This Integrated Resource Plan represents a snapshot of an ongoing resource planning process using current business assumptions. The planning process is constantly evolving and may be revised as conditions change and as new information becomes available. Before embarking on any final strategic decisions or physical actions, the Companies will continue to evaluate alternatives for providing reliable energy while complying with all regulations in a least-cost manner. Such decisions or actions will be supported by specific analyses and will be subject to the appropriate regulatory approval processes.

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4 Format

4.(1) Organization

This plan is organized by using the Section and Subsection numbers found in the Administrative Regulation 807 KAR 5:058, “Integrated Resource Planning by Electric Utilities,” as shown in the preceding Table of Contents. This report is filed with the Public Service Commission of Kentucky in compliance with the aforementioned regulation.

4.(2) Identification of individuals responsible for preparation of the plan

Chris Balmer, Director Transmission Strategy and Planning

Ralph Bowling, VP Power Production

Kyle Burns, Manager Transmission Substation Construction & Maintenance

Robert Conroy, VP State Regulation and Rates

Michael Drake, Director Generation Services

Daniel Hawk, Manager Electrical Engineering and Planning

David Huff, Director Customer Energy Efficiency and Emerging Technologies

Philip Imber, Manager Environmental Air Section

Nicholas Jewell, Senior Research Engineer

Tom Jessee, VP Transmission

Delyn Kilpack, Manager Transmission Strategy and Planning

Gregory Lawson, Manager Energy Efficiency Planning and Development

Rick E. Lovekamp, Manager Regulatory Strategy/Policy

Beth McFarland, VP Customer Services

Gary Revlett, Director Environmental Affairs

Michael Sebourn, Manager Generation Planning

David S. Sinclair, VP Energy Supply and Analysis

Richard Smith, Manager Sales Analysis and Forecasting

Allyson Sturgeon, Managing Senior Counsel, Regulatory and Transactions

Stuart Wilson, Director Energy Planning, Analysis and Forecasting

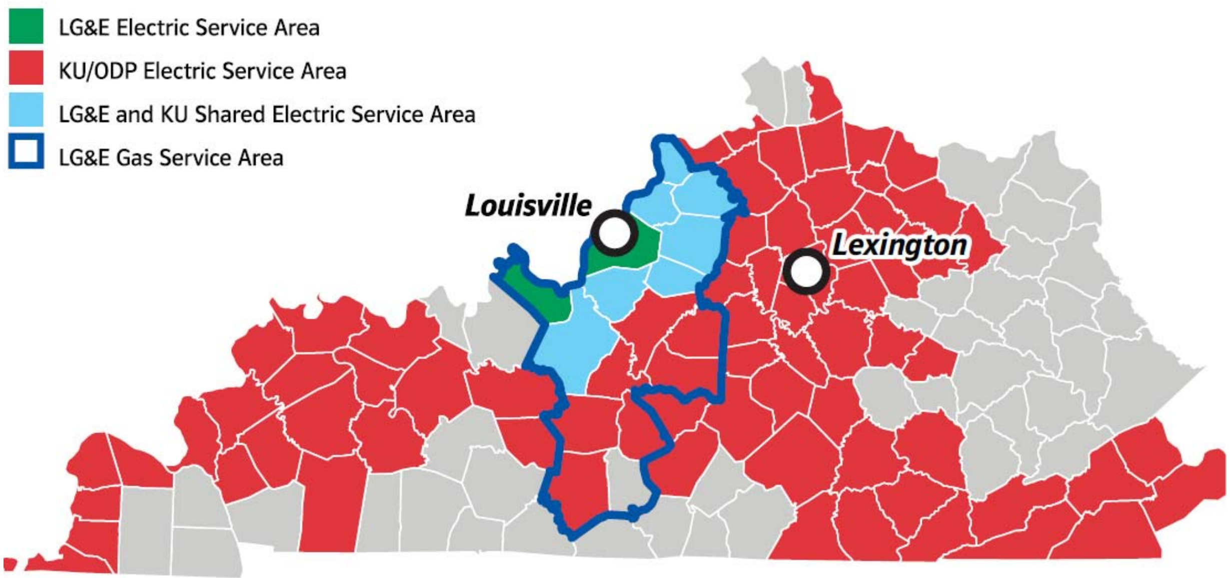
Michael Winkler, Manager Environmental Programs

5 Plan Summary

5.(1) Utility Overview and Planning Objectives

Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (collectively, "the Companies"), part of the PPL Corporation ("PPL") family of companies, are regulated utilities that serve nearly 1.3 million customers primarily in Kentucky and have consistently ranked among the best companies for customer service in the United States. LG&E serves 326,000 natural gas and 411,000 electric customers in Louisville and 16 surrounding counties. Based in Lexington, KU serves 553,000 customers in 77 Kentucky counties and five counties in Virginia, where KU operates under the name Old Dominion Power Company (see Figure 5-1).[1] In addition, KU provides wholesale power to ten municipalities in Kentucky.

Figure 5-1: LG&E and KU Service Territory Map

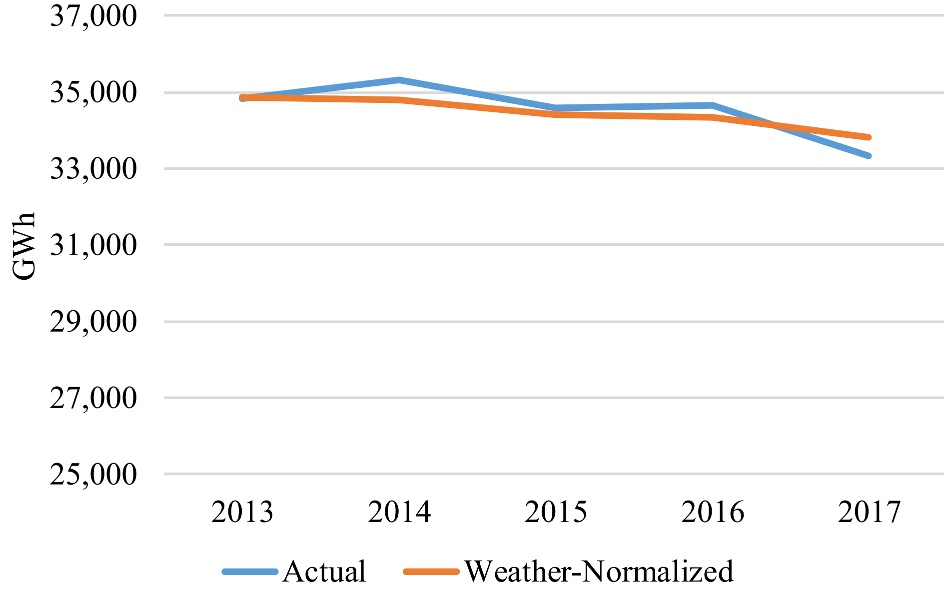


As a leading manufacturer of automobiles, steel, and other products, Kentucky was the 8th most electricity-intensive U.S. state in 2017, as measured by the ratio of electricity consumption and state gross domestic product. As such, reliable, low-cost electricity is critically important to the Commonwealth's economy.

Over the past five years, energy requirements in the LG&E and KU service territories have been flat to declining (see Figure 5-2). Increased consumption from the addition of new customers has been more than offset by mining sector declines, industrial customer losses, industrial production efficiency improvements, and efficiency improvements in residential and commercial end-uses. In addition, residential customer growth has been concentrated in urban areas where homes are on average smaller and more energy-efficient than in rural areas.

[1] KU also serves three customers in Tennessee.

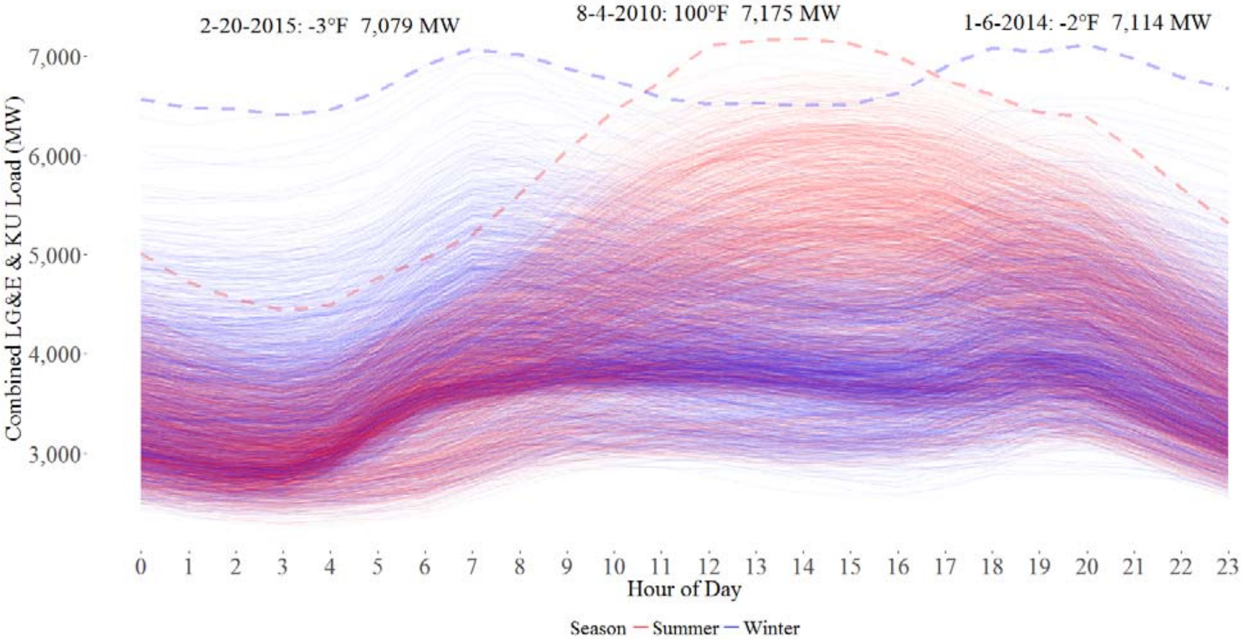
Figure 5-2: LG&E and KU Energy Requirements, 2013-2017



An understanding of the way customers use electricity is critical for planning a generation, transmission, and distribution system that can reliably serve customers in every moment. Temperatures in Kentucky can range from below zero degrees Fahrenheit to above 100 degrees Fahrenheit. Because of the potential for cold winter temperatures and the increasing penetration of electric heating, the Companies are somewhat unique in the fact that annual peak demands can occur in summer and in winter months. The Companies' highest hourly demand occurred in the summer of 2010 (7,175 MW in August 2010). Since then, the Companies have experienced two annual peak demands in excess of 7,000 MW and both occurred during winter months (7,114 MW in January 2014 and 7,079 MW in February 2015).

Figure 5-3 contains the Companies' hourly load profiles for every day over the past ten years. Hourly demands can vary by as much as 600 MW from one hour to the next and by over 3,000 MW in a single day. Summer peak demands typically occur in the afternoons, while winter peaks typically occur in the mornings or evenings during nighttime hours.

Figure 5-3: Hourly Load Profiles, 2008-2017



System demands from one moment to the next can be almost as volatile as average demands from one hour to the next. Figure 5-4 contains a plot of four-second demands from 5:00 PM to 7:00 PM on January 6, 2014 during the polar vortex event. The average demand from 6:00 PM to 7:00 PM was 7,114 MW but the maximum 4-second demand was more than 150 MW higher. To serve customers in every moment, the Companies must have a portfolio of generation resources that can produce power when customers want it.

Figure 5-4: Four-Second Demands, 5:00-7:00 PM on January 6, 2014

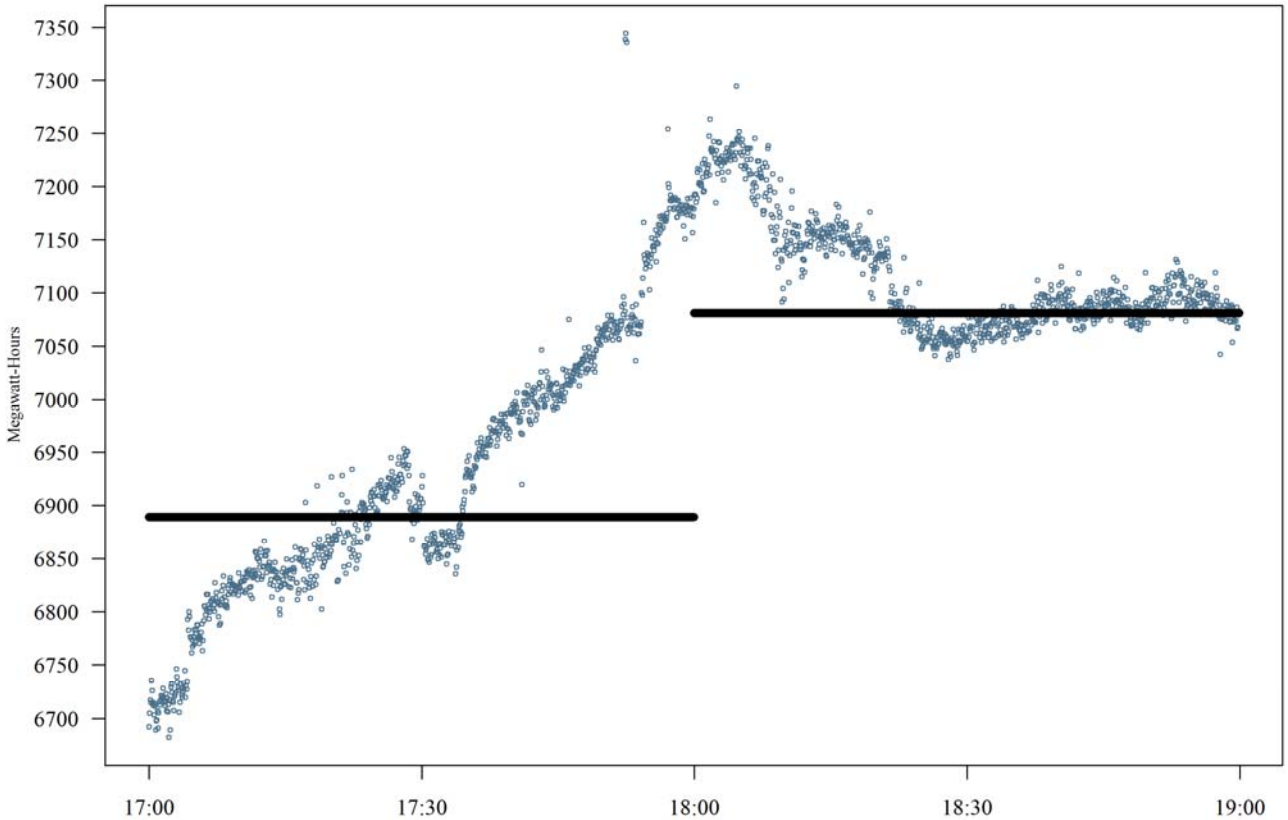


Table 5-1 contains a summary of the Companies' generation and demand-side management resources.[2] Different types of generation resources play different roles in serving customers. The Companies' baseload resources are an excellent source of low-cost energy, but peaking resources are better-suited for following load during peak periods and for responding to unit outages.[3] Renewable resources have little to no fuel or emissions costs, but their availability is uncertain during peak load conditions. The Companies' demand-side management resources are designed to reduce load during peak periods but their availability is also limited.

---

[2] A detailed listing of the Companies' generation resources is included in Table 8-2.

[3] Compared to coal units, simple-cycle combustion turbines ("SCCTs") have higher dispatch costs but lower carrying costs, shorter start-times, and better ramping capabilities.

Table 5-1: LG&E and KU Generation Resources, September 2018

Resource	Number of Units	Unit Size (Range in Net Summer Capacity, MW)	Total Net Capacity (MW) Summer	Winter
Baseload/Intermediate				
Coal	14	106-549	5,156	5,200
Natural Gas Combined Cycle ("NGCC")	1	662	662	683
Peaking				
Large-Frame SCCT[4]	15	12-165	2,172	2,418
Small-Frame SCCT[4]	7	121	87	98
Renewable				
Solar	1	8	8	0
Hydro	11	8-10.5	96	72
Total Generation Resources	49	106-549	8,181	8,471
Demand-Side Management Resources				
Curtailable Service Rider	N/A	N/A	141	141
Demand Conservation Program	N/A	N/A	127	0
Total Demand-Side Resources			8,449	8,612

The totals in Table 5-1 include 272 MW of coal-fired capacity for E.W. Brown Units 1 and 2 ("Brown 1 and 2"), 165 MW of large-frame SCCT capacity for LG&E's capacity purchase and tolling agreement with Bluegrass Generation ("Bluegrass Agreement"), and 14 MW for Zorn 1. The Companies plan to retire Brown 1 and 2 in February 2019 as a means of significantly reducing environmental compliance costs at the E.W. Brown Generating Station. The end of the Bluegrass Agreement is April 30, 2019, and coincides with the departure of eight of KU's municipal customers. Zorn 1 is planned to be retired by 2021 as the anticipated cost to comply with impending gas pipeline regulations and maintain sufficient gas pressure to operate Zorn 1 is in the tens of millions of dollars, which overshadows the benefits of keeping Zorn 1.

Table 5-2 contains a listing of the Companies' generating stations. With the exception of the Companies' 172 MW share of Ohio Valley Electric Corporation ("OVEC"), all of the generating stations in Table 5-2 are located in Kentucky.[5] In addition to these generation resources, the

[4] Small-frame SCCTs comprise Cane Run 11, Paddy's Run 11 & 12, Zorn 1, and Haefling 1 & 2. All of the Companies' other SCCTs are large-frame SCCTs.

[5] A detailed listing of the Companies' generation portfolio is contained in Section 8.(3).(b).

Companies operate an electric grid consisting of almost 26,000 miles of electric transmission and distribution lines.

Table 5-2: LG&E and KU Generating Stations, Net Summer Capacity (MW), Sep. 2018[6]

Generating Station	Coal	NGCC	Large-Frame SCCT	Small-Frame SCCT	Solar	Hydro	Total
E.W. Brown	681		906		8	32	1,627
Cane Run		662		14			676
Ghent	1,919						1,919
Mill Creek	1,465						1,465
Trimble County	919		954				1,873
Paddy's Run			147	35			182
Haefling				24			24
Zorn				14			14
Ohio Falls						64	64
OVEC	172						172
Bluegrass (PPA)			165				165
Total	5,156	662	2,172	87	8	96	8,181

The Companies have a well-established annual planning process that has enabled them to reliably meet their customers' around-the-clock energy needs both in the short-term and long-term at the lowest reasonable cost. The 2018 Integrated Resource Plan ("IRP") represents a snapshot of this planning process using current business assumptions and assessment of risks. Because the planning process is constantly evolving, the Companies' resource plan may be revised as conditions change and as new information becomes available. Even though the IRP represents the Companies' analysis of the best options to meet customer needs at this point in time, this plan is reviewed, re-evaluated, and assessed against other market available alternatives prior to commitment and implementation.

The Companies considered the Commission Staff Report on the 2014 Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company dated March 2016 (Case No. 2014-00131) while preparing this IRP. The Companies have addressed the suggestions and recommendations contained in the Staff report. A summary of the ways in which these suggestions and recommendations were addressed is provided in Volume III ("Recommendations in PSC Staff Report on the Last IRP Filing").

5.(2) IRP Methodology and Key Assumptions

The Companies' integrated resource planning process begins with the development of a robust forecast of hourly energy requirements or "load." Then, a resource plan is developed with the goal of meeting future energy requirements at the lowest reasonable cost. The models, methods,

[6] Net summer ratings reflect the expected output at the time of the summer peak.

data, and key assumptions for each part of the planning process are summarized in the following sections.

Energy Requirements Forecast

The production of a robust forecast of system energy requirements is a prerequisite for efficient planning and control of utility operations. The modeling techniques employed by the Companies allow energy and demand forecasts to be tailored to address the unique characteristics of the KU and LG&E service territories. New forecasting approaches are continually evaluated to optimize all aspects of the exercise.

Models and Methods

Energy requirements are the sum of electricity sales and transmission and distribution losses. LG&E and KU's electricity sales forecasts are developed through econometric modeling of energy sales by rate class, but also incorporate specific intelligence on the prospective energy requirements of the utilities' largest customers. Econometric modeling captures the (observed) statistical relationship between energy consumption – the dependent variable – and one or more independent explanatory variables such as the number of households or the level of economic activity in the service territory. Forecasts of electricity sales are then derived from a projection of the independent variable(s).

This widely accepted approach can readily accommodate the influences of national, regional and local (service territory) drivers of electricity sales. This approach may be applied to forecast the number of customers, energy sales, or use-per-customer. The statistical relationships will vary depending upon the jurisdiction being modeled and the class of service.

The LG&E sales forecast comprises one jurisdiction: Kentucky-retail. The KU sales forecast comprises three jurisdictions: Kentucky-retail, Virginia-retail, and FERC-wholesale. Within the retail jurisdictions, the forecast typically distinguishes several classes of customers including residential, commercial, public authority, and industrial.

The econometric models used to produce the forecast pass two critical tests. First, the explanatory variables of the models must be theoretically appropriate and widely used in electricity sales forecasting. Second, the inclusion of these explanatory variables must produce statistically significant results that lead to an intuitively reasonable forecast. In other words, the models must be theoretically and empirically robust to explain the historical behavior of the Companies' customers.

Sales to several of the Companies' largest customers are forecast based on information obtained through direct discussions with these customers. These regular communications allow the Companies to directly adjust sales expectations given the first-hand knowledge of the utilization outlook for these companies. The modeling of residential and commercial sales also incorporates elements of end-use forecasting – covering base load, heating and cooling components of sales – that recognize expectations with regard to appliance saturation trends, efficiencies, and price or income effects.

Once monthly sales forecasts are developed for each of the Companies' rate classes, the sales forecasts are aggregated by company and adjusted for transmission and distribution losses to produce a preliminary forecast of monthly energy requirements for each company. Monthly energy requirements for each company are then allocated to hours using normalized load duration curves and adjusted to reflect the forecasted impact of increasing distributed solar generation and electric vehicle penetrations.[7]

A more detailed description of the Companies' forecasting models and methods is included in Volume II ("Energy and Demand Forecast Process").

Data Inputs

Table 5-3 lists key inputs to the energy requirements forecast process. The national outlook for U.S Gross Domestic Product ("GDP"), industrial production, and consumer prices are key macro-level variables that establish the broad market environment within which the Companies operate. Local influences include trends in population, employment, personal income, end-use assumptions, and cost of service provision (i.e., the 'price' of electricity). A more detailed discussion of these inputs is included in Volume II ("Energy and Demand Forecast Process").

[7] The forecasted impact of increasing distributed solar generation and electric vehicle penetrations must be layered into the forecast of hourly energy requirements separately because the normalized load durations curves used to allocate monthly energy requirements to hours are derived based on hourly loads in historical periods with immaterial amounts of distributed solar generation and electric vehicle consumption.

Table 5-3: Key Inputs to Energy Requirements Forecast

Data	***Source***	***Format***
State Macroeconomic and Demographic Drivers (e.g., Employment, Wages, Households, Population)	IHS Markit, Kentucky Data Center	Annual or Quarterly by County – History and Forecast
National Macroeconomic Drivers	IHS Markit	Annual or Quarterly – History and Forecast
Personal Income	IHS Markit	Annual by County
Weather	National Oceanic and Atmospheric Administration ("NOAA")	Daily HDD/CDD Data and Hourly Solar Irradiance by Weather Station – History
Billing Portion Schedule	Revenue Accounting	Monthly Collection Dates – History and Forecast
Appliance Saturations/Efficiencies	Energy Information Administration ("EIA"), 2010 LG&E/KU Residential Customer Survey	Annual – History and Forecast
Structural Variables (e.g., dwelling size, age, and type)	EIA, 2010 LG&E/KU Residential Customer Survey	Annual – History and Forecast
Elasticities of Demand	EIA / Historical Trend	Annual – History
Billed Sales History	CCS Billing System	Monthly by Service Territory and Rate Group
Number of Customers History	CCS Billing System	Monthly by Service Territory and Rate Group
Energy Requirements History	Energy Management System ("EMS")	Hourly Energy Requirements by Company
Annual Loss Factors	2012 Loss Factor Study (by Management Applications Consulting, Inc.)	Annual Average Loss Factors by Company
Solar Installations	CCS Billing System, National Renewable Energy Laboratory ("NREL")	Net Metering/Qualifying Facility Customers, Solar Net Metering Customer Forecast
Electric Vehicles	IHS Markit, Bloomberg New Energy Finance ("BNEF"), NREL, Electric Power Research Institute ("EPRI")	Monthly Cars on Road (historical), Monthly Cars on Road (forecast), Hourly EV Charging Shapes

Base Case Forecast Assumptions

The Companies developed base, high, and low forecasts of energy requirements to evaluate resource planning decisions under multiple energy requirement scenarios. These forecasts as well as a discussion of the uncertainties considered in developing the high and low forecasts are included in Section 5.(3). The following is a discussion of key base case forecast assumptions:

1. Economic Assumptions

The U.S. economy remains on solid footing. Real gross domestic product increased by 2.7 percent during the first half of the year, and IHS is projecting growth just above three percent during the second half of 2018.

IHS is projecting real economic growth to average 2.0 percent for 2018-2028, just below the post-Great Recession average (2010-2017) of 2.2 percent.[8] The first two years are expected to see the strongest growth potential due to the fiscal stimulus from the Tax Cuts and Jobs Act of 2017.

Kentucky's economic growth rate continues to lag behind the U.S. average. The Commonwealth's economy expanded 1.8 percent during 2017 as compared to 2.2 percent for the U.S. overall. This was the strongest annual growth rate since the state's economy expanded 4.5 percent in 2010, the first year after the Great Recession.

The IHS forward economic outlook for Kentucky remains broadly positive. For the 2018-2033 period, IHS is projecting average annual growth of 1.5 percent, above the post-Great Recession (2010-2017) average of 1.4 percent. Similar to the U.S. overall, IHS is projecting stronger growth in the first two years of the timeframe — 2.2 percent in 2018 and 2.3 percent in 2019.

2. Energy Efficiency

Over the past five years, customers have taken significant action to use electricity more efficiently. The base energy requirements forecast assumes these energy efficiency trends will continue throughout the forecast period.

Figure 5-5 contains a plot of industrial energy requirements through 2033. Over the past five years, industrial sales have been flat to declining. Despite forecasted U.S. economic growth, industrial sales are forecast to remain flat as efficiency improvements offset production increases.

[8] The economic growth assumptions were derived from the IHS, Baseline growth scenario (2/5/2018).

Figure 5-5: Industrial Sales, 2010-2033

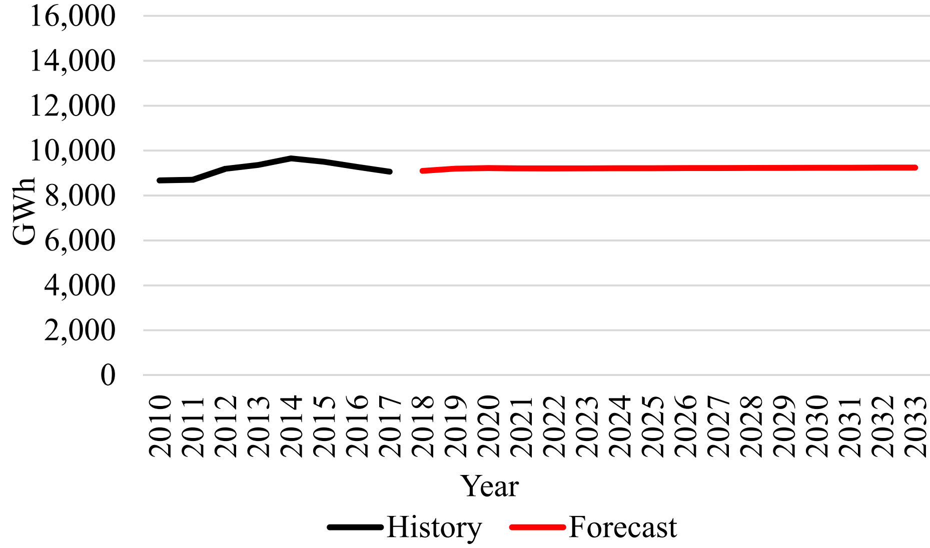
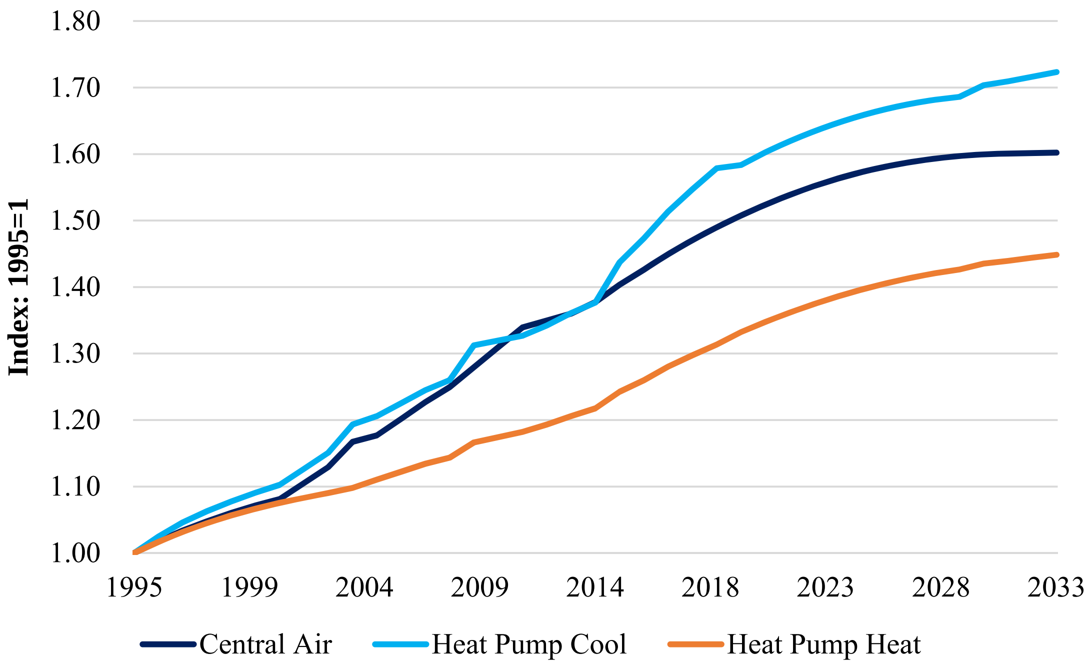


Figure 5-6 demonstrates the improved efficiencies of heat pumps and central air conditioners over the past 23 years as well as the assumed efficiency improvements through the forecast period. Forecasted end-use efficiency improvements are explicitly incorporated in the residential and commercial energy requirements forecasts.

Figure 5-6: Efficiency Improvements for Heat Pumps and Central Air Conditioning[9]

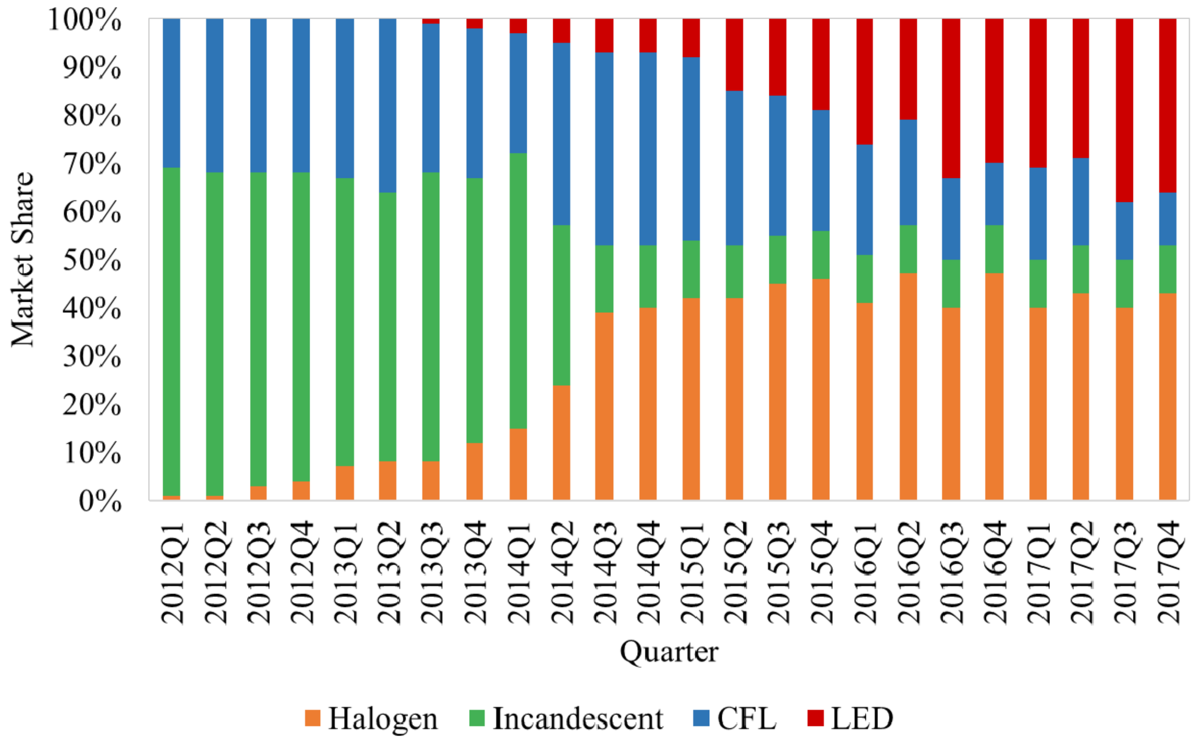


The light emitting diode ("LED") has revolutionized the lighting market and significantly reduced electricity consumption for lighting. A 60-watt equivalent LED consumes 9 watts per

[9] Source: Energy Information Administration

hour, approximately 85 percent less than the equivalent incandescent light bulb, 31 percent less than an equivalent compact fluorescent light ("CFL"), and 79 percent less than the equivalent halogen bulb. Figure 5-7 contains a chart of U.S. lighting sales from 2012 to 2017. CFL and incandescent lights accounted for the vast majority of lighting sales in 2012, but LED and halogen lights have made significant gains since then. The base energy requirements forecast assumes the penetration of LEDs will continue to increase throughout the forecast period.

