charges for residential customers, helping to alleviate the financial burden the Companies' fixed- and low-income customers faced from the time new rates were placed into effect following the Companies' 2018 rate cases and the beginning of the state of emergency arising from the COVID-19 pandemic. From the beginning of the pandemic through September 2020, the Companies waived over $4 million in late-payment charges for residential customers, many of whom are fixed- and low-income customers. The Companies will continue to waive late payment charges for residential customers through the end of the year.

In an effort to further increase low-income customers' awareness of these many assistance programs – including Home Utility Gift certificates applied directly to a customer's account – as well as no- and low-cost energy efficiency tips to save energy and money, the Companies use a variety of communication methods. These include targeted billboards and city bus messaging (both interior and exterior signage), print advertisements, social media posts, customer newsletters and bill inserts, promotions inside the Companies' business offices and within elected officials' constituent newsletters. In addition, the Companies have held meetings with various community agencies and low-income advocates to further inform these representatives of the programs and discuss how these advocates can assist low-income customers with their participation in the programs. All of these efforts demonstrate the Companies' commitment to assisting their fixed- and low-income customers.

III. COST MANAGEMENT

Q. Are the Companies facing rising costs to meet customer expectations for service?

A. Yes. Customer Services forecasts an increase of $8.3 million in operation and maintenance costs for the forecast test year, as compared to the forecast test year in the Companies' previous base rate cases. $3.3 million of this increase is attributable to contract increases for meter reading, field services, and site security. Another $1.7 million of the increase is attributable to rising costs to maintain the Companies' facilities.

Q. Please describe the Companies' latest efforts and contract for meter reading and field services and security services.

A. The Companies contract with third parties to provide these services. And the need for these services is significant. Contractors perform over 14.5 million assigned meter reads per year. As reviewed in the Companies' 2018 rate cases, the last contract for meter reading and field services expired in May 2019. Therefore, before that expiration, we began the process of entering into new contracts to meet the Companies' customer service needs.

We first issued a request for proposals for meter reading and field services and invited six entities to respond. Of those six, five responded for either meter reading or field services, or both; and we eliminated two of those responders based on historical safety performance that did not meet the Companies' criteria. The results of the request for proposals confirmed that the market conditions for meter reading and field services had changed significantly.

Ultimately, the Companies selected three contractors to perform meter reading and field services effective June 2019 through May 2024 based on their established criteria: Olameter for LG&E meter reading, Scope Services for KU field services and meter reading, and Ops Plus for LG&E field services. The Companies selected different contractors based on qualification and to mitigate staffing and performance risks that affected the previous contracts. The resulting contracts reflect a combined 45% increase over the previous contract and up to a 2.5% escalator per year. The new contracts took effect in mid-2019 and account for most of the cost increase of approximately $1.9 million from the prior forecast test year to the current forecast test year for meter reading services and a $500,000 increase for field services.

Likewise, the Companies' new five-year contract for third-party uniformed security services negotiated in 2020 with an effective date of January 2021 is approximately 24% higher than the previous contract. The prior contract was negotiated in 2015 and did not include any escalation for wages over the life of the agreement. The new contract reflects increased market wages for security guards at the Companies' facilities. This contract increase contributed to a total cost increase for security services of approximately $900,000 for the forecast test year.

Q. Why are facilities maintenance costs increasing?

A. The $1.7 million cost increase for facilities operations and maintenance is attributable to several factors including costs to maintain additional square footage added to the facility portfolio around the service territory as well as increased expenses associated with utilities (water, sewage, garbage, gas), and maintenance of mechanical systems for the Company's facilities. Additional COVID-19 related expenses for emergency disinfecting, janitorial, supplies, consumables and modifications to workspaces are also anticipated in the forecasted test year. There are also increased contract costs across multiple supplemental contractors to perform the maintenance services described above.

<u>Efficiency Programs</u>

Q. What programs have been implemented to enhance efficiency and promote cost savings in customer services?

A. The Companies are committed to providing new methods of serving customers while simultaneously creating operational efficiencies that reduce costs. By leveraging improved technology and expanding self-service programs, the Companies provide more flexibility for customers and conserve operational resources.

Recently the Companies have offered additional choices that provide flexibility for customers to interact with us through the method they prefer. These include additional Interactive Voice Response and online (My Account) self-service options, more ways to pay including enhanced online payments using debit or credit cards, text, PayPal, Amazon Pay and Venmo and additional "in person" options at retailers such as Kroger and Walmart. The Companies have also automated certain tasks in the production of timely and accurate customer bills which has resulted in significant cost savings.

Q. What enhancements have been made to self-service options to improve customer experience and add efficiency to operations?

A. In the last rate case, Lonnie E. Bellar described the Interactive Voice Response system as a means to allow customers to address certain telephone inquiries without involvement from a customer service representative. Since that time, more self-service options are available to customers through Interactive Voice Response and My Account. Eligible customers who need to request additional time to pay bills can do so through these self-service channels. Specifically, customers who need additional time to pay when they have received a disconnection notice, if eligible, can enter into a time extension. Customers with accounts already on a payment arrangement can be reminded of the details including the amount due and due date, all without the assistance of a customer service representative. In addition, when customers use My Account to request a move out from their current location customer service representative manual review is no longer required. While emergencies such as power outages can be reported in multiple ways, we have improved the process for doing so through Interactive Voice Response. In addition, customers can opt in to receive notifications regarding their account by their choice of text, phone call, email or all three.

Q. How do self-service improvements contribute to efficiency and reduce costs?

A. A great benefit of self-service is that it puts our customers in the driver's seat. They can choose a way of interacting with us that works best for them. Certain information, including power outage status, account information, balance due, payment due date and payment plan details, is available to customers anytime, day or night. This gives customers more options for connecting with the Companies and addressing their needs. Furthermore, automation of processes like time extensions for payment free up customer service representatives to handle more complex customer needs. The self-service option for time extensions in particular has been heavily used by customers and has achieved significant cost savings. Over 31 months of offering this option, nearly

400,000 time-extension calls were handled by the Interactive Voice Response, representing over half of all customer time-extension requests. This added feature resulted in $260,000 in cost savings through reduced overtime for customer service representatives in 2019, as compared to 2018.

Q. What efficiencies have been added to the billing integrity process?

A. The Companies have integrated Robotic Process Automation ("RPA") to billing integrity functions that had previously been performed manually. RPA is also used elsewhere in customer services to increase paperless billing enrollments for customers who are moving their service address.

Q. How does the use of RPA in billing integrity contribute to efficiency and reduce costs?

A. Use of RPA in billing integrity functions reduces labor cost associated with manual review. It also reduces manual entry errors. From 2019 to 2020, RPA allowed the Companies to reduce billing integrity headcount by three full-time positions. This savings translated to nearly $185,000 in cost reductions in 2019.

IV. CAPITAL INVESTMENTS

Q. Please summarize capital investments made by Customer Services.

A. Customer Services makes capital investments to support multiple operational areas of the Companies, including electric transmission and distribution, gas operations, and customer services operations. For the period from November 1, 2019 to December 31, 2021, Customer Services will invest approximately $103 million in capital. This spending includes $86 million for facility improvements throughout the Companies, $12 million for meters, and $5 million for all other projects.

Q. What key facility capital investments are the Companies making in support of Operations?

A. Facility and site improvements throughout the Companies will address Americans with Disabilities Act ("ADA") compliance standards, inadequate restroom facilities for female employees, lack of meeting and conference rooms, crowded office spaces, co-location of employee work groups and management teams, replacement of outdated workspaces, establishment of a relay protection and control laboratory in Louisville, and needed warehouse and storage space in Lexington.

The facilities affected by these projects include improvements to KU's general office in Lexington ($13.9 million from November 1, 2019 to December 31, 2021), consolidation of KU's Limestone and Loudon facilities in Lexington to support distribution, transmission, and customer services operations ($11 million for this period), expansion and renovation of LG&E's Auburndale Operations Center in Louisville to support electric and gas distribution operations personnel ($8.6 million for this period), and expansion and renovation of the South Service Center in Louisville ($8.4 million for this period). Improvements to these aging facilities are necessary for their continued productive use, will make them better suited to the Companies' operational needs and will enhance efficiency and the level of service the Companies provide to customers. This will be made possible through co-location of complimentary services and personnel, increased collaboration among employees and contractors, and centralization of operational functions.

V. ADVANCED METERING

Q. Before turning to the Companies' request for approval for Advanced Metering Infrastructure ("AMI"), what is the status of the Companies' Advanced Metering Systems ("AMS") Opt-In Program?[10]

A. In early 2014, the Companies filed a smart-metering proposal called the AMS Opt-In Program.[11] The Companies were authorized to deploy as many as 5,000 AMS meters for each of KU and LG&E (electric only), along with the necessary network and other communications and back-end equipment. Importantly, the offering is entirely voluntary and available to residential and small commercial customers (Rates RS, RTOD, and GS). The offering provides a MyMeter web portal allowing participants to view 15-minute, hourly, or daily energy-usage information (typically available 4-6 hours after usage occurs), which enables customers to understand their energy use and take actions to manage it. In October 2018, the Commission authorized the Companies to continue the AMS Opt-In Program and increased the potential customer participation to 10,000 electric meters for each utility. Customers responded enthusiastically to that expansion and LG&E became fully-subscribed at 10,000 customers in May 2019 and KU became fully-subscribed in June 2019 – both within only eight months of the program expansion. Since then, the Companies ceased direct education campaigns for the program but have allowed customers to continue to enroll while making clear that they are waitlisted. As customers move or otherwise leave the program, a slot is made

[10] The Demand Side Management AMS program is being promoted with customers as the Advanced Meter Program or AMP. AMP, AMS, "AMS Offering", and "AMS Opt-In" all reference the same program.
[11] *In the Matter of: Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for Review, Modification, and Continuation of Existing, and Addition of New, Demand-Side Management and Energy Efficiency Programs*, Case No. 2014-00003, Application (Jan. 17, 2014).

available to customers on the waitlist. To date, approximately 5,200 customers have enrolled on the waitlist for the AMS Opt-In Program.

Q. Will the Companies be addressing customer expectations with AMI?

A. Yes. Fundamentally, customers expect safe, reliable, and affordable energy to meet their needs. Customers expect to know when power is out to their home, when it will be restored, to be provided with the means to understand their electric use so they can be active and informed consumers, and the tools to manage their energy consumption. Customer expectations, however, are continuing to change. Increasingly, customers want more from their utility.

Increasingly, customers are interested in understanding how their behavior drives their energy bills, how their energy use affects the environment, and which programs or products are available that make sense for their needs. Full AMI deployment allows the Companies to meet customers' service expectations by providing access to detailed and personalized consumption data, corresponding tools to actively manage their energy usage, and tailored recommendations that can save customers money. Today's legacy meters provide consumption data to bill customers on a monthly basis, but they do nothing to serve the growing expectations of customers.

Q. Are some of the innovative tools that can be available through AMI available today to AMS Opt-In Program Customers?

A. Yes, but not the complete package. Today, customers in the AMS Opt-In Program and Solar Share Program have an AMI meter and access to an online portal called MyMeter that provides them tools to meet some of their increasing expectations. MyMeter provides customers with additional means to understand their electric use so they can be active and better-informed consumers; empowering customers to manage their energy consumption. Additionally, MyMeter assists customers in understanding how their behavior drives their energy bills, how their energy use affects the environment, and receive personalized energy cost comparisons across optional rates to give customers confidence in selecting amongst those optional rates. Customers definitely benefit from tools that help them manage their bill, engage them to save energy through behavior changes or invest in energy efficiency, empower them to understand self-generation, evaluate optional rates, and assess environmental impact. While our current AMS Opt-In Program makes numerous innovative tools available to some customers, full deployment of AMI will provide that availability to all. The specific features related to each of these categories are shown in Exhibit ELS-1.

Q. How do AMS Opt-In and Solar Share Customers know about the benefits associated with their AMI meter?

A. From the time they sign up for these programs, we regularly communicate with our customers regarding the status of the installation process, what tools are available to them after installation, and how to access those tools. These communications are done in multiple ways to align with customer preference differences. One example is a monthly e-update that highlights functionality and typically features instructional videos to encourage engagement. The e-updates also frequently ask customers to share how they are using the data to support their needs. The instructional videos are available on our website[12] to help customers use AMI capabilities, understand how their

[12] https://lge-ku.com/advanced-meter

behaviors affect their bill, and how to access the tools and programs that best meet their needs.

Q. As AMI is fully deployed and then fully operational, do you expect to be able to provide additional customer benefits beyond those currently available?

A. Absolutely. AMI provides the foundation for new innovation and capabilities that are only available through full deployment. Some of the benefits do not require customers to have internet access or directly take action. Mr. Wolfe discusses in his testimony how customers will benefit from distribution operations' use of AMI. The distribution benefits realized from AMI are important to customers as power quality and reliability consistently rank as the most important component of customer satisfaction and have the greatest influence on the relative value of other key utility customer satisfaction. The indices in the J.D. Power customer studies confirm this observation.

AMI will help the Companies improve the customer experience with power outages because it helps the Companies to better manage those outages. AMI can:

- Help the Companies proactively identify equipment issues and thus plan maintenance to minimize or avoid outages;
- Enhance the Companies' ability to know when an outage has occurred which can result in faster restoration;
- Enable the Companies to identify the reason for the outage more quickly which will reduce estimated restoration time (which will help customers with lodging and refrigeration decisions based on outage duration); and
- Improve the Companies' ability to inform customers when power is restored because AMI quickly informs the system of that restoration.

Many customers also are interested in solar options, electric vehicles, and energy storage. AMI will assist those customers in assessing the effectiveness of those items as it will allow them to make decisions and adjust behavior based on the granular usage data AMI provides. Without AMI, customers now must either install their own energy monitoring equipment or use engineering estimates to calculate the value of using solar, electric vehicles, or storing energy. And many of these same customers are interested in net billing or net metering. Here again, AMI will help provide the data needed for customers to match their usage with energy they are generating from their own solar equipment.

Another AMI customer benefit we will implement is the ability to accomplish remote service switching. Remote service switching will allow the Companies to reconnect service more quickly without having to dispatch and complete a field work order. This will be especially helpful for customers who are moving from one residence to another. It also allows for more efficient and lower cost reconnection of service after disconnection for non-payment. As a result, the Companies expect that the special charge associated with disconnection and reconnection due to non-payment will be reduced to $0 for customers with appropriately equipped advanced meters once the necessary systems are installed. Having said that, the Companies remain committed to continue to work closely with low-income customers and their advocates to provide the payment assistance and timely communication that those customers need, deserve and expect.

The benefits concerning outages, power quality, and detailed energy usage will allow the Companies' customer service representatives to better address the customer's needs the first time they contact us. When a customer contacts the Companies with a question or an issue, they expect it to be resolved or answered on the initial interaction. AMI will facilitate that.

AMI will enable customer service representatives to have more current and robust information about outages and energy usage that can be used to efficiently and quickly address the customer's concern in a single communication in some scenarios without needing to roll a truck for field investigation. For example, customers who have questions about their last meter reading may have that question answered by the customer service representative's retrieval of a current meter read while the customer is on the phone. The customer service representative can then evaluate the current meter read to the billing meter read and discuss any issues with the customer. Additionally, because a customer service representative will be able to see interval data for individual customers, they can have an informed discussion with the customer about a high bill concern.

As for outages, the customer service representative will be able to tell whether an entire circuit is experiencing an outage or if a problem is behind the customer's meter. Thus, AMI data provides additional tools for customer service representatives to utilize to provide additional insights and answer customer questions that are not available without it.

Finally, AMI is critical to offering a prepay service option for customers. Some customers prefer a pay-as-you go or a prepay alternative much like they pay for vehicle fuel or groceries. The option allows those who want it to choose it. The Companies are committed to offering a voluntary prepay option upon full deployment of AMI and the necessary systems.

Q. Has the Companies' experience with COVID-19 taught any lessons about how customers want their meters read?

A. Yes. Generally speaking, customers are expressing dislike of the presence of meter readers on their property. For obvious reasons, that dislike increased even more when the COVID-19 pandemic began. This dislike for meter readers accessing their property to read the meters causes customer dissatisfaction and at times dangerous conditions due to the presence of dogs, weapons and threatening customers.

And for meters located inside a structure as compared to outside, the situation is worse. The Companies have approximately 25,000 interior electric meters and 2,000 interior gas meters. Reading these meters on a monthly basis can be challenging for the Companies and inconvenient for the customers, which has been exacerbated due to COVID-19. COVID-19 or not, AMI will eliminate the challenges of gaining interior access by enabling remote meter reading, connection, and disconnection (electric only) services. The Companies will no longer need to enter these customers' homes on a monthly basis. Additionally, remote meter reading reduces the customer inconvenience of providing keys to neighbors or to the Companies and eliminates the access issues currently experienced, such as reading delays and struggles with setting mutually convenient times to gain access.

At the beginning of the pandemic, inside meters were estimated until proper personal protective equipment was available and safe entry procedures were established. Implementing these new procedures quickly was important to accessing certain meters that only store data for a limited number of days, such as demand meters. Also during this time, limitations of current estimation capabilities surfaced. Only monthly usage data points are available without AMI meters, twelve total usage numbers for a calendar year per account. The current estimation algorithm assumes similar usage for the month being estimated compared to the same month one-year prior and adjusted for weather differences. At the start of the pandemic, usage patterns were atypical with many residential customers working from home and several commercial customers shutting down temporarily. AMI meters would have provided insight into shifting usage patterns during the month. This usage pattern would have been helpful to estimate missing interval data, if needed. It also would have provided valuable information for financial and operational planning.

Converting these meters to AMI improves customer experience, and reduces costs, interior access challenges, and safety issues.