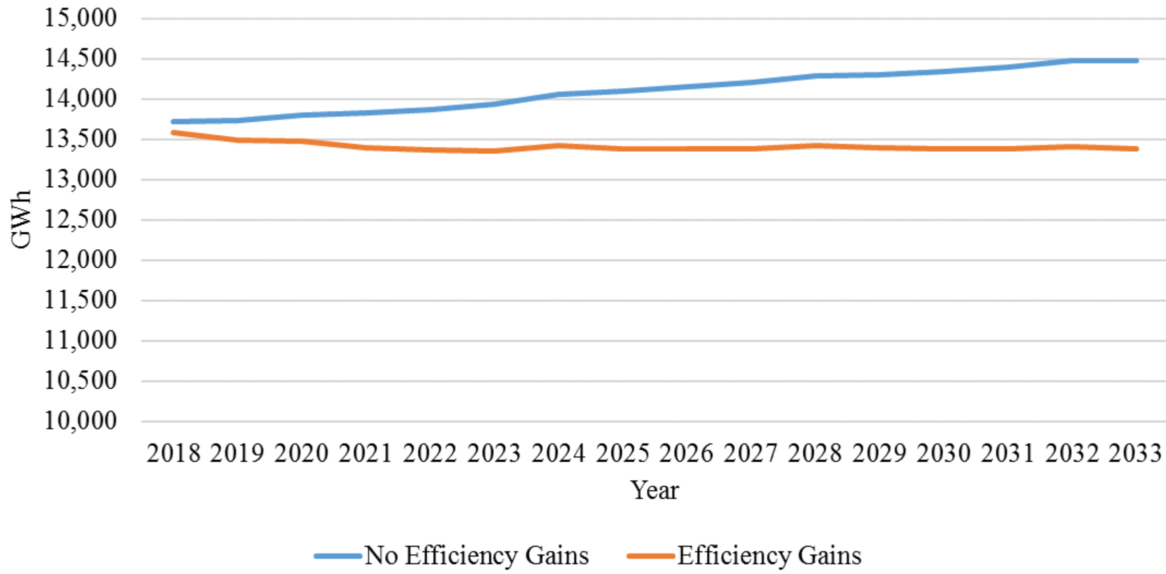
Figure 5-7: Market Share of U.S. Lighting Sales[10]



By 2033, energy efficiency improvements reduce residential and commercial energy requirements by almost 8 percent (see Figure 5-8). These improvements include the impact of company-sponsored Demand Side Management – Energy Efficiency ("DSM-EE") programs. Through August 2018, the Companies' DSM-EE programs have produced cumulative energy and gas savings of approximately 1,143 GWh and 6.9 million Ccf, along with a cumulative gross demand reduction of over 473 MW. The Companies' DSM-EE programs have been a tremendous success. However, with declining load growth projections, low fuel costs, and sufficient generating capacity, some of the Companies' DSM-EE programs are no longer cost-effective. The recently approved 2019-2025 DSM-EE Program Plan includes programs to support continued energy efficiency measures for low-income customers, nonresidential customers, in addition to residential and nonresidential demand conservation.

[10] Source: National Electric Manufacturers Association (NEMA)

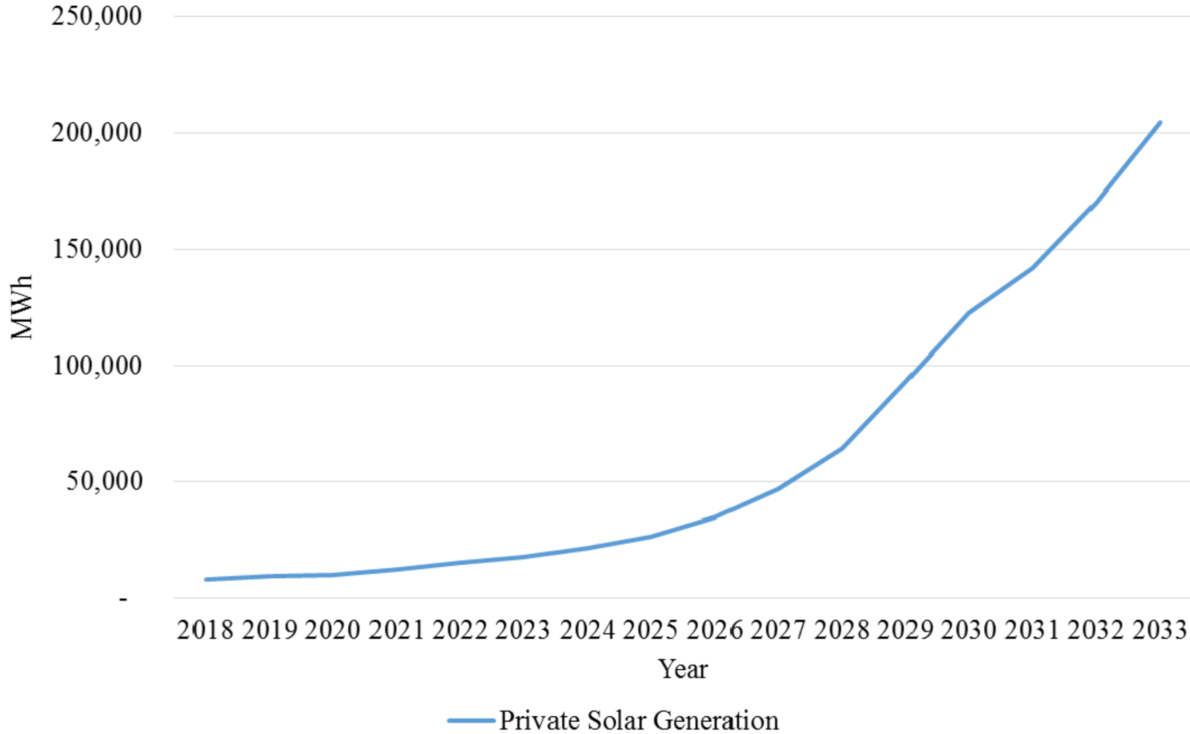
Figure 5-8: Impact of Energy Efficiency Improvements on Residential and Small Commercial Sales Forecast



3. Distributed Generation

Distributed generation includes generation from net metering customers and qualifying facilities. All growth in distributed generation through 2033 is forecasted to occur through net metering. Figure 5-9 contains the Companies' base distributed solar generation forecast, which reflects existing net metering laws and current plans to discontinue the federal investment tax credit ("ITC") in 2022. From 2014 to 2017, the number of net metering customers increased 100% from 243 to 486. There are four customers with wind generation and one customer with hydro generation while the vast majority have solar generation. As a result of declining solar prices and favorable net metering policy, net metering solar capacity is forecasted to increase from 3 MW to 170 MW by the end of 2033, but this forecast is particularly uncertain. Distributed solar generation is included in the discussion of Key Forecast Uncertainties in Section 5.(3).

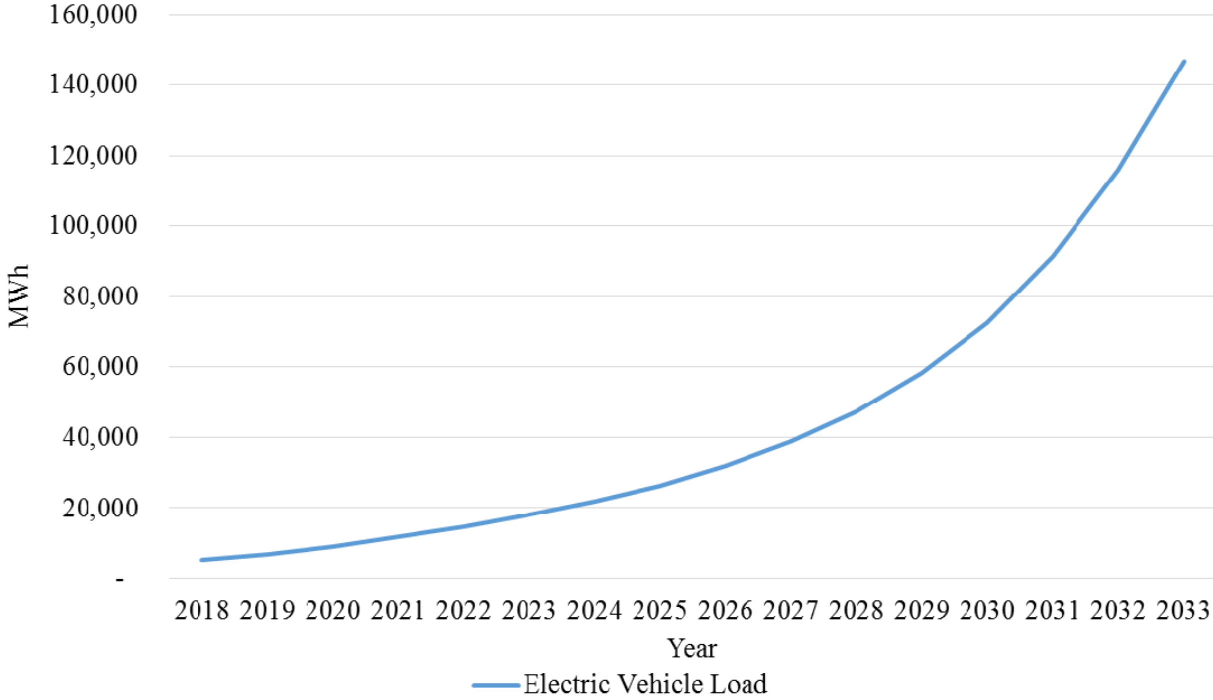
Figure 5-9: Private Solar Generation, Base Energy Requirements Forecast



4. Electric Vehicle Penetration

Figure 5-10 contains the Companies' base forecast for electric vehicle ("EV") electricity consumption. From 2014 to 2017, the estimated number of vehicles-in-operation in the LG&E and KU service territories increased 165% from 531 to 1,409. EV vehicles-in-operation are forecast to increase to over 44,000 by the end of 2033. Like distributed solar generation, the future penetration of electric vehicles is a key forecast uncertainty and is discussed further in Section 5.(3).

Figure 5-10: Electric Vehicle Energy Consumption, Base Energy Requirements Forecast



Resource Plan

The Companies' resource planning process consists of the following activities:

1. Screening of demand-side and supply-side resource options
2. Assessment of target reserve margin criterion
3. Development of long-term resource plan

The models and methods for each of these activities are summarized in the following sections.

Resource Screening Analysis – Models and Methods

A detailed evaluation (using production cost simulation models) of all demand-side and supply-side resource options is impractical due to the significant amount of time required for computer simulation. Therefore, the Companies conducted a resource screening analysis to identify a subset of the most competitive resource options to include in more detailed resource planning analyses.

As mentioned previously, different types of resources play different roles in serving customers' energy requirements. For this reason, the resource screening analysis was designed to identify the least-cost options for each of the following resource types:

1. Demand-side resources
2. Baseload/intermediate resources
3. Peaking resources
4. Renewable resources

A complete summary of this analysis is included in Volume III ("2018 IRP Resource Screening Analysis").

Reserve Margin Analysis – Models and Methods

The reliable supply of electricity is vital to Kentucky's economy and public safety, and customers expect it to be available at all times and in all weather conditions. As a result, the Companies have developed a portfolio of generation and DSM resources with the operational capabilities and attributes needed to reliably serve customers' year-round energy needs at a reasonable cost. In addition to the ability to serve load during the annual system peak hour, the generation fleet must have the ability to produce low-cost baseload energy, the ability to respond to unit outages and follow load, and the ability to instantaneously produce power when customers want it. While the results of this analysis are generally communicated in the context of a summer peak reserve margin, the mathematics – like past reserve margin analyses – assess the Companies' ability to reliably serve customers in all hours.

Figure 5-11 illustrates the costs and benefits of adding capacity to a generation portfolio.[11] As capacity is added, reliability and generation production costs decrease (i.e., the generation portfolio becomes more reliable) but fixed capacity costs increase.[12] In their reserve margin analysis, the Companies evaluate these costs and benefits over a range of reserve margins. The reserve margin at which the sum of (a) capacity costs and (b) reliability and generation production costs is minimized is the economic reserve margin.

[11] As mentioned previously, different types of generation resources play different roles in serving customers; not all resources provide the same reliability and generation production cost benefit.

[12] Reliability costs result from generation shortages and comprise the cost to customers of unserved energy and the cost of power purchases that exceed the Companies' marginal generation cost.

Figure 5-11: Costs and Benefits of Generation Capacity (Illustrative)

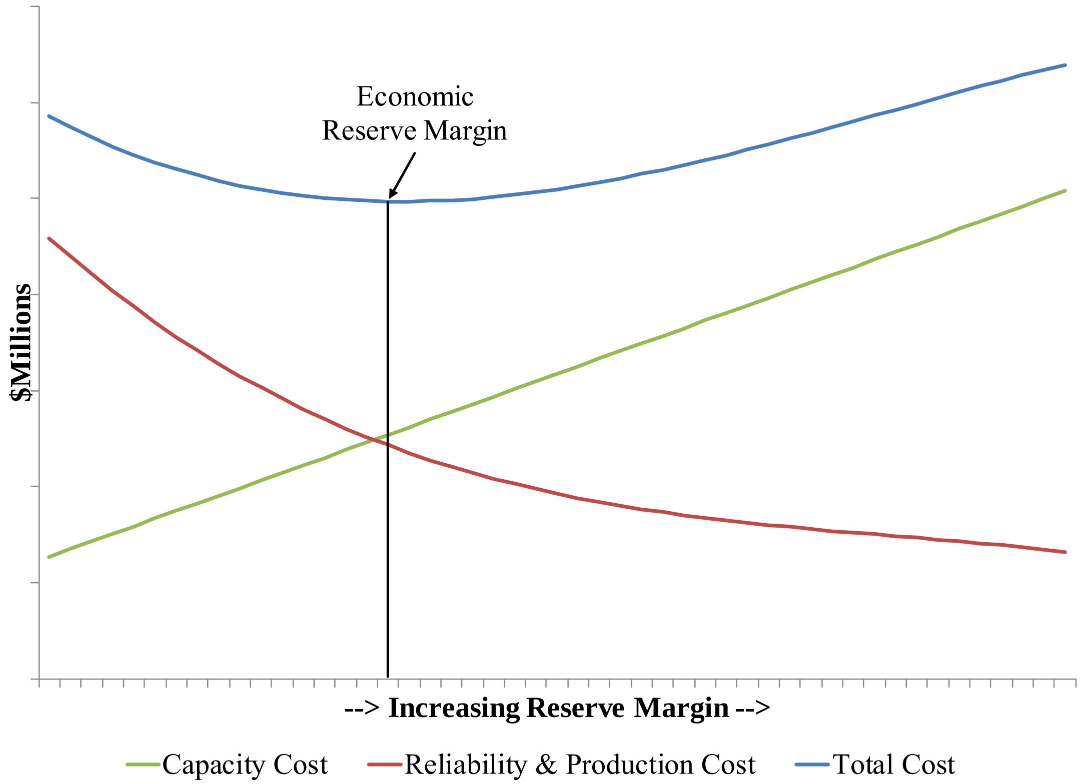
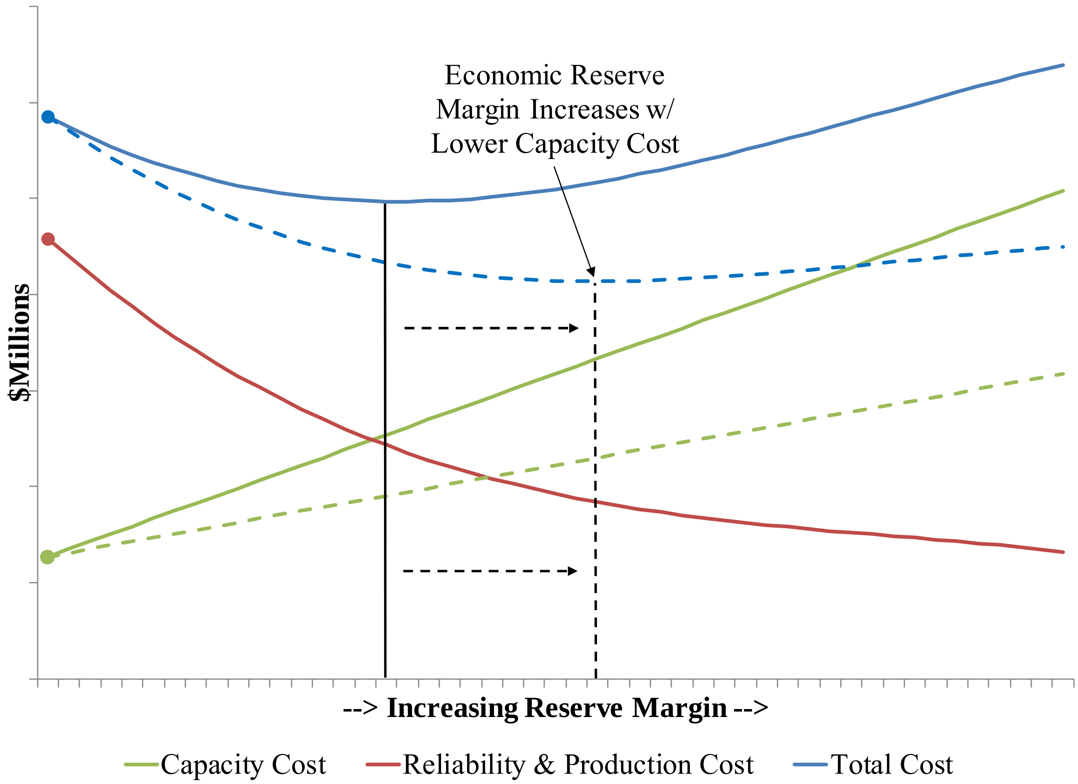


Figure 5-12 includes an alternative capacity cost scenario (dashed green line) for capacity with the same dispatch cost and reliability characteristics. The large dots mark the minimum of the range of reserve margins that is begin evaluated. In this scenario, reliability and generation production costs are unchanged but total costs (dashed blue line) are lower and the economic reserve margin is higher. This result is not surprising; in an extreme case where the cost of capacity is free, the Companies would add capacity until the value of adding capacity reduced to zero.[13]

[13] In Figure 5-12, as more capacity is added to the generation portfolio, the value of adding the capacity decreases (i.e., the slope of the reliability and production cost line is flatter at higher reserve margins).

Figure 5-12: Economic Reserve Margin and Capacity Cost (Illustrative)



For new capacity, the capacity cost includes the fixed costs required to operate and maintain the unit as well as the revenue requirements associated with constructing the unit. When a portion of the evaluated reserve margin range falls below the Companies' forecasted reserve margin, the Companies must consider the costs and benefits of retiring their existing marginal resources to evaluate this portion of the range. When contemplating the retirement of an existing resource, any unrecovered revenue requirements associated with the construction of the unit are considered sunk; the savings from retiring a unit includes only the unit's ongoing fixed operating and maintenance costs.

The Companies evaluated reserve margins ranging from 12 to 24 percent in their 2014 IRP Reserve Margin Analysis. As this analysis was being developed, the Companies were evaluating the addition of Green River 5 (670 MW) at the Green River Generating Station. Without Green River 5, the Companies' reserve margin in 2018 was forecast to be 12 percent. Therefore, their reserve margin analysis evaluated only the costs and benefits of adding new capacity to their generation portfolio.

In the 2018 IRP base energy requirements forecast, the Companies' forecasted reserve margin in 2021 is 23.5 percent. Therefore, to evaluate a similar range of reserve margins using the same methodology, the Companies evaluated the retirement of existing marginal resources as well as the addition of new resources. The cost of continuing to operate each of the Companies' marginal resources is currently less than the cost of adding and operating new resources.

In North America, the most commonly used physical reliability guideline is the 1-in-10 loss-of-load event ("1-in-10 LOLE") guideline. Systems that adhere to this guideline are designed such that the probability of a loss-of-load event is one event in ten years. In addition to the economic reserve margin, this analysis considers the resources needed to meet this guideline. The reserve margin that meets the 1-in-10 LOLE guideline does not necessarily coincide with the economically optimal reserve margin.

The Companies used the Equivalent Load Duration Curve Model ("ELDCM") and Strategic Energy Risk Valuation Model ("SERVM") to complete this analysis. ELDCM estimates LOLE and reliability and generation production costs based on an equivalent load duration curve. SERVM is a simulation-based model and was used to complete the reserve margin studies for the 2011 and 2014 IRPs. A complete summary of this analysis is included in Volume III ("2018 IRP Reserve Margin Analysis").

Long-Term Resource Planning Analysis – Models and Methods

The primary focus of resource planning is risk management. Key categories of risk stem from uncertainties related to the way customers use electricity, the performance of generation units, the price of fuel and other commodities, and the future impact of new state and federal regulations. Given these uncertainties, the Companies developed long-term resource plans for numerous cases over a range of forecasted energy requirements, fuel prices, carbon dioxide ("CO_2") prices, and generating unit operating lives. Each of these inputs is discussed in the following section.

In developing their resource plans, the Companies evaluated whether – in the near-term – existing resources should be replaced with a combination of battery storage and renewables. Several of the cases required significant amounts of replacement capacity in the latter part of the 15-year planning period. For these cases, the Companies evaluated replacement generation portfolios with varying amounts of natural gas and renewable generation, as well as battery storage, for the purpose of demonstrating under what circumstances different portfolios would be least-cost for customers.

For each case, the PROSYM production cost model from ABB was used to model generation production costs for hundreds of alternative resource plans. The analysis also considered the capital revenue requirements and fixed costs associated with these plans. The optimal resource plan for each case was identified as the plan with the lowest present value of revenue requirements ("PVRR"). A complete summary of this analysis is included in Volume III ("2018 IRP Long-Term Resource Planning Analysis").

Resource Planning Inputs and Uncertainties

As mentioned previously, the primary focus of resource planning is risk management. The following sections summarize key resource planning inputs and uncertainties.

1. Energy Requirements

A key category of risk in resource planning stems from uncertainty related to the way customers use electricity. A discussion of this risk is included in Section 5.(3).

2. *State and Federal Regulations*

After the retirement of Brown 1 and 2 in February 2019, all of the Companies' coal units will be equipped with fabric filter baghouses ("baghouses") and flue-gas desulfurization equipment ("FGD"), and all but three coal units will be equipped with selective catalytic reduction ("SCR"). After the Companies complete projects that are currently in progress to comply with the Coal Combustion Residual Rule ("CCR Rule"), all of the Companies' generating units will be in compliance with known state and federal regulations. However, because three of the Companies' coal units are not retrofitted with SCR, future changes to National Ambient Air Quality Standards ("NAAQS") may require one or more of the following actions in the next 3 to 7 years: investment to control emissions of nitrogen oxides ("NO_x"), changes in plant operations during ozone season, unit retirements, or acquisition of new generation.

In addition, on August 21, 2018, the U.S. Environmental Protection Agency ("EPA") proposed the Affordable Clean Energy Rule ("ACE Rule"), which would establish guidelines for states to regulate CO_2 emissions from existing fossil fuel-based electric generating units. The effective date of the ACE Rule is uncertain due to the regulatory process and litigation expectations.[14] Upon the effective date, as it is currently proposed, states have up to three years to submit a State Implementation Plan ("SIP") that establishes the guidelines. The EPA has one year to approve the SIP. At a minimum, due to the regulatory timeline, fleet and unit specific planning for the ACE Rule is uncertain for the next two to four years.

3. *Generating Unit Operating Life*

Approximately one-third (2,500+ MW) of the Companies' existing generation capacity will be 50 years old or older by 2030. As a generation unit ages, the economics of retrofitting the unit to comply with new environmental regulations become less favorable. For these reasons, the IRP considers two operating life scenarios for its generating units: 55-years and 65-years. Table 5-4 summarizes the amount of capacity that is assumed to be retired over the 15-year planning period in each operating life scenario. In the 55-year operating life scenario, 2,428 MW of summer capacity is retired through 2033. In the 65-year operating life scenario, only 49 MW of capacity is retired through 2033 (although a significant amount of capacity would be retired just beyond 2033).

[14] The previously proposed Clean Power Plan became effective nearly one year after it was published to the Federal Register.

Table 5-4: Unit Retirement Scenarios

	55-Year Operating Life		65-Year Operating Life	
Year	Retired Summer Net Capacity (MW)	Retired Units	Retired Summer Net Capacity (MW)	Retired Units
2023	49	LG&E Small-Frame SCCTs		
2024				
2025	24	Haefling 1-2		
2026	415	Brown 3		
2027	299	Mill Creek 1		
2028				
2029	770	Ghent 1, Mill Creek 2		
2030				
2031				
2032	481	Ghent 2		
2033	390	Mill Creek 3	49	LG&E Small-Frame SCCTs
Total	2,428		49	

4. Generating Unit Performance

Uncertainty related to the performance and availability of generating units is a key consideration in resource planning. From one year to the next, the average availability of generating units is fairly consistent. However, the timing and duration of unplanned outage events in a given year can vary significantly. A key aspect in developing a target reserve margin is properly considering the likelihood of unit outages during extreme weather events.

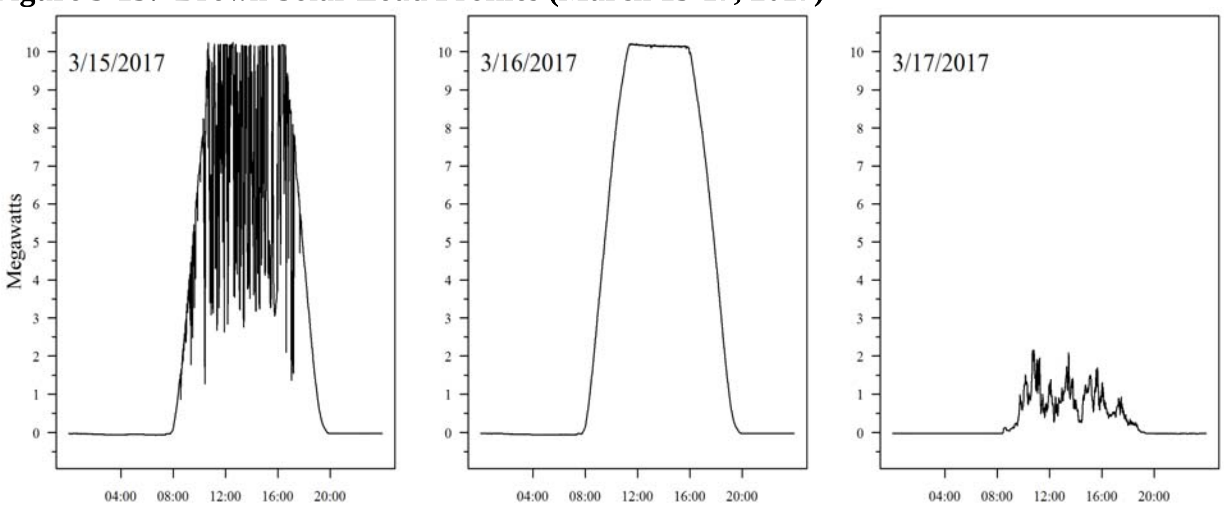
In addition to being reliable, a generation portfolio must possess numerous other attributes to produce power when customers want it. For example, a generation portfolio must possess the ramping capabilities to follow abrupt changes in customers' energy requirements, as demonstrated in Figure 5-4. In addition, the Companies must be able to dispatch at least a significant portion of their generating units when they are needed. Peaking units can start quickly and are needed to respond to unit outages. Baseload units take longer to start, but because their start times are predictable, the Companies can bring them online when they are needed. The size of a resource is also important. If a unit is too big, taking the unit offline for maintenance can be problematic. If a unit is too small, its value in responding to unit outages is limited.

Customers consume electricity every hour of the year but none of the Companies' generation resources are available in every hour. Considering the need for maintenance, the Companies' baseload units and large-frame SCCTs are available to be utilized up to 90 percent of hours in a year. The Companies' small-frame SCCTs are close to 50 years old and are far less reliable than large-frame SCCTs. The Companies' Curtailable Service Rider ("CSR") limits the ability to curtail participating customers to hours when all large-frame SCCTs have been dispatched. As a result, the ability to utilize this program is limited to, at most, a handful of hours each year.

As the Companies evaluate integrating more renewables into their generation portfolio, they must consider the fact that renewables lack many of the characteristics required to serve customers in every moment. Compared to coal- and natural gas-fired resources, the availability of renewables is less predictable and their fuel supply (e.g., sunshine, wind, or water) is more intermittent. Furthermore, because annual peak demands can occur during the winter months and because winter peaks typically occur during nighttime hours, solar generation has virtually no value in the Companies' service territories as a source of winter capacity.

Figure 5-13 contains load profiles from Brown Solar for three successive days in March 2017. On March 15, intermittent clouds caused the array's output to swing significantly. March 16 was a clear day and the array performed optimally. Then, on March 17, the array's output was limited significantly by heavy cloud cover. If the cost of renewables continues to decline, the Companies may add more renewables to their generation portfolio. However, in doing this, they must ensure their portfolio as a whole maintains the ability to produce power when customers want it.

Figure 5-13: Brown Solar Load Profiles (March 15-17, 2017)



5. Fuel and Emission Prices

Table 5-5 contains the delivered coal and natural gas prices considered in this analysis, and Table 5-6 contains the CO_2 prices considered in this analysis. These inputs, along with the costs of replacement generation and battery storage, play a significant role in determining what replacement generation technologies are least-cost for customers. With no regulations specifying a market for CO_2 emissions allowances or a CO_2 emissions tax, the Companies assumed CO_2 prices would begin in 2026 in the High CO_2 price scenario. The High CO_2 scenario is not linked in any way to the proposed ACE Rule. A broader discussion of CO_2 price forecasts is included in Volume III ("2018 IRP Long-Term Resource Planning Analysis").

Table 5-5: Delivered Coal and Natural Gas Prices (Nominal $/mmBtu)

Year	Natural Gas[15]			Coal[16]				
	Low	Mid	High	Brown	Ghent	Mill Creek	Trimble High Sulfur	Trimble PRB
2019	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2020	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2021	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2022	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2023	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2024	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2025	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2026	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2027	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2028	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2029	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2030	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2031	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2032	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2033	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[15] The natural gas price forecast reflects forecasted Henry Hub market prices plus variable costs for pipeline losses and transportation, excluding any fixed firm gas transportation costs. In 2019, the low and high natural gas price is the forecast of the commodity price at Henry Hub based upon NYMEX market prices as of April 18, 2018, plus transportation to Cane Run 7's delivery meter. In subsequent years, the base forecast is a blend of forward market prices and a smoothed version of EIA's High Oil and Gas Resource case from its 2018 Annual Energy Outlook ("AEO"). The low Henry Hub price forecast reflects forward market prices, which are extrapolated through the end of the study period. The high Henry Hub gas price forecast is a smoothed version of the EIA's reference case forecast from its 2018 AEO.

[16] The coal price is the volume-weighted average of the contracted coal price and the market price of coal. In the first five years of the forecast, the market price is a blend of coal bids received, but not under contract, and the forecast from an independent third party consultant. Beyond the fifth year, prices are increased at the compound annual growth rate reflected in the Energy Information Administration's latest Annual Energy Outlook for "All Coals, Minemouth" price forecast.

Table 5-6: CO_2 Prices (Nominal $/short ton)[17]

Year	Zero	High
2019	0	0
2020	0	0
2021	0	0
2022	0	0
2023	0	0
2024	0	0
2025	0	0
2026	0	17.00
2027	0	18.17
2028	0	19.37
2029	0	20.62
2030	0	21.90
2031	0	23.23
2032	0	24.59
2033	0	26.00

6. *Generation Technology Costs*

The generation cost forecasts utilized in this analysis were taken from the 2018 Annual Technology Baseline from the National Renewable Energy Laboratory, which can be accessed at https://atb.nrel.gov/. Since the Companies' 2014 IRP, the cost of renewable and battery technologies have decreased significantly. NREL expects this trend to continue, albeit at a slower rate. Compared to gas-fired technologies, the pace of renewable and battery technology development is far less certain.

5.(3) Load Forecast Summary

Base Energy Requirements Forecast

Table 5-7 contains the Companies' base energy requirements forecast for the 15-year planning period. The decrease in KU energy requirements from 2018 to 2020 reflects the departure of eight municipal customers, effective April 2019. From 2020 to 2033, the Companies' energy requirements forecast is flat to slightly declining, as energy efficiency gains are assumed to offset the impact of new customer growth.

[17] The High CO_2 emissions price is based on a forecast developed by Synapse Energy Economics in March 2016. Synapse's Spring 2016 Low CO_2 price forecast began in 2022 and was presented in real 2015 dollars. For this analysis, it was escalated to nominal dollars at 1.8% annually and the onset was delayed to 2026. See Synapse's "Spring 2016 National Carbon Dioxide Price Forecast" report (March 16, 2016) at http://www.synapse-energy.com/sites/default/files/2016-Synapse-CO2-Price-Forecast-66-008.pdf.

Table 5-7: Base Energy Requirements Forecast (GWh)

Year	KU	LG&E	Combined Companies
2018	21,815	12,370	34,185
2019	20,731	12,363	33,094
2020	20,237	12,372	32,609
2021	20,153	12,353	32,506
2022	20,116	12,357	32,473
2023	20,094	12,366	32,460
2024	20,143	12,392	32,535
2025	20,113	12,389	32,502
2026	20,107	12,400	32,507
2027	20,102	12,409	32,511
2028	20,120	12,430	32,550
2029	20,086	12,417	32,503
2030	20,066	12,411	32,477
2031	20,063	12,423	32,486
2032	20,078	12,443	32,521
2033	20,052	12,435	32,487

The distribution of energy requirements throughout the year is an important consideration for resource planning because planned maintenance is performed in the spring and fall "shoulder" months when energy requirements are lowest. Table 5-8 contains monthly energy requirements for 2021 as well as the percentage of total energy requirements consumed during nighttime hours.

Table 5-8: Monthly Energy Requirements, 2021 (MWh)

	KU	LG&E	Combined Companies	CC Night
Jan	2,095	1,027	3,123	58%
Feb	1,679	898	2,577	54%
Mar	1,599	955	2,554	49%
Apr	1,405	856	2,261	40%
May	1,631	1,029	2,659	37%
Jun	1,674	1,143	2,818	33%
Jul	1,814	1,301	3,114	34%
Aug	1,851	1,319	3,170	37%
Sep	1,521	1,051	2,571	44%
Oct	1,444	884	2,328	50%
Nov	1,623	917	2,540	57%
Dec	1,818	973	2,791	57%
Total	20,153	12,353	32,506	46%

Table 5-9 contains the Companies' base case summer and winter peak demand forecasts. The decrease in summer peak from 2018 to 2019 and the decrease in winter peak from 2019 to 2020 reflects the April 2019 departure of eight municipal customers.[18] From 2020 to 2033, the compound annual growth rate ("CAGR") for peak winter demands is somewhat higher than the CAGR for peak summer demands (0.2 percent versus 0.0 percent) due to assumed increases in electric heating penetration. The variability in summer and winter energy requirements is discussed in the following section.

Table 5-9: Base Summer and Winter Peak Demand Forecast (MW)

Year	Summer	Winter
2018	6,655	6,322
2019	6,360	6,220
2020	6,361	5,972
2021	6,350	5,975
2022	6,338	5,970
2023	6,338	5,966
2024	6,325	5,972
2025	6,330	5,991
2026	6,344	6,013
2027	6,352	6,027
2028	6,351	6,047
2029	6,357	6,069
2030	6,355	6,085
2031	6,353	6,100
2032	6,343	6,114
2033	6,339	6,129

Key Forecast Uncertainties

Uncertainties impacting the ways customers use electricity are a key consideration in resource planning. These uncertainties are discussed in the following sections.

1. Weather

The Companies develop their long-term energy requirements forecast with the assumption that weather will be average or "normal" in every year.[19] While this is a reasonable assumption for long-term resource planning, weather from one year to the next is never the same. For this reason, to support the Companies' Reserve Margin Analysis, the Companies produced 45 hourly energy requirement forecasts for 2021 based on weather in each of the last 45 years.

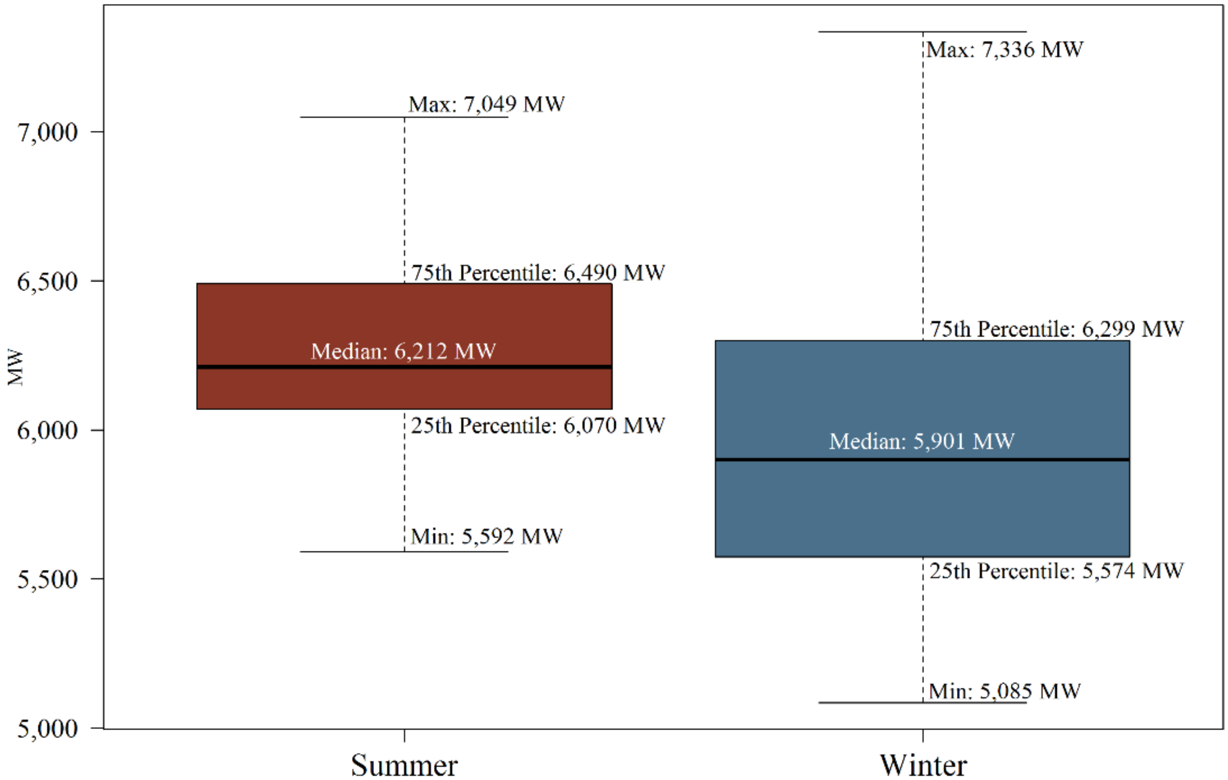
Figure 5-14 contains distributions of the Companies' summer and winter peak demands for 2021 based on the "weather year" forecasts. While the median peak demand is higher in the summer, the variability in peak demands – as experienced over the past five years – is much higher in the

[18] The non-coincident summer peak energy requirement for the departing municipal customers is approximately 325 MW. The reduction from 2018 to 2019 reflects the reduction in the municipal customers' coincident peak energy requirement (approximately 285 MW) as well as other factors.

[19] The Companies use 20 years of historical weather data to develop their normal weather forecast.

winter.[20] This is largely due to electric heating systems with heat pumps consuming significantly more energy during extreme cold weather when the need for backup resistance heating is triggered. The variability in energy requirements due to weather is a key consideration in resource planning.

Figure 5-14: Distribution of Summer and Winter Peak Demands, 2021



2. Economy

The key upside risk to Kentucky's economy is that the housing market continues to perform well. Total housing starts increased 11.7 percent per year between 2015 and 2017, the 11th quickest pace in the country. For 2017-2019, the pace is expected to slow a bit to 11 percent according to IHS. The housing increase has been concentrated in the urban areas of the state, though growth has softened in recent months.

A downside risk to Kentucky's economy is the potential for a full-blown trade war as exports account for approximately 15 percent of the state's economic output, one of the higher percentages in the U.S. The largest portion of these exports (5.7 percent of the total) is from the aerospace industry, but these manufacturers are largely located in Northern Kentucky outside of the LG&E

[20] The distributions in Figure 5-14 do not reflect load reductions associated with the Companies' Curtailable Service Rider ("CSR") because this program is modeled as a generation resource; CSR load reductions are forecast to be 141 MW in 2021. The maximum winter peak demand (7,336 MW) is forecasted based on the weather from January 20, 1985 when the average temperature was -8 degrees Fahrenheit and the low temperature was -16 degrees Fahrenheit. For comparison, the Companies' peak demand on January 6, 2014 during the polar vortex was 7,114 MW, the average temperature was 8 degrees Fahrenheit, and the low temperature was -3 degrees Fahrenheit. CSR customers were curtailed during this hour and the departing municipals' load was 285 MW.

and KU service territories. The potential negative impact on the large automobile manufacturers in the service territory is a concern, however, as the tariffs on steel and aluminum are likely to raise production costs. Auto manufacturers are already experiencing headwinds as lightweight vehicle sales declined in 2017 after back-to-back record years.

3. Cost of Service

Electricity prices are a consideration in the electric load forecast. Forecast models incorporate class-specific estimates of price elasticity between -0.1 and -0.3. These numbers are similar to those from a 2010 survey conducted by energy consultant Itron. In a review of other utility IRPs, a figure of -0.1 to -0.2 was commonly used with the EIA and the Electric Power Research Institute ("EPRI") being among the most commonly cited sources.

Electricity prices are anticipated to increase at a planned rate over the first five years of the forecast period. Thereafter, prices are expected to increase by two percent per year, consistent with long-term inflation expectations. If higher-than-expected prices materialize, the Companies anticipate a decline in sales as compared to the current forecast (all else equal) due to the negative price elasticities incorporated into the forecasting models.

The Companies consistently evaluate the robustness of elasticity assumptions and sensitivity to changes in both price and elasticity. The changing economics of distributed generation and electric vehicles are of particular interest as declining prices of these technologies are driving increased adoption in both cases. However, their effects on the demand curve could offset as distributed generation decreases the quantity demanded while electric vehicles increase the quantity demanded at a given price. Other factors increasing the price of electricity would accelerate the payback on distributed generation. EV adoption could be hindered by increasing electricity prices as the total cost of EV ownership increases.

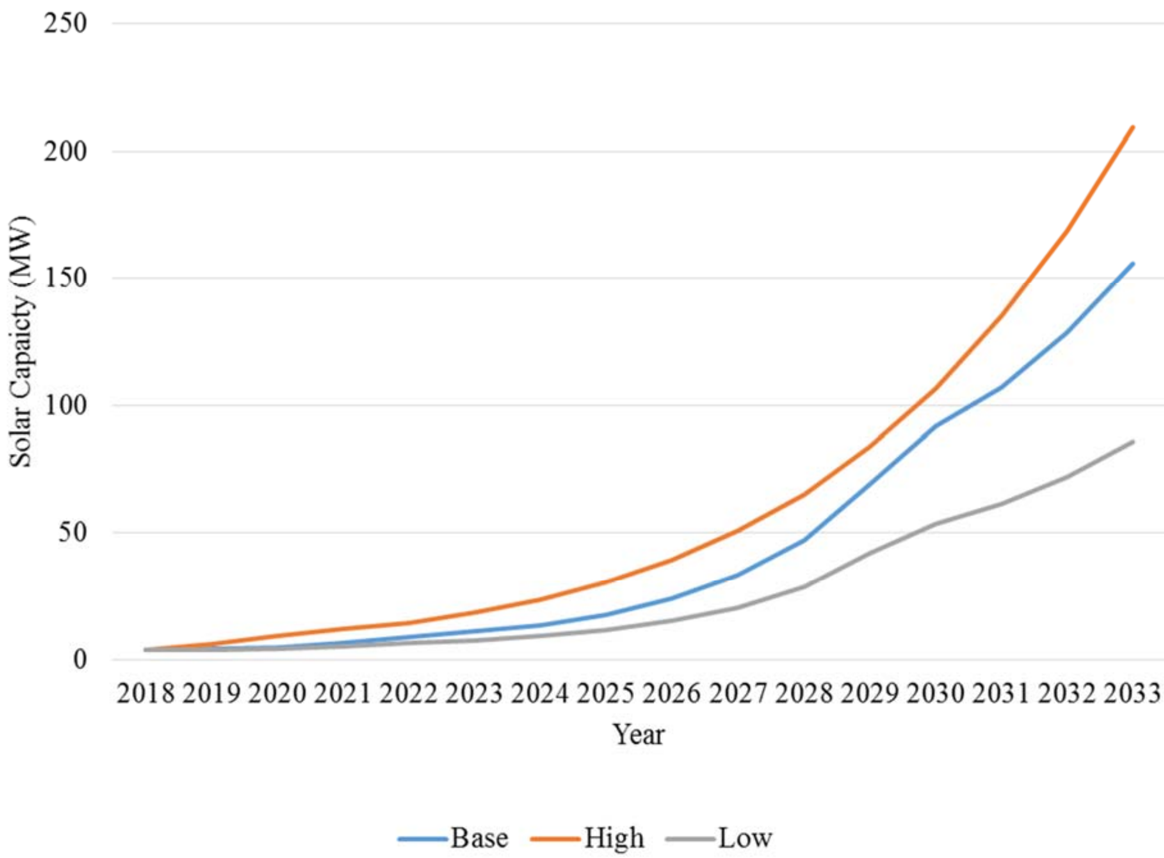
The load forecasting process explicitly contemplates short-run price elasticity of demand via statistically adjusted end-use models. Further, examples of new long-run demand side analysis since the 2014 IRP include the incorporation of private solar and electric vehicle forecasts into the base load forecast. As such, major potential drivers of change in long-run price elasticity of demand are incorporated into the load forecast directly as opposed to via the price elasticity of demand proxy. The Companies continue to view this delineation as appropriate and necessary given the hourly load profiles of these technologies. The base case load forecast represents the Companies' view of the most likely development in prices, end use saturations and efficiencies, distributed energy resources, demographics, and economic conditions in the service territory.

4. Distributed Generation

Distributed generation includes generation from net metering customers and qualifying facilities. All growth in distributed generation through 2033 is forecasted to occur through net metering. The base distributed solar generation forecast reflects existing net metering laws and current plans to discontinue the federal ITC. These assumptions along with the cost for installing solar at a residential or commercial premise are key variables in determining future levels of distributed solar generation.

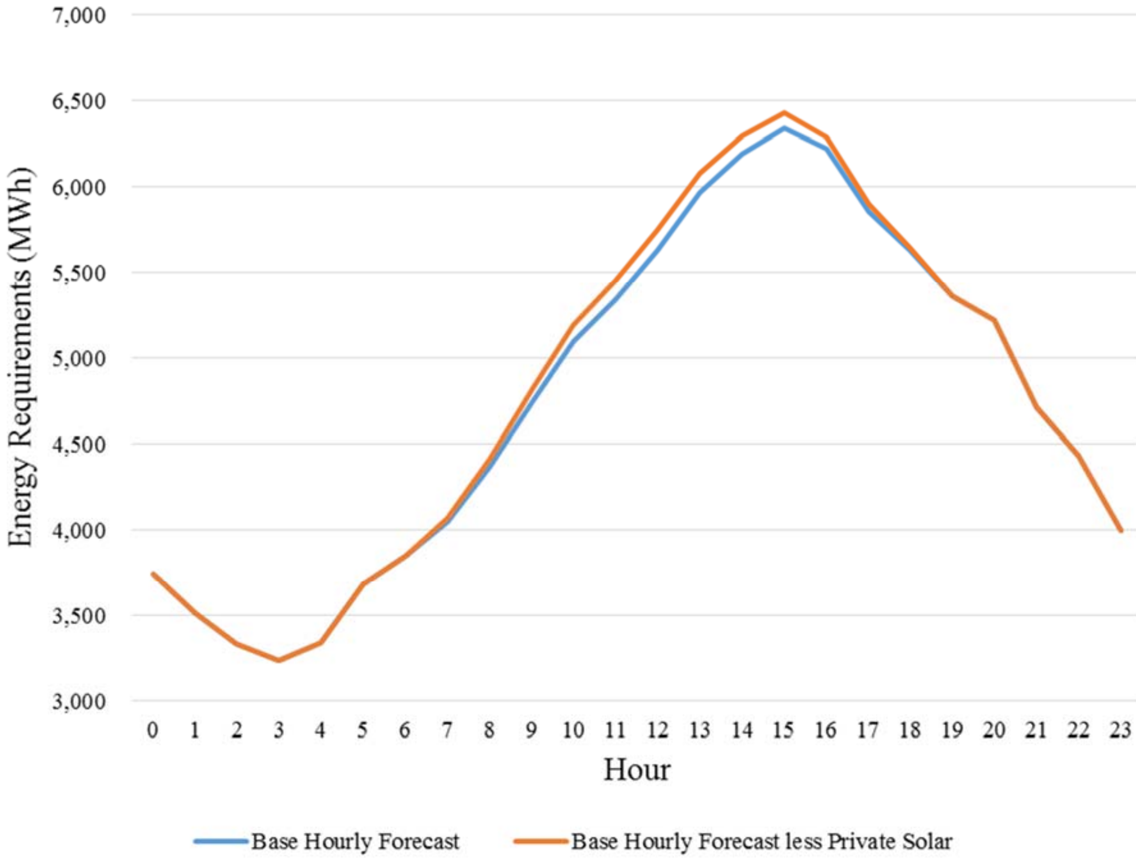
Figure 5-15 compares the high and low distributed solar generation forecast scenarios to the base forecast. The high scenario was derived from a National Renewable Energy Laboratory ("NREL") forecast of distributed solar generation for the Companies' service territories and assumes a more aggressive consumer adoption rate than the base scenario. The base and low adoption scenarios were developed by the Companies. Changes in growth rates beyond 2028 are explained by changes in NREL's Annual Technology Baseline forecast of the cost of private solar installations. Compared to the base scenario, the low scenario assumes less aggressive consumer adoption in the near-term and net metering laws are modified in the longer-term to compensate net metering customers for solar generation pushed back to the electric grid (i.e., solar generation in excess of the customer's energy consumed from the grid) at the utilities' avoided cost of energy (versus the retail rate). This change has a limited impact on the number of solar installations but reduces the average installation size by creating the incentive to limit solar generation pushed back to the grid. With this change, net metering customers continue to be compensated at the retail rate for solar generation that reduces consumption from the grid.

Figure 5-15: Distributed Solar Generation Forecasts, Installed Capacity



In states like California with mandated high levels of solar generation, the timing imbalance between customers' peak energy requirements and the availability of solar generation results in a daily energy requirements profile known as the "duck curve" that increases steeply in the afternoon hours. As demonstrated in Figure 5-16, even in the high distributed solar generation scenario, the impact of distributed solar generation on the Companies' load profile is small.

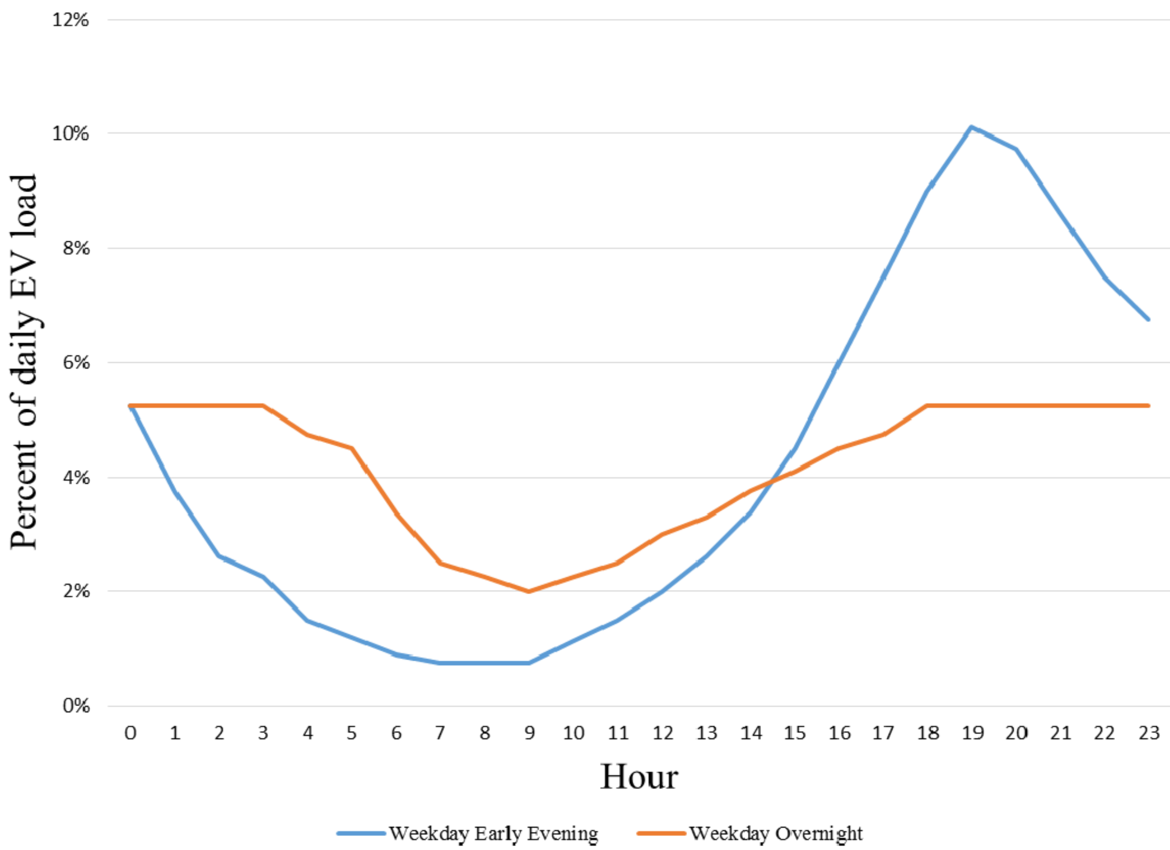
Figure 5-16: Impact of High Distributed Solar Generation on August 26th, 2033



5. Electric Vehicles

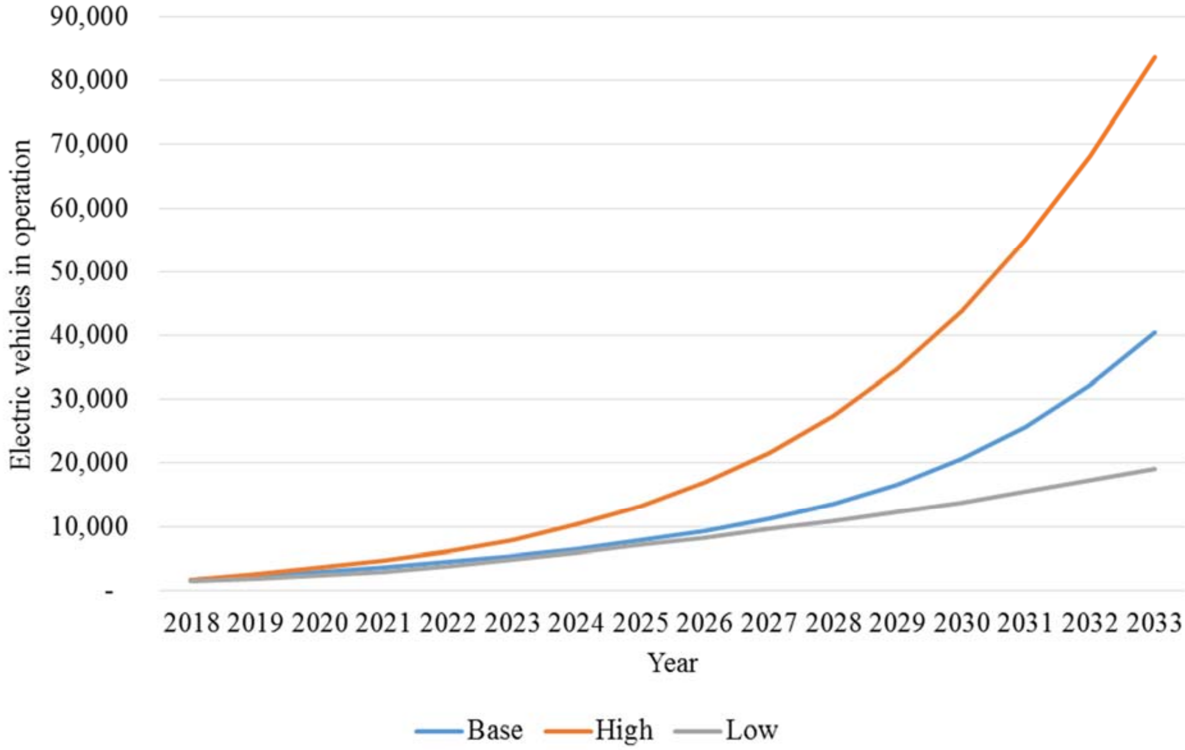
The primary factors impacting electricity consumption by electric vehicles are the number of electric vehicles in the Companies' service territories and the distance driven per vehicle. However, resource planning considerations for electric vehicles focus less on these factors and more on the way customers charge their vehicles. If electric vehicles are charged overnight when energy requirements would otherwise be low, the vehicles can likely be charged with the Companies' existing generation assets. However, if electric vehicles are charged early in the evenings (e.g., when customers get home from work), electric vehicle charging could exacerbate summer and winter peak energy requirements and potentially create the need for additional peaking capacity or load control programs. These charging patterns are depicted in Figure 5-17.

Figure 5-17: Electric Vehicle Charging Patterns; High Forecast, 2033



In addition to the base forecast for electric vehicle electricity consumption, the Companies developed high and low forecasts by varying the rate of electric vehicle adoption (see Figure 5-18). In the high scenario, the Companies evaluated both "overnight" and "early evening" charging patterns but did not find material differences in peak demands based on the assumed levels of electric vehicle adoption during the planning period.

Figure 5-18: Electric Vehicles in Operation



High and Low Energy Requirement Forecasts

The Companies' high and low energy requirements forecasts are summarized in Table 5-10 with the base energy requirements forecast. Compared to the base case forecast, the high forecast reflects a scenario with stronger economic growth, lower-than-expected cost of service, higher electric vehicle adoption, and lower distributed solar generation due to net metering reform. Conversely, the low forecast reflects a scenario with weaker economic growth, higher-than-expected cost of service, lower electric vehicle adoption, and higher distributed solar generation.

The low energy requirements scenario is analogous to a deindustrialization where – by the end of the planning period – the Companies' six largest industrial customers shut down, the remaining municipal customers seek alternatives sources of supply, and residential and commercial sales decline by five percent. Average annual growth in the high energy requirements scenario is comparable to the average annual growth experienced by the state of Tennessee between 1980 and 2010.

Table 5-10: Energy Requirements Forecasts, Combined Companies (GWh)

Year	Base	High	Low
2018	34,185	34,409	33,885
2019	33,094	33,420	32,656
2020	32,609	33,058	32,006
2021	32,506	33,094	31,721
2022	32,472	33,213	31,485
2023	32,460	33,369	31,251
2024	32,535	33,626	31,088
2025	32,502	33,789	30,798
2026	32,507	34,005	30,532
2027	32,511	34,234	30,249
2028	32,550	34,513	29,988
2029	32,503	34,723	29,630
2030	32,477	34,970	29,273
2031	32,486	35,261	28,917
2032	32,521	35,592	28,571
2033	32,486	35,869	28,136

Table 5-11 summarizes the base, high, and low forecasts for summer and winter peak demands. In all forecasts, the difference between the summer and winter peaks narrows through the forecast period.

Table 5-11: Peak Demand Forecasts, Combined Companies (MW)

	Summer			Winter		
Year	**Base**	**High**	**Low**	**Base**	**High**	**Low**
2018	6,655	6,697	6,598	6,322	6,355	6,277
2019	6,360	6,389	6,248	6,220	6,272	6,151
2020	6,361	6,408	6,214	5,972	6,045	5,876
2021	6,350	6,409	6,156	5,975	6,082	5,856
2022	6,338	6,394	6,079	5,970	6,123	5,835
2023	6,338	6,476	6,090	5,966	6,123	5,769
2024	6,325	6,494	6,031	5,972	6,379	5,944
2025	6,330	6,526	5,980	5,991	6,350	5,839
2026	6,344	6,569	5,938	6,013	6,440	5,841
2027	6,352	6,592	5,862	6,027	6,472	5,785
2028	6,351	6,661	5,844	6,047	6,532	5,752
2029	6,357	6,699	5,772	6,069	6,578	5,695
2030	6,355	6,761	5,729	6,085	6,542	5,569
2031	6,353	6,789	5,636	6,100	6,600	5,518
2032	6,343	6,817	5,534	6,114	6,702	5,506
2033	6,339	6,845	5,437	6,129	6,764	5,446

5.(4) Resource Plan Summary

Resource Screening Analysis

Table 5-12 lists the least-cost demand-side, baseload/intermediate, peaking, and renewable resources from the Resource Screening Analysis. These resources and the Companies' existing resources are evaluated further in the Reserve Margin Analysis and Long-Term Resource Planning Analysis.[21]

[21] The Long-Term Resource Planning Analysis did not evaluate efficiency improvements for the Companies' existing resources. However, the Companies will evaluate these improvements as opportunities arise with consideration of any applicable environmental regulations.

Table 5-12: Resource Screening Analysis Results

	Demand-Side Resources	Generation Resources (2018 Dollars)				
		Peaking		Baseload/ Intermediate	Renewables	
	Demand Conservation Program[22]	SCCT	Battery Storage	NGCC	Non-KY Wind	PV Solar
Summer Capacity (MW)[23]	127	201	1-500	368	50-500	1-500
Winter Capacity (MW)[23]	0	220	1-500	429	50-500	1-500
Contribution to Summer Peak	100%	100%	100%	100%	15%	80%
Contribution to Winter Peak	0%	100%	100%	100%	33%	0%
Net Capacity Factor	N/A	5-90%	5-40%	10-90%	40-50%	18-22%
Heat Rate (MMBtu/MWh)[24]	N/A	9.8	N/A	6.4	N/A	N/A
Capital Cost ($/kW)[24]	N/A	911	2,073	1,070	1,515	1,093
Fixed O&M ($/kW-yr)[24]	18	13	9	11	53	10
Firm Gas Cost ($/kW-yr)[25]	N/A	22	N/A	19	N/A	N/A
Variable O&M[24]	$5/customer	$7.31/MWh	$2.72/MWh	$2.83/MWh	N/A	N/A
Fuel Cost ($/MWh)	N/A	27.90	N/A	18.36	N/A	N/A
Transmission Cost ($/MWh)	N/A	N/A	N/A	N/A	12	N/A

Target Reserve Margin Range

Table 5-13 contains the Companies' reserve margin forecast with planned retirements in the base energy requirements forecast scenario. Summer peak demand decreases from 2018 to 2019 primarily due to the departure of eight municipal customers. Load reductions associated with the Companies' DSM programs reflect changes to DSM programs from the Companies' recently

[22] Inputs for the DCP reflect program modifications proposed in the Companies' most recent DSM filing. The summer capacity of this program is forecast to decrease from 127 MW in 2018 to 87 MW in 2021 due to customer attrition, but any actual decline is uncertain. Fixed O&M is the annual cost that could be saved if the DCP was discontinued.

[23] NREL's 2018 ATB did not specify capacity values. The capacities shown are representative of typical installations.

[24] Source: NREL's 2018 ATB (https://atb.nrel.gov/). The Companies inflated NREL's cost forecasts, which were provided in real 2016 dollars, to nominal dollars at 2% annually.

[25] Firm gas transportation costs are based on the cost of firm gas transportation for Cane Run 7 and the Trimble County SCCTs.

approved DSM filing in Kentucky.[26] The Companies' generation capacity decreases by 437 MW in 2019 due to the planned retirement of Brown 1 and 2 (272 MW) and the expiration of the Bluegrass Agreement (165 MW), and by 14 MW in 2021 due to the planned retirement of Zorn 1, which is expected to occur within the next three years.

Table 5-13: Reserve Margin Forecast (MW, Base Energy Requirements Forecast)

	2018	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2027**	**2030**	**2033**
Gross Peak Load	7,028	6,703	6,688	6,674	6,657	6,653	6,638	6,655	6,650	6,627
DCP	-127	-96	-91	-87	-84	-80	-77	-67	-59	-52
DSM	-247	-247	-236	-236	-236	-236	-236	-236	-236	-236
Net Peak Load	**6,655**	**6,360**	**6,361**	**6,350**	**6,338**	**6,338**	**6,325**	**6,352**	**6,355**	**6,339**
Existing Capability[27]	7,754	7,476	7,476	7,476	7,477	7,477	7,478	7,478	7,478	7,478
Small-Frame SCCTs	87	87	87	73	73	73	73	73	73	73
CSR	141	141	141	141	141	141	141	141	141	141
Bluegrass	165	0	0	0	0	0	0	0	0	0
OVEC[28]	152	152	152	152	152	152	152	152	152	152
Total Supply	**8,299**	**7,856**	**7,856**	**7,842**	**7,843**	**7,843**	**7,844**	**7,844**	**7,844**	**7,844**
Reserve Margin	1,644	1,495	1,495	1,491	1,505	1,505	1,518	1,492	1,489	1,505
Reserve Margin %	**24.7%**	**23.5%**	**23.5%**	**23.5%**	**23.7%**	**23.7%**	**24.0%**	**23.5%**	**23.4%**	**23.7%**

The 2018 IRP reserve margin analysis evaluates (a) annual capacity costs and (b) annual reliability and generation production costs for 2021 over a wide range of summer peak reserve margins to identify the optimal generation mix for customers. The forecasted summer peak reserve margin in 2021 is 23.5 percent in the base energy requirements forecast scenario. To evaluate operating at lower reserve margins with less reliability, the Companies compared the reliability and production cost benefits for their marginal baseload and peaking resources to the savings that would be realized from retiring these resources. Specifically, the Companies evaluated the retirement of their small-frame simple-cycle combustion turbines ("SCCTs"), the Demand Conservation Program ("DCP"), one or more Brown 11N2 SCCTs, and Brown 3.[29,30] To determine if adding resources would cost-effectively improve reliability, the Companies compared the costs and benefits of adding new SCCT capacity to the generation portfolio.

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[26] *In the Matter of: Electronic Joint Application of Louisville Gas and Electric and Kentucky Utilities Company for Review, Modification, and Continuation of Certain Existing Demand-Side Management and Energy Efficiency Programs*, Case No. 2017-00441.

[27] Existing capability is shown excluding small-frame SCCTs, CSR, Bluegrass, and OVEC and including 1 MW derates on each of the E.W. Brown Units 8, 9, and 11, which are planned to be resolved by 2024.

[28] OVEC's capacity reflects the 152 MW that is expected to be available to the Companies at the time of the summer peak, not its rating of 172 MW.

[29] The Brown 11N2 SCCTs comprise Brown 5, Brown 8, Brown 9, Brown 10, and Brown 11.

[30] The rationale for selecting these resources is included in Volume III ("2018 IRP Reserve Margin Analysis").

The results of this analysis show that the Companies' existing resources are economically optimal for meeting system reliability needs in 2021. In other words, it is not cost-effective to alter annual or summer peak hour reliability by either retiring existing resources or adding new resources. With the exception of the DCP, the reliability and generation production cost benefit for each of the Companies' marginal resources clearly exceeds the costs that would be saved by retiring these units. Consistent with the analysis supporting the Companies' December 2017 DSM filing, the DCP is only marginally favorable. However, given uncertainties moving forward related to load and environmental regulations, and considering physical reliability guidelines, the DCP should be continued at least in the near-term.