Q. What will the Companies do to engage and educate customers and stakeholders about AMI?

A. We have a developed plan to engage and educate customers and stakeholders about fully-deployed AMI. The development began several years ago during regular meetings with interested stakeholders to discuss how customers would be engaged and educated about AMI. In part as a result of those meetings, the Companies have developed an Advanced Metering Infrastructure Customer Engagement and Communication Plan (attached as Exhibit ELS-2) that includes: awareness, education, and engagement.

Upon approval by the Commission, the Companies will immediately begin to make customers aware that AMI is going to be available during the course of the next several years in a phased installation. We will use our established communication channels of bill inserts, website postings, print, radio and television ads, direct mail, media relations, community outreach and events, and social media to promote awareness of the AMI technology and deployment schedule. We will continue to educate customers about the conveniences and advantages of AMI.

Our goal is for full adoption of AMI by all customers because full adoption is required to maximize the benefits. The Companies are committed to educating their customers on the safety and security of AMI so they can make an informed decision. In the event customers wish to refuse an AMI meter, we will inform them about their opt-out options. Finally, as AMI meters are deployed, we will use the same established communication channels to engage customers by encouraging them to take full advantage of the benefits that will be available from day one. We will encourage them to track their energy usage and avail themselves of innovative rate structures so they can make more informed decisions and reduce their bills.

Q. How will the Companies staff the AMI deployment?

A. Needed resources will peak from months 12 to 21 into the project at about 120 - 150 full-time equivalent ("FTE") personnel not including approximately 200 FTEs for meter and communications infrastructure installation. We expect to begin seeing meter reader savings phase in as meters are deployed approximately 14 months after approval and field service savings approximately 31 months after approval.

Q. How will AMI impact the Companies' staffing?

A. While resource needs will certainly change, normal attrition and retirements are expected to largely offset any incremental employment additions. Specifically, the Companies expect to add eleven FTE personnel (nine in customer service and two in information technology) related to maintaining AMI equipment and monitoring the data, events, and alarms that come in from the field. The Companies' other project personnel utilized during the deployment will return to available roles at the time their project role ends. After AMI deployment, a very limited number of the Companies' Meter Reading employees will remain to support the meters outside the scope of the AMI project and the meter reading needs resulting from customers who opt-out of AMI.

Q. Who will own and maintain AMI components?

A. As with all existing meters, the Companies will own and maintain all electric and gas meters, gas indices, the corresponding AMI communications network, and all back-office system processing and data storage equipment. To be clear, AMI does not adjust the established ownership structure of equipment. The Companies will continue to oversee all testing, inventory, and records associated with these assets and maintain them as needed.

Q. What will happen if a customer-owned meter base is found to be damaged, or is damaged, in the process of installing an AMI meter?

A. The Companies expect this to be an issue only in a small percentage of instances. If that occurs, the Companies will offer through the meter deployment vendor to repair or replace the meter base as needed. The meter deployment vendor will coordinate this work through a licensed electrical contractor at no additional cost to the customer, provided the customer signs a waiver confirming their understanding that these repairs are on a one-time basis and that the customer is responsible for meter base repairs and maintenance going forward. The customer would also have the option to refuse this service and repair the meter base using a contractor of their choice at their own cost.

Q. What impacts will full deployment of AMI have on the Companies' existing DSM-EE AMS Customer Service Offering?

A. The Companies will continue to operate the AMS Opt-In Program as a DSM-EE program during the AMI deployment to all customers. The Companies plan to request Commission approval to terminate the AMS Opt-In Program at the appropriate time without interruption to AMS service for these customers.

Q. Is a customer's privacy at risk with AMI?

A. No. The Companies have a long and established practice of protecting our customers' privacy. That commitment will not change as a result of AMI. The Companies are committed not to sell individual customer data to third parties.[13] This commitment is confirmed to customers in the privacy policy the Companies have publicly posted on their website for years.[14] In addition, the Companies remain committed to data security. The particular AMI technology provides state-of-the-art data security in the AMI network. The Companies have an established culture of protecting all of their data, including customer data, due to cyber-security concerns. This same culture will encompass AMI data.

[13] *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, Hearing Video at 1:59:11 – 1:59:16.
[14] https://lge-ku.com/privacy.

Q. In sum, do you believe AMI is an appropriate solution for both customers and the Companies?

A. Yes, AMI is an excellent solution. The customer benefits from a fully deployed AMI are very real and significant. And AMI is also the most cost-effective solution for meter reading needs. AMI will serve our customers very well for decades to come.

VI. CUSTOMER SERVICES PROGRAM UPDATE

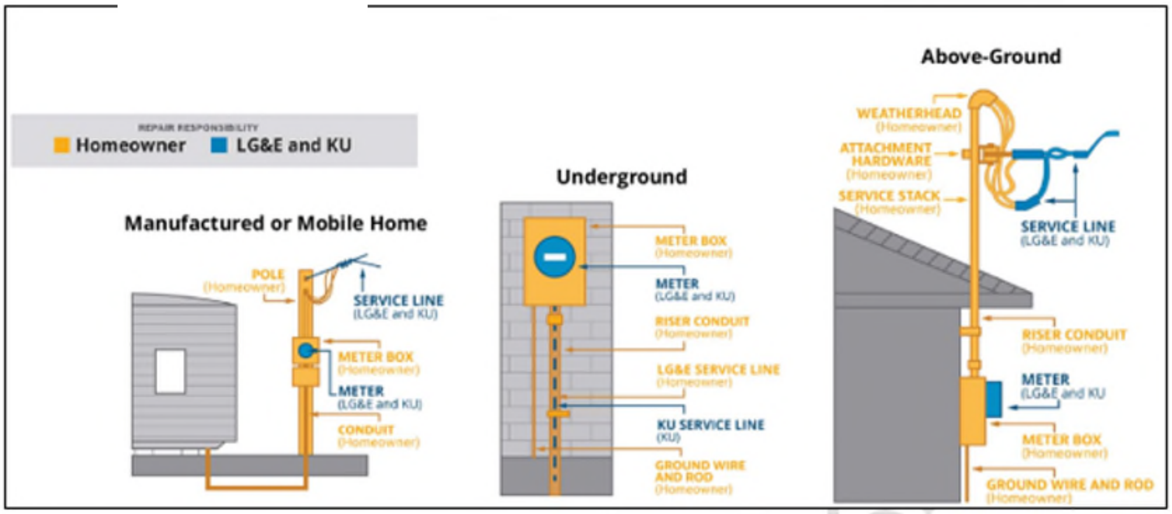
Q. How are the Companies' customer services programs changing?

A. The Companies are committed to improving customer services programs to provide better overall service to customers, provide them more options, add convenience, and promote use and adoption of alternative energy. The addition of the HomeServe equipment protection program and planned additions to the Companies' electric vehicle support offerings are proposed to meet these objectives.

HomeServe Protection Plan for Customer-Owned Equipment

Q. Are customers responsible for a portion of the service equipment that connects the Companies' electric service line to their home or business?

A. Yes. Under the Companies' tariffs, customers are responsible for maintaining and repairing most of the equipment that connects the Companies' electric service line to their service address. Depending on the type of service and whether the service is provided by KU or LG&E, customer equipment generally includes the meter box, conduit, weatherhead (for overhead service), ground wire and rod, and, in most instances, the service wire that connects the Companies' service to the meter. The Companies own and are responsible for maintaining only the meter itself and, for KU underground service only, the service line connecting to the customer's service. The following figure illustrates which equipment is customer-owned and which equipment is company-owned for different service types:



Q. Does customer equipment sometimes get damaged?

A. Yes, customer-owned exterior electric equipment can be damaged by inclement weather, flooding, outages, or other factors. In 2019 alone, LG&E customers experienced over 2,000 instances of damage to customer-owned exterior electric equipment, while KU customers experienced approximately 750 instances of damage.

Q. If customer equipment is damaged and in need of repair, how are repairs handled?

A. At all times, the customer bears the responsibility to have customer-owned equipment repaired by a qualified electrician and inspected by a state-certified electrical inspector. Once the repair is completed, the customer or the customer's electrician must have the work inspected and approved by a qualified inspector. If an inspection does not occur within five days of the date of repair, the Companies must turn off service to the affected property until the inspection can be made.

Q. Does this process present difficulty for customers?

A. Often it does. Although the Companies communicate the customer responsibility through various outlets such as bill inserts, and website communication, customers still may be surprised to learn that they own and are responsible for repairing damage to exterior electric equipment at their home or business. Customers may have difficulty locating and hiring a qualified, licensed electrician to perform repairs. Furthermore, customers may not appreciate that they must promptly have all repair work inspected in order to receive continued service. There is sometimes miscommunication between a customer and the electrician on who will obtain the inspection. In some circumstances, the repairs may be extensive and costly.

Q. How do the Companies propose to address this challenge?

A. The Companies propose to enter into an arrangement with HomeServe USA ("HomeServe") under which HomeServe will offer the Companies' customers a voluntary exterior electric equipment protection plan for a monthly fee of $5.99. Customers would receive notice of the availability of the plan and be offered an opportunity to subscribe. For those customers who subscribe, the Companies would perform billing and collection services for HomeServe using their monthly bills for energy services. A separate line item would appear on the monthly bills of customers who are enrolled in the HomeServe plan. The Companies would collect the monthly fee, retain 15% of the collected fees for marketing and billing services, and remit the remainder to HomeServe.

Q. What would the HomeServe plan offer to customers?

A. Under HomeServe's exterior electric equipment protection plan, HomeServe will, within two hours of being contacted by a customer who has opted into the program, assign a local qualified electrician to perform repair work to the damaged customer equipment and arrange for an inspection by a licensed inspector once complete. The exterior line protection plan provides for coverage of 100 percent of the cost to repair or replace covered equipment, subject to an annual maximum repair cost of $5,000. Any costs in excess of $5,000 annually would be the customer's responsibility.

HomeServe will contract for the services of local licensed electricians to perform the repair work. The Companies would not be involved in the selection, dispatch, oversight, or training of these electricians.

Q. Are there any proposed tariff changes associated with the HomeServe program?

A. Yes, the Companies are proposing to add a new rider to their tariffs to set forth the terms under which the Companies may perform billing and collection services associated with warranties for customer-owned exterior electric equipment. Mr. Conroy's testimony describes the proposed additions in his testimony.

<u>Electric Vehicle ("EV") Charging Stations</u>

Q. Please describe the Companies' existing electric vehicle charging program.

A. Empowering customers who may be interested in purchasing and operating an electric vehicle is important to the Companies. To promote EV use, the Companies have a multifaceted approach that includes education and information, public charging infrastructure, a hosted station program (Electric Vehicle Supply Equipment "EVSE" tariff) and new practices for fast charging. More specifically, through the LG&E-KU

website, the Companies offer resources for customers desiring to learn more about EVs, purchase an EV, or save on total energy costs associated with EVs.

Beginning in 2016, as part of a pilot program, the Companies installed twenty public EV charging stations across the Commonwealth: ten in LG&E's service territory and ten in KU's service territory. These charging stations are Level 2 stations, meaning they run on 240-volt power and can achieve a full range charge in 2 to 12 hours. Customers are charged an hourly rate of $0.75 for the first two hours and $1.00 for every hour after the first two hours to use these charging stations under rate EVC in the Companies' current tariffs. The Companies also hosts five stations at customer locations so that they may empower their employees and patrons to drive an electric vehicle.

Q. Can the existing charging stations support the anticipated growth of EV use in the Companies' service territories?

A. No. The type of chargers currently in use as well as the relatively small number of chargers in Kentucky's major corridors are not suitable for long distance travel by EV drivers. Because EVs remain the only alternative fuel passenger vehicle commercially available today and into the foreseeable future, the Companies anticipate significant growth in the use of EVs where sufficient infrastructure is in place. The Companies aim to support economic development and growth in Kentucky interstate corridors by providing infrastructure necessary for the future of transportation and customer demands.

Q. Is there a current opportunity for Kentucky to expand EV support infrastructure?

A. Yes. As a result of the historic 2016 consent decree between Volkswagen and the federal government relating to emissions standards,[15] Kentucky will receive $20.3 million from an Environmental Mitigation Trust to invest in vehicle emissions reduction. The General Assembly has approved a spending plan for these funds which would allocate over $3 million toward the purchase of light-duty, zero-emission vehicle supply equipment, such as EV charging stations. These funds are required to be matched equally by the recipient. In response to the Kentucky Energy and Environment Cabinet's request for comment on this investment , the Companies, along with other investor-owned utilities and cooperatives operating in the state, have provided a conceptual proposal for how these funds could be allocated to install new EV charging stations in the Commonwealth.

Q. What is included in the submitted concept for new EV charging infrastructure?

A. The electric utilities' concept contemplates adding 35 new EV charging locations along Kentucky's major highway corridors and urban centers. Unlike the charging stations currently in existence under the Companies' pilot program, the proposed charging stations would be direct current fast charging ("DCFC") stations, also known as Level 3 charging stations. Level 3 charging stations are capable of providing a much greater EV range in a much shorter amount of time than Level 2 chargers: more than 300 miles of range per hour of charge, although charging speeds vary. This type of charging station is most commonly used by light duty passenger vehicles - long distance travelers

[15] https://www.epa.gov/sites/production/files/2016-10/documents/amended20lpartial-cd.pdf (last visited Nov. 13, 2020).

and local commuters alike. Each location would include at least two Level 3 charging stations. Consistent with Federal Highway Administration guidelines for DCFC corridors, the locations would be spaced no more than 50 miles apart. Based on current funding guidance from the Kentucky Energy and Environment Cabinet, between 13 and 18 DCFC charging stations could be constructed with Environmental Mitigation Trust plus matching funds, with a smaller pool of funds being allocated to Level 2 charging stations in Kentucky State Parks and other municipal and community areas. The Companies anticipate that the Kentucky Energy and Environment Cabinet will soon be issuing a Request for Proposals for allocation of these funds.

Q. Do the Companies have plans to install new DCFC stations in Kentucky?

A. Yes, beginning in 2022 the Companies are planning to install eight total DCFC stations in Kentucky, four in each company's service territory, contingent upon receipt of matching funding from the Environmental Mitigation Trust. If matching funding is not received, four total DCFC stations will be installed. The preliminary estimated cost of each station is $306,000.

Q. Are the Companies proposing to change their tariff structure for EV charging?

A. Yes, although the rate itself will not change, the Companies are proposing some modifications to the terms of the tariff for Rate EVC (Level 2 charging stations). The Companies are also proposing a new rate – EVC-FAST, which would apply to DCFC (Level 3) charging stations. The testimonies of Mr. Seelye and Mr. Conroy discuss these changes and the proposed new rate.

VII. CONCLUSION

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

The undersigned, **Eileen L. Saunders**, being duly sworn, deposes and says she is the Vice President, Customer Services for Louisville Gas and Electric Company and Kentucky Utilities Company and an employee of LG&E and KU Services Company, and that she has personal knowledge of the matters set forth in the foregoing testimony, and the answers contained therein are true and correct to the best of her information, knowledge and belief.

Eileen L. Saunders

Eileen L. Saunders

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 20th day of November 2020.

Kimberly C Burk

Notary Public

Notary Public, ID No. KYNP14646

My Commission Expires:

10-16-2024

APPENDIX A

Eileen L. Saunders
Vice President - Customer Services
Kentucky Utilities Company
Louisville Gas and Electric Company
220 West Main Street
Louisville, Kentucky 40202
Telephone: (502) 627-2431

Previous Positions

Kentucky Louisville Gas & Electric Company Utilities Company

Director, Safety and Technical Training	April 2017-January 2020
Director, Generation Services	March 2013-April 2017
Manager, Major Capital Projects	March 2005-March 2013
SCR Technology Transfer Manager	May 2002-March 2005
Manager, Maintenance Power Generation, Trimble County	June 1996-May 2002
Manager, Organizational Effectiveness	October 1994-June 1996

AT&T

Resource Manager and Organizational Consultant	June 1989-October 1994

Professional/Trade Memberships

American Gas Association	2017-2019

Education

Bachelor of Arts in Communications, The American University, Washington DC, 1989
Master of Science, Human Resources and Human Development, The American University, Washington, DC, 1993
Executive Development Program, University of Pennsylvania, The Wharton School, 2013

Civic Activities

Kentucky Performing Arts Foundation Board Member	2020-Present
Family Scholar House Board of Directors	2014-2020
Power and Energy Institute Board of Directors, University of Kentucky	2013-2017
Alpha Kappa Alpha Sorority, Inc.	1987-Present

Innovative Tools Available to Customers with an AMI Meter

Bill and Consumption Related Tools

- View energy usage data in graphical or numeric formats to track and compare down to 15-minute intervals. (Slide A-2)
- Compare energy consumption patterns plotted against temperature. (Slide A-3)
- View usage that has accrued since last month's bill and see how that compares to the same timeframe of the prior bill. (Slide A-4)
- Compare changes in energy usage, in kWh or dollars, from the previous week, month, or 90-day average. (Slide A-5)
- Set and receive alerts to assist in managing daily and monthly energy usage. Notifications can be set in $ or kWh. MyMeter will send a customized update when the customer reaches a configured threshold by text or email based upon customer preference. (Slide A-6)

Note: See Appendix slide referenced for Screenshots of MyMeter Dashboard that demonstrate these tools.

Innovative Tools Available to Customers with an AMI Meter (Continued)

Engaging Customers to Save Energy

- Compare energy usage to others within the same zip code using the neighborhood comparison tool. (Slide A-7)
- Assess the energy efficiency of the home by benchmarking against Energy Star's Home Energy Yardstick. (Slide A-8)
- Download or export data to spreadsheets or Green Button Download enabled products to facilitate additional review or analysis. (Slide A-9)
- Set "Energy Markers" that create a customized date reminder when customers make any changes that could impact how energy in consumed, e.g., appliance replacements or thermostat set-point changes. Provides energy consumption comparison between before and after the marker. (Slide A-10)
- Provides an Energy Challenge which allows customers to set energy reduction goals and track their progress. (Slide A-11)
- Ability to make consumption data available to third parties, as designated by the customer. (Slide A-12)
- Enable easy customer access to MyMeter through the use of mobile devices.