The target reserve margin range established in the 2014 IRP Reserve Margin analysis was 16 to 21 percent. In that analysis, the high end of the range (21 percent) was the reserve margin required to meet the 1-in-10 LOLE physical reliability guideline. Based on the Companies' current load forecast, the reserve margin required to meet this guideline is approximately 25 percent.[31] To determine the minimum of the target reserve margin range, the Companies estimated the increase in load that would result in the addition of generation resources. All other things equal, if the Companies' load increases by 300 to 400 MW, the reliability and production cost benefits from adding new SCCT capacity would more than offset the cost of the capacity. With this load increase, the Companies' reserve margin would end up being 16 to 18 percent. Therefore, based on reliability guidelines and the cost of new capacity, the Companies will target a reserve margin range of 17 to 25 percent for resource planning.

Long-Term Resource Plan

The Companies developed resource plans over a number of energy requirements and generating unit operating life scenarios. Table 5-14 summarizes the Companies' need for new or replacement capacity in these scenarios. The ranges of capacity needs are computed based on the 17 to 25 percent target reserve margin range. As discussed previously, 2,428 MW of existing capacity is assumed to be retired by 2033 in the 55-year life scenario; only 49 MW is assumed to be retired in the 65-year life scenario (see Table 5-4). For each of the scenarios in Table 5-14, the Companies utilized the most competitive resources in Table 5-12 from the Resource Screening Analysis to develop resource plans over six natural gas and CO_2 price scenarios.

[31] The increase from 21 percent to 25 percent is driven primarily by an increase in the assumed variability of winter peak demands. The reserve margin analysis for the 2014 IRP was completed in 2013 and did not consider the possibility of the winter peak demands exceeding 7,000 MW (as experienced in 2014 and 2015).

Table 5-14: New or Replacement Capacity Needs (MW)

Year	55-Year Operating Life			65-Year Operating Life		
	Base Load	High Load	Low Load	Base Load	High Load	Low Load
2019	0	0	0	0	0	0
2020	0	0	0	0	0	0
2021	0	0	0	0	0	0
2022	0	0	0	0	0	0
2023	0	0	0	0	0	0
2024	0	0	0	0	0	0
2025	0	0	0	0	0	0
2026	50 - 550	350 - 850	0	0	0	0
2027	350 - 900	650 - 1,200	0	0	0	0
2028	350 - 900	750 - 1,250	0	0	0	0
2029	1,150 - 1,650	1,550 - 2,100	450 - 950	0	0	0
2030	1,150 - 1,650	1,600 - 2,150	400 - 900	0	50 - 600	0
2031	1,150 - 1,650	1,650 - 2,200	300 - 750	0	100 - 650	0
2032	1,600 - 2,100	2,150 - 2,700	650 - 1,100	0	150 - 700	0
2033	2,000 - 2,500	2,600 - 3,150	950 - 1,400	0	200 - 750	0

Table 5-15 lists the least-cost resource plans from this analysis. Each plan was developed in consideration of the need to reliably serve customers in the summer and winter months and considers, for example, the availability of renewable resources under summer and winter peak load conditions. In developing these resource plans, the Companies evaluated whether – in the near-term – existing resources should be replaced with a combination of battery storage and renewables and determined that this is not least-cost.

Table 5-15: Long-Term Resource Plans

Generating Unit Life	Load Scenario	Gas Price	Zero CO_2 Price	High CO_2 Price
55-Year	Base	Base	5 1x1 NGCCs, 300 MW Solar	5 1x1 NGCCs, 400 MW Solar
		High	5 1x1 NGCCs, 300 MW Solar	5 1x1 NGCCs, 500 MW Solar
		Low	5 1x1 NGCCs, 300 MW Solar	5 1x1 NGCCs, 300 MW Solar
	High	Base	7 1x1 NGCCs, 100 MW Solar	7 1x1 NGCCs, 100 MW Solar
		High	7 1x1 NGCCs, 100 MW Solar	7 1x1 NGCCs, 500 MW Solar
		Low	7 1x1 NGCCs, 100 MW Solar	7 1x1 NGCCs, 200 MW Solar
	Low	Base	4 1x1 NGCCs	4 1x1 NGCCs, 300 MW Solar
		High	4 1x1 NGCCs	4 1x1 NGCCs, 500 MW Solar
		Low	4 1x1 NGCCs	4 1x1 NGCCs
65-Year	Base	Base	No additional changes	No additional changes
		High	No additional changes	No additional changes
		Low	No additional changes	No additional changes
	High	Base	1 1x1 NGCC, 100 MW Batteries	2 1x1 NGCC, 400 MW Solar
		High	1 1x1 NGCC, 100 MW Batteries	1 1x1 NGCC, 300 MW Solar, 300 MW Wind
		Low	1 1x1 NGCC, 100 MW Batteries	2 1x1 NGCC, 400 MW Solar
	Low	Base	Retire Small-Frame SCCTs, DCP, Brown 3 or Brown 11N2 SCCTs	Retire Small-Frame SCCTs, DCP, Brown 3 or Brown 11N2 SCCTs
		High	Retire Small-Frame SCCTs, DCP, Brown 3 or Brown 11N2 SCCTs	Retire Small-Frame SCCTs, DCP, Brown 3 or Brown 11N2 SCCTs
		Low	Retire Small-Frame SCCTs, DCP, Brown 3 or Brown 11N2 SCCTs	Retire Small-Frame SCCTs, DCP, Brown 3 or Brown 11N2 SCCTs

In both operating life scenarios, NGCC capacity consistently appears as the least-cost source of replacement capacity in the longer-term, even in the high gas price and high CO_2 price scenarios. An NGCC resource provides better availability year-round than renewable resources, and is a cheaper source of energy than an SCCT resource. The Companies' small-frame SCCTs, Demand Conservation Program, and Brown 3 are assumed to be retired in the 65-year operating life scenario with low load because the Companies' reserve margin would otherwise be well above 25 percent.

The optimal expansion plans in the 55-year generating unit life scenario contain up to 500 MW of solar generation, as excess winter capacity from modeled NGCC units provides an opportunity for incremental volumes of solar generation to shore up summer reserve margin needs without compromising winter reliability. Wind generation is optimal only in the 65-year generating unit life scenario with high energy requirements, high gas prices, and high CO_2 prices. However, depending on actual energy requirements at the end of the planning period and the relative costs of renewables and battery storage versus NGCC or SCCT capacity, optimal expansion plans could include small amounts of solar generation, wind generation, or battery storage as a means to fill gaps where an incremental NGCC or SCCT unit may exceed the Companies' needs. For example, the optimal expansion plans in the 65-year operating life scenario with high energy requirements and no CO_2 prices contain 100 MW of battery storage because battery storage can be deployed in smaller capacity increments relative to the alternative of SCCT capacity.

CO_2 prices do not reduce the optimal quantities of NGCC capacity. While this may seem counterintuitive, NGCCs are the most competitive source of baseload and intermediate capacity and would be displacing a significant amount of coal-fired generation (with roughly 2.5 times the CO_2 output). CO_2 prices also weaken the overall value of battery storage, as the energy arbitrage value from off-peak coal-fired generation is eroded.

The economics of meeting load exclusively with renewable assets (wind and solar), coupled with SCCTs and batteries for peaking needs, is not cost effective. In the absence of significantly lower than forecasted costs of renewables and battery storage or significantly higher natural gas or CO_2 prices, NGCC capacity is forecasted to be the primary source of replacement capacity as coal resources are retired.

The Companies continually evaluate their resource needs. This study represents a snapshot of this ongoing resource planning process using current business assumptions and assessment of risks. Because the planning process is constantly evolving, the Companies' least-cost expansion plan may be revised as conditions change and as new information becomes available. Even though the resource assessment represents the Companies' analysis of the best options to meet customer needs at this given point in time, this plan is reviewed, re-evaluated, and assessed against other market available alternatives prior to commitment and implementation.

The Companies identify transmission construction projects and upgrades required for maintaining the adequacy of its transmission system for meeting projected customer demands. The construction projects currently identified are included in Volume III ("Transmission Information").

5.(5) Steps to be Taken During Next Three Years to Implement Plan

Aside from the planned retirements of Brown 1, Brown 2, and Zorn 1, no changes or additions to the Companies' generation resources are planned for the next three years. The Companies will continue to monitor developments in renewable technology and battery storage as well as key issues impacting the way customers use electricity (e.g., electric heating penetration, energy efficiency trends, electric vehicle adoption, distributed solar penetration). In addition, the Companies will continue to monitor developments related to environmental regulations, in particular NAAQS for ozone and the ACE. Any new information from this research will be incorporated in the Companies' annual planning process.

5.(6) Key Issues that Could Affect Plan Implementation

Changes to the Companies' resource plan would most likely result from significant decreases to the Companies' load or changes to environmental regulations. In the near-term, significant load increases may not create the need for additional resources but a significant load decrease may lower the reliability and production cost benefit of marginal resources such that their continued operation is not warranted. As discussed in Section 5.(2), changes to NAAQS for ozone may require the Companies to take actions in the next three to seven years. The Companies will consider any new information in their annual planning process and update their resource plan as needed to ensure that they can continue to reliably meet their customers' around-the-clock energy needs at the lowest reasonable cost.

6 Significant Changes

The Companies amended their 2014 IRP in October 2014 to reflect the planned municipal customers' departure by April 2019. The following sections summarize significant changes since October 2014.

Recent Sales Trends

As mentioned previously, energy requirements in the LG&E and KU service territories have been mostly flat over the past five years. Increased consumption from the addition of new customers has been offset by mining sector declines, industrial customer losses, industrial production efficiency improvements, and efficiency improvements in residential and commercial end-uses. In addition, the penetration of electric heating has increased among residential customers and residential customer growth has been concentrated in urban areas where homes are on average smaller and are less electricity intensive than those in rural areas. Each of these items is discussed further in the following sections.

Mining Declines

Sales to the mining sector have continued to decline since the last IRP. Between 2011 and 2014, Kentucky coal output declined by 29 million tons (27 percent). In the subsequent three years, Kentucky coal production declined by an additional 35 million tons (46 percent). The Companies expected a decline over this period due to the retirement of coal units for environmental compliance, but not to this extent.

There are two major reasons for the larger-than-expected decline. First, the Great Recession caused a greater-than-expected decline in demand for energy commodities. Second, natural gas prices have been lower than expected due to advances in hydraulic fracturing technology, which has only become more efficient in recent years. As a result, natural gas greatly increased its share of electric power generation at the expense of coal as shown in Figure 6-1.

Figure 6-1: U.S. Electricity Generation from Selected Fuels[32]

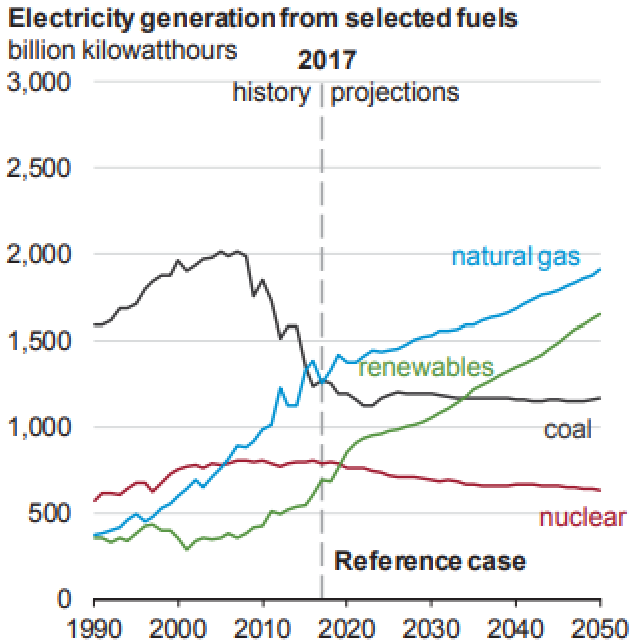
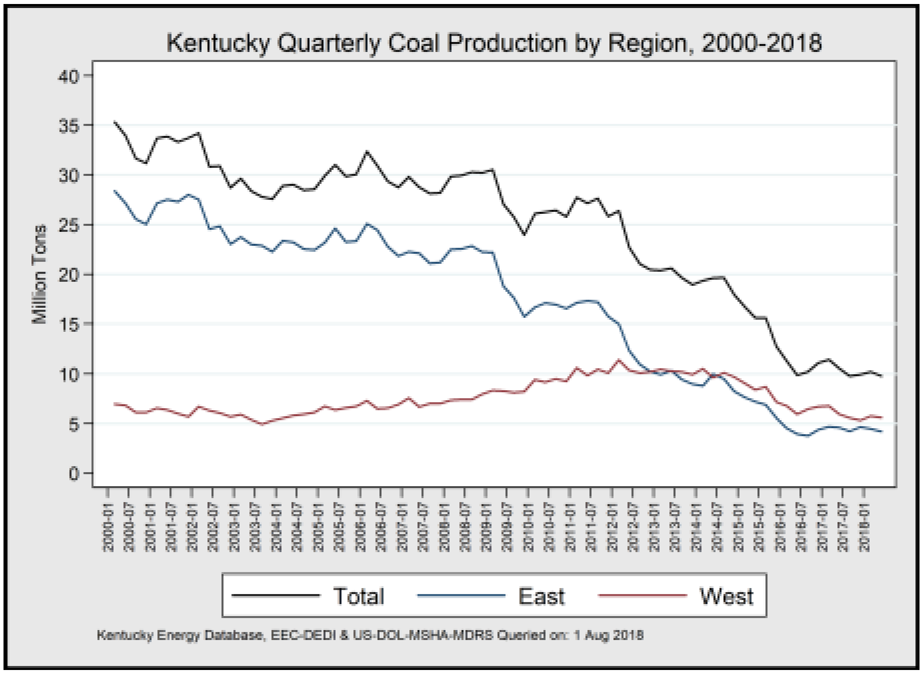


Figure 6-2 shows the decline in Kentucky coal output by region. Much of the narrative surrounding Kentucky coal declines has centered on the eastern portion of the state, where high-energy content coal is mined. Indeed, Appalachia is the area of the country where the majority of the declines have occurred, as many utilities have switched to cheaper, higher-sulfur coal from the Interior and Powder River Basin due to their mandated investments in new scrubber technology. However, the Companies have been impacted most by declines in the western region. KU only serves two major coal-producing counties in eastern Kentucky: Harlan and Bell. Since the 2014 IRP, load from coal-related customers in eastern Kentucky declined 13 GWh. KU's largest coal producers are in western Kentucky in Union, Hopkins, Muhlenberg, and Webster counties. Since the 2014 IRP, load from customers in the western part of the state declined 215 GWh.[33]

[32] Energy Information Agency (EIA)
[33] The majority of this decline was due to mine closures in Hopkins and Union counties.

Figure 6-2: Kentucky Quarterly Coal Production by Region, 2000-2018[34]



While the outlook for coal remains weak, the Companies do not expect sales to the mining sector to continue to decline at the same rate moving forward. This is due to the following reasons:

- The majority of announced coal-fired generating unit retirements have already occurred.
- A significant portion of baseload energy production has shifted from coal-fired to natural gas generation due to coal unit retirements and natural gas prices that have remained low for a prolonged period of time. Moving forward, near-term gas prices are not expected to change materially and the pace of coal retirements is expected to slow.[35] As a result, while natural gas and renewables are anticipated to meet future demands for power generation, coal consumption in the sector is anticipated to decline only slightly moving forward according to the EIA (Figure 6-1 above).
- Coal exports to foreign markets remain a viable option for producers. U.S. steam coal exports increased from 3.5 million short tons to 12.3 million short tons between the third quarter of 2016 and the first quarter of 2018.

Loss of Large Customers

A number of the Companies' large customers have closed since 2014 resulting in a total decline in annual load of 555 GWh compared to 2014. When developing the 2014 IRP, these closure plans were not known by the Companies.[36]

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[34] Kentucky Quarterly Coal Report: April to June 2018

[35] PJM coal capacity retirements in the most recent five years (2014-2018) total just over 20 GW, while announced PJM coal capacity retiring in the next five years (2019-2023) only total just over 3 GW.

[36] All load impacts in the following list are annual impacts.

Industrial Efficiency Gains
Efficiency improvements among industrial customers have increased in recent years. One of the most popular investments has been to replace halide or fluorescent fixtures with LEDs. Further, industrial customers are investing in more efficient manufacturing equipment and adding features such as adjustable-speed drives to large motors. Many customers are also taking a more comprehensive approach to finding energy savings by investing in internal energy teams or external energy managers. Specific examples of approaches to improving energy efficiency from customers in the service territory are as follow:

- Hiring an engineering firm to conduct an air study
- Conducting "treasure hunt" activities to identify areas for energy cost savings
- Implementation of new controls to reduce consumption from energy intensive compressors
- Installation of real-time metering equipment on chillers and air compressors to better manage usage
- Replacement of T-8 fluorescent fixtures (220 watts per fixture) with a similar number of LED fixtures (50 watts per fixture)
- Idling reactors on certain days of the week for "utility optimization"
- Investments to increase power factor

These improvements have offset projected growth from planned expansions and reduced industrial customers' peak demand levels, resulting in a much flatter growth projection in the 2018 IRP as compared to the 2014 IRP.

Residential and Commercial Efficiency Gains
Energy efficiencies in the residential and commercial sectors have continued to improve in recent years. While these improvements were discussed in the 2014 IRP, the pace has been stronger than anticipated for the following reasons:

- Faster adoption of LED Lighting among residential and commercial customers
- Tremendous improvements in cooling efficiencies, leading to a material decline in load during the summer months
- A flattening of load for miscellaneous usage moving forward, particularly in the LG&E portion of the service territory
- Greater efficiency projections in commercial office spaces due to the release of a new EIA benchmarking study

Figure 6-3 demonstrates how projections for residential energy consumption per household (energy intensity) have decreased since the last IRP. The graph uses end-use energy consumption projections from Itron (by way of the EIA) which has been subsequently adjusted for the Companies' service territories. Since absolute levels change, the projection for the major sectors is indexed to 2014.

Figure 6-3: KU Total Household Energy Intensity Projections Indexed to 2014 Levels

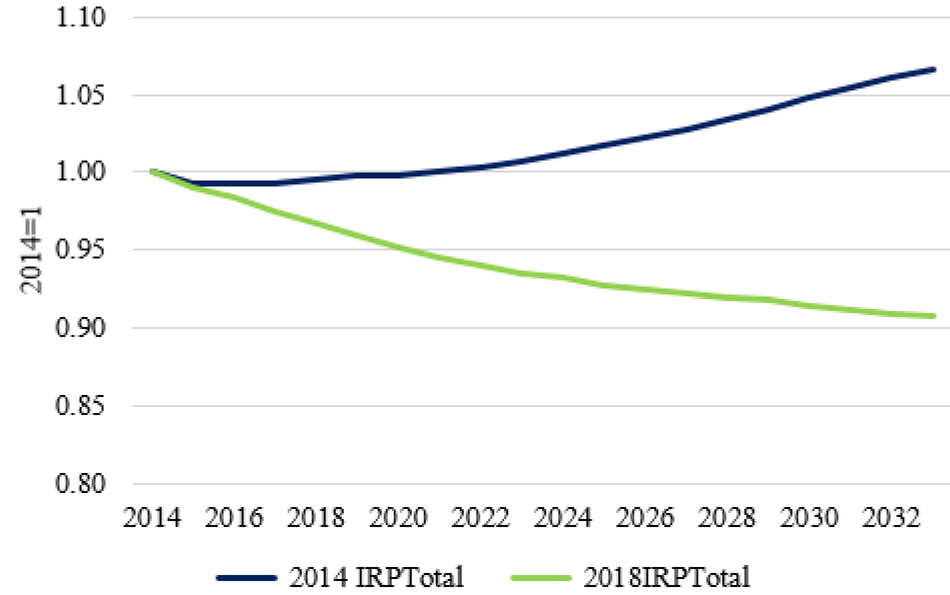


Figure 6-3 shows that residential energy intensity in the KU service territory was projected to remain mostly flat through 2018 in the 2014 IRP, and then increase 6.6 percent by 2033. In the 2018 IRP, this index declined 3.3 percent from 2014 to 2018 and is projected to decrease an additional 6 percent from 2018 to 2033. Figure 6-4 contains a chart of residential energy intensity for the LG&E service territory.

Figure 6-4: LG&E Total Energy Intensity Projections Indexed to 2014

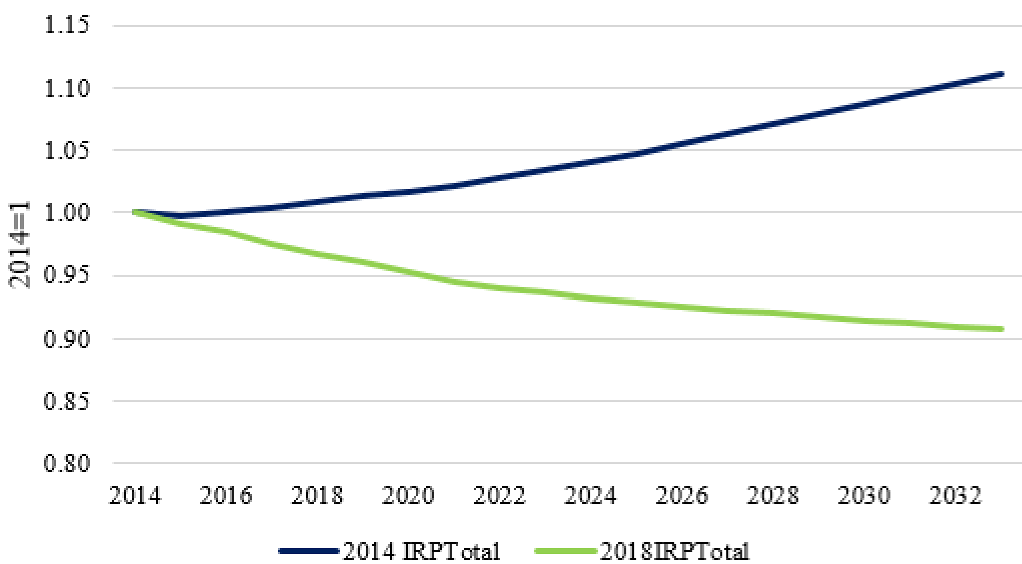


Table 6-1 shows the projected changes in selected end-use intensities from 2014 to 2033. Lighting intensities were projected to fall in the 2014 IRP due to the increased saturation of LEDs. Much of this decline was due to new EIA lighting standards that began in 2012 with a second phase beginning in 2020. However, prices for LEDs have since collapsed, leading to widespread adoption in residential homes at a much more rapid pace than initially projected. As a result, the pace of intensity decline for residential lighting is much higher in the 2018 IRP.

Table 6-1: Projected Changes in End-Use Intensities from 2014 to 2033

	Lighting	Heating	Cooling	Miscellaneous	Total
2014 IRP - KU	-27%	-3%	3%	40%	7%
2018 IRP - KU	-45%	-5%	-12%	0%	-9%
2014 IRP - LG&E	-27%	5%	18%	40%	11%
2018 IRP - LG&E	-45%	-5%	-12%	0%	-9%

Cooling intensities is another area where projected intensities have changed significantly. Cooling intensities were projected to increase in the 2014 IRP due in part to EIA assumptions regarding the efficiency of residential building shells. In the 2018 IRP, the decline in cooling intensities is driven by assumed efficiency improvements in cooling end-uses.

“Miscellaneous” end-uses include all other end-uses and is the largest end-use sector. For the 2014 IRP, Itron was projecting electricity consumption by miscellaneous end-uses to increase by 40 percent from 2014 to 2033. However, much of this growth has not materialized and consistent with the last several years, miscellaneous consumption is forecast to remain flat through 2033 in the 2018 IRP.

Like residential sales, commercial sales since 2014 have also been lower than forecast due to higher-than-expected efficiency improvements. The Companies use end-use efficiency indices, both historical and projected, from EIA’s Annual Energy Outlook (“AEO”). The EIA’s projections for commercial end-uses by region are based upon the Commercial Buildings Energy Consumption Survey (“CBECS”) that is conducted every 5 to 10 years. The 2016 AEO was based upon the 2003 CBECS, while the 2017 AEO was based on the much more recent 2012 CBECS. Most notably, lighting’s contribution to commercial energy consumption in the 2012 CBECS has decreased significantly with LEDs and CFLs taking the place of incandescent bulbs. For the commercial sector nationally, lighting’s share of total electricity consumption has decreased from 38% to 17% survey-to-survey (see Figure 6-5).

Figure 6-5: Lighting as a Percent of U.S. Commercial Electricity Usage[37]

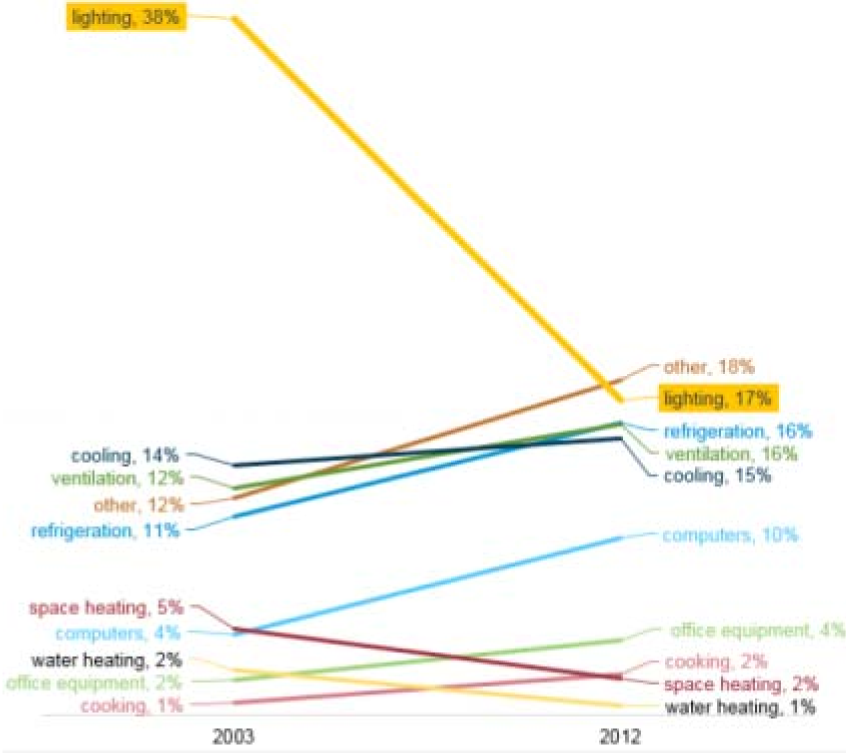


Table 6-2 compares the 2014 IRP and 2018 IRP intensity projections for the major commercial end-uses. All projections are lower in the 2018 IRP as compared to the 2014 Amended IRP.

Table 6-2: Change in Commercial Electricity Intensity Projections, 2014-2033

	Lighting	Heating	Cooling	Miscellaneous	Total
2014 IRP	-5%	-13%	-12%	42%	5%
2018 IRP	-24%	-25%	-18%	21%	-5%

Rural-to-Urban Population Movement

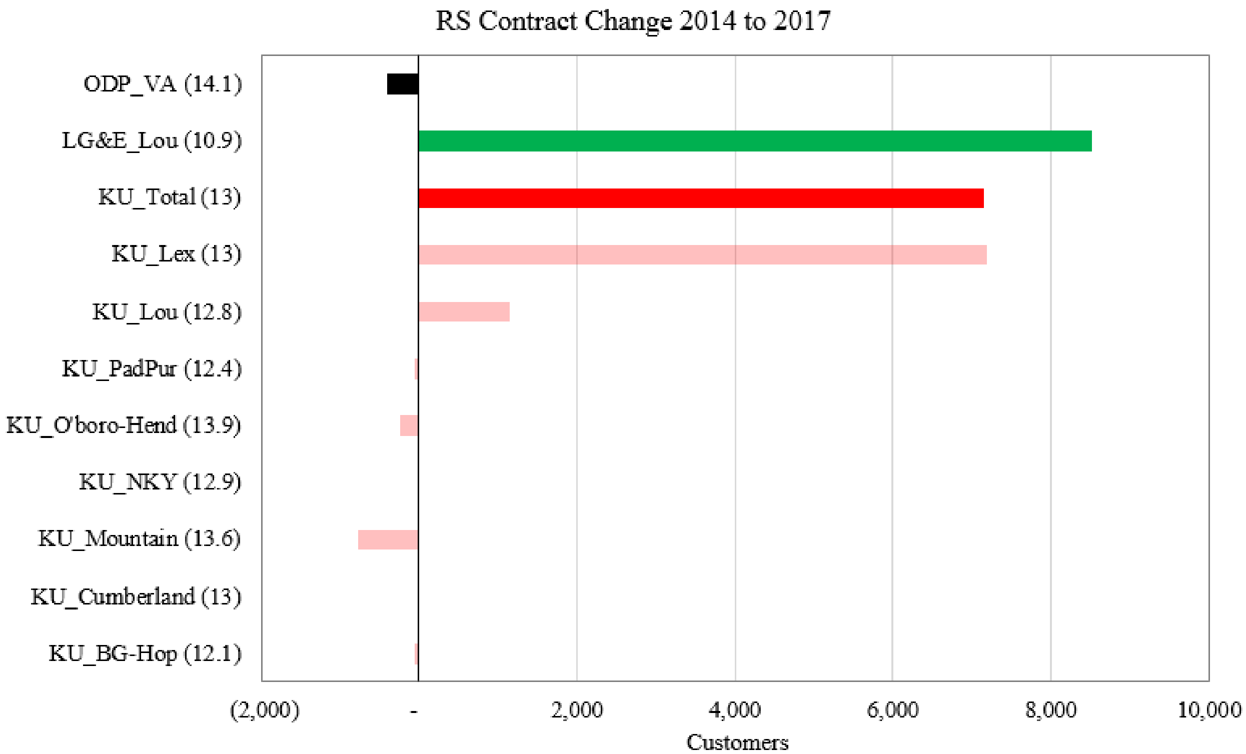
The Company has experienced strong customer growth in recent years. Indeed, 2017 residential customer growth was the strongest since at least 2010. However, the impact on load has not been as large as expected due to the impact of efficiency gains and the concentration of customer growth in urban areas of the service territory. The shift to the urban areas is important for two reasons. First, there is greater access to natural gas for heating load in Louisville and in Lexington as compared to the rural areas of the state, which potentially reduces electricity consumption. Second, even though there has been an uptick in all-electric consumption, many of

[37] Source: EIA

the new premises in these urban areas are multi-family housing units, which typically are smaller and have lower electricity consumption as compared to the average single-family home.

Figure 6-6 shows the change in electric customers between 2014 and 2017 for each economic region of Kentucky. The 2017 use-per-customer for each region is listed in parentheses as well. The largest decline in residential contracts since 2014 occurred in the Mountain region of eastern Kentucky (Bell and Harlan counties) where average use-per-customer is high. This concentration of growth in urban areas is anticipated to continue for the foreseeable future, though total customer growth is anticipated to slow a bit compared to recent years. As a result, the Companies anticipate further declines in residential use-per-customer through 2033.

Figure 6-6: Rural to Urban Population Movement[38]



Increasing Electric Heating Penetration

The percentage of residential customers with electric heating has increased in the LG&E and KU service territories since 2010. Table 6-3 compares the electric heating penetration for customers added in each year since 2010 to the electric heating penetration for all customers added through 2010. In the KU service territory, 53 percent of all residential customers added through 2010 have electric heating, but close to 70 percent of new customers added since 2010 have electric heating. This increase is even more pronounced in the LG&E service territory. Almost 50 percent of customers added in 2015 and 2016 have electric heating whereas only 22 percent of customers added through 2010 have electric heating.

[38] 2017 use-per-customer figure is displayed beside each economic region on the y-axis

Table 6-3: KU and LG&E Electric Heating Penetration

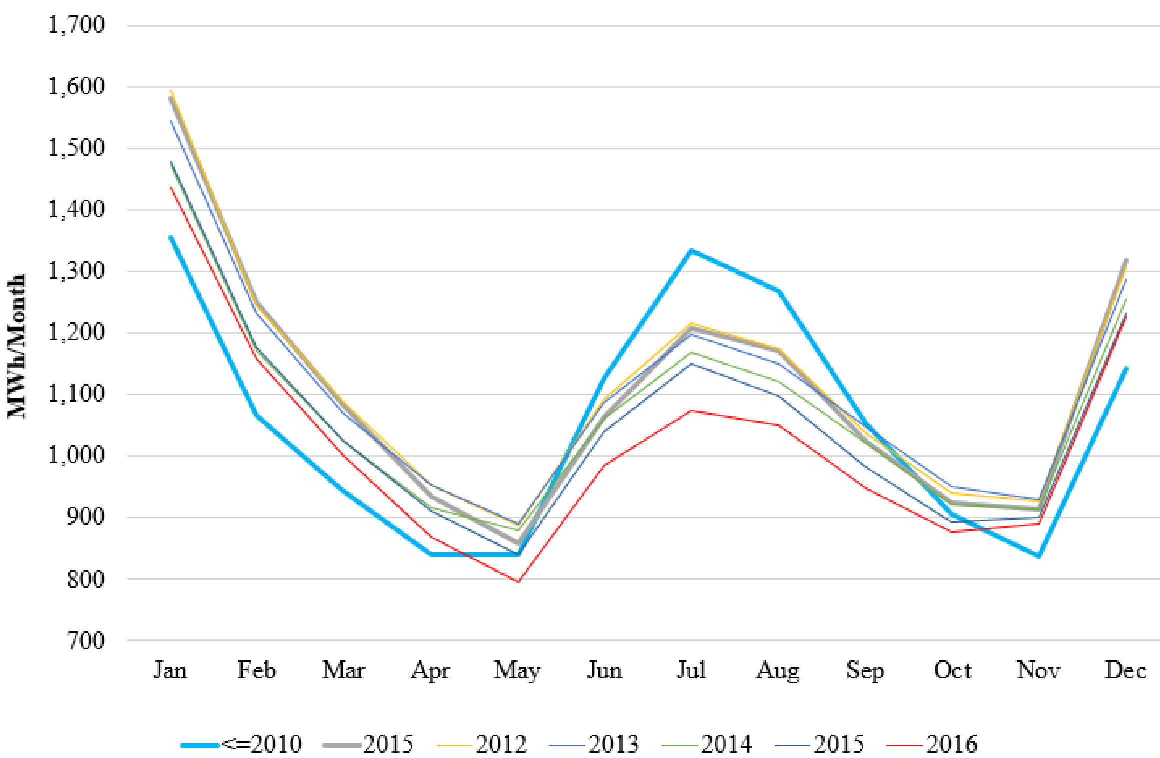
	KU			LG&E		
	Electric Heating Penetration	Avg 2017 Billed kWh	Customers	Electric Heating Penetration	Avg 2017 Billed kWh	Customers
<=2010*	53%	13,195	394,837	22%	11,119	334,978
2011	71%	13,418	4,028	35%	11,416	2,444
2012	69%	13,036	3,904	38%	12,704	2,102
2013	69%	12,797	4,014	42%	12,470	2,523
2014	67%	12,908	3,444	46%	11,210	3,258
2015	68%	12,387	3,485	49%	11,138	3,310
2016	68%	11,266	4,144	49%	10,610	3,198

* <=2010 existing stock; 2011-2016 new premises

Table 6-3 also contains each customer group's average electricity consumption in 2017. All other things equal, customer groups with a higher electric heating penetration would be expected to consume more electricity, but this has not been the case for customers added in recent years. For example, despite a higher electric heating penetration, the average consumption for customers added in 2016 is lower than that for customers added through 2010. This result reflects the previously mentioned gains in lighting and cooling end-use efficiencies as well as the fact that recent customer growth has been concentrated in urban areas where homes are smaller on average than in rural areas.