Note: See Appendix for Screenshots of MyMeter Dashboard that demonstrate these tools.

Innovative Tools Available to Customers with an AMI Meter (Continued)

Empowering Customer Owned Generation

- Self-generation customers (net metering) can view the amount of energy being imported and exported to the grid in 15-minute intervals. (Slide A-13)
- Solar Share Program customers can see their pro rata solar energy from their shares in relation to their on-premise consumption in 15-minute intervals. (Slide A-14)
- Ability to make consumption data available to third parties that the customer engages to aid them in appropriately sizing solar or other customer owned generation before they invest. (Slide A-12)

Note: See Appendix for Screenshots of MyMeter Dashboard that demonstrate these tools.

Innovative Tools Available to Customers with an AMI Meter (Continued)

Evaluating and Managing Optional Rates

- Customers already enrolled in one of the Companies' Residential time-of-day (RTOD) rates have usage during the most expensive periods highlighted for analysis and behavioral change. (Slide A-15)
- Rate comparison tool for residential customers (RS, RTOD-E, and RTOD-D) provides personalized energy cost comparisons across the three rate options so customers can determine which rate would be of benefit based on historical usage patterns. (Slide A–16)

Educating Customers on Environmental Impact

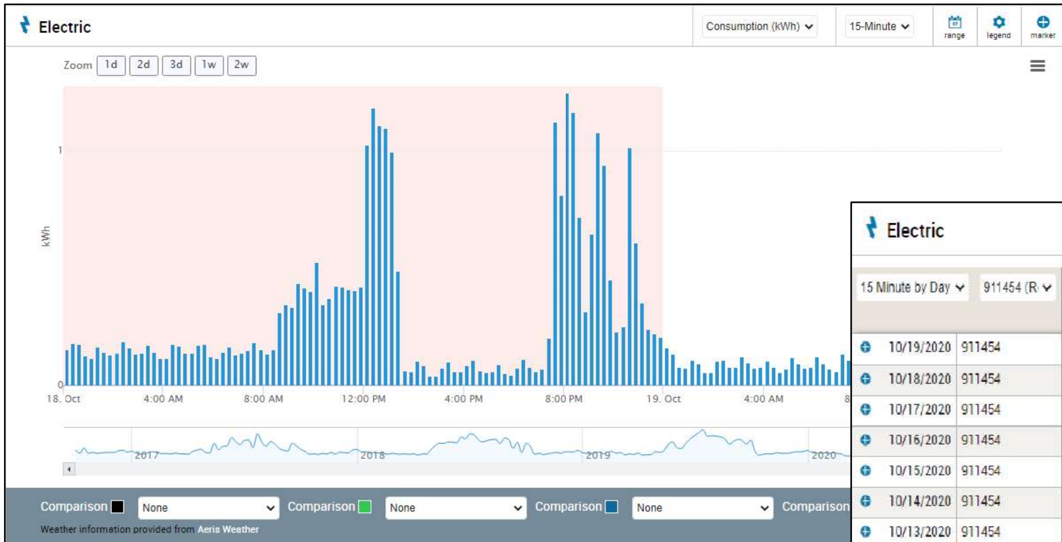
- Review energy usage in terms of Carbon Dioxide (CO_2) emissions and equivalent miles driven. (Slide A-17)

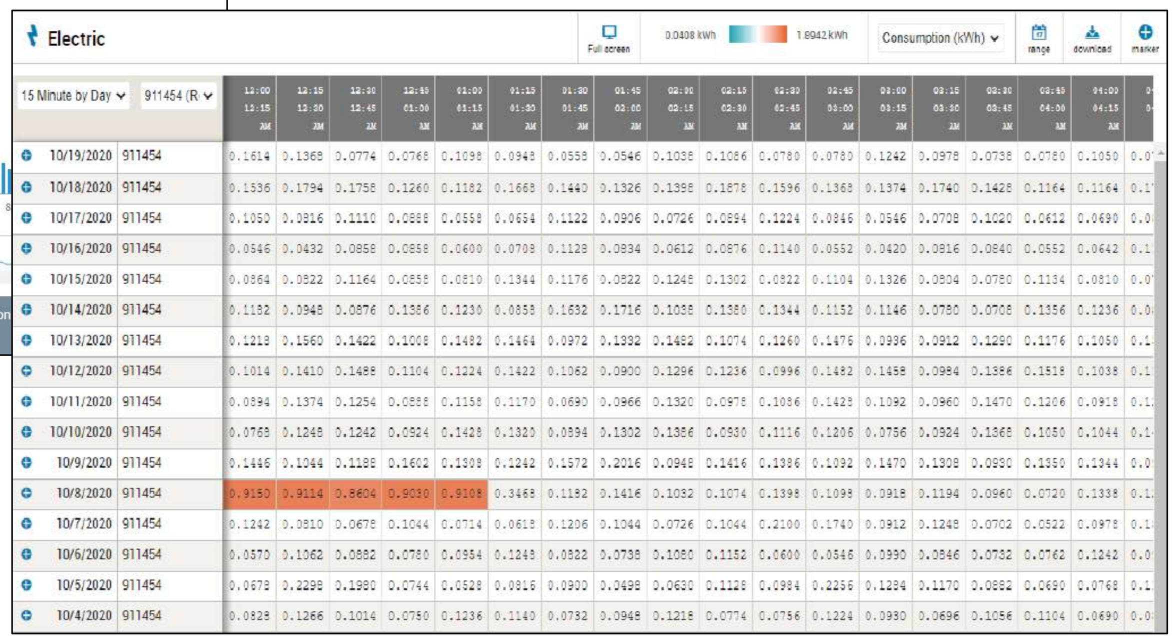
Note: See Appendix for Screenshots of MyMeter Dashboard that demonstrate these tools.

Appendix

MyMeter Screenshots

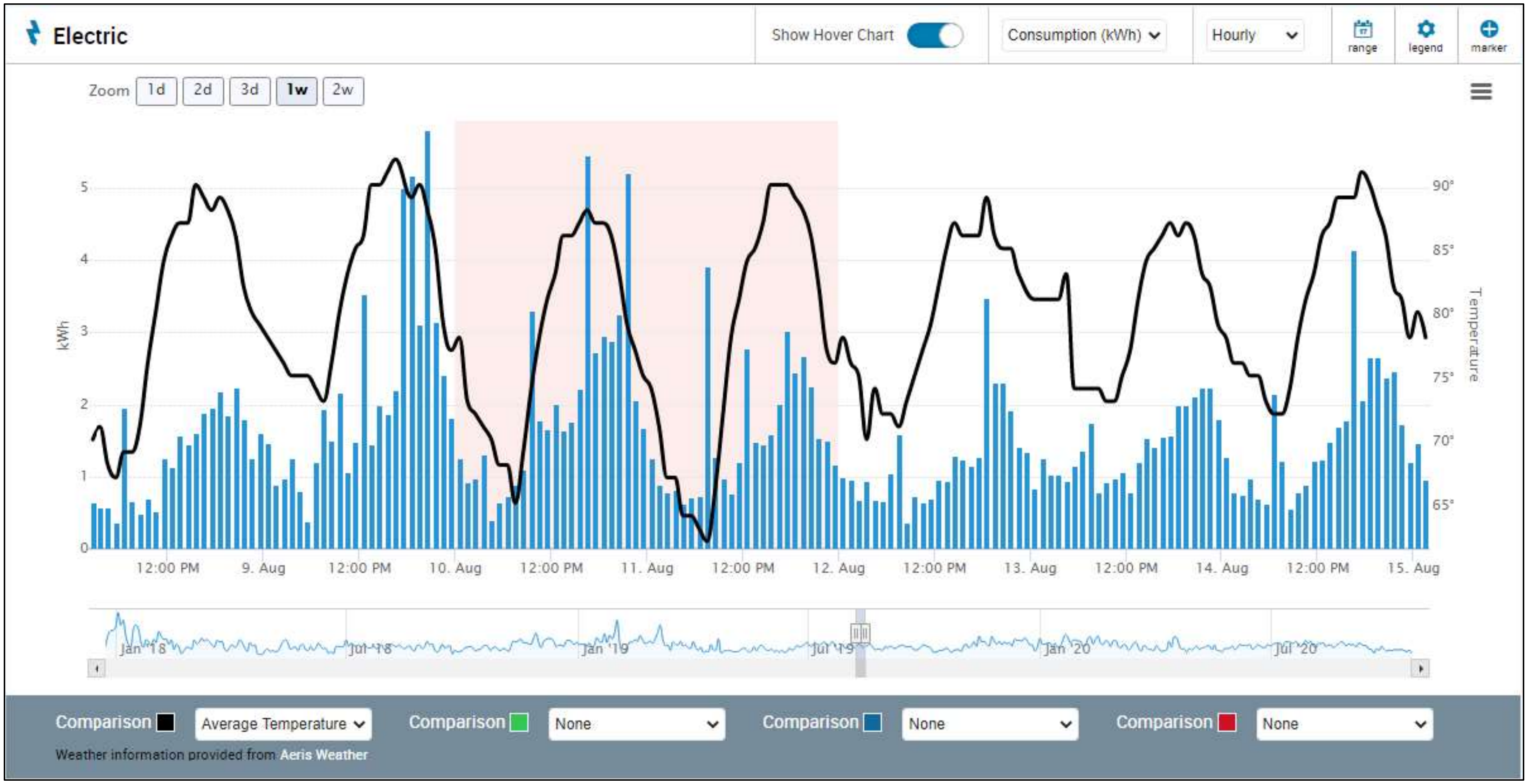
View data in graphical or numeric formats to track and compare down to 15-minute intervals.



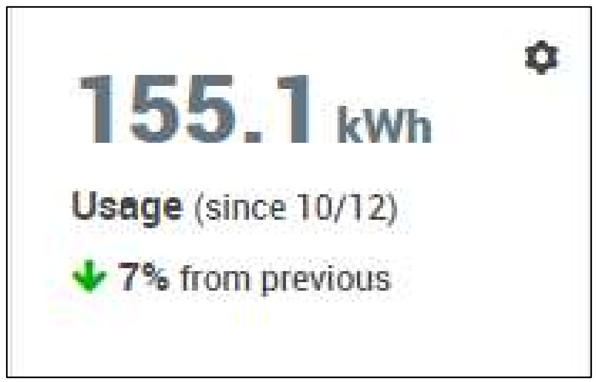


Date	Meter	12:00 12:15 AM	12:15 12:30 AM	12:30 12:45 AM	12:45 01:00 AM	01:00 01:15 AM	01:15 01:30 AM	01:30 01:45 AM	01:45 02:00 AM	02:00 02:15 AM	02:15 02:30 AM	02:30 02:45 AM	02:45 03:00 AM	03:00 03:15 AM	03:15 03:30 AM	03:30 03:45 AM	03:45 04:00 AM	04:00 04:15 AM
10/19/2020	911454	0.1614	0.1368	0.0774	0.0768	0.1098	0.0948	0.0558	0.0546	0.1038	0.1086	0.0780	0.0780	0.1242	0.0978	0.0738	0.0780	0.1050
10/18/2020	911454	0.1536	0.1794	0.1758	0.1260	0.1182	0.1668	0.1440	0.1326	0.1398	0.1878	0.1596	0.1368	0.1374	0.1740	0.1428	0.1164	0.1164
10/17/2020	911454	0.1050	0.0816	0.1110	0.0888	0.0558	0.0654	0.1122	0.0906	0.0726	0.0894	0.1224	0.0846	0.0546	0.0708	0.1020	0.0612	0.0690
10/16/2020	911454	0.0546	0.0432	0.0858	0.0858	0.0600	0.0708	0.1128	0.0834	0.0612	0.0876	0.1140	0.0552	0.0420	0.0816	0.0840	0.0552	0.0642
10/15/2020	911454	0.0864	0.0822	0.1164	0.0858	0.0810	0.1344	0.1176	0.0822	0.1248	0.1302	0.0822	0.1104	0.1326	0.0804	0.0780	0.1134	0.0810
10/14/2020	911454	0.1182	0.0948	0.0876	0.1386	0.1230	0.0858	0.1632	0.1716	0.1038	0.1380	0.1344	0.1152	0.1146	0.0780	0.0708	0.1356	0.1236
10/13/2020	911454	0.1218	0.1560	0.1422	0.1008	0.1482	0.1464	0.0972	0.1332	0.1482	0.1074	0.1260	0.1476	0.0936	0.0912	0.1290	0.1176	0.1050
10/12/2020	911454	0.1014	0.1410	0.1488	0.1104	0.1224	0.1422	0.1062	0.0900	0.1296	0.1236	0.0996	0.1482	0.1458	0.0984	0.1386	0.1518	0.1038
10/11/2020	911454	0.0894	0.1374	0.1254	0.0888	0.1158	0.1170	0.0690	0.0966	0.1320	0.0978	0.1086	0.1428	0.1092	0.0960	0.1470	0.1206	0.0918
10/10/2020	911454	0.0768	0.1248	0.1242	0.0924	0.1428	0.1320	0.0894	0.1302	0.1386	0.0930	0.1116	0.1206	0.0756	0.0924	0.1368	0.1050	0.1044
10/9/2020	911454	0.1446	0.1044	0.1188	0.1602	0.1308	0.1242	0.1572	0.2016	0.0948	0.1416	0.1386	0.1092	0.1470	0.1308	0.0930	0.1350	0.1344
10/8/2020	911454	0.9150	0.9114	0.8604	0.9030	0.9108	0.3468	0.1182	0.1416	0.1032	0.1074	0.1398	0.1098	0.0918	0.1194	0.0960	0.0720	0.1338
10/7/2020	911454	0.1242	0.0810	0.0678	0.1044	0.0714	0.0618	0.1206	0.1044	0.0726	0.1044	0.2100	0.1740	0.0912	0.1248	0.0702	0.0522	0.0978
10/6/2020	911454	0.0570	0.1062	0.0882	0.0780	0.0954	0.1248	0.0822	0.0738	0.1080	0.1152	0.0600	0.0546	0.0990	0.0846	0.0732	0.0762	0.1242
10/5/2020	911454	0.0678	0.2298	0.1980	0.0744	0.0528	0.0816	0.0900	0.0498	0.0630	0.1128	0.0984	0.2256	0.1284	0.1170	0.0882	0.0690	0.0768
10/4/2020	911454	0.0828	0.1266	0.1014	0.0750	0.1236	0.1140	0.0732	0.0948	0.1218	0.0774	0.0756	0.1224	0.0930	0.0696	0.1056	0.1104	0.0690

View energy consumption patterns plotted against temperature.

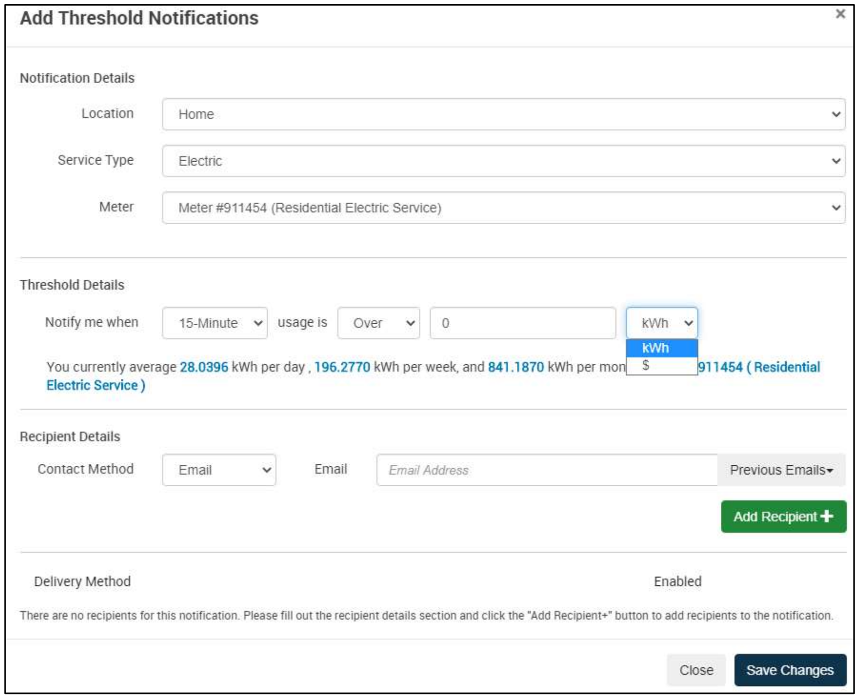


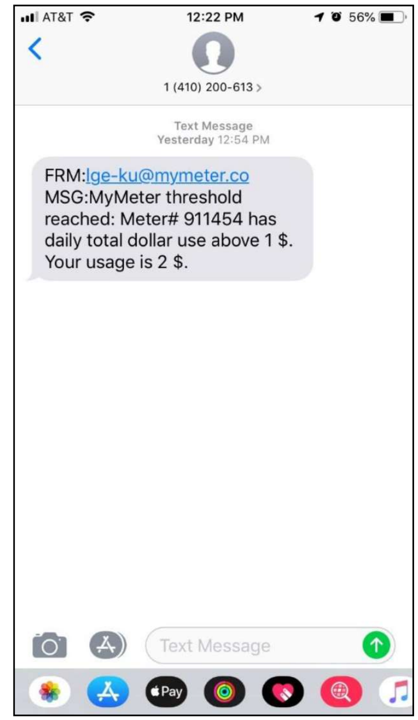
View usage that has accrued since last month's bill and see how that compares to the same timeframe of the prior bill.



Compare changes in energy usage, in kWh or dollars, from the previous week, month, or 90-day average.

Set and receive alerts to assist in managing daily and monthly energy usage. Notifications can be set in $ or kWh.



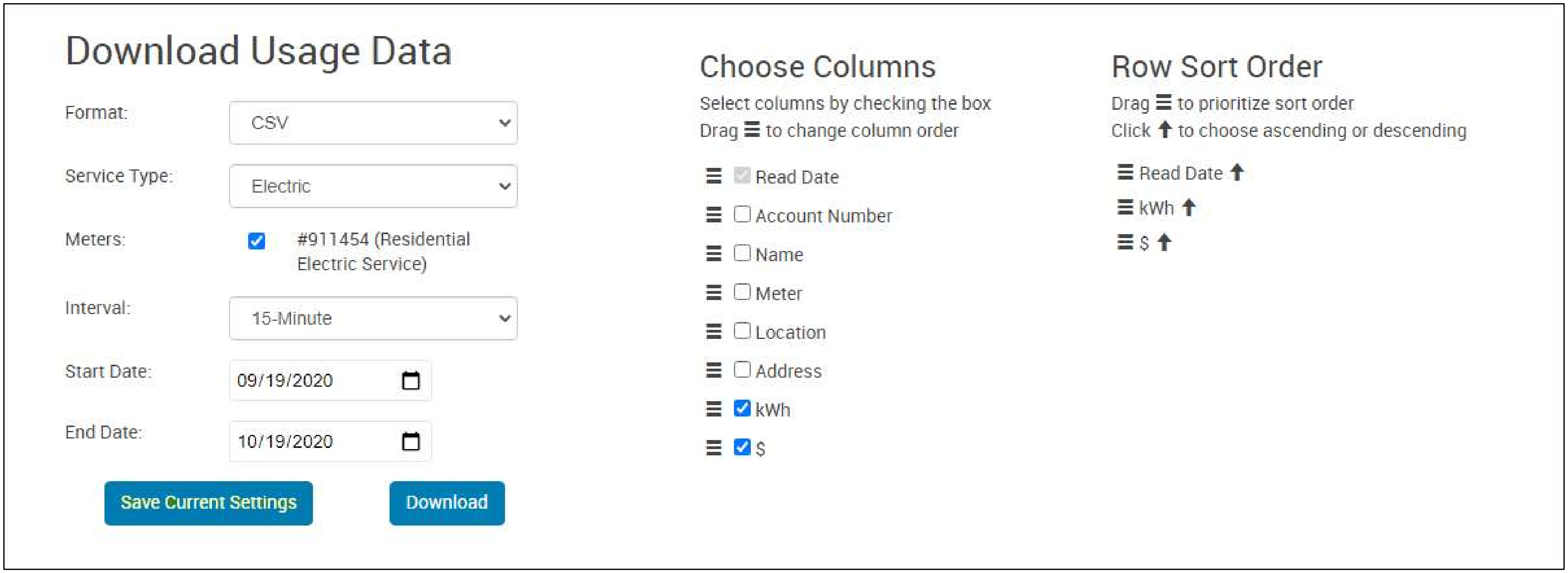


Compare energy usage to others within the same zip code using the neighborhood comparison tool.

Assess the energy efficiency of the home by benchmarking against Energy Star's Home Energy Yardstick.

For more information please visit:
https://www.energystar.gov/index.cfm?fuseaction=home_energy_yardstick.showHowItWorks

Download or export data to spreadsheets or Green Button Download enabled products to facilitate additional review or analysis.



Set "Energy Markers" that create a customized date reminder when customers make any changes that could impact how energy in consumed, e.g., appliance replacements or thermostat set-point changes. Provides energy consumption comparison between before and after the marker.

Energy Markers

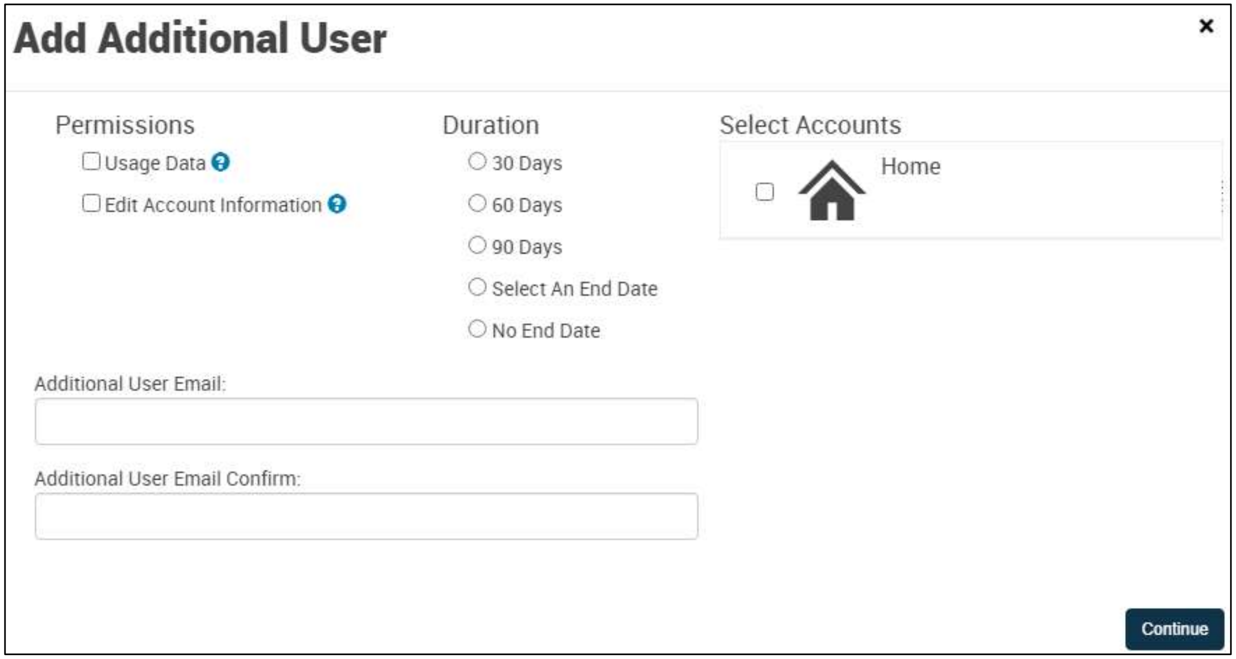
marker

		Details	Type	Date(s)	Avg Before	Avg During	Avg After	
	Home	COVID-19; everyone home	Travel	03/13/2020 08:00:00 AM - 12/31/2020 08:00:00 AM	30.95 kWh	36.36 kWh		
	Home	Home for the Holidays	Travel	12/25/2017 - 01/01/2018 11:59:00 PM	27.94 kWh	29.59 kWh	31.48 kWh	
	Home	Thermostat from 78 - 72	Event	07/23/2017	26.39 kWh		31.04 kWh	

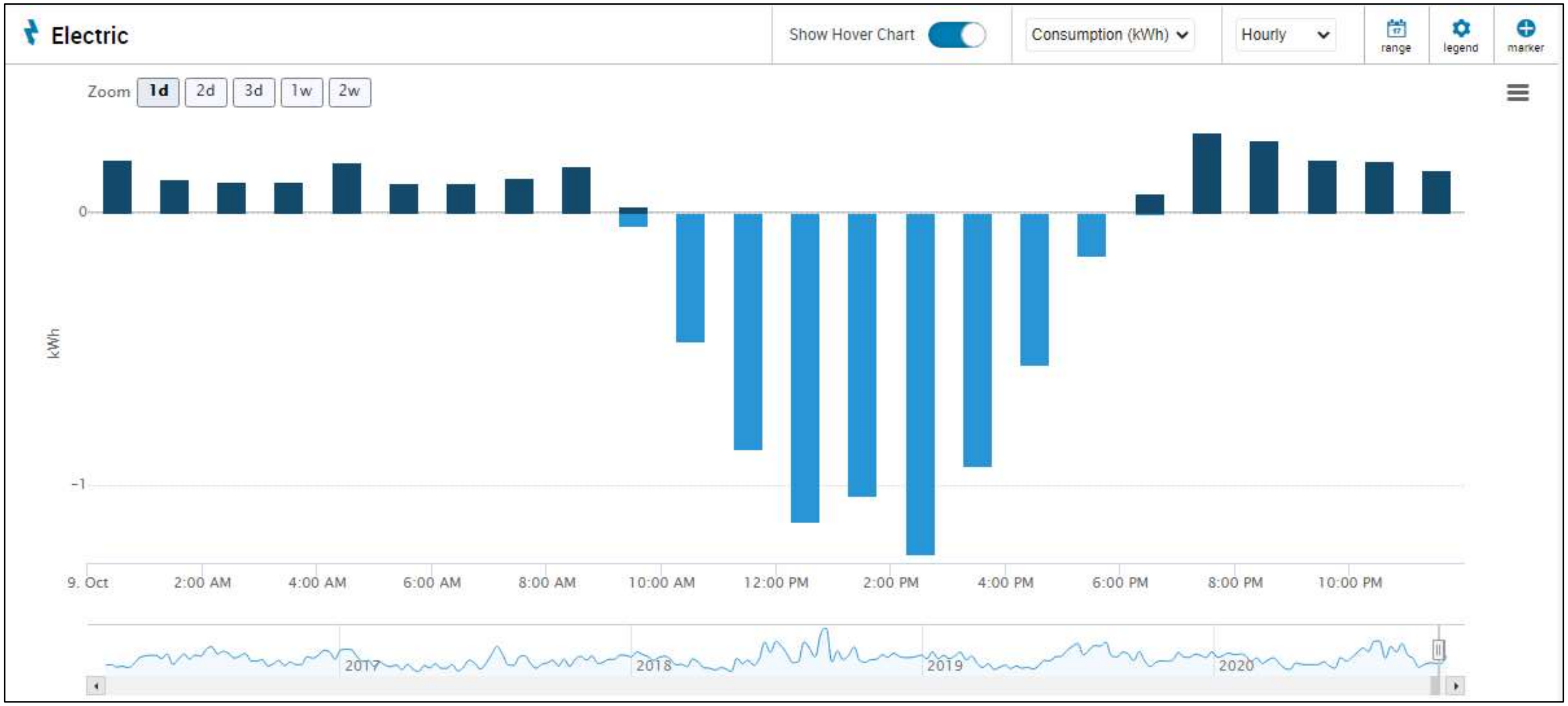
Provides an Energy Challenge which allows customers to set energy reduction goals and track their progress.

Range	Last Year's Usage	Last Year's Avg. Temp.	Your Challenge Goal	Goal kWh Savings	Goal $ Savings	Actual Usage to Date	This Year's Avg. Temp.	Achieved
5/1/2019 - 5/31/2019	1236.1170 kWh	75°	1186.6723 kWh	49.4447 kWh	$5	984.1278 kWh	69°	20%
6/1/2019 - 6/30/2019	1499.5242 kWh	78°	1439.5432 kWh	59.9810 kWh	$6	1197.4482 kWh	74°	20%
7/1/2019 - 7/31/2019	1629.1578 kWh	79°	1563.9915 kWh	65.1663 kWh	$6	1974.2232 kWh	80°	-21%
8/1/2019 - 8/31/2019	1536.3618 kWh	79°	1474.9073 kWh	61.4545 kWh	$6	1632.1050 kWh	78°	-6%
9/1/2019 - 9/30/2019	1084.5480 kWh	74°	1041.1661 kWh	43.3819 kWh	$4	1411.4322 kWh	77°	-30%
10/1/2019 - 10/31/2019	806.2068 kWh	61°	773.9585 kWh	32.2483 kWh	$3	661.8420 kWh	60°	18%
Challenge Results	**7792 kWh**	**74°**	**7481 kWh**	**310 kWh**	**$30**	**7860 kWh**	**73°**	**-1%**

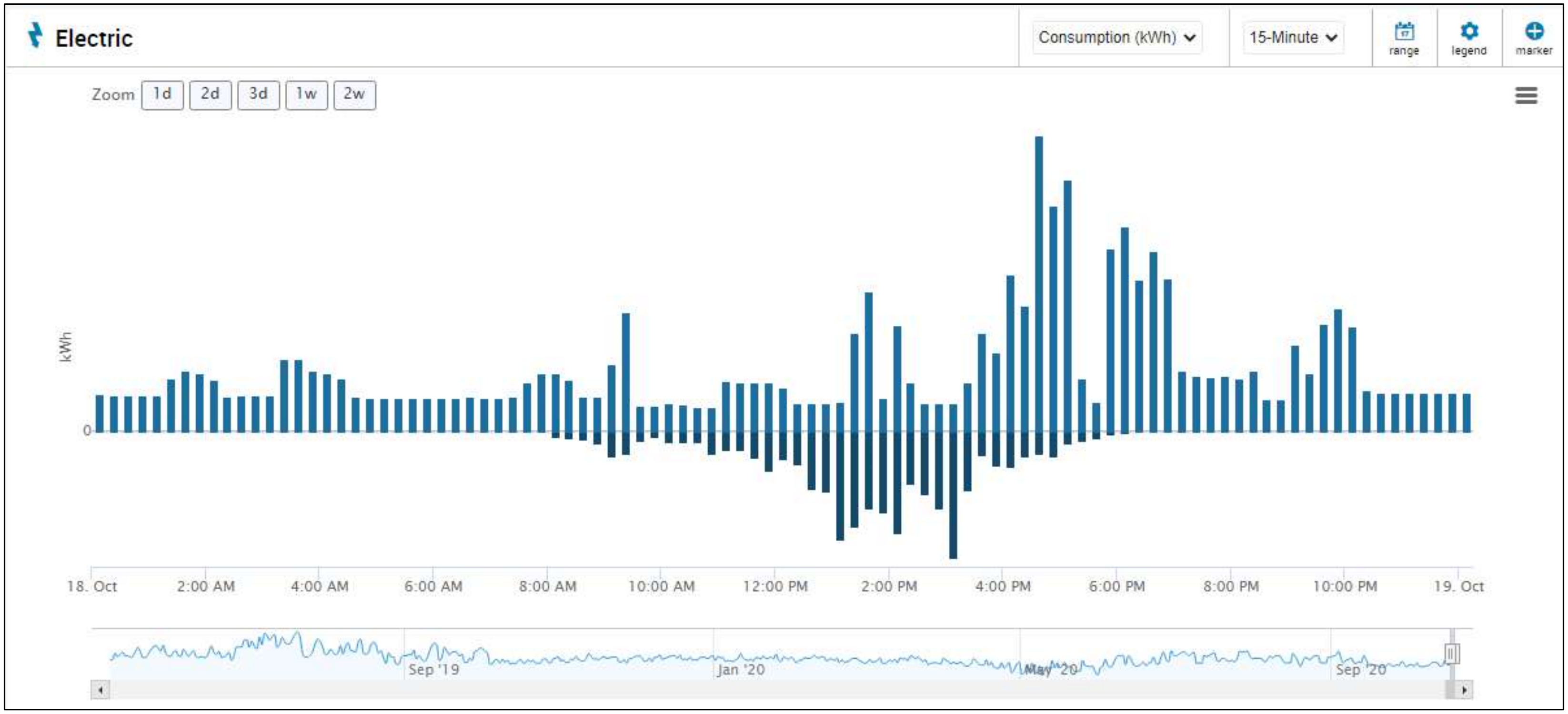
Ability to make consumption data available to third parties, as designated by the customer.



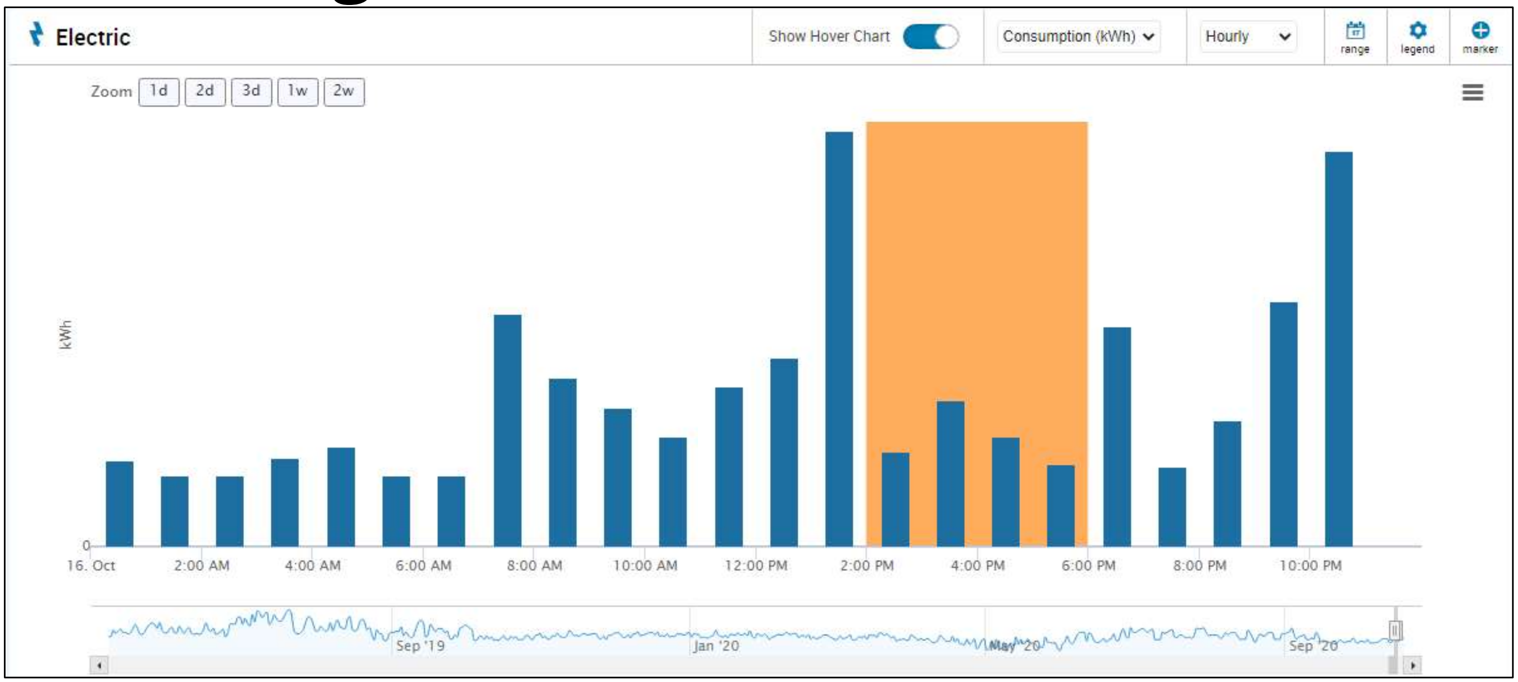
Self-generation customers (net metering) can view the amount of energy being imported and exported to the grid in 15-minute intervals.