Figure 6-7 compares the monthly use-per-customer in 2017 for these customer groups. Compared to customers added through 2010, newer customers have significantly lower usage in the summer months due to more efficient cooling end-uses and slightly higher usage in the winter months due to higher electric heating penetrations.

Figure 6-7: Monthly Use-Per-Customer by Estimated Housing Vintage



Load Forecast

Combined Company

The changes to the 2018 IRP forecast compared to the 2014 Amended IRP are significant. The major reasons, as mentioned above, pertain to significant and unexpected improvements in end-use efficiencies and the loss of significant load from major industrial manufacturers and coal mines. Table 6-4 compares the Amended 2014 IRP and 2018 IRP energy requirements forecasts for the combined companies. Both forecasts reflect the April 2019 departure of municipal customers. Beginning in 2020, total energy requirements in the 2018 IRP forecast are nearly 3,000 GWh lower and grow at a slower rate (0.0 percent versus 0.7 percent).

Table 6-4: Energy Requirements Forecast (GWh)

Year	2018 IRP	Amended 2014 IRP	Change
2018	34,185	36,602	(2,417)
2019	33,094	35,871	(2,778)
2020	32,609	35,607	(2,997)
2021	32,506	35,813	(3,307)
2022	32,472	36,026	(3,553)
2023	32,460	36,231	(3,771)
2024	32,535	36,532	(3,997)
2025	32,502	36,762	(4,260)
2026	32,507	37,002	(4,496)
2027	32,511	37,249	(4,737)
2028	32,550	37,525	(4,974)
2029	32,503	37,776	(5,272)
2030	32,477	38,061	(5,584)
2031	32,486	38,291	(5,805)
2032	32,521	38,518	(5,998)
2033	32,486	38,777	(6,292)
2018-2023 Average	-1.0%	-0.2%	
2020-2033 Average	0.0%	0.7%	

Table 6-5 compares the Amended 2014 IRP and 2018 IRP peak demand forecasts for the combined companies. In the 2018 IRP, summer peak demand is 627 MW lower in 2020 and 1,357 MW lower in 2033. Due to the increasing penetration of electric heating, winter peak demands in the 2018 IRP grow at a faster rate than summer peak demands from 2020-2033.

Table 6-5: Summer and Winter Peak Demand Forecasts (MW)

	Summer			Winter		
Year	2018 IRP	Amended 2014 IRP	Change	2018 IRP	Amended 2014 IRP	Change
2018	6,655	7,183	(528)	6,322	6,126	196
2019	6,360	6,932	(572)	6,220	6,178	42
2020	6,361	6,988	(627)	5,972	5,931	41
2021	6,350	7,045	(695)	5,975	6,009	(34)
2022	6,338	7,102	(764)	5,970	6,027	(57)
2023	6,337	7,154	(817)	5,967	6,057	(90)
2024	6,325	7,207	(882)	5,973	6,084	(111)
2025	6,330	7,260	(930)	5,991	6,120	(129)
2026	6,344	7,312	(968)	6,013	6,176	(163)
2027	6,351	7,366	(1,015)	6,028	6,243	(215)
2028	6,352	7,421	(1,069)	6,048	6,271	(223)
2029	6,357	7,476	(1,119)	6,068	6,287	(219)
2030	6,355	7,531	(1,176)	6,084	6,332	(248)
2031	6,353	7,586	(1,233)	6,101	6,368	(267)
2032	6,343	7,641	(1,298)	6,114	6,421	(307)
2033	6,339	7,696	(1,357)	6,128	6,473	(345)
2018-2023 Average	-1.0%	-0.1%		-1.1%	-0.2%	
2020-2033 Average	0.0%	0.7%		0.2%	0.7%	

Table 6-6 shows the changes in sales forecasts for KU, LG&E, and the Combined Companies. The majority of the change in the Combined Companies' sales comes from the KU service territory, which has been impacted most by industrial losses and the decline in rural customers. Sales in both service territories are flat to declining as efficiency gains are expected to offset the impact of growing customers.

Table 6-6: Energy Sales Forecast (GWh)

	KU			LG&E			Combined Companies		
Year	**2018 IRP**	**Amended 2014 IRP**	**Change**	**2018 IRP**	**Amended 2014 IRP**	**Change**	**2018 IRP**	**Amended 2014 IRP**	**Change**
2018	19,745	21,348	-1,603	11,650	12,253	-603	31,395	33,602	-2,207
2019	18,741	20,555	-1,814	11,643	12,351	-708	30,384	32,906	-2,522
2020	18,290	20,218	-1,928	11,652	12,435	-783	29,942	32,654	-2,712
2021	18,224	20,338	-2,114	11,635	12,513	-878	29,859	32,851	-2,992
2022	18,195	20,446	-2,251	11,638	12,596	-958	29,833	33,042	-3,209
2023	18,181	20,549	-2,368	11,647	12,682	-1,035	29,828	33,231	-3,403
2024	18,218	20,710	-2,492	11,672	12,795	-1,123	29,890	33,505	-3,615
2025	18,195	20,836	-2,641	11,670	12,886	-1,216	29,865	33,722	-3,857
2026	18,197	20,965	-2,768	11,683	12,977	-1,294	29,880	33,942	-4,062
2027	18,198	21,095	-2,897	11,693	13,081	-1,388	29,891	34,176	-4,285
2028	18,221	21,225	-3,004	11,717	13,201	-1,484	29,938	34,426	-4,488
2029	18,199	21,352	-3,153	11,714	13,310	-1,596	29,913	34,662	-4,749
2030	18,192	21,494	-3,302	11,715	13,429	-1,714	29,907	34,923	-5,016
2031	18,193	21,602	-3,409	11,727	13,535	-1,808	29,920	35,137	-5,217
2032	18,209	21,715	-3,506	11,746	13,634	-1,888	29,955	35,349	-5,394
2033	18,189	21,840	-3,651	11,741	13,744	-2,003	29,930	35,584	-5,654
2018-2023 Average	-1.6%	-0.8%		0.0%	0.7%		-1.0%	-0.2%	
2020-2033 Average	0.0%	0.6%		0.1%	0.8%		0.0%	0.7%	

Residential

Table 6-7 shows the decline in the residential sales forecast from the Amended 2014 IRP to the 2018 IRP. The residential class accounts for 37 percent of the decline in Combined Company sales in 2018 and 51 percent by 2033. Residential sales are forecast as the product of a use-per-customer forecast and a customer forecast. In the KU service territory, forecasted use-per-customer is lower in the 2018 IRP due to end-use efficiencies, which are forecast to improve at a faster rate than in the Amended 2014 IRP. Customer counts are also much lower due to the population declines in the rural areas of the service territory. The residential customer count is 1.8 percent lower in 2018 and 3.1 percent lower in 2033.

Table 6-7: Residential Sales Forecasts

	KU			LG&E			Combined Company		
Year	2018 IRP	2014 IRP	Change	2018 IRP	2014 IRP	Change	2018 IRP	2014 IRP	Change
2018	6,021	6,514	-493	4,096	4,418	-322	10,117	10,932	-815
2019	5,977	6,598	-621	4,075	4,492	-417	10,052	11,090	-1,038
2020	5,974	6,657	-683	4,081	4,551	-470	10,055	11,208	-1,153
2021	5,937	6,721	-784	4,067	4,613	-546	10,004	11,333	-1,329
2022	5,917	6,788	-871	4,069	4,675	-606	9,986	11,463	-1,477
2023	5,908	6,842	-934	4,077	4,732	-655	9,985	11,573	-1,588
2024	5,948	6,931	-983	4,097	4,811	-714	10,045	11,742	-1,697
2025	5,934	6,994	-1,060	4,097	4,873	-776	10,031	11,868	-1,837
2026	5,940	7,060	-1,120	4,108	4,938	-830	10,048	11,998	-1,950
2027	5,945	7,125	-1,180	4,118	5,008	-890	10,063	12,132	-2,069
2028	5,967	7,205	-1,238	4,138	5,092	-954	10,105	12,297	-2,192
2029	5,956	7,273	-1,317	4,136	5,162	-1,026	10,092	12,435	-2,343
2030	5,955	7,362	-1,407	4,138	5,248	-1,110	10,093	12,611	-2,518
2031	5,960	7,418	-1,458	4,150	5,323	-1,173	10,110	12,740	-2,630
2032	5,980	7,481	-1,501	4,169	5,392	-1,223	10,149	12,873	-2,724
2033	5,969	7,559	-1,590	4,168	5,473	-1,305	10,137	13,033	-2,896
2018-2023 Average	-0.4%	1.0%		-0.1%	1.4%		-0.3%	1.1%	
2020-2033 Average	0.0%	1.0%		0.2%	1.4%		0.0%	1.2%	

The 2018 IRP residential sales forecast is also lower in the LG&E service territory. Louisville continues to add significant multi-family apartment complexes, which typically comprise smaller energy footprints than stand-alone single-family homes. This and improving end-use efficiencies contribute to a lower use-per-customer forecast. However, this use-per-customer impact is partially offset by a faster-growing customer forecast. LG&E customers are 0.5 percent lower in 2018 as compared to the 2014 Amended IRP but are actually 2.1 percent higher in 2033.

Commercial

Table 6-8 below shows the change in the Companies' Commercial sales forecast between the 2018 IRP and the 2014 Amended IRP. Commercial sales is one major sector where there is divergence between the Companies. KU forecasts have moved from 0.7 percent growth in the 2014 Amended IRP to a 0.2 percent decline between 2020 and 2033. This is largely due to efficiency gains in the small commercial space as well as with the primary service rates. LG&E, on the other hand, is actually higher in the 2018 IRP as compared to the prior iteration. Overall, the commercial sector load forecast remains lower than in the 2014 IRP, contributing 10 percent of the total decline in 2018 and 15 percent in 2033.

Table 6-8: Commercial Sales Forecast

	KU			LG&E			Combined Company		
Year	2018 IRP	2014 IRP	Change	2018 IRP	2014 IRP	Change	2018 IRP	2014 IRP	Change
2018	3,789	4,173	-384	3,861	3,706	155	7,650	7,879	-229
2019	3,823	4,201	-378	3,903	3,711	192	7,726	7,912	-186
2020	3,811	4,230	-419	3,903	3,718	185	7,714	7,948	-234
2021	3,801	4,250	-449	3,901	3,720	181	7,702	7,970	-268
2022	3,793	4,269	-476	3,902	3,724	178	7,695	7,993	-298
2023	3,786	4,292	-506	3,902	3,729	173	7,688	8,020	-332
2024	3,781	4,326	-545	3,904	3,738	166	7,685	8,063	-378
2025	3,771	4,355	-584	3,900	3,744	156	7,671	8,100	-429
2026	3,763	4,384	-621	3,898	3,749	149	7,661	8,133	-472
2027	3,756	4,417	-661	3,897	3,756	141	7,653	8,173	-520
2028	3,752	4,449	-697	3,899	3,763	136	7,651	8,212	-561
2029	3,741	4,490	-749	3,895	3,774	121	7,636	8,264	-628
2030	3,732	4,524	-792	3,892	3,782	110	7,624	8,306	-682
2031	3,724	4,557	-833	3,890	3,791	99	7,614	8,348	-734
2032	3,718	4,588	-870	3,889	3,799	90	7,607	8,387	-780
2033	3,707	4,618	-911	3,884	3,804	80	7,591	8,422	-831
2018-2023 Average	0.0%	0.6%		0.2%	0.1%		0.1%	0.4%	
2020-2033 Average	-0.2%	0.7%		0.0%	0.2%		-0.1%	0.4%	

Industrial

Table 6-9 below shows the change in the Companies' industrial sales forecast between the 2018 IRP and the Amended 2014 IRP. In the 2018 IRP, total industrial sales are more than 1,000 GWh lower in 2018 due to the aforementioned loss of industrial manufacturing and mining customers over the past four years. Industrial sales are projected to grow during the planning period, but at a slower rate compared to the 2014 Amended IRP. In the 2018 IRP, KU industrial sales grow by 0.0 percent on a compound average growth basis while LG&E is only 0.2 percent higher. This compares to growth rates of 0.4 percent and 0.6 percent, at KU and LG&E respectively. The increase in energy-efficiency investments is the main reason this rate has declined, as these improvements are offsetting load from planned expansions.

Table 6-9: Industrial Sales Forecast

	KU			LG&E			Combined Company		
Year	2018 IRP	2014 IRP	Change	2018 IRP	2014 IRP	Change	2018 IRP	2014 IRP	Change
2018	6,490	7,112	-622	2,605	2,995	-390	9,095	10,108	-1,013
2019	6,576	7,162	-586	2,622	3,012	-390	9,198	10,175	-977
2020	6,592	7,206	-614	2,624	3,029	-405	9,216	10,236	-1,020
2021	6,578	7,234	-656	2,624	3,043	-419	9,202	10,278	-1,076
2022	6,578	7,250	-672	2,624	3,059	-435	9,202	10,309	-1,107
2023	6,580	7,266	-686	2,626	3,081	-455	9,206	10,347	-1,141
2024	6,581	7,289	-708	2,628	3,105	-477	9,209	10,394	-1,185
2025	6,582	7,308	-726	2,630	3,126	-496	9,212	10,434	-1,222
2026	6,584	7,329	-745	2,633	3,146	-513	9,217	10,475	-1,258
2027	6,586	7,349	-763	2,635	3,171	-536	9,221	10,519	-1,298
2028	6,589	7,355	-766	2,637	3,197	-560	9,226	10,553	-1,327
2029	6,589	7,361	-772	2,639	3,223	-584	9,228	10,584	-1,356
2030	6,590	7,368	-778	2,641	3,246	-605	9,231	10,614	-1,383
2031	6,592	7,376	-784	2,643	3,268	-625	9,235	10,643	-1,408
2032	6,593	7,383	-790	2,644	3,286	-642	9,237	10,670	-1,433
2033	6,594	7,390	-796	2,645	3,309	-664	9,239	10,699	-1,460
2018-2023 Average	0.3%	0.4%		0.2%	0.6%		0.2%	0.5%	
2020-2033 Average	0.0%	0.3%		0.1%	0.7%		0.1%	0.4%	

Supply-Side and Demand-Side Resources

The Companies have made several significant changes to their supply-side and demand-side resources since the Amended 2014 IRP was filed in October 2014. To comply with the EPA's Clean Air Transport Rule ("CATR"), National Ambient Air Quality Standards ("NAAQS"), and Mercury and Air Toxics Standards ("MATS"), the Companies retired the Green River and Cane Run coal units (726 MW) in 2015 and added Cane Run 7 (662 MW), the Companies' first NGCC unit. In 2016, as part of the same least-cost environmental compliance plan, the Companies completed the installation of emission controls (e.g., pulse-jet fabric filter systems, dry sorbent injection systems, powdered activated carbon injection systems, etc.) at the Mill Creek, Ghent, Trimble County, and E.W. Brown generating stations.

In June 2016, the Companies commissioned Brown Solar, a 10 MW (AC) solar facility at the E.W. Brown Station. In addition, the Companies completed the rehabilitation of the Ohio Falls hydro units in 2017. This project increased the maximum output of each of the eight Ohio Falls units from 10 MW to 12.6 MW.

As mentioned previously, to reduce costs for customers while maintaining an adequate level of generation reliability, the Companies plan to retire Brown 1 and Brown 2 (272 MW) in February 2019 and Zorn 1 (14 MW) by 2021. In addition, the Companies' capacity purchase and tolling agreement with Bluegrass Generation (165 MW) ends on April 30, 2019.

In October 2018, the Companies received approval from the Kentucky Public Service Commission for all of the proposed programs in their 2019-2025 DSM-EE Program Plan except for the School Energy Management Program ("SEMP"). This plan reflects considerable challenges that changing conditions introduced to the design and delivery of conservation programs. For example, because the Companies are experiencing very low load growth and have no capacity constraints, the 2019-2025 DSM-EE Program Plan uses zero avoided capacity costs, which has a significant impact on program and portfolio cost-effectiveness. In addition, the declining cost of natural gas reduces the avoided energy cost associated with the variable cost of generation, further negatively impacting the cost-effectiveness of energy efficiency measures. As a result, some of the energy efficiency measures offered in past DSM-EE Program Plans are no longer cost-effective; therefore, they have not been included in the 2019-2025 DSM-EE Program Plan. In light of these significant and complex challenges, the Companies proposed a smaller portfolio of program offerings that save energy and meet customers' needs and the Companies' objectives for providing safe and reliable energy in addition to customer service.

In addition, the 2019-2025 DSM-EE Program Plan recognizes changes in the Companies' approach to working with industrial customers by making nonresidential programs available to all commercial and industrial customers. Going forward, industrial customers will be included in the Companies' DSM rate recovery mechanism, and will be eligible for all nonresidential programs offerings, unless they meet the Companies' opt-out criteria and formally follow the Companies' opt-out process.

The Companies have established seven-year electricity savings goals of 214,667 MWh of electric energy savings and 557,143 CCF of gas savings. This Plan also anticipates preserving an average estimated 178.9 MW of coincident peak demand reduction over the seven-year planning horizon. These savings goals are based on rigorous research and analysis and informed by an objective, third-party assessment of potential. The Companies intend to achieve these savings goals by offering incentives on commercially available technologies with the highest cost-effective achievable energy savings potential.

Generation Capacity Needs

Table 6-10 contains a summary of peak energy requirements and resources from the Amended 2014 IRP. When the Companies received termination notices from nine municipal customers in April 2014, they withdrew their then-pending application seeking approval to build Green River 5 (670 MW) and secured 165 MW of short-term capacity through April 2019, the end of the departing municipals' contract term. As seen in Table 6-10, based on the Companies' then-current load projections, these actions were sufficient to address the municipal load departure while maintaining an adequate level of generation reliability. The Companies' forecasted reserve margin in 2019 was 16.4% percent and the next need for generation capacity was as early as 2020.

Table 6-10: Energy Requirements and Resource Summary (MW, Amended 2014 IRP)

	2015	2016	2017	2018	2019	2020	2025	2028
Forecasted Peak Load	7,364	7,450	7,520	7,607	7,337	7,394	7,666	7,826
DSM	(336)	(365)	(394)	(423)	(406)	(406)	(406)	(406)
Net Peak Load	7,028	7,085	7,126	7,183	6,932	6,988	7,260	7,421
Existing Resources[39]	7,152	7,135	7,135	7,135	7,135	7,135	7,135	7,135
Planned/Proposed Resources								
Cane Run 7	640	640	640	640	640	640	640	640
Brown Solar[40]	0	9	9	9	9	9	9	9
Bluegrass Capacity Purchase	165	165	165	165	0	0	0	0
Firm Purchases (OVEC)	155	155	155	155	155	155	155	155
Curtailable Load	131	131	131	131	131	131	131	131
Total Supply	8,243	8,234	8,235	8,235	8,070	8,070	8,070	8,070
Reserve Margin	1,215	1,149	1,109	1,052	1,138	1,082	810	649
Reserve Margin %	17.3%	16.2%	15.6%	14.6%	16.4%	15.5%	11.2%	8.7%

A summary of energy requirements and resources for the 2018 IRP is contained in Table 6-11. Given the changes in retail energy requirements, absent further retirements, the Companies do not have a need for new capacity through the 15-year planning period.

Table 6-11: Energy Requirements and Resource Summary (MW, 2018 IRP)

	2018	2019	2020	2021	2022	2023	2024	2027	2030	2033
Gross Peak Load	7,028	6,703	6,688	6,674	6,657	6,653	6,638	6,655	6,650	6,627
DCP	-127	-96	-91	-87	-84	-80	-77	-67	-59	-52
DSM	-247	-247	-236	-236	-236	-236	-236	-236	-236	-236
Net Peak Load	**6,655**	**6,360**	**6,361**	**6,350**	**6,338**	**6,338**	**6,325**	**6,352**	**6,355**	**6,339**
Existing Capability[41]	7,754	7,476	7,476	7,476	7,477	7,477	7,478	7,478	7,478	7,478
Small-Frame SCCTs	87	87	87	73	73	73	73	73	73	73
CSR	141	141	141	141	141	141	141	141	141	141
Bluegrass	165	0	0	0	0	0	0	0	0	0
OVEC[42]	152	152	152	152	152	152	152	152	152	152
Total Supply	**8,299**	**7,856**	**7,856**	**7,842**	**7,843**	**7,843**	**7,844**	**7,844**	**7,844**	**7,844**
Reserve Margin	1,644	1,495	1,495	1,491	1,505	1,505	1,518	1,492	1,489	1,505
Reserve Margin %	**24.7%**	**23.5%**	**23.5%**	**23.5%**	**23.7%**	**23.7%**	**24.0%**	**23.5%**	**23.4%**	**23.7%**

[39] Existing resources include the retirement of Tyrone 3 in February 2013 and the planned retirement of Green River 3-4 in April 2015 and Cane Run 4-6 in May 2015.
[40] 90% of the capacity of Brown Solar was assumed to be available at the time of peak.
[41] Existing capability is shown excluding small-frame SCCTs, CSR, Bluegrass, and OVEC and including 1 MW derates on each of the E.W. Brown Units 8, 9, and 11, which are planned to be resolved by 2024.
[42] OVEC's capacity reflects the 152 MW that is expected to be available to the Companies at the time of the summer peak, not its rating of 172 MW.

Environmental Regulations

Significant changes to environmental regulations since the 2014 IRP are briefly summarized in the following sections. Section 8.(5).(f) contains a more complete discussion of current environmental regulations.

Clean Water Act - 316(b) - Regulation of Cooling Water Intake Structures

EPA published a final version of the 316(b) regulations on August 15, 2014 and they became effective on October 14, 2014. The regulation addresses both impingement and entrainment impacts for aquatic species. With the retirement of the coal-fired units at Cane Run, Green River and Tyrone, all the remaining generating units, except for Mill Creek Unit 1, meet the impingement standard by utilizing closed-cycle cooling which is one of the listed compliance options. Regarding the entrainment standard, only the combined units of Mill Creek Station will exceed the withdrawal threshold for entrainment, which will require a series of studies to be conducted and a final report submitted to the Kentucky Division of Water. Negotiations with the state agency will then determine appropriate technology strategies needed to obtain compliance with the regulation.

Clean Water Act – Steam Electric Power Generating Effluent Limitation Guidelines

EPA published final Effluent Limitation Guidelines ("ELG") regulations on November 3, 2015, which became effective on January 4, 2016. The revised regulations require major changes to wastewater treatment systems at existing coal-fired plants, especially facilities with wet scrubbers. New discharge limits will be incorporated into each facility's National Pollutant Discharge Elimination System ("NPDES") water discharge permit starting in 2018 but no later than 2023. On September 18, 2017, the EPA published a final rule that postponed certain compliance dates for the ELG regulations until no sooner than November 1, 2020, while EPA reconsiders portions of the regulation. Since the ELG regulations have no impact on Kentucky's recently updated state water quality standards, new physical/chemical treatment systems are currently under construction at each coal-fired station in the fleet. Additional treatment systems may be required in the future based on EPA's revisions to the ELG rule. EPA expects to have a revised ELG rule finalized by December 2019.

Coal Combustion Residuals

EPA issued a new coal combustion residuals ("CCR") regulation on December 19, 2014, with an effective date of October 14, 2015. The new rule makes significant changes in the management and storage practices of CCR managed in ash treatment basins (ash ponds) or special waste landfills.

After several years of review and public comment, EPA chose to regulate CCR as a non-hazardous solid waste under Resource Conservation and Recovery Act Subtitle D. EPA imposed a set of minimum standards all CCR storage units must meet within prescribed timeframes to remain in operation. Unlined CCR storage impoundments (which account for most of the Companies' ponds) must monitor groundwater surrounding CCR impoundments and begin closure of the ponds within 6 months if a statistically significant increase in contaminates is found. Those studies are nearing an end and will likely lead to the eventual closure of all current CCR storage impoundments. EPA is currently reconsidering portions of the CCR rule and published the first round of revisions in the Federal Register on July 18, 2018. Additional revisions to the CCR rule are expected to be implemented by spring 2019.

Clean Air Interstate Rule / Cross-State Air Pollution Rule

As an update to the 2014 IRP, the Clean Air Interstate Rule ("CAIR") was replaced by the Cross-State Air Pollution Rule ("CSAPR"). The Companies successfully implemented NO_x operating targets in 2017 to meet CSAPR Update allowance allocations. The Companies plan to continue to operate and maintain the affected facilities in compliance with the CSAPR Update requirements.

Hazardous Air Pollutant Regulations/Mercury and Air Toxics Standard ("MATS")

Since the 2014 IRP, installation of emission controls (e.g., pulse-jet fabric filter systems, dry sorbent injection systems, powdered activated injection systems, etc.) to meet MATS emission limits has been completed. Continued compliance is managed per MATS defined monitoring, testing, work practices, record keeping and reporting.

National Ambient Air Quality Standards ("NAAQS") - Ozone

On October 26, 2015, the EPA published the 2015 ozone NAAQS at 70 ppb. On September 30, 2016, Kentucky submitted their recommendations for classifications. Kentucky recommended that Boone, Campbell, and Kenton counties be designated as "nonattainment" and that all other counties be designated as "unclassifiable/attainment". In assessing the attainment designations, the EPA included 2016 data. By including the 2016 data, the EPA concluded via the December 20, 2017 120-day letter that Jefferson, Oldham, and Bullitt counties will be classified marginal non-attainment.

The EPA published final non-attainment classification designations on April 30, 2018, which included Boone, Campbell, Kenton, Jefferson, Oldham, and Bullitt counties in Kentucky as marginal non-attainment. Upon publication, marginal non-attainment areas have a three-year deadline to get into attainment. Marginal areas are not required to submit the traditional attainment plan for bringing areas into attainment. States with marginal areas are only required to submit an emissions inventory and emissions statement for those areas. However, states are required to achieve attainment by 2021 and may implement measures in-state to do so. The Companies will continue to follow these ozone NAAQS issues and assess their impacts on operating facilities.

Greenhouse Gases

As an update to the 2014 IRP, the Greenhouse Gas New Source Performance ("GHG NSPS") final rule was published by EPA in the Federal Register on October 23, 2015. On April 4, 2017, the EPA announced that it would be reviewing the GHG NSPS pursuant to a March 2017 Executive Order signed by President Trump with the intent to suspend, revise, or rescind the rule. On August 10, 2017, the U.S. Court of Appeals for the D.C. Circuit issued an order holding all challenges to the GHG NSPS in abeyance "pending further order of the court." Additionally, on October 23, 2015, EPA published a final existing source performance standard—the final Clean Power Plan ("CPP")—in the Federal Register. In response to applications for stay by numerous parties, on February 9, 2016, the Supreme Court granted a stay of the CPP pending judicial review of the rule. The stay will remain in effect pending Supreme Court review if such review is sought. On October 16, 2017, the EPA proposed a repeal of the CPP. On December 28, 2017 the EPA published Advanced Notice of Proposed Rulemaking for a replacement of the CPP.

On August 21, 2018, the EPA proposed the Affordable Clean Energy ("ACE") Rule to replace the 2015 CPP. The proposed ACE rule would establish emission guidelines for states to develop plans to address greenhouse gas ("GHG") emissions from existing fossil fuel-fired power plants. As proposed, ACE defines the best system of emissions reduction for GHG emissions from existing power plants as on-site, heat-rate efficiency improvements. Included in this proposed rulemaking are revisions to the New Source Review permitting program, allowing states the option to adopt an hourly emissions increase test that incentivizes efficiency improvements.

7 Load Forecasts

7.(1) Specification of Historical and Forecasted Information Requirements by Class

The data submissions in the following subsections conform to the specifications provided in Section 7.(1) of Administrative Regulation 807 KAR 5:058 to the fullest extent possible. Energy and demand forecasts reflect the impact of the Companies' DSM programs.

7.(2) Specification of Historical Information Requirements

The data submissions in the following subsections conform to the specifications provided in Section 7.(2) of Administrative Regulation 807 KAR 5:058 to the fullest extent possible. Energy and demand forecasts reflect the impact of the Companies' DSM programs.

7.(2).(a) Average Number of Customers by Class

Table 7-1: KU Average Number of Customers by Class

	2013	2014	2015	2016	2017
Residential	420,223	421,978	423,957	426,230	429,411
Commercial	80,252	80,047	80,162	80,674	81,236
Industrial	2,734	2,926	2,969	2,842	2,662
Public Authority	7,579	7,342	7,423	7,646	7,751
Street Lighting	1,353	1,408	1,446	1,456	1,454
Virginia Retail	28,742	28,526	28,350	28,221	28,122
Req. Sales for Resale	12	12	11	11	10
Total Customers	540,895	542,239	544,318	547,080	550,646

Table 7-2: LG&E Average Number of Customers by Class

	2013	2014	2015	2016	2017
Residential	348,048	350,587	353,419	356,424	359,658
Commercial*	42,065	42,264	42,697	42,914	43,574
Industrial*	426	437	473	580	573
Public Authority	4,124	4,098	4,123	4,154	4,253
Street Lighting	650	656	659	672	680
Total Customers	395,313	398,042	401,371	404,744	408,738

* LG&E's largest commercial customer was classified as an industrial customer until November 2015; therefore, data prior to 2016 reflect the current classification to more easily assess historical trends.

7.(2).(b) Annual Energy Sales & Energy Requirements

Table 7-3: KU Annual Energy Sales & Requirements (GWh)

	2013	2014	2015	2016	2017
SYSTEM BILLED SALES:					
Recorded	21,206	21,631	21,317	20,549	19,897
Weather-Normalized	21,128	21,346	20,923	20,493	20,423
SYSTEM USED SALES:					
Recorded	21,269	21,611	20,902	20,757	19,984
Weather-Normalized	21,262	21,254	20,792	20,603	20,291
ENERGY REQUIREMENTS:					
Recorded	22,602	23,023	22,261	22,073	21,257
Weather-Normalized	22,595	22,642	22,144	21,909	21,584
RECORDED SALES BY CLASS:					
Residential	6,195	6,335	5,995	6,048	5,698
Commercial	3,906	3,883	3,803	3,849	3,778
Industrial	6,843	7,071	6,884	6,635	6,499
Lighting	41	42	42	43	44
Public Authorities	1,542	1,558	1,556	1,571	1,508
Requirement Sales for Resale	1,880	1,886	1,855	1,876	1,755
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KENTUCKY Retail	20,407	20,775	20,135	20,022	19,282
VIRGINIA Retail	862	836	767	735	702
SYSTEM LOSSES	1,311	1,389	1,338	1,294	1,256
Utility Use	22	23	21	22	17
ENERGY REQUIREMENTS	22,602	23,023	22,261	22,073	21,257
WEATHER-NORMALIZED SALES BY CLASS:					
Residential	6,180	6,148	5,963	5,947	5,929
Commercial	3,908	3,797	3,757	3,833	3,809
Industrial	6,844	7,061	6,880	6,635	6,501
Lighting	41	42	42	43	44
Public Authorities	1,543	1,539	1,547	1,569	1,513
Requirement Sales for Resale	1,879	1,846	1,849	1,856	1,788
VIRGINIA Retail	867	822	756	719	708

Table 7-4: LG&E Annual Energy Sales & Requirements (GWh)

	2013	2014	2015	2016	2017
SYSTEM BILLED SALES:					
Recorded	11,682	11,838	11,888	11,919	11,503
Weather-Normalized	11,726	11,748	11,796	11,740	11,669
SYSTEM USED SALES:					
Recorded	11,698	11,817	11,767	11,948	11,527
Weather-Normalized	11,732	11,686	11,722	11,812	11,690
ENERGY REQUIREMENTS:					
Recorded	12,245	12,282	12,329	12,570	12,066
Weather-Normalized	12,279	12,146	12,282	12,426	12,237
RECORDED SALES BY CLASS:					
Residential	4,164	4,157	4,081	4,215	4,004
Commercial*	3,863	3,904	3,905	3,943	3,854
Industrial*	2,522	2,584	2,617	2,640	2,562
Public Authorities	1,131	1,155	1,145	1,131	1,087
Lighting	18	17	19	19	20
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TOTAL LG&E SALES	11,698	11,817	11,767	11,948	11,527
SYSTEM LOSSES	525	439	540	600	518
Utility Use	22	26	22	22	21
ENERGY REQUIREMENTS	12,245	12,282	12,329	12,570	12,066
WEATHER-NORMALIZED SALES BY CLASS:					
Residential	4,190	4,033	4,061	4,082	4,138
Commercial*	3,691	3,711	3,726	3,940	3,873
Industrial*	2,701	2,773	2,774	2,641	2,569
Public Authorities	1,131	1,152	1,142	1,129	1,090
Lighting	18	17	19	19	20

* LG&E's largest commercial customer was classified as an industrial customer until November 2015; therefore, data prior to 2016 reflect the current classification to more easily assess historical trends.