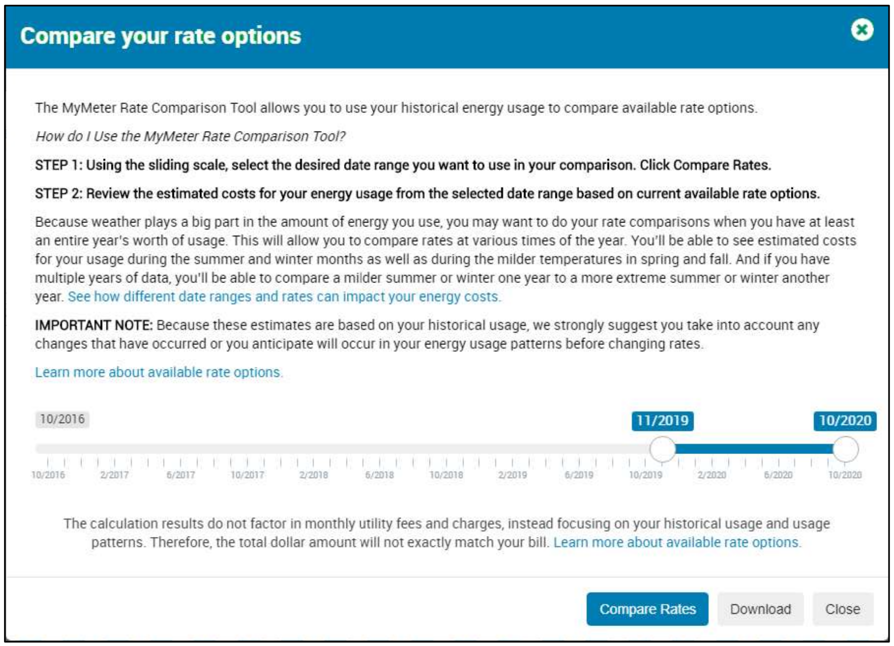
Solar Share Program customers can see their pro rata solar energy from their shares in relation to their on-premise consumption in 15-minute intervals.

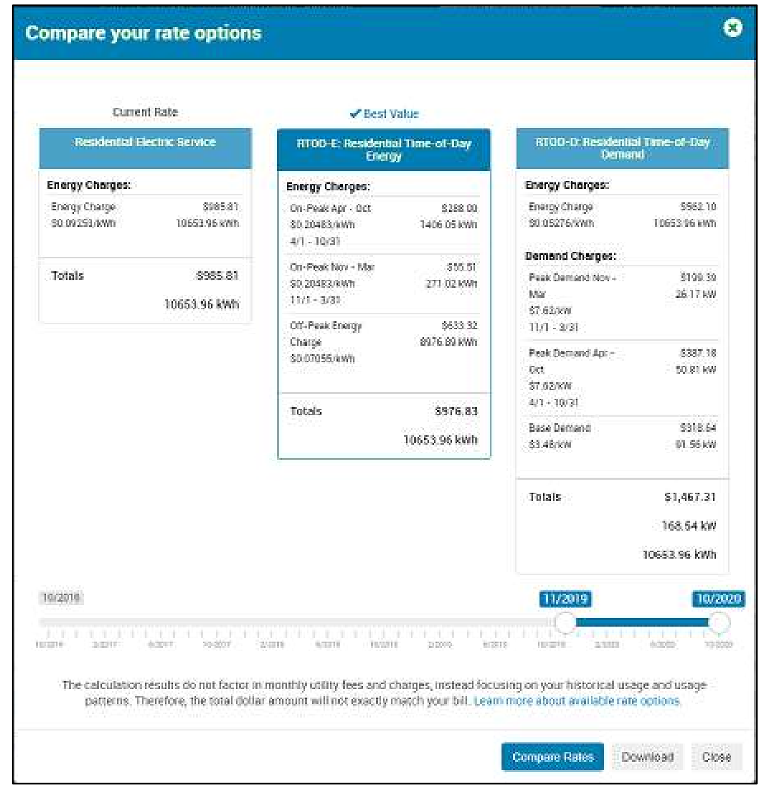


Customers already enrolled in one of the Companies' Residential time-of-day (RTOD) rates have usage during the most expensive periods highlighted for analysis and behavioral change.

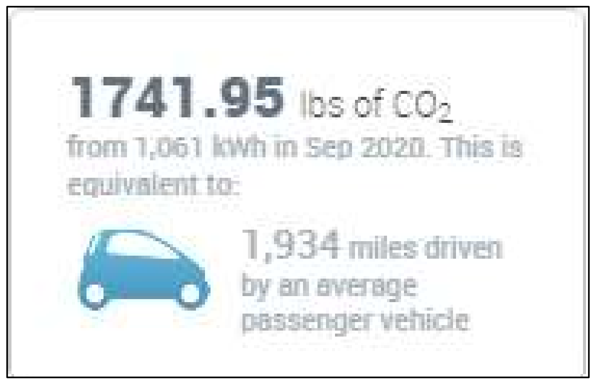


Rate comparison tool for residential customers





Review energy usage in terms of Carbon Dioxide (CO2) emissions and equivalent miles driven.



Advanced Metering Infrastructure Customer Engagement and Communication Plan

PPL companies

October 2020

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Introduction and Background

The LG&E and KU Advanced Metering Infrastructure (AMI) will consist of new digital meters to replace existing electric meters for all customers, new communication modules for gas meters in areas of combined electric and gas service, and a new two-way system that will allow for wireless communication between the meters and the utilities. Initially, AMI will require a significant investment in the meters and supporting infrastructure that will, over time, lead to cost savings from reductions in operational expenses associated with reading meters and service connections/disconnections/reconnections.

In addition, there are many short- and long-term benefits to the customer experience. For example, the new service will allow for enhancements in outage detection that will lead to faster and more efficient power restoration, especially when combined with automated controls that already are being installed in electric distribution. Moreover, the new meters will capture more detailed and real-time energy usage information that can:

- help customers become more informed about their usage patterns and behaviors; and
- help LG&E and KU develop and offer new programs and rate options, both of which offer the potential for lower energy bills and greater customer satisfaction.

AMI provides customers new data, tools, and control over their energy consumption. A robust customer engagement strategy is the key element in engaging customers to take advantage of the benefits AMI offers. Without robust customer communications, education, and support before, during and after deployment, the Companies are likely to encounter customer concern, resistance, and low adoption of advanced capabilities. Consequently, the Companies are committed to educating and engaging customers and other interested parties to help them understand and take advantage of the benefits of their AMI meters.

Using the Companies proven approach to communications, LG&E and KU will:

- communicate to customers the benefits of AMI; the installation process; and greater control, increased options, and improved convenience available with AMI meters.
- encourage customers, and any third parties they designate to adopt AMI meters and their associated benefits.
- establish communication channels that allows the companies to reach all customers with information about AMI meters.
- support collaboration with stakeholders to enhance customer adoption and identify opportunities for additional programs and benefits.

The LG&E and KU AMI Customer Education and Engagement Plan (Plan) reflects a customer-focused, collaborative strategy resulting from the Companies' research, customer surveys, experience with participants in the LG&E and KU voluntary Advanced Metering System (AMS) Opt-In Program, collaboration with third-party stakeholders, and benchmarking with peer utilities. LG&E and KU developed an education and engagement strategy that:

- ensures customers receive messages consistent with their preferences,
- ensures third parties receive messages that enable them to educate and engage with their constituents, and

- encourages customers and third parties to participate in discussions with the Companies about customer preferences and options.

The Plan was developed through a collective and holistic process involving the Companies and various stakeholders. LG&E and KU gained insights into how best to communicate with their customers about AMI meters while promoting and installing meters through their voluntary AMS Opt-In Program. In addition to anecdotal feedback LG&E and KU received from participants, the Companies reached out with surveys inviting customers to share direct feedback and comments. To further shape the Plan the Companies drew upon the expertise of industry professionals, research, and benchmarking from other utilities of similar size that have deployed AMI meters system-wide.

Various studies of third-party customer satisfaction surveys showed a connection between strong, proactive customer communications and positive customer experiences with AMI programs. With this in mind, LG&E and KU developed this comprehensive Plan to educate customers, as well as community stakeholders, throughout the duration of the deployment and after customers' AMI meters are installed to encourage participation and support of AMI and future programs.

The Plan includes providing customers a robust offering of information on a variety of topics, including:

- how an AMI meter works
- the meter installation process
- new tools and features available through AMI
- the online dashboard MyMeter which provides features, tools, and ways to help manage energy use

The overarching objective of the Plan is to inform customers of the benefits of AMI meters and promote engagement post AMI meter installation. The Companies have an unwavering commitment to customer service and satisfaction, and implementing the action plan laid out in the Plan will ensure a positive customer experience before, during and after a system-wide rollout of an AMI.

While communications tactics will be triggered based upon AMI deployment in geographic areas as part of the multi-phase strategy, the overall campaign will reflect two positions:

- **General Awareness**: Raise customers' and stakeholders' awareness of our AMI meter rollout and educate our audiences about the benefits of modernizing our system (with specific emphasis on the role AMI meters play).
- **Direct Outreach:** Target and engage affected customers with direct communications (pre- and post-rollout) to:
    - set expectations about the installation process (what to expect),
    - how the meter works,
    - how customers benefit from AMI, and
    - the tools, information and features they can access to gain the most benefit from their new AMI meter.

Figure 1, below depicts the timing of these two positions based upon AMI deployment milestones and the multi-phase approach of the Plan discussed further below.

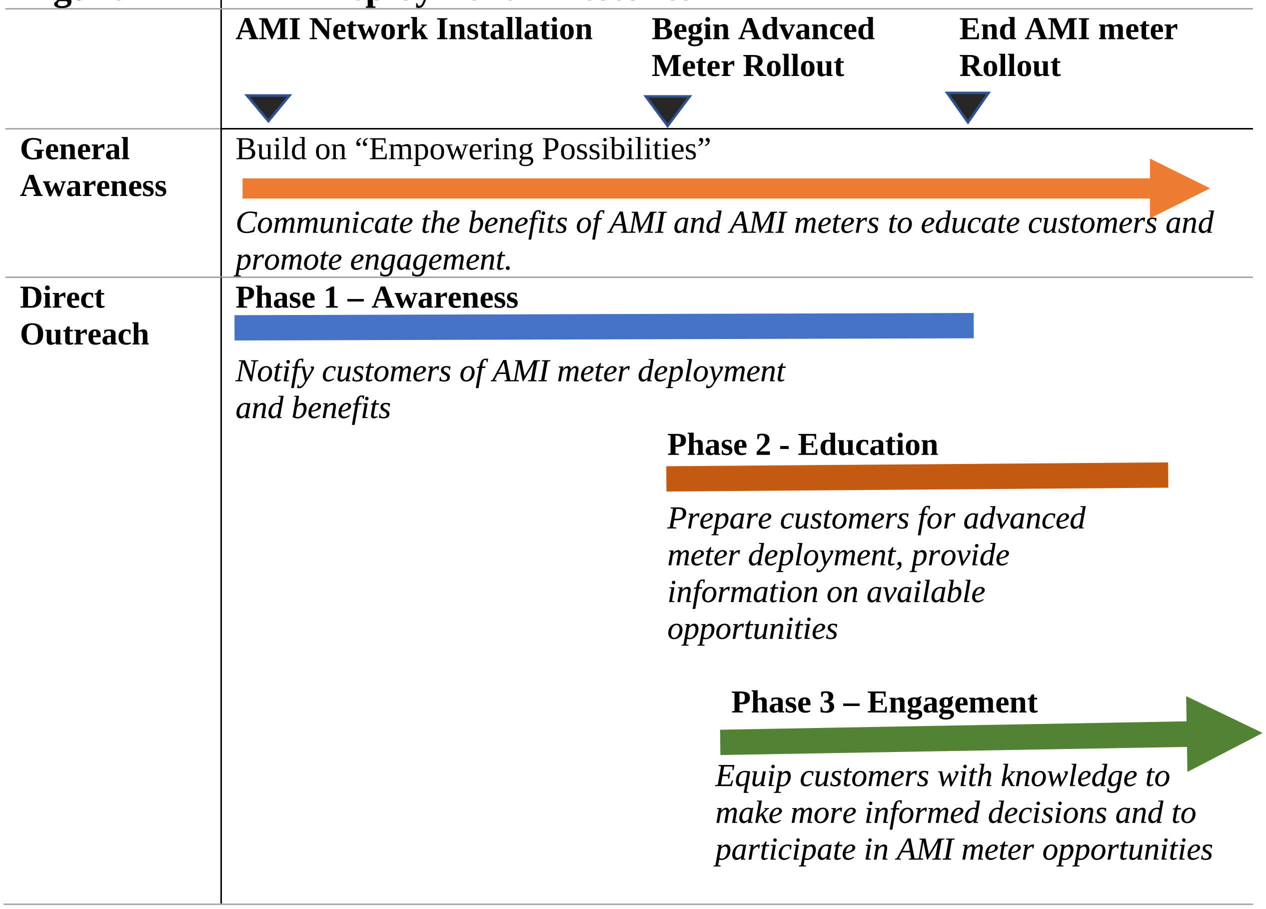

Figure 1 **AMI Deployment Milestones**

In executing the Plan, LG&E and KU will encourage adoption of the capabilities of AMI meters and provide customers with resources that allow them to manage their energy usage and costs. During and after full deployment, the Companies will continue to work to identify opportunities that engage customers and third parties, and to enhance the customer experience and improve community relations.

History of Strong Customer Education and Engagement

At LG&E and KU, the customer experience is one of our highest priorities. Employees understand and recognize the importance of ensuring a positive experience with every customer interaction. In addition, they appreciate knowing that their efforts to hold down costs and maximize performance also contribute to a positive customer experience. The Companies understand that a robust customer education and engagement plan is paramount to the success of AMI and to ensuring a positive customer experience.

In 2015, the Companies established Customer Experience Action and Advisory committees to develop and implement strategies that enhance the customer experience. Internal leaders representing all lines of business comprise each committee. Through regular communication, including strong internal messaging, a corporate website and mobile app available to all employees and contractors, the committees emphasize the importance of positive customer interactions. The committees advise all departments throughout the Companies on what, when, and how to communicate effectively with customers. The committees are key to continuing the Companies' outstanding customer satisfaction and will be utilized to assure AMI messaging resonates with customers.

Prior to developing the Plan, the Companies conducted numerous surveys among customers to gauge their awareness and understanding of AMI meters. In addition, the Companies surveyed participants in their voluntary AMS Opt-In Program to gauge awareness and engagement. Survey results and industry research drove the development of a multi-phased communication approach. The Plan focuses on three phases – Awareness, Education and Engagement – that build on the Companies' existing "Empowering Possibilities" messaging phase which launched in early 2019.

Understanding Customer Needs, Priorities and Expectations

A successful plan must focus on understanding and anticipating the needs, priorities and expectations of customers. To that end, LG&E and KU reached out to existing advisory groups for feedback and insights into customer preferences and an understanding of AMI meters and their associated infrastructure. Respondents to our surveys provided the following insights into customers' preferences, awareness, and perceptions about AMI meters:

- **Overall Awareness:** In a brand favorability survey conducted among residential customers in April 2018, nearly 25% indicated they were familiar with the Companies' AMS Opt-In Program. When asked to describe their overall feelings about advanced meters, 45% of those surveyed indicated they felt extremely or very favorable while 37% indicated they were somewhat favorable. Extremely favorable and very favorable responses were higher among customers in Eastern Kentucky with 57% expressing favorable feelings. Generation X customers were far more likely to have favorable feelings about advanced meters (58%) than Baby Boomers (40%) and Millennials (39%).
- **Sources of Knowledge:** Customers who participated in the April 2018 brand favorability survey were asked to indicate their sources for general news and information. Three-fourths of them (75%) cited television; more than half (54%) indicated general internet; and over half (51%) cited social media. When asked for preferences for how to receive company news and information, more than half (56%) said email; 42% said a flyer with the bill; and 37% said direct mail. Other sources – LG&E and KU website, television, social media, print or digital customer newsletter – were also mentioned.
- **Feelings About Advanced Meters:** In a survey conducted from August 24 to September 8, 2020 among customers who participate in the voluntary AMS Opt-In Program, more than half the respondents expressed satisfaction with the program. Customers who are most satisfied with the program mentioned ease of use and the ability to look at detailed data and usage trends to help make informed, energy-saving decisions as reasons for satisfaction.

Customer Education and Engagement Plan

LG&E and KU recognize the importance of engaging all market segments as well as the challenges in reaching every customer. To that end, the Plan includes customized approaches for all customers, including low income, seniors, high usage customers, customers with plug-in electric vehicles, and customers with private solar systems. The Plan, which was shaped by feedback from our customers, informs and engages customers throughout the various phases of implementation. LG&E and KU will reach out to customers to obtain feedback about their experience and adjust communication messages and channels based on customer feedback and preferences.

There is no "one size fits all" approach to communicating with customers. Customers will select the messaging methods they prefer. One of the Plan's strengths is that it allows flexible, scalable, and measurable communications as the customer evolves and becomes more engaged. The Companies utilize tools and data that analyze which communications are most effective for educating and engaging each customer segment. The result of this analysis informs the Companies to adjust plans, communication channels, and messages to resonant with customers.

Multi-Channel Communications

The Companies are committed to customer service and satisfaction, and they plan to ensure a positive customer experience before, during and after a system-wide rollout of an advanced meter infrastructure. The overarching objective of the Plan is to inform customers of the benefits of advanced meters and promote engagement post advanced meter installation.

LG&E and KU will use a diverse range of methods to educate and communicate with customers about:

- the Companies' plans to deploy advanced meters system-wide
- the installation process, and
- the benefits afforded by advanced meters and the supporting infrastructure

The Companies approach to communications includes using a variety of communication channels to distribute information. This includes but is not limited to, direct mail, emails, bill inserts, bill messages, outdoor signage (e.g. billboards), newspapers, radio, television, corporate website (e.g. information and videos), brochures/flyers, etc. In instances where there are key stakeholder groups (e.g. low-income agencies), the Companies will also provide education and materials to the groups to prepare them for any questions they may receive.

The Plan involves a three-phased approach that builds on the Companies' existing "Empowering Possibilities" campaign. Empowering Possibilities is a territory-wide campaign that serves as an introduction and the foundation that gives all LG&E and KU customers a broad sense of the future of the energy industry, its landscape and new technologies that benefit customers and add value to the communities served by the utilities. For more information about the campaign, please see Appendix A.

Phase 1 – Awareness

The Awareness Phase occurs prior to the installation of a customer's advanced meter. The Awareness Phase will include customized messages aimed at notifying all LG&E and KU customers of the Companies' plans to deploy AMI system-wide and emphasizing the high-level benefits to customers and to LG&E and KU. The Companies will ensure customers from urban areas to more rural settings receive the messages.

When interacting across multiple channels, customers recognize the messages easier and awareness increases. Messaging around the Awareness Phase will begin soon after receiving approval for full deployment.

During this phase, messaging will emphasize AMI technologies along with benefits and opportunities to give customers more control, choice and convenience. Other messages will provide information, resources and assurance to customers who express concerns over safety, privacy and security.

Awareness Objectives

- Educate all LG&E and KU customers about the Companies' plans for system-wide deployment of new advanced meters.
- Explain the reasons LG&E and KU are making this investment, with a focus on customer benefits, "What's does it do for them?"
- Educate LG&E and KU employees with a strong focus on those who have direct customer interaction so they can fully and effectively discuss the benefits and specifics of AMI with customers.
- Start to inform elected officials, media, and other stakeholders (e.g., low-income advocacy groups) generally about AMI, the benefits, and the implementation process.

Phase 2: Education

The Education Phase would begin as the Companies approach meter installation in a specific area. Stakeholder communications will generally begin approximately six weeks before any advanced meter installations in an area. Direct customer communication will begin approximately four weeks prior to scheduled installation; additional communication will be deployed to each customer approximately two weeks prior to scheduled installation and again the week of the installation. The focus is on educating customers on the deployment process and the benefits of an advanced meter.

Education Objectives

- Educate LG&E and KU employees with a strong focus on those who have direct customer interaction so they can fully and effectively discuss the benefits and specifics of the initiative with customers.
    - Prior to the beginning of deployment, customer-facing employees will be trained on the process, provided detailed information about the schedule, and key points about the advanced meter and the capabilities it provides customers.
- Follow up with elected officials, media, and other stakeholders (e.g., low-income advocacy groups) regarding the deployment process and timeline.
    - Approximately six weeks in advance of deployment in a specific area, the Companies will use a variety of communication channels to ensure all stakeholders are aware of the deployment schedule and the advantages of an advanced meter. This includes but is not limited to, local news interviews, newspaper articles, phone calls, etc.

- Inform and educate all LG&E and KU customers about the Companies' plans for system-wide deployment of new advanced meters.
    - The Companies will send three direct communications to customers prior to the installation of their advanced meter (i.e. two letters and one automated telephone call).

Messaging Initiatives

The Education Phase will focus on AMI meter benefits and emphasize control, choice and convenience. Each deployment area will receive multiple messages through three distinct initiatives:

1) **Schedule and Deploy:** Provide customers with clear and accurate information to prepare them for and facilitate the installation of their new AMI meter and gas AMI module (only applicable to LG&E electric and gas customers), and inform customers of opt-out process, and address other concerns.
2) **Opt-Out Coordination:** Further, educate customers on advanced meter benefits and the opt-out process.
3) **Minimize Inconvenience:** Find ways to address concerns customers have about any inconveniences that may occur as a result of their advanced meter installation.

Schedule and Deploy

Specific information will be presented to the seven segmented audiences listed in the stakeholder column in the table below, as a notification prior to advanced meter deployment. Given experiences with meter replacement, the Companies have decided that the most effective deployment notification should be delivered to customers approximately four weeks before their advanced meter is scheduled for installation. The initial communication will be followed by two additional communications – one approximately two weeks prior to scheduled installation and the other the week of installation. See the table below, which depicts customer communications prior to AMI meter installation.

~6 weeks prior	~4 weeks prior	~2 weeks prior	Installation Week
Stakeholder Communications KYPSC Local Officials Low Income Agencies Medical Alert Special Needs Key Accounts Media	**Customer Notifications**	**Customer Notifications**	**Customer Notifications** *or* **Meter Installed**

This initiative will conclude when LG&E and KU inform the customer that the advanced meter has been installed and will seek to assess the customer's satisfaction with the process. This will be done through the following actions:

- LG&E and KU will leave a door hanger on the door to notify each customer when their new advanced meter has been installed. The door hanger has instructions for accessing and registering their online account via the MyMeter portal and how/when they can begin to use the functionality.
- Customers who have registered their email address with LG&E and KU will receive an email notification that their new advanced meter has been installed. The email includes instructions for accessing the MyMeter portal.
- The Companies will periodically execute customer satisfaction surveys to assess the deployment and installation processes.

Opt-Out Coordination

LG&E and KU will focus their opt-out campaigns on decreasing the number of customers who decline to allow the Companies to install an AMI meter by proactively alleviating typical concerns through awareness and education. For those customers who choose to opt-out even after reviewing the information, LG&E and KU will provide a clear opt-out process.

Opt-out information will be included in the letter/notification customers receive. Customers who wish to opt-out will be instructed to call LG&E or KU. Opt-out coordination will be handled by employees specifically trained to provide customers with accurate and up-to-date information regarding advanced meters and the available opt-out process. Front-office employees and other individuals who will be handling customer contact and meter installations will receive information about opt-out processes.

Minimize Inconvenience

Consistent with each phase, LG&E and KU will design communications that are aligned with successful examples the Companies have employed in their voluntary AMS Opt-In Program, other large-scale company projects, and materials used throughout the energy industry.

LG&E and KU materials will be clear, concise, non-technical and segmented based on customer demographics. Appendix B contains samples of materials LG&E and KU have used along with drafts of materials LG&E and KU would use.

Phase 3: Engagement

The Engagement Phase starts when a customer receives an AMI meter and access to the tools necessary to better understand their energy consumption as well as optional rates available to them. The objective of the Engagement Phase is to assess and use insights gathered from customer surveys concentrating on the post installation user experience, focus groups and outreach experience to refine and promote new customer opportunities and future offerings. These activities will facilitate greater customer interaction with the Companies' programs, increase access to energy efficiency tools and information, and provide for other energy management opportunities offered by the Companies and other innovative third-party vendors.

A campaign will be developed to promote the information and benefits customers can access after their AMI meter is installed via the online MyMeter portal. Additionally, LG&E and KU will highlight tools and features to customers via periodic notifications. This approach has proven to be extremely helpful during the existing voluntary program.

For example, in early 2019, the Companies launched a monthly email update to AMS Opt-In Program participants[1]. Each update offers information about existing – or new – tools and features available to customers via the MyMeter portal. Not only have LG&E and KU seen strong open rates and interest in the email updates, but engagement on the portal increases significantly in the days after an email update is deployed.[2]

LG&E and KU have tools in place to increase customer engagement, and the Companies are investing more and more in digital channels. These digital channels will have the ability to gather and store customer preferences for the delivery of personalized, timely, effective, and educational communications. These communications will allow customers to make smarter energy decisions. Paired with information the Companies gather from the advanced meters, the engagement tools will allow LG&E and KU to transform their relationship with their customers by proactively providing new usage insights to customers.

Engagement Objectives

- Educate customers about online resources and how to access MyMeter.

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[1] A history of these communications can be viewed at https://lge-ku.com/advanced-meter/roadmap
[2] See Appendix D

  - The Companies will use multiple communication channels to engage the customer (e.g. bill messages, bill inserts, corporate website, videos, etc.)
- Make it easy for customers to select energy management tools and energy efficiency offerings that are available to them based on their personal preferences.
  - For example, written materials and videos that explain each feature and how it can be used to accomplish an individual's goals.

Messaging Initiatives

The Engagement Phase provides digital experiences while still recognizing that many customers prefer non-digital channels. Outreach programs will provide education materials through social and traditional channels to enhance face-to-face outreach from LG&E and KU personnel. The Engagement Phase is a long-term, holistic approach that leverages several digital and non-digital channels to engage and educate customers.

The Digital Experience

Among the digital channels used for ongoing customer engagement is the MyMeter portal. LG&E and KU will create added value for customers by providing access to personalized and useful energy usage data. The portal enables customers to leverage this information to gain insights into how they use energy and then turn those insights into action. Specifically, the MyMeter portal:

- Provides customers with an easy, intuitive method to view their energy usage in near real time.
- Provides a customized and personalized experience anywhere, anytime and on any device.
- Provides customers the ability to download usage data in various formats, including Green Button format, which is the national standard.
- Provides improved analytical capabilities to better understand customer behavior and empower customers with tools to make informed decisions.
- Provides the ability to overlay additional data, including weather, price and comparisons to other Advanced Meter customers in the customer's zip code and throughout the LG&E and KU service territory all in graphical format.
- Utilizes a customer analytics engine that leverages advanced meter usage data to provide customers with insights and energy savings tips as well as personalized action plans to conserve and save.
- Provides customers with proactive alerts associated with projected billing, home energy use, and customized thresholds set by customers (energy use or projected cost).
- Provides the ability for customers to set markers for dates when they make certain energy improvements so they can monitor to gauge the effectiveness of their actions.

MyMeter portal functionality is tailored to specific customer segments (residential, small business, large commercial) and optimized for viewing on multiple devices (e.g., desktops and tablets). The portal integrates with the LG&E and KU corporate website, which means customers experience seamless access via a single sign-in process. The multi-channel experience extends to the front office, which allows LG&E and KU customer service employees access to the same data screens as the customer.

The end result of the MyMeter portal is a low-effort, high-satisfaction digital customer experience that drives increased customer adoption. With “customers first” as the guiding principle at LG&E and KU, the MyMeter portal sets the Companies’ direction while AMI provides the platform that helps bring it to life.

Personalized Data Insights

An important element of customer engagement is personalization. Traditional utility communications have been largely one-size-fits-all. LG&E and KU are committed to using a software platform that sends information that is relevant to each customer’s unique situation. The information takes the form of periodic energy reports for customers, customized with information ranging from new plots to energy saving tips to benchmark comparisons. The tips can be further refined based on publicly available non-utility information about the customer, such as the age of the customer’s house. In addition to the MyMeter tools listed under the Digital Experience, below are even more tools integrated into the MyMeter portal that LG&E and KU will employ to increase customer engagement:

- A user-friendly, interactive visualization tool will allow customers to analyze their energy usage trends through a series of views. Customers will be able to see their data by different time periods (e.g., days, weeks, months, years). Customers also will be able to see their bill costs in addition to usage data.
- Personalized energy cost comparisons across the standard residential rate and the Companies’ two residential time-of-day rates so that customers can determine what rate offers the best value for them.
- A bill comparison tool will allow customers to compare their last bill to their previous bill or to the corresponding bill from the same time period the previous year. Comparing bills is a useful way for customers to track their energy use and identify possible causes for an increase or decrease in their bill. AMI data allows for a more personalized and detailed breakdown of bill differences, including the impacts of weather, rate plan changes, and peak versus off-peak usage.
- Modules highlighting the resources available on the online portal and encouraging customers to engage with LG&E and KU online.

The tools in the Digital Experience and Personal Data Insights are complementary to each other and will drive a customer journey for years after the deployment of AMI meters. See Appendix C for screen shots of some of the tools, data and information customers can access via the MyMeter portal.

Engaging All Customer Segments

There are customer segments throughout the LG&E and KU service territory that require special engagement efforts. Some customers may not be comfortable receiving messages through digital channels while others may not have access to online services. LG&E and KU will use a range of channels beyond digital means to engage customers. Engagement with non-digital, seniors, low- to moderate-income and non-English speaking customers will include the efforts of Customer Outreach Ombudsmen. These employees will determine which customer segments are not receiving the appropriate messages and take action to fill those gaps. Mail, community groups, events, social services, libraries, and government centers can all be leveraged as channels for reaching customers with education materials or personal interactions.

The Companies also acknowledge that there are customer segments (e.g., high usage customers, customers with electric vehicles, solar customers) within their service territory that may have opportunities to take part in additional offerings. As such, LG&E and KU will provide targeted messaging to these customers that will revolve around additional opportunities to become involved in energy efficiency, third-party offerings, or other ways to save.

Customer engagement will evolve over the course of AMI deployment through lessons learned, surveys, focus groups, and a building of awareness across the LG&E and KU service territory. More opportunities to engage across channels means customers will participate more and begin to adopt new behaviors.

Conclusion

This Plan provides a framework to communicate and collaborate with customers and interested third parties in support of the Companies' AMI initiative. While AMI and the MyMeter portal provide technologies that support customer control, choice and convenience, the Plan will help customers and third-parties better understand how to best take advantage of AMI.

The Companies combined research, past experiences, benchmarking, and outreach to develop the Plan. The Companies' collaborative relationship with customers, energy service companies, and other interested parties played an invaluable role in gaining extensive support for the effort. Energy data access, rate pilots, and additional AMI-enabled opportunities detailed in the Plan support security and convenience for customers and third parties. The Companies will continuously seek and benefit from feedback from interested parties to maintain a customer-centric focus as new AMI-enabled opportunities arise.

In summary, the LG&E and KU AMI Customer Awareness and Engagement Plan provides a robust framework for successful customer awareness, understanding and engagement as part of AMI deployment.

Appendix A - Empowering Possibilities – Awareness Phase

In early 2019, LG&E and KU launched its "Empowering Possibilities" campaign, which was developed in response to quantitative and qualitative customer research conducted in summer 2018. In the quantitative survey, the Companies gauged customer satisfaction and brand sentiment, attempting to understand what content appeals to LG&E and KU customers and discover which targeted communication channels customers prefer.

The Companies sampled four specific regions across Kentucky, which included Louisville, Lexington, and Eastern and Western Kentucky.

Phase 1 findings helped shape the Companies' approach to the second phase of research, the qualitative or focus group portion of the study.

- LG&E and KU conducted focus groups in four cities that represented the same areas sampled in Phase 1 — namely, Louisville, Lexington, Middlesboro and Morganfield.
- With each location, the Companies conducted three two-hour customer focus groups with Millennials, Generation X and Baby Boomers.
- With each group, LG&E and KU received feedback on brand sentiment and the drivers of it from the perspective of the customer, and conducted a diagnostic assessment around the brand attributes of innovation, customer focus, affordability, and energy efficiency.
- With those attributes, the Companies received direct customer feedback on content (discovering what customers want to hear), voice (who customers want to hear it from), and style (how they want to see/hear it).
- Overall brand sentiment was positive; however, there were several areas that were identified by the survey as opportunities for improvement — namely, through the focus groups, the Companies sought customer insights on the brand attributes of Innovation, Customer Focus, and Affordability.
- AMI meters fall into the Innovation category, but the Companies also wanted to glean some information in the areas of Customer Focus to ensure the Companies reach customers with messages in the manner the customers wish to receive those messages.
- LG&E and KU wanted to determine which content is most appealing to customers, how best to deliver messages through the appropriate voice, and, visually, to identify the style — or the look and feel of the message — that customers most wanted to see.
- It was clear — in every focus group — that customers needed to quickly see and understand how any offering or investment the Companies make would positively impact and benefit their day-to-day lives.
- The "what's in it for me" mentality means that LG&E and KU must provide "proof points," or evidence that if the customer takes an action, such as enroll in a program (e.g., the voluntary AMS Opt-In Program), the customer will quickly understand how they can benefit from the program.
- Overall, customers felt that mid-level LG&E and KU workers, employees who are "in the trenches," would be best suited to speak credibly to the programs and services the Companies offer, and the investments the Companies are making that benefit customers.
- Customers believed that presenting a positive employee voice is a signal that the Companies are doing right by their employees, which, in turn, has a positive impact on the customer experience.

- Customers tended to react favorably to the style and imagery that presented a more literal representation of a program, service or investment, which allowed them to better understand the end benefit and how it directly relates to them.
- Finally, customers want to see how these programs and services impact the household and their lifestyle, but they need to see the "proof" and not just "shiny happy faces."

The "Empowering Possibilities" campaign capitalizes on LG&E and KU employees' credibility and expertise. The campaign humanizes the Companies while integrating customer experiences to validate the benefits of offerings to customers.

The campaign includes messages designed to build trust among LG&E and KU customers and set the stage for future technologies and a changing energy landscape.

Elements of the campaign feature content and visuals that create a localized sense of place, showcase actual LG&E and KU employees where appropriate, and present the Companies' infrastructure and use of technology in a clear and meaningful way.