7.(2).(c) Recorded and Weather-Normalized Coincident Peak Demands

Table 7-5: KU Coincident Peak Demands (MW)

	2013	2014	2015	2016	2017
SUMMER					
Actual	3,919	3,870	3,807	3,934	3,914
WN	3,907	4,000	3,954	4,066	4,081
	2012/2013	**2013/2014**	**2014/2015**	**2015/2016**	**2016/2017**
WINTER					
Actual	4,153	5,035	5,112	4,415	4,016
WN	4,137	4,670	4,714	4,435	4,506

Table 7-6: LG&E Coincident Peak Demands (MW)

	2013	2014	2015	2016	2017
SUMMER					
Actual	2,515	2,443	2,585	2,524	2,589
WN	2,573	2,441	2,596	2,566	2,669
	2012/2013	**2013/2014**	**2014/2015**	**2015/2016**	**2016/2017**
WINTER					
Actual	1,754	2,079	1,967	1,808	1,797
WN	1,789	2,042	1,961	1,806	2,015

Table 7-7: Combined Company Coincident Peak Demands (MW)

	2013	2014	2015	2016	2017
SUMMER					
Actual	6,434	6,313	6,392	6,458	6,503
WN	6,480	6,441	6,550	6,632	6,750
	2012/2013	**2013/2014**	**2014/2015**	**2015/2016**	**2016/2017**
WINTER					
Actual	5,907	7,114	7,079	6,223	5,813
WN	5,926	6,712	6,675	6,241	6,521

7.(2).(d) Sales and Demand for Customers with Firm, Contractual Commitments

Table 7-8: KU Energy Sales and Coincident Peak Demand for Firm and Contractual Commitment Customers

	2013	2014	2015	2016	2017
Energy Sales (GWh)	19,749	20,044	19,353	18,925	18,172
Coincident Peak Demand (MW)	3,843	4,922	5,030	3,782	3,747

Table 7-9: LG&E Energy Sales and Coincident Peak Demand for Firm and Contractual Commitment Customers

	2013	2014	2015	2016	2017
Energy Sales (GWh)	11,308	11,384	11,311	11,504	11,004
Coincident Peak Demand (MW)	2,486	2,048	1,915	2,468	2,525

7.(2).(e) Energy Sales and Coincident Peak Demand for Interruptible Customers

Table 7-10: KU Interruptible Customer Energy Sales and Combined Company Coincident Peak

	2013	2014	2015	2016	2017
Energy Sales (GWh)	658	731	782	1,097	1,110
Coincident Peak Demand (MW)	76	113	82	152	167

Table 7-11: LG&E Interruptible Customer Energy Sales and Combined Company Coincident Peak

	2013	2014	2015	2016	2017
Energy Sales (GWh)	390	433	456	444	523
Coincident Peak Demand (MW)	28	31	52	56	64

7.(2).(f) Annual Energy Losses

Table 7-12: KU Annual Energy Losses

	2013	2014	2015	2016	2017
Annual Energy Loss (GWh)	1,311	1,389	1,338	1,294	1,256
Loss Percent of Energy Requirements	6.2%	6.4%	6.4%	6.2%	6.3%

Table 7-13: LG&E Annual Energy Losses

	2013	2014	2015	2016	2017
Annual Energy Loss (GWh)	525	439	540	600	518
Loss Percent of Energy Requirements	4.3%	3.6%	4.4%	4.8%	4.3%

7.(2).(g) Impact of Existing Demand-Side Management Programs

Table 7-14 contains the cumulative impact of DSM programs on both energy and demand. Descriptions of DSM programs are included in Section 8.

Table 7-14: Impact of Existing DSM Programs (cumulative for KU and LG&E)

	2013	2014	2015	2016	2017
Energy Savings (GWh)	671	811	897	994	1,101
Demand Savings (MW)	331	341	382	427	466

7.(2).(h) Other Data Illustrating Historical Changes in Load and Load Characteristics

Actual sales and customer data as reported in tables in Sections 7.(2)(a-f) above are calculated using the Companies' FERC Form 1 filings as the basis for class segmentation. Historical actual calendar (not weather-normalized) average energy use-per-customer by class is shown in Table 7-15 and Table 7-16. Historical percentage share of class sales (not weather-normalized) to total energy sales is presented in Table 7-17 and Table 7-18. Section 6 provides a more detailed discussion of class-level trends.

Table 7-15: KU Average Annual Use-per-Customer by Class (kWh)

	2013	2014	2015	2016	2017
Residential	14,742	15,013	14,141	14,190	13,269
Commercial	48,672	48,509	47,441	47,711	46,506
Industrial	2,502,926	2,416,610	2,318,626	2,334,624	2,441,397
Public Authority	203,457	212,204	209,619	205,467	194,556
Utility Use & Other	30,303	29,830	29,046	29,533	30,261

Table 7-16: LG&E Average Annual Use-per-Customer by Class (kWh)

	2013	2014	2015	2016	2017
Residential	11,964	11,857	11,547	11,826	11,133
Commercial*	92,012	92,372	91,458	91,881	88,447
Industrial*	5,920,188	5,913,043	5,532,770	4,551,724	4,471,204
Public Authority	274,248	281,845	277,710	272,268	255,584
Utility Use & Other	27,692	25,915	28,832	28,274	29,412

* LG&E's largest commercial customer was classified as an industrial customer until November 2015; therefore, data prior to 2016 reflect the current classification to more easily assess historical trends.

Table 7-17: KU Class Percentage of Total Energy Sales

	2013	2014	2015	2016	2017
Residential	30%	29%	29%	29%	28%
Commercial	18%	18%	18%	19%	19%
Industrial	32%	33%	33%	32%	32%
Public Authority	7%	7%	7%	7%	8%
Lighting	0%	0%	0%	0%	0%
Virginia Retail	4%	4%	4%	4%	4%
Req. Sales for Resale	9%	9%	9%	9%	9%
Total Company	100%	100%	100%	100%	100%

Table 7-18: LG&E Class Percentage of Total Energy Sales

	2013	2014	2015	2016	2017
Residential	36%	35%	35%	35%	35%
Commercial	33%	33%	33%	33%	33%
Industrial	21%	22%	22%	22%	22%
Public Authority	10%	10%	10%	10%	10%
Lighting	0%	0%	0%	0%	0%
Total Company	100%	100%	100%	100%	100%

7.(3) Specification of Forecast Information Requirements

The information regarding the energy sales and peak load forecasts in the following subsections conform to the specifications outlined in Section 7.(3) of Administrative Regulation 807 KAR 5:058 to the fullest extent possible.

7.(4) Energy and Demand Forecasts

7.(4).(a) Forecasted Sales by Class and Total Energy Requirements

Table 7-19: KU Forecasted Calendar Sales by Class and Total Energy Requirements after DSM (GWh)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Residential	6,021	5,977	5,974	5,937	5,917	5,908	5,948	5,934	5,940	5,945	5,967	5,956	5,955	5,960	5,980	5,969
Commercial	3,789	3,823	3,811	3,801	3,793	3,786	3,781	3,771	3,763	3,756	3,752	3,741	3,732	3,724	3,718	3,707
Industrial	6,490	6,576	6,592	6,578	6,578	6,580	6,581	6,582	6,584	6,586	6,589	6,589	6,590	6,592	6,593	6,594
Total C & I	10,279	10,399	10,403	10,379	10,371	10,366	10,362	10,353	10,347	10,342	10,341	10,330	10,322	10,316	10,311	10,301
Public Authority	1,559	1,449	1,446	1,440	1,437	1,435	1,434	1,432	1,432	1,431	1,431	1,430	1,430	1,430	1,430	1,429
Lighting	42	42	42	41	40	40	39	38	37	37	36	35	35	34	33	33
Sales for Resale	1,844	874	425	427	430	432	435	438	441	443	446	448	450	453	455	457
Total Kentucky	19,745	18,741	18,290	18,224	18,195	18,181	18,218	18,195	18,197	18,198	18,221	18,199	18,192	18,193	18,209	18,189
Virginia	723	709	698	685	678	675	676	670	666	662	660	656	653	650	648	645
Total KU Sales	20,468	19,450	18,988	18,909	18,873	18,856	18,894	18,865	18,863	18,860	18,881	18,855	18,845	18,843	18,857	18,834
Losses	1,347	1,281	1,249	1,244	1,243	1,238	1,249	1,248	1,244	1,242	1,239	1,231	1,221	1,220	1,221	1,218
Total Requirements	21,815	20,731	20,237	20,153	20,116	20,094	20,143	20,113	20,107	20,102	20,120	20,086	20,066	20,063	20,078	20,052

Table 7-20: LG&E Forecasted Calendar Sales by Class and Total Energy Requirements after DSM (GWh)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Residential	4,096	4,075	4,081	4,067	4,069	4,077	4,097	4,097	4,108	4,118	4,138	4,136	4,138	4,150	4,169	4,168
Commercial	3,861	3,903	3,903	3,901	3,902	3,902	3,904	3,900	3,898	3,897	3,899	3,895	3,892	3,890	3,889	3,884
Industrial	2,605	2,622	2,624	2,624	2,624	2,626	2,628	2,630	2,633	2,635	2,637	2,639	2,641	2,643	2,644	2,645
Public Authority	1,069	1,024	1,025	1,024	1,024	1,024	1,025	1,025	1,026	1,026	1,026	1,027	1,027	1,028	1,028	1,028
Lighting	19	19	19	19	19	18	18	18	18	17	17	17	17	16	16	16
Total LG&E Sales	11,650	11,643	11,652	11,635	11,638	11,647	11,672	11,670	11,683	11,693	11,717	11,714	11,715	11,727	11,746	11,741
Losses	720	720	720	718	719	719	720	719	717	716	713	703	696	696	697	694
Total Requirements	12,370	12,363	12,372	12,353	12,357	12,366	12,392	12,389	12,400	12,409	12,430	12,417	12,411	12,423	12,443	12,435

7.(4).(b) Summer and Winter Peak Demand

Table 7-21: KU Summer and Winter Coincident Peak Demand after DSM (MW)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Summer	3,981	3,680	3,679	3,676	3,687	3,655	3,648	3,649	3,655	3,665	3,656	3,659	3,655	3,655	3,637	3,675
	17/18	**18/19**	**19/20**	**20/21**	**21/22**	**22/23**	**23/24**	**24/25**	**25/26**	**26/27**	**27/28**	**28/29**	**29/30**	**30/31**	**31/32**	**32/33**
Winter	4,496	4,440	4,208	4,185	4,166	4,176	4,176	4,229	4,208	4,222	4,223	4,236	4,260	4,299	4,271	4,273

Table 7-22: LG&E Summer and Winter Coincident Peak Demand after DSM (MW)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Summer	2,674	2,680	2,682	2,674	2,651	2,682	2,677	2,681	2,689	2,686	2,696	2,698	2,700	2,698	2,706	2,664
	17/18	**18/19**	**19/20**	**20/21**	**21/22**	**22/23**	**23/24**	**24/25**	**25/26**	**26/27**	**27/28**	**28/29**	**29/30**	**30/31**	**31/32**	**32/33**
Winter	1,826	1,780	1,764	1,790	1,804	1,791	1,797	1,762	1,805	1,806	1,825	1,832	1,824	1,802	1,843	1,855

7.(4).(c) Monthly Sales by Class and Total Energy Requirements

Table 7-23: KU Monthly Calendar Sales by Class and Total Energy Requirements after DSM (GWh)

	Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Residential	**2018**	775	601	519	403	401	432	546	549	426	349	425	593	6,021
	2019	761	598	532	394	389	433	537	545	425	348	428	586	5,977
Commercial	**2018**	352	277	270	267	321	329	357	355	308	299	317	336	3,789
	2019	357	282	278	270	324	335	361	359	312	300	315	332	3,823
Industrial	**2018**	563	470	486	479	602	580	561	585	499	533	582	551	6,490
	2019	572	475	496	487	615	587	568	592	505	538	586	554	6,576
Total C & I	**2018**	915	747	756	746	923	909	918	940	807	832	899	887	10,279
	2019	929	757	774	757	939	922	929	951	817	838	901	886	10,399
Public	**2018**	143	115	110	111	146	144	154	154	128	116	116	122	1,559
Authority	**2019**	131	105	101	101	134	132	142	141	116	110	115	121	1,449
Lighting	**2018**	5	4	4	3	3	3	3	3	3	4	4	4	42
	2019	5	4	4	3	3	3	3	3	3	4	4	4	42
Sales for	**2018**	165	145	145	133	146	163	181	180	154	140	138	156	1,844
Resale	**2019**	166	146	146	133	32	36	41	41	34	32	31	36	874
Total	**2018**	2,003	1,612	1,534	1,396	1,619	1,651	1,802	1,826	1,518	1,441	1,582	1,762	19,746
Kentucky	**2019**	1,992	1,610	1,557	1,388	1,497	1,526	1,652	1,681	1,395	1,332	1,479	1,633	18,742
Virginia	**2018**	95	74	67	54	54	49	51	51	43	45	59	77	723
	2019	93	73	68	53	52	48	50	50	43	43	59	76	709
Total KU	**2018**	2,098	1,686	1,601	1,450	1,673	1,700	1,853	1,877	1,561	1,486	1,641	1,839	20,468
Sales	**2019**	2,085	1,683	1,625	1,441	1,549	1,574	1,702	1,731	1,438	1,375	1,538	1,709	19,450
Total	**2018**	2,260	1,812	1,700	1,529	1,769	1,815	1,984	2,014	1,656	1,567	1,742	1,968	21,815
Requirements	**2019**	2,245	1,808	1,724	1,520	1,638	1,681	1,821	1,858	1,526	1,451	1,632	1,828	20,731

Table 7-24: LG&E Monthly Calendar Sales by Class and Total Energy Requirements after DSM (GWh)

	Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Residential	**2018**	368	312	301	255	299	365	488	487	372	270	260	319	4,096
	2019	360	310	312	250	291	368	481	485	372	270	263	315	4,075
Commercial	**2018**	317	276	294	289	341	359	378	375	320	295	304	312	3,861
	2019	319	281	302	292	344	365	382	380	325	297	304	311	3,903
Industrial	**2018**	206	183	212	204	245	236	232	243	201	200	226	218	2,605
	2019	211	184	215	207	247	236	232	243	206	199	226	217	2,622
Public	**2018**	86	78	85	74	98	96	109	109	91	80	82	81	1,069
Authority	**2019**	80	75	82	70	93	91	103	103	87	78	81	81	1,024
Lighting	**2018**	2	2	2	1	1	1	1	1	2	2	2	2	19
	2019	2	2	2	1	1	1	1	1	2	2	2	2	19
Total LG&E	**2018**	979	851	894	823	984	1,057	1,208	1,215	986	847	874	932	11,650
Sales	**2019**	972	852	913	820	976	1,061	1,199	1,212	992	846	876	926	11,643
Total	**2018**	1,034	898	937	861	1,038	1,138	1,311	1,322	1,045	887	916	983	12,370
Requirements	**2019**	1,029	899	956	857	1,029	1,144	1,301	1,319	1,051	885	918	975	12,363

7.(4).(d) Forecasted Impact of Existing Demand-Side Management Programs
The impacts of existing and future demand-side programs on both energy sales and peak demands are estimated in Table 8-11 and Table 8-12. The energy sales forecasts presented in the preceding sections include the impacts of those programs.

7.(5) Historical and Forecast Information for a Multi-State Integrated Utility System

This section is not applicable to KU. Virginia energy sales constitute less than 5 percent of total KU sales. Energy sales for Virginia are shown as a separate line item in Table 7-3, while demand is treated as part of KU's overall system demand.

7.(6) Updates of Load Forecasts

Any updates to load forecasts will be filed when adopted by the Companies.

7.(7) Load Forecasting Methodology

7.(7).(a) Data Sets Used in Producing Forecasts
Table 5-3 in Section 5.(2) contains a summary of the data sets used in producing the energy requirements forecast. A detailed discussion of these inputs is included in Volume II ("Energy & Demand Forecast Process").

7.(7).(b) Key Assumptions and Judgments
Section 5.(2) highlights key assumptions to the forecast. A detailed discussion is included in Volume II ("Energy & Demand Forecast Process").

7.(7).(c) General Methodological Approach
Section 5.(2) contains an overview of the load forecasting process. A more detailed description of the forecast process, including model design and specification, is included in Volume II ("Energy & Demand Forecast Process").

7.(7).(d) Treatment and Assessment of Forecast Uncertainty
Section 5.(3) summarizes the uncertainties that could affect the load forecasts of KU and LG&E. Across forecast cycles, forecast uncertainty is addressed by reviewing and revising the model specifications to ensure that the relationships between variables are properly quantified and that the structural relationships remain valid.

Within each forecast cycle, there is uncertainty in the forecast values of the independent variables. To address this uncertainty, the company develops high and low forecast scenarios to support sensitivity analysis of the various resource acquisition plans being studied.

7.(7).(e) Sensitivity Analysis
High and low energy requirements forecasts are presented in Section 5.(3) along with a discussion of the uncertainties considered in developing these forecasts (see Table 5-10 and Table 5-11).

7.(7).(f) Research and Development

While the Companies use proven econometric techniques to robustly and consistently update the load forecast, research to provide additional insight or explanatory power is consistently conducted. The Companies participate in numerous EPRI research projects which help inform the load forecasting process. In particular, the EPRI Battery Storage Project at Brown has provided valuable insight into grid-connected storage. Also at Brown, the 10 MW solar facility and subsequent analysis has informed the development of load shapes for customer-owned solar installations. This data is important to not only develop average load shapes but to understand the risk associated with variability in solar without significant geographic diversity.

Participation in the EPRI Transportation project provides data and insight into the impact of electrification in the transport segment. Available technology is changing rapidly so participation in a group project provides the most current data. In addition, the Companies use data from its electric vehicle rates and metering of third-party EV chargers to improve and validate the incorporation of this developing technology into the load forecasting process.

7.(7).(g) Development of End-Use Load and Market Data

The Companies use their load research program to provide detailed and accurate data on class level end-uses. In addition, participation in industry groups specializing in load research such as the AEIC Load Research & Analytics helps gain access to data and insights. The Companies participate in an Energy Forecaster Group managed by Itron, in which collaborative efforts with other utilities provide the development of regional end-use saturation and efficiency data for the various classes of service.

The Companies also seek to utilize other sources of data to supplement their load research program. The recently approved expansion of the AMS Pilot Program provides a valuable source of data to understand residential end-use trends. Utilizing the existing MyMeter platform, there is the ability to combine this data with customer-provided data points such as appliance upgrades and remodels. Two-way communication on air conditioner load control devices and MAISY End-Use data are additional supplemental data sources.

The Companies utilize survey data and direct feedback from large customers to understand usage. To further their knowledge and understanding, the Companies plan to conduct commercial surveys and continue residential surveys, ad hoc studies and the online panel. Finally, there is an increasing availability of data provided openly especially in the realms of economics and demographics. The Companies will take advantage of opportunities to leverage this data to improve the load forecasting process.

8 Resource Assessment and Acquisition Plan

8.(1) Plan Overview

Table 8-1 contains the Companies' reserve margin forecast with planned retirements in the base energy requirements forecast scenario. Load reductions associated with the Companies' DSM programs reflect changes to DSM programs from the Companies' recently approved DSM filing in Kentucky.[43] The Companies' generation capacity decreases by 437 MW in 2019 due to the planned retirement of Brown 1 and 2 (272 MW) and the expiration of the Bluegrass Agreement (165 MW), and by 14 MW in 2021 due to the planned retirement of Zorn 1, which is expected to occur within the next three years. Retiring additional resources is not economic given their reliability benefits. Absent further retirements, the Companies do not have a need for capacity through the 15-year planning period.

Table 8-1: Reserve Margin (MW, Base Energy Requirements Forecast)

	2018	2019	2020	2021	2022	2023	2024	2027	2030	2033
Gross Peak Load	7,028	6,703	6,688	6,674	6,657	6,653	6,638	6,655	6,650	6,627
DCP	-127	-96	-91	-87	-84	-80	-77	-67	-59	-52
DSM	-247	-247	-236	-236	-236	-236	-236	-236	-236	-236
Net Peak Load	**6,655**	**6,360**	**6,361**	**6,350**	**6,338**	**6,338**	**6,325**	**6,352**	**6,355**	**6,339**
Existing Capability[44]	7,754	7,476	7,476	7,476	7,477	7,477	7,478	7,478	7,478	7,478
Small-Frame SCCTs	87	87	87	73	73	73	73	73	73	73
CSR	141	141	141	141	141	141	141	141	141	141
Bluegrass	165	0	0	0	0	0	0	0	0	0
OVEC[45]	152	152	152	152	152	152	152	152	152	152
Total Supply	**8,299**	**7,856**	**7,856**	**7,842**	**7,843**	**7,843**	**7,844**	**7,844**	**7,844**	**7,844**
Reserve Margin	1,644	1,495	1,495	1,491	1,505	1,505	1,518	1,492	1,489	1,505
Reserve Margin %	**24.7%**	**23.5%**	**23.5%**	**23.5%**	**23.7%**	**23.7%**	**24.0%**	**23.5%**	**23.4%**	**23.7%**

The Companies' resource planning process consists of the following activities:

1. Screening of demand-side and supply-side resource options
2. Assessment of target reserve margin criterion
3. Development of long-term resource plan

[43] *In the Matter of: Electronic Joint Application of Louisville Gas and Electric and Kentucky Utilities Company for Review, Modification, and Continuation of Certain Existing Demand-Side Management and Energy Efficiency Programs*, Case No. 2017-00441.
[44] Existing capability is shown excluding small-frame SCCTs, CSR, Bluegrass, and OVEC and including 1 MW derates on each of the E.W. Brown Units 8, 9, and 11, which are planned to be resolved by 2024.
[45] OVEC's capacity reflects the 152 MW that is expected to be available to the Companies at the time of the summer peak, not its rating of 172 MW.

The models and methods for each of these activities are summarized in Section 5.(2). The results of these analyses are presented in Section 5.(4). And a complete summary of each analysis is included in Volume III. The Companies concluded from these analyses that no action is required at this time.

8.(2) Options Considered for Inclusion in Plan

The following sections describe the options considered for the Companies' resource plan.

8.(2).(a) Improvements to and More Efficient Utilization of Existing Facilities

Generation

Efficiency Improvements

The Companies are planning several activities in the business plan to improve generation efficiencies. These include updating controls to the latest technologies, turbine overhauls and repair work, boiler tube replacements, pulverizer rebuilds, air quality control replacements, cooling system repairs, and generator rewinds and repair work. A number of other projects have furthered efforts to reduce environmental impact, maintain the efficient utilization of generation facilities, and meet regulatory compliance.

Controls/Distributed Control Systems/Generator

Technologically advanced controls continue to be one of the most proven applications for maintaining the efficiency of generating stations. New control technologies allow for tighter control of key operating parameters and provide for coordination of integrated systems not previously available with analog controls. There are several replacements of distributed control systems ("DCS") planned, including hardware upgrades on Cane Run 7, Ghent 1, 2, 3, and 4; Mill Creek 1, 2, 3, and 4; Ohio Falls Station, and Trimble County 1 and 2. Other turbine/generator electrical work in the plan include generator rewind/refurbishment on Brown 3; and replacement of the voltage regulators on Brown 6, Brown 7, and Mill Creek 4.

Turbines/Boiler Feed Pumps

Another proven area to maintain efficiency in generating stations is restoring turbine degradation. A worn/degraded turbine can decrease the station efficiency by not extracting as much energy from the steam as possible. Major turbine overhauls are planned on Mill Creek 1, 3, and 4; Ghent 1, 2, and 4, and Brown 3. The overhauls include ensuring all stationary sealing joints are serviceable, refurbishing radial steam seals, replacing inlet seal rings, ensuring optimal steam flow by restoring area dimensions on rotating and stationary blading, and polishing defects from rotating and stationary blade replacement to return the efficiency of the turbine to at or near design values.

Boiler feed pump degradation also robs the steam/water cycle of efficiency. If pumps are running off their design, then they require extra power, either steam or electricity, to drive the required flow. In the case of turbine driven pumps, the feed pump turbine is overhauled as well to restore its efficiency. Pumps are typically overhauled along with the main turbines.

Boiler Tubes/Burners/Precipitators/Combustion

Boiler tube failures continue to be the largest contributor to the fleet's equivalent forced outage rate. To improve availability, boiler tube studies utilizing software modeling tools and inspections are routinely conducted using the latest technology to identify boiler sections in need of replacement. All units across the fleet have planned boiler outages within the business plan period to replace boiler tube sections. These efforts continue to ensure maximum boiler availability and reliability.

Changes in coal supply and coal burner modifications to reduce gaseous emissions have negatively impacted boiler slagging and precipitator performance. Several units plan to install new or modify existing burners to ensure flexibility in the types of fuel that can be burned while still minimizing emissions. These units are Ghent 1, 2, and 3, Trimble County 2, and Mill Creek 1, 2, 3, and 4. Precipitator upgrades/rebuild projects are planned on Mill Creek 1, 2, and 3.

Other Improvements

Other planned efficiency and utilization projects include:

- Pulverizer rebuilds
- Cooling tower rebuilds at Mill Creek 2 and Ghent 1, 2, and 4
- Cooling tower pump overhauls at Trimble County 1 and 2
- Air compressor replacement and controls upgrades on units, improving operating efficiency and lowering the dew point which reduces the number of instrument related unit derates
- Gas path outlet duct and expansion joint replacement on numerous units in which sections of the expansion joints are replaced improving performance issues
- Air heater basket replacements, improving air flow and boiler efficiency
- Condensate equipment:
    - Feedwater heater control replacements on Ghent 1, 2 and 4 to maximize heat transfer to the water entering the boiler
    - Condenser vacuum pump overhauls on Brown 3 to maintain removal of gases from the condenser for heat transfer

Air Quality Control Systems

SCRs allow for the reduction of NO_x emissions in the flue gas via ammonia injection. SCR catalyst must be in proper operating condition to affect the removal and to prevent ammonia slip, which allows ammonia downstream to form ammonium bisulfate on air heater baskets. SCR projects are in the plan to install new catalyst material as a replacement for existing layers at Ghent 1, 3, and 4; Mill Creek 3 and 4; Trimble County 1 and 2, and Brown 3.

There are also several projects in the plan related to FGD equipment, which include:

- Trimble County limestone mill upgrades
- Brown, Ghent 1 and 3, and Trimble County 2 FGD agitator blade and/or shaft replacements
- Brown oxidation air blower replacements

- Ghent 2 header replacements
- Ghent 1 and Trimble County 2 mist eliminator spray piping.

Landfill projects continue at E.W Brown, Ghent, Mill Creek, and Trimble County stations. A combination of CCR sales and ash containment expansions will extend the life of the landfills, helping to control overall generation costs. All units in the fleet are continuing to analyze and replace stack emissions monitoring equipment to continue to maintain a high level of accuracy of the emissions data being collected.

Combustion Turbines ("CTs")

Significant efforts to maintain our combustion turbine fleet continue in the plan. These efforts have the goal of both maintaining reliability and maintaining efficiency. Trimble County 7, 8, and 9 have a hot gas path inspection ("HGPI") included in the plan. The HGPI includes a thorough evaluation and potential repair of the components of the CT from the air inlet section to the exhaust section, and includes all components of the combustor, and turbine sections. Additionally, Trimble County 5-10 have turbine control upgrade packages included in the plan. Replacement of hydraulically operated gas control valves with electrically operated actuators will improve reliability and lower maintenance costs. Relay and battery upgrades are also planned.

There have also been similar efforts conducted at the Brown CT site. Brown 5, 6, and 7 have planned Static Frequency Converter controls upgrades and Brown 6, 7, and 9 have inspections and overhauls scheduled.

Hydroelectric Units

The completion of the multi-year rehabilitation at the Ohio Falls Station brought many improvements in reliability and output. New trash racks and DCS upgrades are included in the plan.

At the Dix Dam hydro site, structural improvement of the dam parapet wall is scheduled. Upgrades to the station auxiliary power system are planned along with improvements to the crest gate walkway. All these efforts improve the reliability and efficiency of the Dix Dam hydro site.

Blackstart Capability Additions

Completion of the blackstart project has improved resiliency of the system restoration plan. The project included the installation of new diesel engine powered generator packages at the Trimble County and Cane Run stations. Each package is capable of starting any primary combustion turbine on site (e.g., Trimble County 5-10 or Cane Run 7's two CTs).

The addition of blackstart capability was accomplished through the purchase and installation of diesel generator systems and associated support systems and modifications to existing infrastructure to allow for start-up during a widespread system power outage.

The identified primary combustion turbines are a critical portion of the system restoration path. Investing in diesel generators for blackstart conversion simplifies the electrical connections and complexity of startup while improving the overall reliability of the system restoration path. The installation of the diesel generator systems also adds the ability to more easily test the blackstart capability of the associated primary combustion turbines, without configuration changes to the transmission and distribution systems, which improves reliability and flexibility of the overall system.

Distribution

Common practices, guidelines, and standards are used to manage the Companies' distribution system. The distribution system has been enhanced over the years through the construction and enhancement of substations and distribution lines, as well as the integration of modern technology to meet growing customer loads and to improve service reliability and quality.

Peak substation transformer loads are monitored annually and load forecasts are developed for a ten-year planning period. Loading data and other system information is used to develop a joint ten-year plan for major capacity enhancements necessary to address load growth and improve system performance. In addition to planned major enhancements, the Companies' distribution personnel continue to plan and construct an appropriate level of conductors, distribution transformers, and other equipment necessary to satisfy the normal service needs of new and existing customers. Distributed generation introduces an additional level of complexity to efficiently plan and operate the distribution system. While Kentucky overall does not have a large amount of distributed generation today, the Companies continue to learn from the industry leaders and plan their systems to accommodate future installations.

The Companies have completed projects to install, upgrade, or replace distribution substation transformers in the Companies' service territories to serve new customers and improve service reliability. New business requests in the service territory have increased since 2012, but gains in energy efficiency technology have slowed load growth. Therefore, the Companies have shifted their distribution focus to reliability and aging infrastructure projects rather than capacity enhancement projects. Projects that improve the worst performing circuits and mitigate the effects on customers following a major equipment failure have received more emphasis.

The Companies continue to design, build, and operate the distribution system in a cost-effective, efficient manner. Substation and distribution transformers are purchased using Total Ownership Cost criteria that minimize the first cost and the cost of losses over the life of the asset. Distribution transformer efficiencies are now DOE compliant or better. The Companies continue to install capacitors on the distribution system to provide more efficient use of transmission, substation, and distribution facilities. The Companies plan to continue to design for near unity power factor at the substation bus where capacitor installations on the distribution system are reasonable and feasible.

Transmission

The Companies routinely identify transmission construction projects and upgrades required to maintain the adequacy of their transmission system to meet projected customer demands. These projects are provided separately in Volume III ("Transmission Information").

8.(2).(b) New Demand-Side Management Programs
The Companies recently received approval for DSM programs in Case No. 2017-00441. From this order, the Companies were able to continue some programs while also ending other programs. The following programs will continue to operate in the 2019 to 2025 DSM portfolio period: WeCare, AMS Customer Service Offering, Residential and Small Nonresidential Demand Conservation, Large Nonresidential Demand Conservation, and Nonresidential Rebates. The following programs have expired or will expire in 2018: Residential Refrigerator Removal, Residential Incentives, Residential Conservation/Home Energy Performance, Smart Energy Profile, and Customer Education and Public Information. The School Energy Management Program ("SEMP") was not approved. Additional discussion of the Companies' demand-side management programs is contained in Sections 8.(3).(e) and 8.(5).(a). An in-depth description and discussion of DSM programs is also contained in the case referenced above (see Exhibit GSL-1 from Case No. 2017-00441).

8.(2).(c) New Generating Facilities
The models and methods used to identify the resource options included in the resource planning analyses are summarized in Section 5.(2). The results of this screening analysis are presented in Table 5-12 in Section 5.(4). A complete summary of this analysis is included in Volume III ("2018 IRP Resource Screening Analysis").

8.(2).(d) Non-Utility Generation Options
The Companies consider short-term market purchases from other utilities on a non-firm basis. The Companies offer tariffs for Large Capacity Cogeneration and Small Power Production Qualifying Facilities. As needed, the Companies use an RFP process to obtain offers for energy and capacity from the electricity market.

8.(3) Existing and Planned Resource Data

The following sections provide details regarding the Companies' existing and planned resources.

8.(3).(a) Map of Existing and Planned Facilities
A map of the Companies' transmission system and generating facilities and a list of planned transmission projects are included in Volume III ("Transmission Information").

8.(3).(b) List Existing and Planned Generating Resources
Table 8-2 shows the characteristics of the Companies' existing and currently planned generating resources. The following tables show the actual and projected cost and operating information. Costs in years beyond the Companies' business plan are assumed to escalate at 2% annually.