The Companies' "Empowering Possibilities" campaign establishes LG&E and KU as proponents of renewable energy and advanced technologies that put more control in the hands of customers.

As customers embrace energy management programs and access to information to help them save energy, the Commonwealth, along with LG&E and KU and other Kentucky utilities will continue to work to develop cleaner, more resilient and affordable energy for all Kentuckians. To support this goal, "Empowering Possibilities" campaign messages include a focus on technologies, such as AMI meters and AMI technologies that enable customer control over energy use by:

- providing the data customers need to make more informed decisions (choices)
- increasing customer convenience, and
- streamlining the Companies' relationship with customers.

The Companies promote the "Empowering Possibilities" campaign through their surround-sound approach to communication utilizing owned, earned and paid channels which include:

- the LG&E and KU corporate website
- bill inserts
- social media (Facebook, Instagram, YouTube, Twitter, etc.)
- employee newsletters
- posters in company facilities
- media relations
- digital advertising
- radio
- streaming television
- print ads

"Empowering Possibilities" is a springboard into more direct messaging around AMI meters and the benefits they provide to customers. The campaign is fluid and will continue beyond AMI deployment. The Companies will adjust activities based on feedback from customers (online and telephone surveys, focus groups).

Sample Empowering Possibilities Print Ads

Empowering Possibilities Digital Samples

Appendix B – Education Phase Customer Communication Examples

Sample Letters

Sample 4-weeks Advance Notice Letter[3]

LG&E
a PPL company

Louisville Gas and
Electric Company
Customer Services
PO Box 32010
Louisville, KY 40232
www.lge-ku.com

<INSERT DATE>

We are coming to your area to install advanced meters
Service Address: <INSERT PREMISE ADDRESS>

Dear <INSERT Customer Name>:

In the next several weeks, a trained service technician working on behalf of LG&E will be in your area installing advanced meters. This is part of our plans to upgrade all of our customers' meters. Over time, the new meters will give you improved access to data that will help you better manage your energy use. In addition, the new meters will eventually help us detect outages more quickly meaning we'll be able to respond faster and more efficiently.

Trained and authorized <INSERT VENDOR NAME> technicians working on our behalf will be in your area. We will work with <INSERT VENDOR NAME> to notify you before they begin the work.

You will not need to be present for the installation as long as your meter is outdoors and the technician will have clear and safe access to it. If your meter is located in an area with restricted access, you will need to make arrangements for the technician to have access on the day they are scheduled to exchange your meter(s). We will advise you of the number to call to schedule an appointment as we get closer to your area.

If you do not wish to receive an advanced meter, please call 502-589-1444 (outside Louisville, call 800-331-7370) and press X-X-X. Our representatives will go over the opt-out process with you and explain any fees associated with keeping your existing meter.

We will contact you again closer to your advanced meter installation date. We remain committed to providing you with the safe, reliable service you deserve and to keeping you informed before your meter is replaced.

Visit our website at lge-ku.com/ams to learn more about the meter exchange process and about advanced meters in general.

Sincerely,

<SIGNATURE>

1 | 1

DRAFT

[3] This is a sample letter. The full deployment letter will contain all required information and reference the program as Advance Meter Infrastructure (AMI).

Sample 2-weeks Advance Notice Letter[4]

LG&E
a PPL company

Louisville Gas and Electric Company
Customer Services
P.O. Box 32010
Louisville, KY 40232
www.lge-ku.com

<INSERT DATE>

It's time to replace your meter(s)
Service Address: <INSERT PREMISE ADDRESS>

Dear <INSERT Customer Name>:

Recently, we sent you a letter advising you of the fact we are in your area installing advanced meters. In the next couple of weeks, a trained service technician working on behalf of LG&E will be in your area to replace your existing meter(s).

This is part of our plans to upgrade all of our customers' meters. Over time, the new meters will give you improved access to data that will help you better manage your energy use. In addition, the new meters will eventually help us detect outages more quickly meaning we'll be able to respond faster and more efficiently.

Here's what you can expect during the meter exchange process:

- A representative from <INSERT VENDOR NAME> will perform your meter exchange. Their technicians carry photo identification badges and they are fully trained and authorized to work on our behalf. There should not be any reason the technician will need to enter your home or business.
- The technician installing your new meter(s) will attempt to notify you before they begin the work. The installation should take about five to 15 minutes for each meter. Some meters may require a brief interruption of your power during the meter exchange. If your power must be interrupted, we will attempt to notify you before the interruption takes place.
- You do not need to be present for the installation if your meter is outdoors and the <INSERT VENDOR NAME> technician will have clear and safe access to your meter(s).

1 | 2

[4] This is a sample letter. The full deployment letter will contain all required information, reference the program as Advance Meter Infrastructure (AMI) and be written as concisely as possible to keep it to one page

a PPL company

- If your meter is in an area with restricted access, you will need to plan for our technician to have access on the day they are scheduled to exchange your meter(s). Please contact <INSERT VENDOR NAME> at <INSERT PHONE NUMBER> to schedule an appointment.

If we have your phone number in our records, we will call you in advance of your meter exchange to let you know you're on the schedule for that week.

We remain committed to providing you with the safe, reliable service you deserve and to keeping you informed before your meter is replaced.

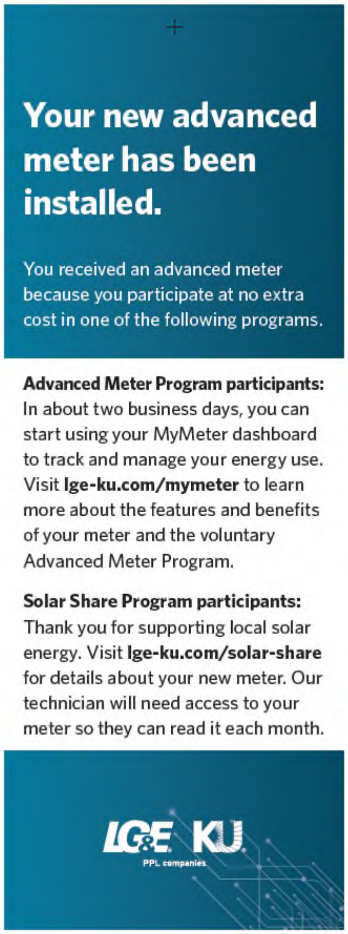
If you do not wish to receive an advanced meter, please call 502-589-1444 (outside Louisville, call 800-331-7370) and press X-X-X. Our representatives will go over the opt-out process with you and explain any fees associated with keeping your existing meter.

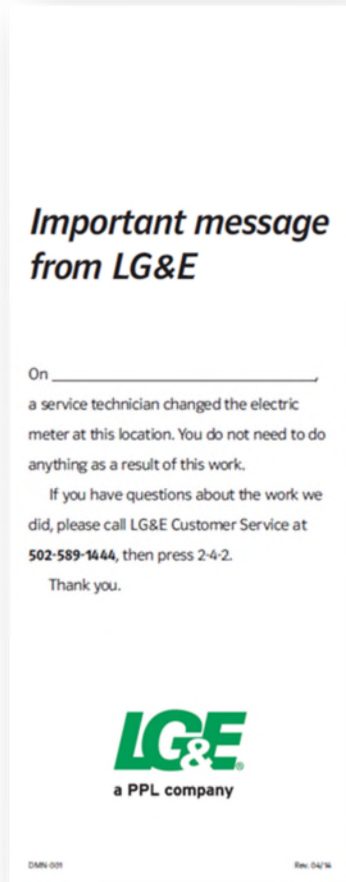
Visit our website at lge-ku.com/ams to learn more about the meter exchange process and about advanced meters in general.

Sincerely,

<SIGNATURE>

Sample Door Hangers (Examples)[5]





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[5] These are sample door hangers. The actual door hangers will include all of the required information and reference the program as Advanced Meter Infrastructure (AMI).

Fact Sheet (Examples)[6]

[6] These are sample newsletters. The actual newsletters will include similar information and refer to the program as Advanced Meter Infrastructure (AMI).

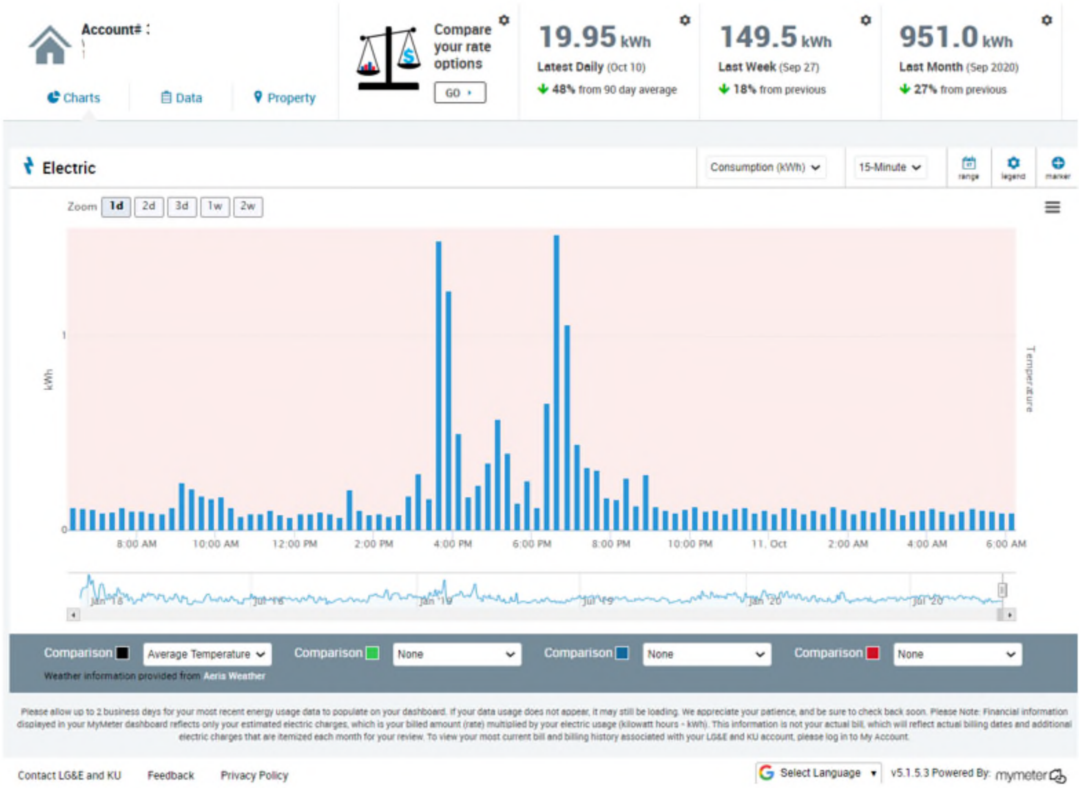
Appendix C – Engagement Phase Communication Examples

Usage Dashboard – Access and Home Page

[7]

[7] https://youtu.be/_6GGqxfxnWw

Usage Dashboard – Charts



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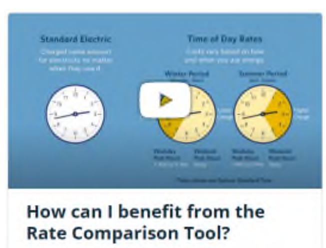

11

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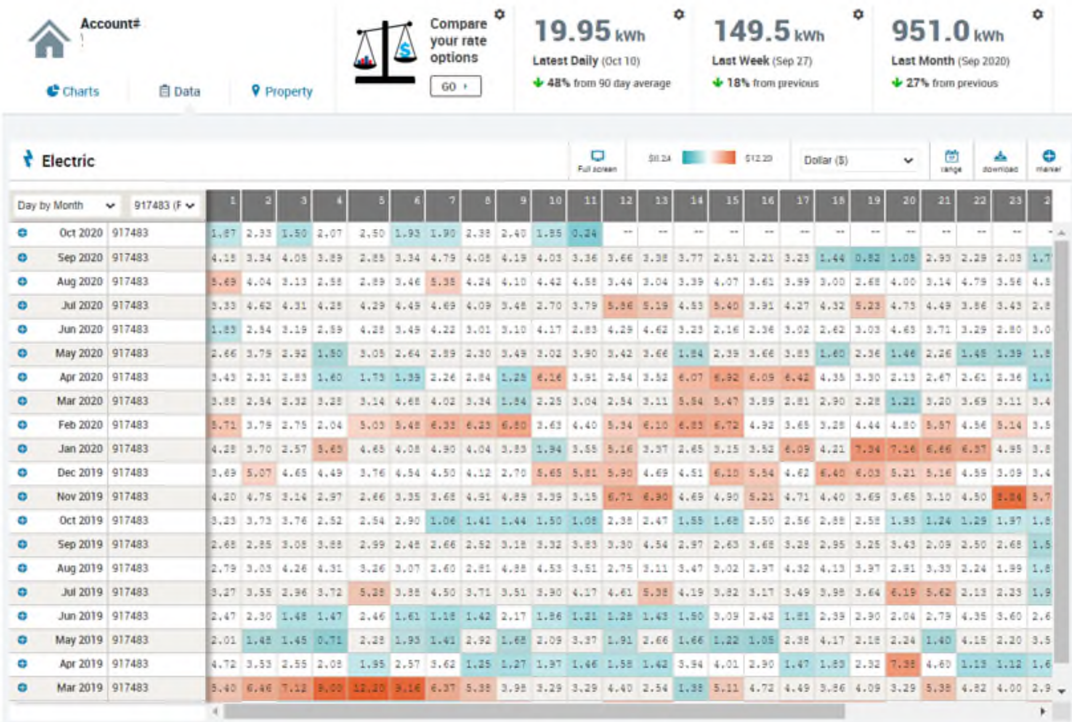
[8] https://youtu.be/nhJ5lcEwvvk

[9] https://youtu.be/WD0N0qlA8zA

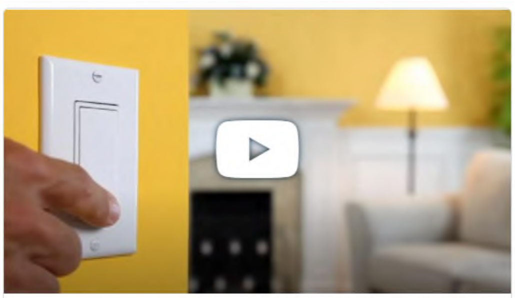
[10] https://youtu.be/tvz0_3PMom0

[11] https://youtu.be/zI9HQw0loVg

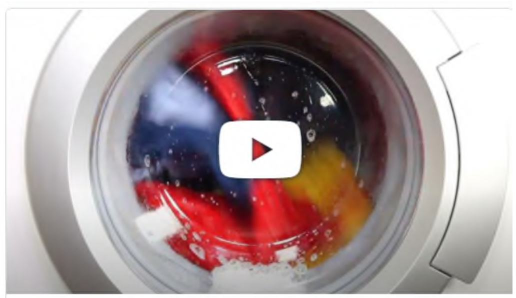
Usage Dashboard – Data



Day by Month	917483 (F	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	2
Oct 2020	917483	1.87	2.33	1.50	2.07	2.50	1.93	1.90	2.38	2.40	1.85	0.24	--	--	--	--	--	--	--	--	--	--	--	--	-
Sep 2020	917483	4.15	3.34	4.05	3.89	2.85	3.34	4.79	4.08	4.19	4.03	3.36	3.66	3.38	3.77	2.51	2.21	3.23	1.44	0.82	1.05	2.93	2.29	2.03	1.7
Aug 2020	917483	5.69	4.04	3.13	2.58	2.89	3.46	5.35	4.24	4.10	4.42	4.58	3.44	3.04	3.39	4.07	3.61	3.99	3.00	2.68	4.00	3.14	4.79	3.56	4.8
Jul 2020	917483	3.33	4.62	4.31	4.25	4.29	4.49	4.69	4.09	3.48	2.70	3.79	5.86	5.19	4.53	5.40	3.91	4.27	4.32	5.23	4.73	4.49	3.86	3.43	2.8
Jun 2020	917483	1.83	2.54	3.19	2.59	4.28	3.49	4.22	3.01	3.10	4.17	2.83	4.29	4.62	3.23	2.16	2.36	3.02	2.62	3.03	4.63	3.71	3.29	2.80	3.0
May 2020	917483	2.66	3.75	2.92	1.50	3.05	2.64	2.89	2.30	3.49	3.02	3.90	3.42	3.66	1.84	2.39	3.66	3.83	1.60	2.36	1.46	2.26	1.45	1.39	1.8
Apr 2020	917483	3.43	2.31	2.83	1.60	1.73	1.39	2.26	2.84	1.25	6.16	3.91	2.54	3.52	6.07	6.92	6.09	6.42	4.35	3.30	2.13	2.67	2.61	2.36	1.1
Mar 2020	917483	3.88	2.54	2.32	3.28	3.14	4.68	4.02	3.34	1.84	2.25	3.04	2.54	3.11	5.54	5.47	3.89	2.81	2.90	2.28	1.21	3.20	3.69	3.11	3.4
Feb 2020	917483	5.71	3.79	2.75	2.04	5.03	5.48	6.33	6.23	6.80	3.63	4.40	5.34	6.10	6.83	6.72	4.92	3.65	3.28	4.44	4.80	5.87	4.56	5.14	3.5
Jan 2020	917483	4.28	3.70	2.57	5.65	4.65	4.08	4.90	4.04	3.83	1.94	3.55	5.16	3.37	2.65	3.15	3.52	6.09	4.21	7.34	7.16	6.66	6.37	4.95	3.8
Dec 2019	917483	3.69	5.07	4.65	4.49	3.76	4.54	4.50	4.12	2.70	5.65	5.81	5.90	4.69	4.51	6.10	5.54	4.62	6.40	6.03	5.21	5.16	4.59	3.09	3.4
Nov 2019	917483	4.20	4.75	3.14	2.97	2.66	3.35	3.68	4.91	4.89	3.39	3.15	6.71	6.90	4.69	4.90	5.21	4.71	4.40	3.69	3.65	3.10	4.50	8.84	5.7
Oct 2019	917483	3.23	3.73	3.76	2.52	2.54	2.90	1.06	1.41	1.44	1.50	1.08	2.38	2.47	1.55	1.68	2.50	2.56	2.88	2.58	1.93	1.24	1.29	1.97	1.8
Sep 2019	917483	2.68	2.85	3.08	3.88	2.99	2.48	2.66	2.52	3.18	3.32	3.83	3.30	4.54	2.97	2.63	3.68	3.28	2.95	3.25	3.43	2.09	2.50	2.68	1.5
Aug 2019	917483	2.79	3.03	4.26	4.31	3.26	3.07	2.60	2.81	4.38	4.53	3.51	2.75	3.11	3.47	3.02	2.97	4.32	4.13	3.97	2.91	3.33	2.24	1.99	1.8
Jul 2019	917483	3.27	3.55	2.96	3.72	5.28	3.88	4.50	3.71	3.51	3.90	4.17	4.61	5.38	4.19	3.82	3.17	3.49	3.98	3.64	6.19	5.62	2.13	2.23	1.9
Jun 2019	917483	2.47	2.30	1.48	1.47	2.46	1.61	1.18	1.42	2.17	1.86	1.21	1.28	1.43	1.50	3.09	2.42	1.81	2.39	2.90	2.04	2.79	4.35	3.60	2.6
May 2019	917483	2.01	1.48	1.45	0.71	2.28	1.93	1.41	2.92	1.68	2.09	3.37	1.91	2.66	1.66	1.22	1.05	2.38	4.17	2.18	2.24	1.40	4.15	2.20	3.5
Apr 2019	917483	4.72	3.53	2.55	2.08	1.95	2.57	3.62	1.25	1.27	1.97	1.46	1.58	1.42	3.94	4.01	2.90	1.47	1.83	2.32	7.38	4.60	1.13	1.12	1.6
Mar 2019	917483	5.40	6.46	7.12	9.00	12.20	9.16	6.37	5.38	3.98	3.29	3.29	4.40	2.54	1.38	5.11	4.72	4.49	3.86	4.09	3.29	5.38	4.82	4.00	2.9



I want to know more about the data I see in my MyMeter dashboard.