Table 8-2: KU and LG&E Existing and Planned Electric Generation Facilities

Plant	Unit	Location	Status	Operation Date	Facility Type	Net Capability (MW)[1] 2018/19 Winter	Net Capability (MW)[1] 2019 Summer	Entitlement KU	Entitlement LGE	Fuel Type	Fuel Storage Capacity	Upgrades Derates, Retirements
Cane Run	7	Louisville	Existing	2015	Turbine	683	662	78%	22%	Gas	None	
	11			1968	Turbine	14	14		100%	Gas / Oil	50,000 Gal.	None
Dix Dam	1-3	Burgin	Existing	1925	Hydro	31.5	31.5	100%		Water	None	None
E.W. Brown	1	Burgin	Existing	1957	Steam	107	106	100%		Coal (Rail)	350,000 Tons	Retiring 2019
	2			1963		168	166					Retiring 2019
	3			1971		413	409					None
	5			2001	Turbine	130	130	47%	53%	Gas	2,200,000 Gal.	None
	6			1999		171	146	62%	38%			
	7			1999		171	146					
	8			1995		128	121	100%		Gas / Oil		
	9			1994		138	121					
	10			1995		138	121					
	11			1996		128	121					
	Solar			2016	Solar	0	8	61%	39%	Solar	None	None
Ghent	1	Ghent	Existing	1974	Steam	479	475	100%		Coal (Barge)	1,200,000 Tons	None
	2			1977		486	485					None
	3			1981		476	481					None
	4			1984		478	478					None
Haefling	1	Lexington	Existing	1970	Turbine	14	12	100%		Gas	None	None
	2			1970		14	12					
Mill Creek	1	Louisville	Existing	1972	Steam	300	300		100%	Coal (Barge & Rail)	1,000,000 Tons	None
	2			1974		295	297					None
	3			1978		394	391					None
	4			1982		486	477					None
Ohio Falls	1-8	Louisville	Existing	1928	Hydro	40	64		100%	Water	None	None
Paddy's Run	11	Louisville	Existing	1968	Turbine	13	12		100%	Gas	None	None
	12			1968		28	23					
	13			2001		175	147	47%	53%			
Trimble County	1	Near Bedford	Existing	1990	Steam	493 (370)[2]	493 (370)[2]	0%	75%	Coal (Barge)	1,000,000 Tons (HS)	None
	2			2011		760 (570)[2]	732 (549)[2]	61%	14%		250,000 Tons (PRB)	None
	5			2002	Turbine	179	159	71%	29%	Gas	None	None
	6			2002		179	159					
	7			2004		179	159	63%	37%			
	8			2004		179	159					
	9			2004		179	159					
	10			2004		179	159					
Zorn	1	Louisville	Existing	1969	Turbine	16	14		100%	Gas	None	Retiring by 2021
Future Units												
Simpsonville Solar (Solar Share)	1	Near Simpsonville	Planned	2019	Solar	0	0.4[4]	[3]	[3]	Solar	None	None

[1] The ratings for Dix Dam, Ohio Falls (run of river), E.W. Brown Solar, and Solar Share reflect the expected output for these facilities at the time of the summer and winter peak demands.
[2] Ratings in parentheses represent the Companies' 75% ownership shares of Trimble County Units 1 and 2.
[3] Solar Share's ownership percentages will be determined by the composition of KU and LG&E customers.
[4] The capacity of Solar Share's first phase (Simpsonville Solar 1) will be approximately 0.4 MW (AC). Solar Share's total 3 MW (AC) will be constructed as customers fully subscribe to subsequent phases.

Table 8-3: Capacity Factors

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Bluegrass/EKPC	4%	3%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Brown 1	34%	22%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Brown 2	45%	29%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Brown 3	35%	19%	19%	20%	20%	19%	20%	21%	21%	20%	23%	23%	20%	21%	22%	23%
Brown 5	9%	14%	11%	11%	11%	9%	9%	2%	2%	2%	2%	1%	1%	1%	1%	2%
Brown 6	10%	9%	7%	8%	9%	6%	5%	5%	6%	6%	5%	4%	4%	3%	5%	6%
Brown 7	9%	5%	5%	5%	8%	4%	4%	4%	5%	5%	5%	3%	3%	3%	4%	5%
Brown 8	3%	2%	1%	1%	1%	1%	1%	1%	1%	1%	1%	0%	0%	0%	0%	1%
Brown 9	2%	2%	2%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
Brown 10	3%	3%	3%	2%	2%	2%	2%	1%	1%	1%	1%	0%	0%	0%	0%	1%
Brown 11	1%	1%	1%	1%	1%	0%	1%	0%	1%	0%	0%	0%	0%	0%	0%	0%
Brown Solar	21%	21%	21%	21%	21%	21%	21%	21%	21%	21%	21%	21%	21%	21%	21%	21%
Cane Run 7	84%	88%	81%	88%	86%	88%	75%	88%	86%	88%	73%	81%	86%	84%	77%	84%
Cane Run 11	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Dix Dam 1-3	38%	28%	28%	28%	28%	28%	28%	28%	28%	28%	28%	28%	28%	28%	28%	28%
Ghent 1	69%	65%	64%	56%	59%	64%	65%	63%	65%	63%	59%	65%	64%	63%	63%	65%
Ghent 2	76%	67%	76%	73%	72%	74%	75%	74%	67%	75%	76%	74%	75%	74%	76%	67%
Ghent 3	54%	54%	54%	51%	51%	50%	55%	50%	54%	53%	55%	55%	54%	54%	47%	51%
Ghent 4	65%	61%	54%	56%	57%	59%	59%	59%	59%	55%	57%	60%	61%	60%	59%	60%
Haefling 1-2	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Mill Creek 1	76%	61%	68%	67%	72%	67%	73%	70%	73%	63%	74%	71%	73%	69%	72%	69%
Mill Creek 2	57%	67%	63%	69%	63%	69%	65%	69%	61%	70%	66%	71%	65%	72%	67%	71%
Mill Creek 3	72%	59%	68%	68%	75%	69%	76%	69%	74%	63%	75%	70%	73%	70%	75%	69%
Mill Creek 4	63%	71%	62%	72%	62%	72%	69%	73%	70%	74%	70%	72%	63%	73%	68%	73%
Ohio Falls 1-8	28%	34%	34%	34%	34%	34%	34%	34%	34%	34%	34%	34%	34%	34%	34%	34%
Paddy's Run 11	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Paddy's Run 12	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Paddy's Run 13	8%	10%	10%	8%	8%	7%	4%	10%	9%	10%	10%	9%	9%	9%	11%	11%
Trimble County 1	78%	72%	73%	67%	74%	72%	77%	66%	76%	73%	78%	73%	76%	71%	78%	65%
Trimble County 2	60%	68%	70%	69%	69%	67%	69%	69%	65%	69%	70%	70%	69%	70%	71%	70%
Trimble County 5	13%	25%	23%	20%	21%	19%	21%	22%	23%	23%	20%	16%	17%	17%	22%	22%
Trimble County 6	12%	18%	17%	15%	15%	14%	18%	16%	15%	18%	17%	13%	15%	14%	18%	18%
Trimble County 7	15%	13%	13%	11%	10%	11%	13%	13%	12%	14%	15%	10%	11%	10%	15%	14%
Trimble County 8	12%	6%	6%	3%	3%	3%	3%	3%	3%	4%	4%	2%	3%	2%	3%	4%
Trimble County 9	11%	4%	3%	8%	8%	8%	8%	9%	10%	10%	12%	7%	8%	7%	11%	11%
Trimble County 10	3%	2%	2%	2%	2%	1%	1%	2%	2%	2%	2%	1%	2%	1%	2%	2%
Zorn 1	0%	0%	0%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Solar Share	N/A	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%

Table 8-4: Equivalent Availability Factors

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Bluegrass/EKPC	86%	77%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Brown 1	87%	91%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Brown 2	89%	92%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Brown 3	84%	76%	89%	85%	87%	91%	87%	85%	87%	78%	87%	91%	87%	91%	87%	91%
Brown 5	85%	84%	84%	86%	84%	82%	86%	84%	86%	84%	86%	86%	86%	86%	86%	86%
Brown 6	90%	74%	86%	88%	88%	88%	88%	88%	88%	88%	88%	90%	90%	90%	90%	90%
Brown 7	93%	88%	86%	76%	88%	88%	88%	88%	88%	88%	88%	90%	90%	90%	90%	90%
Brown 8	92%	83%	83%	72%	84%	84%	84%	84%	84%	84%	87%	87%	87%	87%	87%	87%
Brown 9	86%	83%	81%	83%	83%	83%	71%	87%	87%	87%	87%	87%	87%	87%	87%	87%
Brown 10	91%	87%	87%	84%	87%	87%	87%	87%	73%	87%	87%	87%	87%	87%	87%	87%
Brown 11	74%	85%	85%	85%	85%	83%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%
Brown Solar	21%	21%	21%	21%	21%	21%	21%	21%	21%	21%	21%	21%	21%	21%	21%	21%
Cane Run 7	87%	89%	82%	89%	87%	89%	76%	89%	87%	89%	76%	85%	89%	87%	78%	85%
Cane Run 11	75%	50%	50%	50%	48%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	0%
Dix Dam 1-3	95%	94%	94%	94%	94%	94%	94%	94%	94%	94%	94%	94%	94%	94%	94%	94%
Ghent 1	87%	87%	85%	78%	81%	87%	87%	85%	87%	87%	78%	87%	87%	87%	87%	87%
Ghent 2	90%	76%	85%	85%	87%	87%	87%	87%	78%	87%	87%	87%	87%	87%	87%	78%
Ghent 3	82%	85%	87%	87%	87%	85%	85%	78%	87%	87%	87%	87%	87%	87%	78%	87%
Ghent 4	88%	85%	78%	85%	85%	87%	85%	87%	85%	78%	83%	87%	87%	87%	87%	87%
Haefling 1-2	73%	51%	51%	51%	51%	51%	51%	51%	51%	51%	51%	51%	51%	51%	51%	51%
Mill Creek 1	90%	78%	88%	85%	88%	85%	88%	85%	88%	78%	88%	85%	88%	85%	88%	85%
Mill Creek 2	79%	90%	85%	90%	85%	90%	85%	90%	78%	90%	85%	90%	85%	90%	85%	90%
Mill Creek 3	86%	76%	90%	85%	90%	85%	90%	85%	90%	78%	90%	85%	90%	85%	90%	85%
Mill Creek 4	77%	90%	81%	90%	78%	90%	85%	90%	85%	90%	85%	90%	78%	90%	85%	90%
Ohio Falls 1-8	38%	34%	34%	34%	34%	34%	34%	34%	34%	34%	34%	34%	34%	34%	34%	34%
Paddy's Run 11	69%	51%	51%	51%	49%	51%	51%	51%	50%	51%	51%	51%	51%	51%	51%	0%
Paddy's Run 12	68%	50%	50%	50%	48%	50%	50%	50%	49%	50%	50%	50%	50%	50%	50%	0%
Paddy's Run 13	93%	86%	89%	88%	88%	60%	55%	88%	88%	88%	89%	91%	91%	91%	91%	91%
Trimble County 1	91%	83%	88%	81%	88%	82%	88%	75%	88%	82%	88%	82%	88%	82%	88%	75%
Trimble County 2	65%	74%	77%	77%	77%	76%	77%	77%	71%	77%	77%	77%	77%	77%	77%	77%
Trimble County 5	94%	92%	92%	92%	92%	92%	79%	92%	92%	92%	92%	92%	92%	92%	92%	92%
Trimble County 6	95%	92%	92%	92%	92%	92%	92%	92%	79%	92%	92%	92%	92%	92%	92%	92%
Trimble County 7	85%	92%	92%	92%	92%	92%	92%	92%	83%	92%	92%	92%	92%	92%	92%	92%
Trimble County 8	90%	92%	92%	83%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%
Trimble County 9	92%	90%	83%	92%	92%	92%	92%	92%	92%	83%	92%	92%	92%	92%	92%	92%
Trimble County 10	93%	90%	92%	92%	92%	92%	83%	92%	92%	92%	92%	92%	92%	92%	92%	92%
Zorn 1	47%	50%	50%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Solar Share	N/A	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%

Table 8-5: Average Heat Rate (MMBtu/MWh)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Bluegrass/EKPC	11.0	10.9	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Brown 1	12.4	12.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Brown 2	10.8	10.8	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Brown 3	11.7	12.2	12.2	12.2	12.2	12.2	12.1	12.1	12.1	12.1	12.0	12.1	12.1	12.1	12.1	12.1
Brown 5	14.0	13.6	13.7	13.6	13.5	13.6	13.8	14.2	13.8	14.6	14.7	14.7	15.1	15.0	14.5	14.4
Brown 6	10.6	10.8	10.9	10.9	10.9	10.9	10.9	11.0	11.1	11.3	11.3	11.5	11.5	11.3	11.3	11.1
Brown 7	10.7	10.9	10.9	10.8	10.9	10.9	10.9	10.9	11.1	11.3	11.2	11.4	11.4	11.3	11.3	11.1
Brown 8	13.8	15.4	15.4	14.7	14.4	15.2	15.7	15.8	15.9	16.2	16.8	16.6	16.8	16.8	16.5	16.5
Brown 9	14.7	15.4	15.1	14.6	14.8	14.8	16.2	15.8	15.8	16.4	16.8	16.4	16.7	16.6	16.3	16.5
Brown 10	14.4	15.6	15.2	15.2	15.2	15.4	16.3	15.3	15.6	16.6	17.0	16.8	16.8	16.6	16.8	16.5
Brown 11	15.8	15.5	15.4	14.7	14.7	15.3	15.9	15.1	15.6	17.1	17.7	16.8	16.9	17.3	17.0	16.6
Brown Solar	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Cane Run 7	6.7	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6
Cane Run 11	12.3	14.7	15.0	15.0	15.2	N/A	14.7	13.8	14.8	14.5	14.8	14.3	14.7	N/A	14.5	N/A
Dix Dam 1-3	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Ghent 1	11.0	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9
Ghent 2	10.4	10.1	10.1	10.1	10.2	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1
Ghent 3	11.3	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2	11.2
Ghent 4	11.0	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8
Haefling 1-2	N/A	17.8	17.7	18.1	17.3	16.6	17.8	17.2	17.4	N/A	N/A	17.4	18.0	N/A	17.4	17.6
Mill Creek 1	10.5	10.6	10.6	10.6	10.6	10.6	10.6	10.6	10.6	10.6	10.6	10.6	10.6	10.6	10.6	10.6
Mill Creek 2	10.8	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7	10.7
Mill Creek 3	10.6	10.6	10.7	10.6	10.6	10.6	10.6	10.6	10.6	10.6	10.6	10.6	10.6	10.6	10.6	10.6
Mill Creek 4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.3	10.3	10.3	10.3	10.3	10.3	10.4	10.4
Ohio Falls 1-8	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Paddy's Run 11	N/A	15.7	15.5	15.6	16.1	N/A	15.0	16.2	15.6	15.9	N/A	15.0	15.0	N/A	15.0	N/A
Paddy's Run 12	N/A	17.9	17.8	17.7	17.0	N/A	17.0	17.5	17.8	17.8	17.0	17.0	17.0	N/A	17.7	N/A
Paddy's Run 13	11.2	10.7	10.7	10.6	10.7	10.6	10.7	10.8	10.9	10.9	11.1	11.5	11.2	11.2	11.1	11.0
Trimble County 1	10.3	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4
Trimble County 2	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3	9.3
Trimble County 5	11.1	10.7	10.7	10.7	10.7	10.7	10.7	10.8	10.9	11.1	11.1	11.2	11.2	11.2	11.1	11.0
Trimble County 6	11.1	10.7	10.7	10.7	10.7	10.7	10.8	10.8	10.9	11.1	11.1	11.2	11.2	11.2	11.1	11.0
Trimble County 7	11.1	10.7	10.7	10.7	10.7	10.7	10.8	10.8	10.9	11.1	11.1	11.2	11.2	11.1	11.1	11.0
Trimble County 8	11.2	10.7	10.7	10.7	10.7	10.7	10.7	10.8	10.8	11.0	11.0	11.1	11.1	11.0	11.0	10.9
Trimble County 9	11.2	10.7	10.7	10.7	10.7	10.7	10.8	10.8	10.9	11.1	11.1	11.2	11.2	11.1	11.1	11.0
Trimble County 10	11.3	10.7	10.7	10.7	10.8	10.7	10.8	10.8	10.8	11.0	11.0	11.1	11.1	11.0	11.0	10.9
Zorn 1	N/A	16.5	16.6	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Solar Share	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Table 8-6: Cost of Fuel ($/MMBtu)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Bluegrass/EKPC	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Brown 1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Brown 2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Brown 3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Brown 5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Brown 6	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Brown 7	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Brown 8	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Brown 9	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Brown 10	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Brown 11	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Brown Solar	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Cane Run 7	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Cane Run 11	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Dix Dam 1-3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Ghent 1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Ghent 2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Ghent 3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Ghent 4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Haefling 1-2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Mill Creek 1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Mill Creek 2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Mill Creek 3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Mill Creek 4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Ohio Falls 1-8	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Paddy's Run 11	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Paddy's Run 12	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Paddy's Run 13	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Trimble County 1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Trimble County 2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Trimble County 5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Trimble County 6	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Trimble County 7	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Trimble County 8	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Trimble County 9	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Trimble County 10	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Zorn 1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Solar Share	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Table 8-7: Capital Costs

	Solar Share[46]	1x1 NGCC	SCCT	PV Solar	Wind	Battery
Capital Costs ($/kW)[47]	[redacted]	1,070	911	1,093	1,515	2,073
Total Capital Costs ($000)[48]		426,432	191,839	109,266	151,460	207,281

Table 8-8: Production Costs

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Existing Units																
Variable and Fixed O&M Costs ($M)[49]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Average Variable Production Costs (cents/kWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Electricity Production Costs (cents/kWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[46] Bids for Solar Share have been requested but not yet received and analyzed. Costs reflect the Companies' estimates.
[47] Capital costs ($/kW) are in 2018 "overnight" dollars. Costs for technologies other than Solar Share were sourced from NREL's 2018 ATB (https://atb.nrel.gov/). The Companies inflated NREL's cost forecasts, which were provided in real 2016 dollars, to nominal dollars at 2% annually.
[48] Capital costs were computed based on the average of summer and winter capacities.
[49] Variable and fixed operating and maintenance costs include the cost of fuel.

8.(3).(c) Electricity Purchases and Sales

Table 8-9 provides a forecast of the Companies' electricity transactions.

Table 8-9: Electricity Purchases and Sales (GWh, Base Energy Requirements Forecast)

	2018	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
Bluegrass/EKPC	58	16	0	0	0	0	0	0	0	0	0	0	0	0	0	0
OVEC	800	787	761	762	757	757	778	776	795	813	828	811	797	820	831	823
Market Purchases	10	30	10	11	9	2	6	5	12	11	5	2	7	2	7	7
Off-System Sales	-613	-260	-263	-445	-540	-777	-875	-929	-886	-886	-865	-970	-968	-944	-906	-921

8.(3).(d) Electricity Purchases from Non-Utility Sources

Table 8-10 shows the forecasted capacity and energy purchases from non-utility sources.

Table 8-10: Electricity Purchases from Non-Utility Sources

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Qualifying Facilities																
Capacity (MW)	2.5	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9
Energy (GWh)	2.9	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.4

8.(3).(e) Demand-Side Management Programs
The following sections describe the Companies' recently approved DSM-EE programs.

8.(3).(e).1 Targeted Classes and End-Uses

Residential and Nonresidential Customer Classes

Advanced Metering Systems (AMS) Customer Service Offering

This program allows customers who wish to have consumption data more frequently than once a month an opportunity to request and receive an advanced meter, which will present individual daily consumption through a website/mobile portal. A participating customer's consumption would be captured, communicated, and stored which allows customers to be able to monitor their interval usage through the portal.

Residential and Small Nonresidential Demand Conservation Program

This program cycles central air conditioning units, water heaters, and pool pumps of both LG&E and KU customers. It is designed to provide customers with an incentive to allow the Companies to interrupt service to their equipment at those peak demand periods when the Companies need additional resources to meet customer demand.

Low Income Weatherization Program (WeCare)

This program is an education and weatherization program designed to reduce energy consumption of income-qualified customers. The program provides energy audits, energy education, and installation of weatherization and energy conservation measures in qualified single-family homes as well as tenant units and common areas of qualifying multifamily properties. Thus, both Residential and Nonresidential class customers are the targeted classes with qualifying maximum income requirements. These maximum income requirements make the program available to both Low Income Home Energy Assistance Program and/or Weatherization Assistance Program eligible customers.

Nonresidential Customer Classes

Large Nonresidential Demand Conservation Program

Through this program, the Companies provide load monitoring devices to help business customers reduce the demand for electricity during peak times, when energy consumption is at its highest. This program provides incentives so that customers can have a cost-effective way to quickly shed load for these peak times.

Nonresidential Rebates Program

This program is offered to all nonresidential class customers. The objective is to identify energy efficiency opportunities for customers and assist them in the implementation of these identified energy efficiency opportunities via incentives. The incentives are available for both prescriptive and custom measures, as well as LEED certifications and new construction that exceeds the current building code.

8.(3).(e).2 Program Durations

The Companies received approval for continuation of programming as described in Case No. 2017-00441, except for SEMP, for the seven-year planning period of 2019 to 2025. Previously, all programming was set to expire on December 31, 2018. The new plan as approved will allow the Companies to continue their DSM-EE portfolio through December 31, 2025.

8.(3).(e).3 Energy and Peak Demand Impacts

Load changes for the DSM programs are embedded in the load forecast for energy and demand presented throughout this report. Table 8-11 summarizes the annual incremental energy impact and the summer and winter peak demand of the Companies' DSM programs. Table 8-12 summarizes the cumulative energy impact and the summer and winter peak demand of the Companies' DSM programs.

Table 8-11: KU and LG&E Demand Side Management Energy and Demand Impacts (Incremental)

DSM Energy Reduction (GWh)	Status	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Smart Energy Profile	Expiring	13.0	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	0.0	0.0
Residential Refrigerator Removal	Expiring	7.5	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	0.0
Residential Incentives	Expiring	1.5	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	0.0
Residential Conservation (HEPP)	Expiring	4.7	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	0.0
School Energy Management Program (SEMP)	Expiring	3.2	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	0.0
Customer Education and Public Information	Expiring	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	0.0	0.0
AMS Customer Service Offering	Approved	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	0.0	0.0
Residential and Small Nonresidential Demand Conservation	Approved	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	0.0	0.0
WeCare	Approved	5.7	5.1	5.1	5.1	5.1	5.1	5.1	5.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Large Nonresidential Demand Conservation	Approved	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	0.0	0.0
Nonresidential Rebates	Approved	79.0	25.5	25.5	25.5	25.5	25.6	25.6	25.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Program Development and Administration	Approved	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	0.0	0.0
Total Annual Energy Reduction		114.6	30.6	30.6	30.6	30.6	30.7	30.7	30.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Table 8-11: KU and LG&E Demand Side Management Energy and Demand Impacts (Incremental) Continued

DSM Summer Peak Demand Reduction (MW)	Status	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Smart Energy Profile	Expiring	18.6	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	0.0
Residential Refrigerator Removal	Expiring	0.9	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	0.0
Residential Incentives	Expiring	0.4	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	0.0
Residential Conservation (HEPP)	Expiring	1.4	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	0.0
School Energy Management Program (SEMP)	Expiring	2.1	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	0.0
Customer Education and Public Information	Expiring	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	0.0	0.0
AMS Customer Service Offering	Approved	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	0.0	0.0
Residential and Small Nonresidential Demand Conservation	Approved	(24.8)	(5.4)	(8.2)	(7.7)	(7.4)	(7.0)	(6.8)	(6.4)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
WeCare	Approved	0.5	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Large Nonresidential Demand Conservation	Approved	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	0.0	0.0
Nonresidential Rebates	Approved	29.3	5.2	5.2	5.2	5.2	5.3	5.3	5.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Program Development and Administration	Approved	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	0.0	0.0
Total Annual Demand Reduction		28.3	0.3	(2.5)	(2.1)	(1.7)	(1.3)	(1.0)	(0.6)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Table 8-11: KU and LG&E Demand Side Management Energy and Demand Impacts (Incremental) Continued

DSM Winter Peak Demand Reduction (MW)	Status	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Smart Energy Profile	Expiring	18.6	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	0.0
Residential Refrigerator Removal	Expiring	0.9	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	0.0
Residential Incentives	Expiring	0.4	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	0.0
Residential Conservation (HEPP)	Expiring	1.4	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	0.0
School Energy Management Program (SEMP)	Expiring	2.1	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	0.0
Customer Education and Public Information	Expiring	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	0.0	0.0
AMS Customer Service Offering	Approved	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	0.0	0.0
Residential and Small Nonresidential Demand Conservation	Approved	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	0.0	0.0
WeCare	Approved	0.5	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Large Nonresidential Demand Conservation	Approved	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	0.0	0.0
Nonresidential Rebates	Approved	29.3	5.2	5.2	5.2	5.2	5.3	5.3	5.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Program Development and Administration	Approved	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	0.0	0.0
Total Annual Demand Reduction		53.1	5.7	5.7	5.7	5.7	5.7	5.7	5.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Table 8-12: KU and LG&E Demand Side Management Energy and Demand Impacts (Cumulative)

DSM Energy Reduction (GWh)	Status	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Smart Energy Profile	Expiring	13.0	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	0.0	0.0
Residential Refrigerator Removal	Expiring	50.8	50.8	50.8	50.8	50.8	50.8	50.8	50.8	50.8	50.8	50.8	50.8	50.8	50.8	50.8	50.8
Residential Incentives	Expiring	108.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0
Residential Conservation (HEPP)	Expiring	55.2	55.2	55.2	55.2	55.2	55.2	55.2	55.2	55.2	55.2	55.2	55.2	55.2	55.2	55.2	55.2
School Energy Management Program (SEMP)	Expiring	8.5	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
Customer Education and Public Information	Expiring	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	0.0	0.0
AMS Customer Service Offering	Approved	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	0.0	0.0
Residential and Small Nonresidential Demand Conservation	Approved	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
WeCare	Approved	55.4	60.5	65.6	70.6	75.7	80.8	85.9	90.9	90.9	90.9	90.9	90.9	90.9	90.9	90.9	90.9
Large Nonresidential Demand Conservation	Approved	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Nonresidential Rebates	Approved	482.1	507.6	533.1	558.6	584.1	609.7	635.3	660.9	660.9	660.9	660.9	660.9	660.9	660.9	660.9	660.9
Program Development and Administration	Approved	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	0.0	0.0
Total Annual Energy Reduction		777.2	787.2	817.7	848.3	878.9	909.6	940.3	970.9	970.9	970.9	970.9	970.9	970.9	970.9	970.9	970.9

Table 8-12: KU and LG&E Demand Side Management Energy and Demand Impacts (Cumulative) Continued

DSM Summer Peak Demand Reduction (MW)	Status	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Smart Energy Profile	Expiring	18.6	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	0.0
Residential Refrigerator Removal	Expiring	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8
Residential Incentives	Expiring	20.6	20.6	20.6	20.6	20.6	20.6	20.6	20.6	20.6	20.6	20.6	20.6	20.6	20.6	20.6	20.6
Residential Conservation (HEPP)	Expiring	12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.4
School Energy Management Program (SEMP)	Expiring	2.1	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Customer Education and Public Information	Expiring	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	0.0	0.0
AMS Customer Service Offering	Approved	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	0.0	0.0
Residential and Small Nonresidential Demand Conservation	Approved	167.6	162.2	154.0	146.3	138.9	131.8	125.1	118.7	118.7	118.7	118.7	118.7	118.7	118.7	118.7	118.7
WeCare	Approved	4.0	4.5	4.9	5.3	5.8	6.2	6.6	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1
Large Nonresidential Demand Conservation	Approved	27.5	27.5	27.5	27.5	27.5	27.5	27.5	27.5	27.5	27.5	27.5	27.5	27.5	27.5	27.5	27.5
Nonresidential Rebates	Approved	179.1	184.3	189.5	194.8	200.0	205.3	210.6	215.9	215.9	215.9	215.9	215.9	215.9	215.9	215.9	215.9
Program Development and Administration	Approved	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	0.0	0.0
Total Annual Demand Reduction		437.6	417.5	415.0	413.0	411.2	409.9	408.9	408.3	408.3	408.3	408.3	408.3	408.3	408.3	408.3	408.3

Table 8-12: KU and LG&E Demand Side Management Energy and Demand Impacts (Cumulative) Continued

DSM Winter Peak Demand Reduction (MW)	Status	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Smart Energy Profile	Expiring	18.6	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	0.0
Residential Refrigerator Removal	Expiring	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8
Residential Incentives	Expiring	20.6	20.6	20.6	20.6	20.6	20.6	20.6	20.6	20.6	20.6	20.6	20.6	20.6	20.6	20.6	20.6
Residential Conservation (HEPP)	Expiring	12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.4
School Energy Management Program (SEMP)	Expiring	2.1	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Customer Education and Public Information	Expiring	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	0.0	0.0
AMS Customer Service Offering	Approved	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	0.0	0.0
Residential and Small Nonresidential Demand Conservation	Approved	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	0.0	0.0
WeCare	Approved	4.0	4.5	4.9	5.3	5.8	6.2	6.6	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1
Large Nonresidential Demand Conservation	Approved	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	0.0	0.0
Nonresidential Rebates	Approved	179.1	184.3	189.5	194.8	200.0	205.3	210.6	215.9	215.9	215.9	215.9	215.9	215.9	215.9	215.9	215.9
Program Development and Administration	Approved	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	0.0	0.0
Total Annual Demand Reduction		242.5	227.9	233.6	239.2	244.9	250.6	256.4	262.1	262.1	262.1	262.1	262.1	262.1	262.1	262.1	262.1

8.(3).(e).4 Program Costs

The projected costs provided in Table 8-13 reflect the latest approved DSM-EE Program Portfolio.

Table 8-13: DSM Program Costs ($M)

Program Expenses ($M)	Status	2018	2019	2020	2021	2022	2023	2024	2025	Total
Smart Energy Profile	Expiring	0.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.6
Residential Refrigerator Removal	Expiring	2.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.2
Residential Incentives	Expiring	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.0
Residential Conservation (HEPP)	Expiring	2.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.2
School Energy Management Program (SEMP)	Expiring	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Customer Education and Public Information	Expiring	4.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.3
AMS Customer Service Offering	Approved	0.9	0.9	0.5	0.5	0.5	0.5	0.5	0.5	4.8
Residential and Small Nonresidential Demand Conservation	Approved	5.5	3.6	2.4	2.6	2.4	2.4	2.4	2.3	23.5
WeCare	Approved	7.8	6.3	6.3	6.3	6.7	6.4	6.4	6.4	52.6
Large Nonresidential Demand Conservation	Approved	1.1	0.9	0.8	0.8	1.0	0.9	0.9	0.9	7.3
Nonresidential Rebates	Approved	3.2	2.8	2.9	2.8	2.5	2.5	2.6	2.6	21.8
Program Development and Administration	Approved	1.5	0.7	0.7	0.7	0.8	0.8	0.8	0.8	6.8
Total Programs		**30.3**	**15.3**	**13.6**	**13.8**	**13.8**	**13.4**	**13.4**	**13.4**	**127.1**

8.(3).(e).5 Projected Cost Savings

The Companies project that over the lives of the portfolio of programs that are in the most recently approved DSM-EE filing, customers will reduce demand by an aggregated or cumulative 410 MW through 2025. Customers will also realize in 2025 a total cumulative energy savings of 979 GWh.

8.(4) Planned Capacity and Energy Requirements Summary

The following sections summarize the Companies' forecasted demand and energy requirements and generation resources.

8.(4).(a) Resource Capacity Available at Summer and Winter Peak

Tables Table 8-14 and Table 8-15 summarize the Companies' forecasted loads and resource capacities and the corresponding reserve margins for the summer and winter seasons.

Table 8-14: Summer Peak Demand and Resource Summary (MW)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Gross Peak Load																
Low	6,972	6,591	6,542	6,479	6,399	6,406	6,343	6,289	6,244	6,165	6,145	6,069	6,024	5,929	5,825	5,726
Base	7,028	6,703	6,688	6,674	6,657	6,653	6,638	6,639	6,650	6,655	6,652	6,654	6,650	6,645	6,633	6,627
High	7,071	6,732	6,735	6,732	6,714	6,792	6,806	6,835	6,875	6,895	6,961	6,996	7,056	7,082	7,107	7,133
DCP	-127	-96	-91	-87	-84	-80	-77	-73	-70	-67	-64	-62	-59	-57	-54	-52
DSM	-247	-247	-236	-236	-236	-236	-236	-236	-236	-236	-236	-236	-236	-236	-236	-236
Net Peak Load																
Low	**6,598**	**6,248**	**6,214**	**6,156**	**6,079**	**6,090**	**6,031**	**5,980**	**5,938**	**5,862**	**5,844**	**5,772**	**5,729**	**5,636**	**5,534**	**5,437**
Base	**6,655**	**6,360**	**6,361**	**6,350**	**6,338**	**6,338**	**6,325**	**6,330**	**6,344**	**6,352**	**6,351**	**6,357**	**6,355**	**6,353**	**6,343**	**6,339**
High	**6,697**	**6,389**	**6,408**	**6,409**	**6,394**	**6,476**	**6,494**	**6,526**	**6,569**	**6,592**	**6,661**	**6,699**	**6,761**	**6,789**	**6,817**	**6,845**
Existing Capability[50]	7,754	7,476	7,476	7,476	7,477	7,477	7,478	7,478	7,478	7,478	7,478	7,478	7,478	7,478	7,478	7,478
Small-Frame SCCTs	87	87	87	73	73	73	73	73	73	73	73	73	73	73	73	73
CSR	141	141	141	141	141	141	141	141	141	141	141	141	141	141	141	141
Bluegrass	165	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
OVEC[51]	152	152	152	152	152	152	152	152	152	152	152	152	152	152	152	152
Total Supply	**8,299**	**7,856**	**7,856**	**7,842**	**7,843**	**7,843**	**7,844**	**7,844**	**7,844**	**7,844**	**7,844**	**7,844**	**7,844**	**7,844**	**7,844**	**7,844**
Reserve Margin																
Low	1,700	1,607	1,641	1,686	1,763	1,752	1,813	1,864	1,905	1,981	1,999	2,072	2,114	2,207	2,309	2,406
Base	1,644	1,495	1,495	1,491	1,505	1,505	1,518	1,513	1,499	1,492	1,492	1,487	1,489	1,491	1,501	1,505
High	1,601	1,466	1,448	1,433	1,448	1,366	1,350	1,318	1,274	1,252	1,183	1,145	1,083	1,054	1,027	998
Reserve Margin %																
Low	**25.8%**	**25.7%**	**26.4%**	**27.4%**	**29.0%**	**28.8%**	**30.1%**	**31.2%**	**32.1%**	**33.8%**	**34.2%**	**35.9%**	**36.9%**	**39.2%**	**41.7%**	**44.3%**
Base	**24.7%**	**23.5%**	**23.5%**	**23.5%**	**23.7%**	**23.7%**	**24.0%**	**23.9%**	**23.6%**	**23.5%**	**23.5%**	**23.4%**	**23.4%**	**23.5%**	**23.7%**	**23.7%**
High	**23.9%**	**22.9%**	**22.6%**	**22.4%**	**22.6%**	**21.1%**	**20.8%**	**20.2%**	**19.4%**	**19.0%**	**17.8%**	**17.1%**	**16.0%**	**15.5%**	**15.1%**	**14.6%**

[50] Existing capability is shown excluding small-frame SCCTs, CSR, Bluegrass, and OVEC and including 1 MW derates on each of the E.W. Brown Units 8, 9, and 11, which are planned to be resolved by 2024.
[51] OVEC's capacity reflects the 152 MW that is expected to be available to the Companies at the time of the summer peak, not its rating of 172 MW.