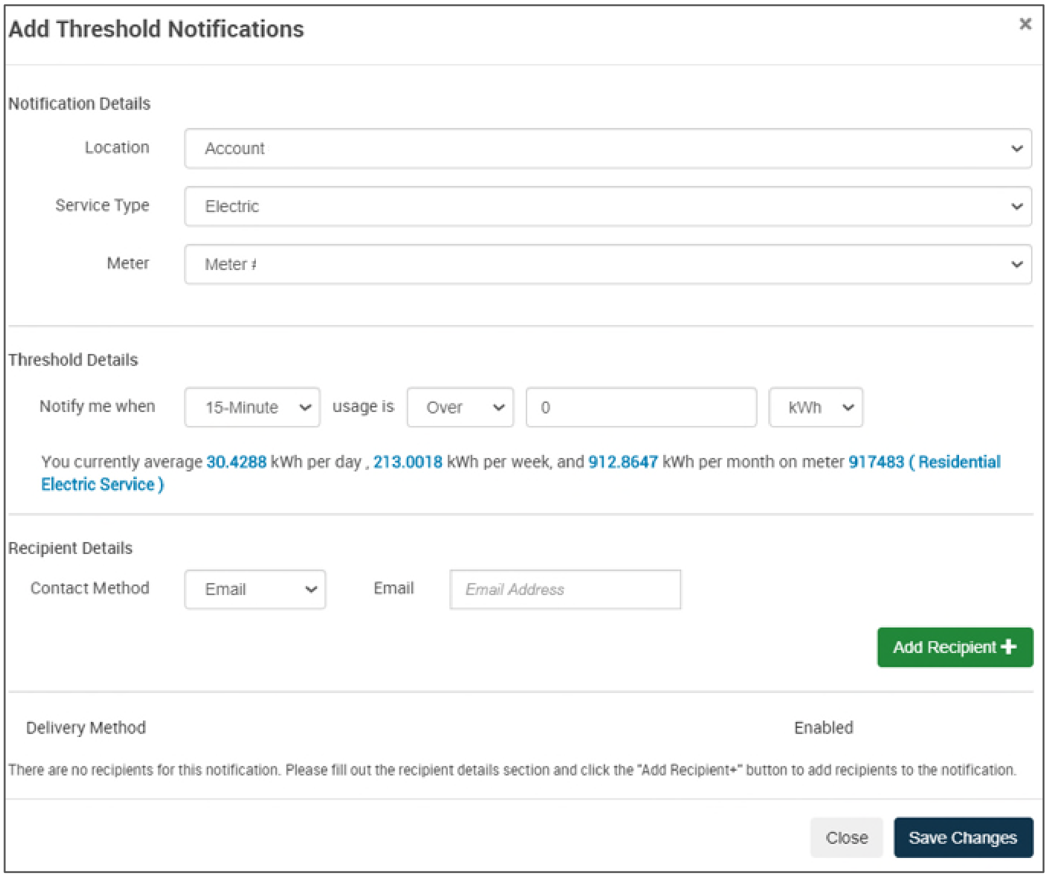
How can I use my MyMeter data to save energy in my home?

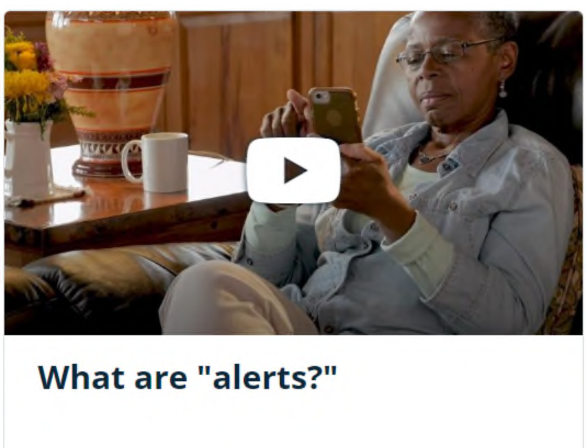
[12,13]

[12] https://youtu.be/57f8WicBKnY

[13] https://youtu.be/DeCgv_TTRcE

Alerts – Notifications

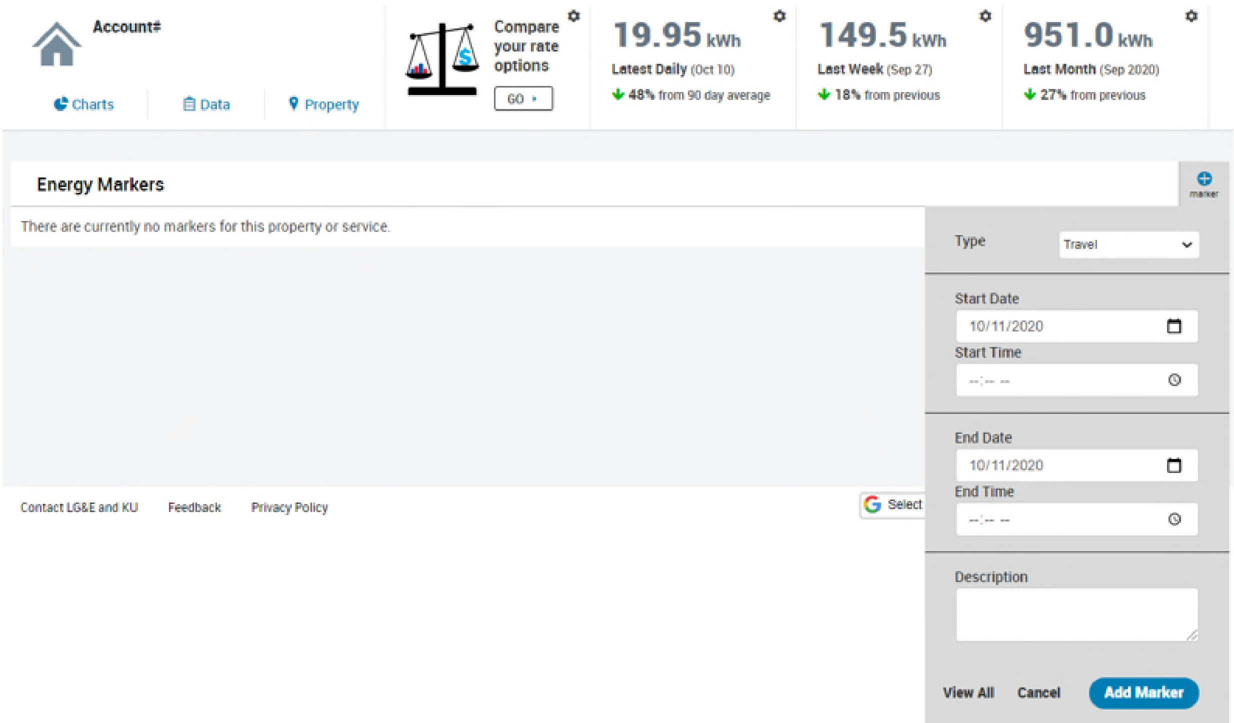




[14]

[14] https://youtu.be/BP2_xuReeKU

Energy Markers



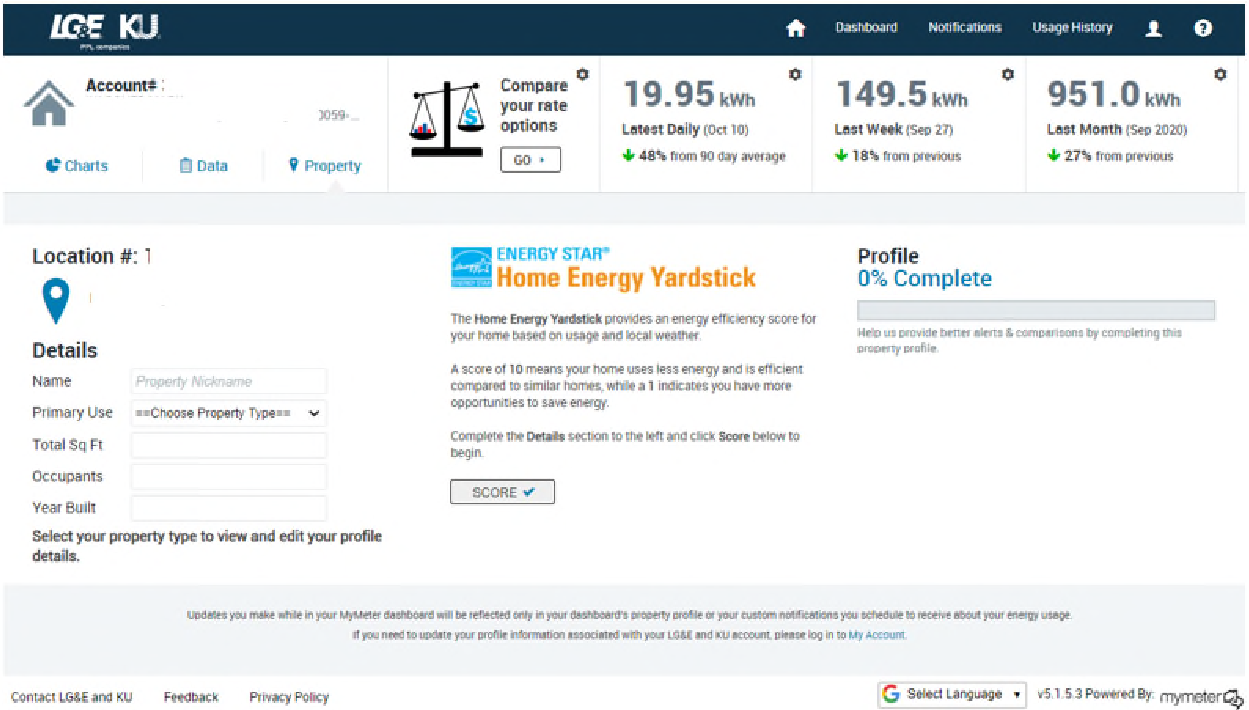
What is an Energy Marker®?[15]

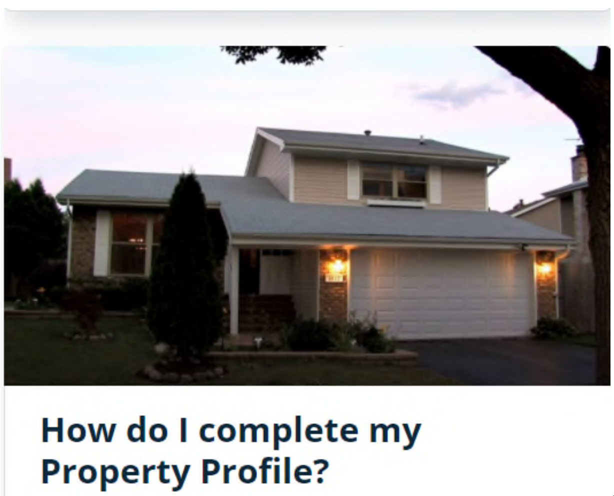
What is the Energy Challenge?[16]

[15] https://youtu.be/GIK7uxoGNpo

[16] https://lge-ku.com/node/16246

Property Profile

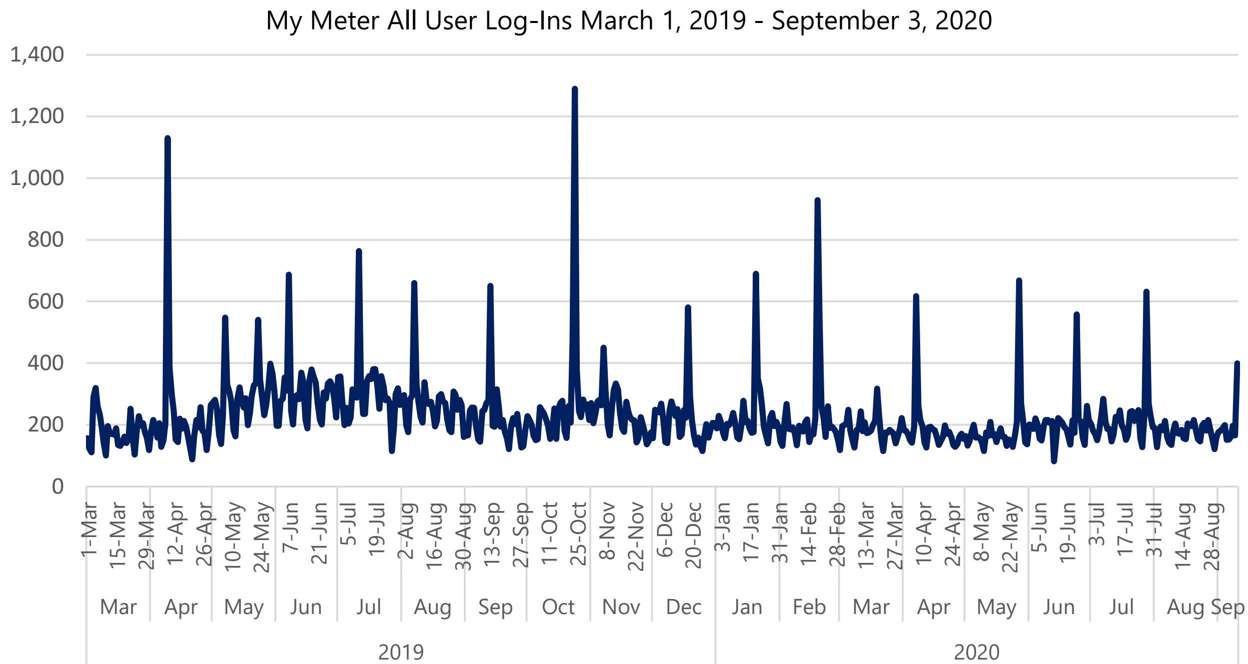




[17]

17 https://lge-ku.com/node/16246

Appendix D – AMS Opt-In MyMeter User Data



***Log-in spikes demonstrate the effectiveness of ongoing engagement communications. Customers who receive the monthly AMP It Up e-updates, which are designed to highlight tools available to customers with advanced meters, are engaging with the content. Among those surveyed in August/September 2020, respondents indicated a high level of satisfaction with the email updates.*

2019 Email Campaign Statistics

Date	Emails Sent	Open Rate	Click-thru Rate*
03/04/19	8,968	37.10%	9.60%
04/09/19	9,865	57.50%	23.60%
05/07/19	10,886	53.50%	11.00%
06/07/19	12,560	50.70%	10.70%
07/11/19	12,358	50.10%	9.90%
08/07/19	17,788	47.10%	6.20%
09/13/19	17,309	41.90%	8.10%
10/23/19	17,695	42.70%	7.90%
10/24/19	17,261	42.30%	13.60%
11/04/19	6,447	37.90%	12.00%
12/18/19	17,598	40.60%	5.20%

**Click-thru Rate is a percentage that indicates how many successfully delivered emails received at least one click.*

January – September 2020 Email Campaign Statistics

Date	Email Sent	Open Rate	Click-thru Rate
01/20/20	17,666	57.70%	10.40%
0219/20	17,563	45.40%	14.20%
04/07/20	17,451	46.30%	9.00%
05/27/20	8,403	56.90%	17.40%
05/27/20	8,342	50.80%	15.90%
06/24/20	8,212	57.10%	13.60%
06/24/20	1,062	41.00%	11.20%
06/29/20	6,009	40.80%	7.50%
07/28/20	3,220	39.00%	10.20%
07/28/20	12,206	42.80%	9.00%
07/28/20	2,153	36.20%	9.00%
07/28/20	4,633	51.70%	2.30%
09/10/20	16,163	45.30%	5.10%