Table 8-15: Winter Peak Demand and Resource Summary (MW)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Gross Peak Load																
Low	6,524	6,398	6,112	6,092	6,071	6,005	6,180	6,075	6,077	6,021	5,988	5,931	5,805	5,754	5,742	5,682
Base	6,569	6,467	6,208	6,211	6,206	6,202	6,208	6,227	6,249	6,263	6,283	6,305	6,321	6,336	6,350	6,365
High	6,602	6,519	6,281	6,318	6,359	6,359	6,615	6,586	6,676	6,708	6,768	6,814	6,778	6,836	6,938	7,000
DCP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DSM	-247	-247	-236	-236	-236	-236	-236	-236	-236	-236	-236	-236	-236	-236	-236	-236
Net Peak Load																
Low	**6,277**	**6,151**	**5,876**	**5,856**	**5,835**	**5,769**	**5,944**	**5,839**	**5,841**	**5,785**	**5,752**	**5,695**	**5,569**	**5,518**	**5,506**	**5,446**
Base	**6,322**	**6,220**	**5,972**	**5,975**	**5,970**	**5,966**	**5,972**	**5,991**	**6,013**	**6,027**	**6,047**	**6,069**	**6,085**	**6,100**	**6,114**	**6,129**
High	**6,355**	**6,272**	**6,045**	**6,082**	**6,123**	**6,123**	**6,379**	**6,350**	**6,440**	**6,472**	**6,532**	**6,578**	**6,542**	**6,600**	**6,702**	**6,764**
Existing Capability[52]	7,996	8,004	7,722	7,722	7,730	7,730	7,555	7,748	7,748	7,748	7,748	7,748	7,748	7,748	7,748	7,748
Small-Frame SCCTs	98	98	98	82	82	82	82	82	82	82	82	82	82	82	82	82
CSR	141	141	141	141	141	141	141	141	141	141	141	141	141	141	141	141
Bluegrass	165	165	0	0	0	0	0	0	0	0	0	0	0	0	0	0
OVEC[53]	158	158	158	158	158	158	158	158	158	158	158	158	158	158	158	158
Total Supply	**8,558**	**8,566**	**8,119**	**8,103**	**8,111**	**8,111**	**7,936**	**8,129**	**8,129**	**8,129**	**8,129**	**8,129**	**8,129**	**8,129**	**8,129**	**8,129**
Reserve Margin																
Low	2,281	2,415	2,243	2,247	2,276	2,342	1,992	2,290	2,287	2,344	2,377	2,434	2,559	2,611	2,622	2,682
Base	2,236	2,346	2,147	2,128	2,141	2,144	1,963	2,138	2,115	2,101	2,081	2,060	2,044	2,029	2,015	2,000
High	2,202	2,293	2,074	2,021	1,988	1,988	1,557	1,779	1,689	1,657	1,597	1,551	1,586	1,529	1,426	1,364
Reserve Margin %																
Low	**36.3%**	**39.3%**	**38.2%**	**38.4%**	**39.0%**	**40.6%**	**33.5%**	**39.2%**	**39.2%**	**40.5%**	**41.3%**	**42.7%**	**46.0%**	**47.3%**	**47.6%**	**49.2%**
Base	**35.4%**	**37.7%**	**35.9%**	**35.6%**	**35.9%**	**35.9%**	**32.9%**	**35.7%**	**35.2%**	**34.9%**	**34.4%**	**33.9%**	**33.6%**	**33.3%**	**33.0%**	**32.6%**
High	**34.7%**	**36.6%**	**34.3%**	**33.2%**	**32.5%**	**32.5%**	**24.4%**	**28.0%**	**26.2%**	**25.6%**	**24.4%**	**23.6%**	**24.2%**	**23.2%**	**21.3%**	**20.2%**

[52] Existing capability is shown excluding small-frame SCCTs, CSR, Bluegrass, and OVEC and including 1 MW derates on each of the E.W. Brown Units 8, 9, and 11, which are planned to be resolved by 2024.
[53] OVEC's capacity reflects the 152 MW that is expected to be available to the Companies at the time of the winter peak, not its rating of 172 MW.

8.(4).(b) Energy Requirements Summary

Table 8-16 summarizes the Companies' forecasted energy requirements.

Table 8-16: Energy Requirements Summary (GWh, Base Energy Requirements Forecast)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Energy Requirements	34,607	33,093	32,609	32,506	32,472	32,460	32,535	32,502	32,507	32,511	32,550	32,503	32,477	32,486	32,520	32,486
Energy by Fuel Type																
Coal	27,428	25,265	25,380	25,121	25,299	25,614	26,414	25,724	25,724	25,534	26,403	26,433	25,993	26,184	26,239	25,711
Gas	6,543	6,856	6,321	6,658	6,547	6,465	5,811	6,525	6,463	6,640	5,779	5,828	6,248	6,025	5,948	6,467
Oil	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hydro	360	381	382	381	381	381	382	381	381	381	382	381	381	381	382	381
Solar	18	18	18	19	18	18	18	18	19	18	18	18	18	18	18	18
Firm Purchases from Other Utilities																
Bluegrass 3	58	16	0	0	0	0	0	0	0	0	0	0	0	0	0	0
OVEC	800	787	761	762	757	757	778	776	795	813	828	811	797	820	831	823
Firm Purchases from Non-Utility Sources	2.9	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.4
Reductions/Increases in Energy from DSM	-247	-247	-236	-236	-236	-236	-236	-236	-236	-236	-236	-236	-236	-236	-236	-236

8.(4).(c) Energy Input and Generation by Fuel Type

Table 8-17 shows the Companies' forecasts of total generation required to meet load and total energy input by primary fuel type.

Table 8-17: Generation and Energy Input by Fuel Type (Base Energy Requirements Forecast)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Coal																
Energy (GWh)	27,428	25,265	25,380	25,121	25,299	25,614	26,414	25,724	25,724	25,534	26,403	26,433	25,993	26,184	26,239	25,711
Fuel Burn (000 Tons)	12,927	11,576	11,608	11,625	11,733	11,982	12,349	12,024	12,034	11,927	12,336	12,363	12,154	12,238	12,257	12,029
Fuel Burn (MMBtu)	299,233	264,961	266,184	263,563	265,406	268,817	277,052	269,714	270,068	267,508	276,717	277,319	272,612	274,504	274,891	269,783
Gas																
Energy (GWh)	6,543	6,856	6,321	6,658	6,547	6,465	5,811	6,525	6,463	6,640	5,779	5,828	6,248	6,025	5,948	6,467
Fuel Burn (000 MCF)	48,240	49,753	45,750	47,486	46,861	45,485	41,851	45,932	45,852	47,372	42,065	40,670	43,830	41,876	42,936	46,437
Fuel Burn (MMBtu)	51,158	52,775	48,546	50,395	49,714	48,305	44,441	48,833	48,737	50,358	44,712	43,256	46,614	44,545	45,656	49,351
Oil																
Energy (GWh)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Fuel Burn (000 Gallons)	20	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Fuel Burn (MMBtu)	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hydro																
Energy (GWh)	360	381	382	381	381	381	382	381	381	381	382	381	381	381	382	381
Solar																
Energy (GWh)	18	18	18	19	18	18	18	18	19	18	18	18	18	18	18	18

8.(5) Resource Planning Considerations

8.(5).(a) Methodology

The Companies' resource planning process consists of the following activities:

1. Screening of demand-side and supply-side resource options
2. Assessment of target reserve margin criterion
3. Development of long-term resource plan

A high-level summary of these activities is included in "Resource Plan" in Section 5.(2). See Volume III for detailed overviews of these analyses.

8.(5).(b) Key Inputs and Uncertainties

The primary focus of resource planning is risk management. Key categories of risk stem from uncertainties related to the way customers use electricity, the performance of generation units, the price of fuel and other commodities, and the future impact of new state and federal regulations. See "Resource Planning Inputs and Uncertainties" in Section 5.(2) for a discussion of key resource planning inputs and uncertainties.

8.(5).(c) Decision Criteria

The goal of the resource planning process is to reliably meet customers' around-the-clock energy requirements both in the short-term and long-term at the lowest reasonable cost.

8.(5).(d) Required Reserve Margin

The reserve margin analysis is discussed in Sections 5.(2) and 5.(4) and is detailed in A complete summary of this analysis is included in Volume III ("2018 IRP Resource Screening Analysis").

8.(5).(e) Research and Development

The Companies' Research and Development Department ("R&D") aims to prepare the Companies for tomorrow's problems. R&D focuses on emerging technologies pertinent to the Companies' future, including renewable/sustainable energy technologies, carbon capture, energy storage, and wastewater treatment. R&D aims to conduct internal research projects, collaborate with groups across the Companies' lines of business, and partner with external organizations, such as EPRI and university entities to leverage available resources and provide a bridge to technical information. R&D exists to support research and education activities and welcome collaboration on potential future projects, both long-term (strategic) and near-term (tactical). The energy industry constantly changes and utility companies must stay at the forefront of this change to continue to provide the best service possible to customers.

Solar Photovoltaic ("PV") Generation

The ability to integrate more renewable generation and battery storage as well as future penetration and charging patterns for electric vehicles are key considerations for future resource planning decisions. Therefore, the Companies gained approval from the Kentucky Public Service Commission in December 2014 to build the first utility-scale solar PV plant in Kentucky. The project was completed in April 2016 for $25 million and began commercial operation in June 2016. R&D currently monitors this generation source closely and is working with industry research partners such as EPRI and universities to better understand performance, degradation, and maintenance needs. Advanced system modeling and performance monitoring is providing the Companies with valuable knowledge that will be used in the design and construction of any future sites. Another aspect to the Brown Solar project is that data collected from the site is also made publicly available via the Companies' external website.

Energy Storage

R&D is researching energy storage technologies regarding cost, performance, and advanced control techniques. Also located at E.W. Brown is an energy storage research and demonstration site, which is a joint venture between the Companies and EPRI. It has testing bays for three megawatt-scale energy storage systems and is designed to accommodate various energy storage technologies. The Companies' investment was $2.5 million for infrastructure and EPRI invested $2 million for the first battery storage system. The Companies are presently testing the currently installed 1 MW, 2 MWh lithium ion battery system and advanced control algorithms. Through partnership with local universities, the Companies are also performing system modeling and developing applications for combining intermittent renewable generation with energy storage.

Electric Transportation

R&D has been tracking developments with electric transportation, both from vehicle technology and charging infrastructure standpoints. A portion of this work includes monitoring electric vehicle registrations in the Companies' service territory and at the state and national levels. This data is used to develop energy demand forecasts and to help determine charging infrastructure locations. Through partnership with EPRI, the Companies also monitor activities at other utilities for novel system adaptations for additional electric load from electric transportation.

Wastewater Treatment

The need for wastewater treatment solutions at the Companies' generation facilities has led R&D to focus a portion of its research on a number of topics related to wastewater treatment, including Effluent Limitation Guidelines, bottom ash pond closure, and sulfite analysis. Pilot and full-scale projects have been constructed at various generation facilities to test these solutions.

Greenhouse Gas Research

As indicated in the 2014 IRP, the Companies support efforts at the University of Kentucky's Center for Applied Energy Research and the Carbon Management Research Group ("CMRG") as related to carbon capture technologies. Leveraging funding from the Companies with a $14.5 million U.S. Department of Energy ("DOE") grant in 2011, the CMRG group installed a carbon capture slip-stream pilot demonstration system at the Companies' E.W. Brown plant. The process take a small portion of the flue gas and uses an amine-based solvent to capture CO_2. The University of Kentucky continues to operate this pilot plant and is trialing a number of amine varieties as well as various process improvements to reduce the overall cost to provide post-combustion carbon capture at a larger scale. Additionally, the University of Kentucky is working with the Companies to secure additional DOE funding to build a larger scale carbon capture plant at the Trimble County Station.

Data Analytics

Increasing numbers of sensors on the electric grid as well as within generation facilities are beginning to produce large amounts of data, and utilities are seeking opportunities to maximize their value. At the same time, anecdotes about value derived from mining "big data" in other industries abound. The Companies aim to understand the potential of data analytics as it applies to better understanding customers and improving operations. However, collecting, managing, analyzing, and providing value from this data is a monumental task. R&D has started looking into various methods for analyzing this data to gain value from it.

Additionally, R&D is developing tools that can be used to streamline the Companies' manual processes, leading to cost-savings and more efficient operations. For example, R&D is using optical character recognition to make drawing databases more searchable, reviewing historical service orders to analyze generation O&M costs, and modeling FGDs.

8.(5).(f) Environmental Regulation Compliance and Planning

Acid Deposition Control Program

The Acid Deposition Control Program was established under Title IV of the CAAA and applies to the acid deposition that occurs when SO_2 and nitrogen oxides NO_x are transformed into sulfates and nitrates and combine with water in the atmosphere to return to the earth in rain, fog or snow. Title IV's purpose is to reduce the adverse effects of acid deposition through a permanent reduction in SO_2 emissions and NO_x emissions from the 1980 levels in the 48 contiguous states. With CAIR implementation in 2009/2010 and CSAPR in 2015, further reductions in SO_2 and NO_x aided in reducing ozone and fine particulate ("$PM_{2.5}$") in affected regions of the country (including Kentucky). However, with implementation of new NAAQS for SO_2, NO_x, $PM_{2.5}$, and ozone, rules covering hazardous air pollutants, rules requiring the reduction of greenhouse gas emissions, requirements of Clean Water Act Section 316(b), rules implementing effluent guidelines under the Clean Water Act, and regulations for management and storage of CCR material, it is certain that significant capital investments will be needed in the future to meet compliance requirements.

Clean Air Interstate Rule / Cross-State Air Pollution Rule

As an update to the 2014 IRP, the Clean Air Interstate Rule ("CAIR") was replaced by the Cross-State Air Pollution Rule ("CSAPR"). Phase 1 of CSAPR began being implemented on January 1, 2015, with Phase 2 of CSAPR beginning on January 1, 2017. Allocations for the Companies' system for Phase 1 of CSAPR were of similar quantity as those from CAIR.

Due to continuing ozone non-attainment issues primarily in the northeast, EPA determined through preliminary modeling that emissions from Kentucky and 8 other states are significantly contributing to downwind ozone attainment issues. On September 7, 2016, EPA finalized the CSAPR Update Rule ("CSAPR II") to further reduce ozone season NO_x allocations 30% compared to the 2017 Phase 2 allocations of the original CSAPR beginning in 2017. Additionally, the number of banked NO_x allowances at the end of 2016 were reduced such that only about 30% could be carried forward for use in 2017 and beyond. The Companies successfully implemented NO_x operating targets in 2017 to meet CSAPR Update allowance allocations. The Companies plan to continue to operate and maintain the affected facilities in compliance with the CSAPR Update requirements.

Hazardous Air Pollutant Regulations/Mercury and Air Toxics Standard

EPA developed final rules to establish National Emission Standards for Hazardous Air Pollutants for the coal- and oil-fired electric utility industry. The Mercury and Air Toxics Standards ("MATS") rule was published in the Federal Register on February 16, 2012, and set emission limits for mercury, acid gases, toxic metals, and organics including dioxins and furans based on the maximum achievable control technology ("MACT") for the industry. Since the 2014 IRP, installation of emission controls (e.g., pulse-jet fabric filter systems, dry sorbent injection systems, powdered activated injection systems, etc.) to meet MATS emission limits has been completed. Continued compliance is managed per MATS defined monitoring, testing, work practices, record keeping and reporting.

National Ambient Air Quality Standards

SO_2

As an update to the 2014 IRP, between 2014 and 2016, LG&E updated all Mill Creek units with state of the art wet flue gas desulfurization equipment. Those installations and subsequent Title V permit updates have successfully aided in reducing SO_2 at the Watson Lane monitor to levels well below the compliance requirement. Although the Sierra Club is contesting the revised Title V permit, the permit received regulatory approval. The subsequent State Implementation Plan submitted by the Louisville Metro Air Pollution Control District ("LMAPCD") is awaiting final EPA approval.

On August 10, 2015, EPA finalized requirements referred to as the Data Requirements Rule ("DRR") for a subsequent phase to assess the attainment status of areas near large sources of SO_2 emissions that did not have adequate ambient monitoring and that were not included in the April 2015 notifications. The DRR required facilities to assess attainment by either modeling or ambient monitoring that had SO_2 emissions in 2014 of 2,000 tons or greater. The Companies received notification from the Kentucky Division for Air Quality ("KDAQ") dated October 22, 2015, that Trimble County and Ghent would need to provide an attainment assessment under the DRR. Air dispersion modeling has indicated the areas near both facilities are in attainment with the NAAQS. The modeling was submitted by the Companies and was approved by the EPA.

Additionally, by Consent Decree entered on January 7, 2017, EPA issued an Integrated Science Assessment for the SO_2 NAAQS on December 13, 2017. The Consent Decree also requires EPA to sign a notice of proposed rulemaking for any revision of the SO_2 NAAQS by May 25, 2018, and sign a final rulemaking by January 28, 2019.

EPA signed a proposed rule on May 25, 2018 and published it on June 8, 2018 to retain the primary SO_2 NAAQS (i.e., retain the 1-hour SO_2 standard at 75 parts per billion ("ppb") as set in 2010. The comment period for the proposed rule closed on August 9, 2018. The Companies will be following these developments and assessing their impacts on operating facilities.

NO_x/NO_2

Additional air quality monitors were to be installed in phases between 2014 and 2017 and were to be utilized in development of future revisions to the nitrogen dioxide (“NO_2”) standard. However, on December 22, 2016, EPA promulgated a rule that removed the requirement for near-road NO_2 monitoring for populations areas between 500,000 and one million people.

EPA is also planning to evaluate whether changes to Prevention of Significant Deterioration (“PSD”) air quality increments are needed. If so, this could place further limits on the allowable amount of increased emissions from a new or modified source.

Additionally, by Consent Decree entered on January 7, 2017, EPA reviewed the NO_2 NAAQS by July 14, 2017 and proposed to retain the current NAAQS (i.e., the 1-hour standard of 100 ppb and the annual average standard of 53 ppb). EPA released a final rule on April 6, 2018 and published it on April 18, 2018 to retain the primary 1-hour and annual NO_2 NAAQS (i.e., retain the 1-hour NO_2 standard at 100 ppb as set in 2010 and the annual standard at 53 ppb as set in 1971). On August 13, 2018, the KDAQ proposed a revision to the State Implementation Plan (“SIP”) that demonstrates the “Good Neighbor” provision of the 2010 NO_2 NAAQS are being met and requests that EPA approve the demonstration in order for Kentucky to fully implement the 2010 1-hour NO_2 NAAQS. The Companies will continue to follow these issues involving NO_2 NAAQS and assess their impacts on operating facilities.

Ozone

On October 26, 2015, the EPA published the 2015 ozone NAAQS at 70 ppb. On September 30, 2016, Kentucky submitted their recommendations for classifications. Kentucky recommended that Boone, Campbell, and Kenton counties be designated as “nonattainment” and that all other counties be designated as “unclassifiable/attainment”. In assessing the attainment designations, the EPA included 2016 data. By including the 2016 data, the EPA concluded via the December 20, 2017 120-day letter that Jefferson, Oldham, and Bullitt counties will be classified marginal non-attainment.

The EPA published final non-attainment classification designations on April 30, 2018, which included Boone, Campbell, Kenton, Jefferson, Oldham, and Bullitt counties in Kentucky as marginal non-attainment. Upon publication, marginal non-attainment areas have a three-year deadline to get into attainment. Marginal areas are not required to submit the traditional attainment plan for bringing areas into attainment. States with marginal areas are only required to submit an emissions inventory and emissions statement for those areas. However, states are required to achieve attainment by 2021 and may implement measures in-state to do so.

Additionally, because of the revision to the ozone NAAQS, KDAQ must submit an “infrastructure” State Implementation Plan (“SIP”) within three years of the promulgation of the new or revised NAAQS. Therefore, KDAQ must submit the infrastructure SIP prior to October 26, 2018. This SIP demonstrates that the state has legal authority and resources to implement the revised SIP. The Companies will continue to follow these ozone NAAQS issues and assess their impacts on operating facilities.

PM / $PM_{2.5}$

On April 7, 2015, EPA published a correction to the attainment designations for Jefferson County including a portion of Bullitt County to a designation of "unclassifiable" and "unclassifiable/attainment" for the remainder of Kentucky based on monitoring data in Kentucky and nearby areas from 2012 through 2014. Additionally, in March 2015, EPA proposed an option for resolution of attainment issues between the 1997 and the 2006 standard, by allowing achievement of attainment status with the 2013 standard to satisfy the attainment status of the 1997 standard, considering the 2013 standard is more restrictive. On August 24, 2016, EPA resolved the attainment issues by revoking the 1997 primary standard because the 2013 standard was lower. KDAQ submitted a final SIP certification letter to EPA in 2016 certifying that Kentucky's SIP contains the necessary provisions for implementing the 2012 $PM_{2.5}$ NAAQS. Additionally, on May 4, 2018, KDAQ submitted a letter to EPA requesting that Jefferson and Bullitt counties in Kentucky be redesignated from "unclassifiable" (due to insufficient data) to "unclassifiable/attainment" (based on new data) for the 2012 PM2.5 NAAQS. EPA has yet to take action on those submittals. As a result of the shutdown of coal-fired generation at the Cane Run facility in 2015 and the installation of pulse jet fabric filters across the Companies' fleet, concerns with the $PM_{2.5}$ attainment status are expected to be minimized.

Greenhouse Gases

As an update to the 2014 IRP, the Greenhouse Gas New Source Performance (GHG NSPS) final rule was published by EPA in the Federal Register on October 23, 2015. EPA's final determination of the NSPS for carbon dioxide ("CO_2") relative to these sources is 1,400 lb CO_2/MWh (gross) based on supercritical pulverized coal unit ("SCPC") with partial carbon capture and storage ("CCS") of approximately 16% with bituminous coal as the best system of emission reduction ("BSER") for newly constructed units. As an alternative for BSER, EPA determined a new SCPC unit co-firing natural gas could also meet the standard. The limit in the final rule is less stringent than the proposed rule of 1,100 lb CO_2/MWh (gross) due to an assumed higher level of partial CCS in the proposed rule.

EPA based the final standards for newly constructed or reconstructed stationary combustion turbines on BSER represented by efficient Natural Gas Combined Cycle ("NGCC") technology for base load natural gas fired units and clean fuels for non-base load and multi-fuel-fired units. The published final limits are 1,000 lb CO_2/MWh (gross) or 1,030 lb CO_2/MWh (net) for base load natural gas-fired units (base load rating of $\geq$ 250 MMBtu/h and > 25 MW (net) of electricity to the grid). For multi-fuel-fired units based on the percentage of co-fired natural gas, the standard is 120 lb CO_2/MMBtu for non-base load natural gas-fired units, and 120 to 160 lb CO_2/MMBtu for multi-fuel-fired units based on the percentage of co-fired natural gas.

In June 2014, EPA proposed a GHG NSPS for modified or reconstructed existing sources that would set an emission rate in units of lb of CO_2 per MWh (net) that is based on a 2% improvement of the best year from a look-back period from 2002 to date of modification or reconstruction. The proposal would set minimums (floors) of 1,900 and 2,100 lb CO_2 per MWh (net) for coal-fired units greater than 2,000 MMBtu/h and 2,100 MMBtu/h respectively. The rule also proposed GHG NSPS for combustions turbines with greater than 33% of the nameplate capacity utilized for electric generation that are modified or reconstructed to meet emission an emission limit of 1,000 and 1,100 lb CO_2 per MWh (net) for units greater than 850 MMBtu/h and less than 850 MMBtu/h, respectively.

EPA's final requirements for reconstructed combustion turbines were included in their final published rule with newly constructed combustion turbines as described above. The final rule was published by EPA in the Federal Register on October 23, 2015, for modified fossil fuel-fired steam generating units and integrated gasification combined cycle units that perform a modification on or after the date of publication of the proposed standards, June 18, 2014. The NSPS for modified existing sources becomes applicable if a modification occurs that results in an increase in CO_2 hourly emissions of more than 10 percent. BSER for modified sources was determined by EPA to represent the most efficient generation at the affected EGU achievable through a combination of "best operating practices and equipment upgrades". The final standards of performance for CO_2 relative to these sources is a unit-specific emission limit determined by the unit's best historical annual CO_2 emission rate (from 2002 to the date of the modification). The emission limit will be no more stringent than 1,800 lb CO_2/MWh (gross) for sources with heat input > 2,000 MMBtu/hr or 2,000 lb CO_2/MWh (gross) for sources with heat input ≤ 2,000 MMBtu/hr. The final rule places a more stringent maximum limit on modified sources than the proposed rule that included limits of 1,900 and 2,100 lb CO_2/MWh (gross) for units > 2,000 and ≤ 2,000 MMBtu/hr respectively. Additionally, EPA proposed regulations in June 2014 for GHG performance standards applicable to existing fossil fuel-fired electric generating units (ESPS) that commenced construction prior to January 8, 2014. The proposed regulation would reduce CO_2 emissions by 30% from 2005 by 2030 with interim reductions beginning in 2020. The regulation was proposed under Section 111(d) of the Clean Air Act as guidelines for development of SIPs to meet "state-specific" emission rate targets in units of lb CO_2 per MWh (net), with an option to convert the target to units of tons CO_2 per year. The proposed emission-rate targets for Kentucky are 1,763 lb CO_2 per MWh (net) by 2030 with an interim emission rate of 1,844 lb CO_2 per MWh (net) by 2020.

GHG NSPS are currently being litigated. On April 4, 2017, the EPA announced that it would be reviewing the GHG NSPS pursuant to a March 2017 Executive Order signed by President Trump with the intent to suspend, revise, or rescind the rule. On August 10, 2017, the U.S. Court of Appeals for the D.C. Circuit issued an order holding all challenges to the GHG NSPS in abeyance "pending further order of the court."

On October 23, 2015, EPA published the final ESPS—the final Clean Power Plan ("CPP")—in the Federal Register. The final rule decreased Kentucky's and many other states' emission targets from those of the proposed rule, primarily due to changes in EPA's analyses of BSER based on regional considerations instead of state-specific considerations. In shifting from a state-specific BSER to a regional based BSER, the building blocks utilized for Kentucky assume a greater utilization of existing NGCC generation and renewable energy (although not necessarily located in Kentucky). Development and use of demand-side management and energy efficiency was eliminated due to concerns that EPA lacked authority to incorporate it in the emission reduction targets. The emission rate goal in units of lb CO_2/MWh (net) for Kentucky was reduced in the final rule from 1,844 to 1,509 in the interim compliance period and from 1,763 to 1,286 by 2030.

With the final rule, the beginning of the interim compliance period was shifted from 2020 to 2022. Each state can craft its own emission reduction trajectory, but milestones must be evaluated for 2022-2024, 2025-2027, and 2028-2029 with the requirement that affected EGUs in the state collectively meet the equivalent reductions of the interim limits. State plans must contain procedures to ensure the required CO_2 reductions are being accomplished and no increases in emissions relative to each state's planned emission reduction trajectory are occurring.

In response to applications for stay by numerous parties, on February 9, 2016, the Supreme Court granted a stay of the CPP pending judicial review of the rule. The stay will remain in effect pending Supreme Court review if such review is sought.

Associated with the final rule for existing source performance standards, EPA published a proposed implementation plan on October 23, 2015, that can be adopted by states or utilized by EPA in the event a state does not submit a timely and acceptable compliance plan to implement the ESPS rule. EPA's proposed implementation plan includes allocations of CO_2 emissions for each state reflective of the final ESPS rule and the requirement to limit emissions of CO_2 from any new sources of generation that might be utilized in place of existing generation. The Companies submitted comments to EPA on January 21, 2016. On March 28, 2017, President Trump signed an executive order to review the CPP for the potential to revise or withdraw the rule. On October 16, 2017 the EPA proposed a repeal of the CPP. On December 28, 2017 the EPA published Advanced Notice of Proposed Rulemaking for a replacement of the CPP.

On August 21, 2018, the EPA proposed the Affordable Clean Energy ("ACE") rule to replace the 2015 CPP. The proposed ACE rule would establish emission guidelines for states to develop plans to address greenhouse gas ("GHG") emissions from existing fossil fuel-fired power plants. As proposed, ACE defines the best system of emissions reduction for GHG emissions from existing power plants as on-site, heat-rate efficiency improvements. Included in this proposed rulemaking are revisions to the New Source Review permitting program, allowing states the option to adopt an hourly emissions increase test that incentivizes efficiency improvements. EPA proposes a list of "candidate technologies" that states would need to consider in establishing standards of performance for individual existing plants. States will determine which of these technologies are appropriate for each plant, and establish a standard of performance that reflects the degree of emission reduction from their application. States will have three years from the date of the final rule to prepare and submit a plan that establishes a standard of performance. Once a state plan is submitted, EPA will have 12 months to evaluate and determine whether the plan can be approved. In the event a state does not submit a plan or fails to submit an approvable plan, EPA will then have two years to develop a federal plan for that state.

Clean Water Act - 316(b): Regulation of Cooling Water Intake Structures

The Clean Water Act section 316(b) requires the reduction of adverse environmental impact upon aquatic populations by using Best Available Control Technology for water withdrawn from a water source for cooling purposes. EPA published a revised version of the 316(b) regulations on August 15, 2014, which became effective on October 14, 2014. The regulation addresses both impingement and entrainment impacts for aquatic species. With the retirement of the coal-fired units at Cane Run, Green River and Tyrone, all the remaining generating units, except for Mill Creek Unit 1, meet the impingement standard by utilizing closed-cycle cooling which is one of the listed compliance options. For the entrainment standard, only the combined four units of Mill Creek Station will exceed the 125 MGD withdrawal threshold for entrainment, which will require a series of aquatic studies to be conducted and a final report submitted to the Kentucky Division of Water. Negotiations with the state agency will then determine appropriate technology strategies needed to obtain compliance with the regulation. The studies must be completed and submitted with the Mill Creek NPDES permit renewal application in 2023.

Clean Water Act: Steam Electric Power Generating ELG

EPA published final effluent limitation guidelines ("ELG") on November 3, 2015, which became effective on January 4, 2016. The revised regulations require major changes to wastewater treatment systems at existing coal-fired plants that generate both bottom and fly ash wastewaters, and for facilities that generate gypsum wastes from flue-gas desulfurization ("FGD") scrubbers. The regulations impose a prohibition on the discharge of ash transport waters by no later than 2023. The new regulations also include greatly reduced the discharge limits from FGD wastewaters on mercury, arsenic, selenium and nitrates. The new discharge standards will require additional treatment of the FGD wastewaters through physical or chemical treatment facilities plus possibly biological treatment technology. New discharge limits will be incorporated into each facility's National Pollutant Discharge Elimination System ("NPDES") water discharge permit starting in 2018 but no later than 2023. On September 18, 2017, the EPA published a final rule that postponed certain compliance dates for the ELG regulations until no sooner than November 1, 2020, while EPA reconsiders portions of the regulation. Since the ELG regulations have no impact on Kentucky's recently updated state water quality standards, new physical or chemical treatment systems are currently under construction at each coal-fired station in the fleet. Additional treatment systems may be required in the future based on EPA's revisions to the ELG rule. EPA expects to have a revised ELG rule finalized by December 2019.

Coal Combustion Residuals

EPA issued a new coal combustion residuals ("CCR") regulation on December 19, 2014, with an effective date of October 14, 2015. The new rule makes significant changes in the management and storage practices of CCR managed in ash treatment basins (ash ponds) or special waste landfills.

After several years of review and public comment, EPA chose to regulate CCRs as a non-hazardous solid waste under Resource Conservation and Recovery Act Subtitle D. EPA imposed a set of minimum standards all CCR storage units must meet within prescribed timeframes to remain in operation. Unlined CCR storage impoundments (which accounts for most all LG&E-

KU ponds) must monitor groundwater surrounding CCR impoundments and begin closure of the ponds within 6 months if a statistically significant increase in groundwater contaminates are found. Those studies are nearing an end and will likely lead to the eventual closure of all current CCR storage impoundments. EPA is currently reconsidering portions of the CCR rule and published the first round of revisions in the Federal Register on July 18, 2018. Additional revisions to the CCR rule are expected to be implemented by spring 2019.

8.(5).(g) Consideration Given to Market Forces and Competition

In the development of the 2018 IRP, the Companies considered market forces and competition. This consideration is reflected in the appropriate sections of the IRP.

9 Financial Information

The revenue requirements resulting from the resource planning analyses are summarized in Volume III ("2018 IRP Long-Term Resource Planning Analysis"). The discount rate used in present value calculations is 7.06%. A 2% inflation rate was used where applicable. An annual forecast of total electricity production costs is shown in Table 8-8.