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.(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

John Bevington, Director Business and Economic Development

Brandan Burfict, Manager Environmental Air

Rebecca Cash, Manager Environmental Land & Water

Lauren Colberg, Acting Manager Emerging Business Planning and Development

Robert Conroy, VP State Regulation and Rates

Michael Drake, Director Generation Services

David Huff, Director Advanced Meter Initiatives

Philip Imber, Director Environmental Affairs

Tim Jones, Manager Sales Analysis and Forecasting

Delyn Kilpack, Principal Engineer Transmission Strategy and Planning

Rick E. Lovekamp, Manager Regulatory Strategy/Policy

Beth McFarland, VP Transmission

Brad Pabian, Manager Generation Engineering

Aron Patrick, Manager Technology Research and Analysis

Karmen Powell, Manager Distribution Electric Engineering

Eileen Saunders, VP Customer Services

Michael Sebourn, Manager Generation Planning

David S. Sinclair, VP Energy Supply and Analysis

Allyson Sturgeon, Managing Senior Counsel, Regulatory and Transactions

Steve Turner, VP Power Production

Stuart Wilson, Director Energy Planning, Analysis and Forecasting

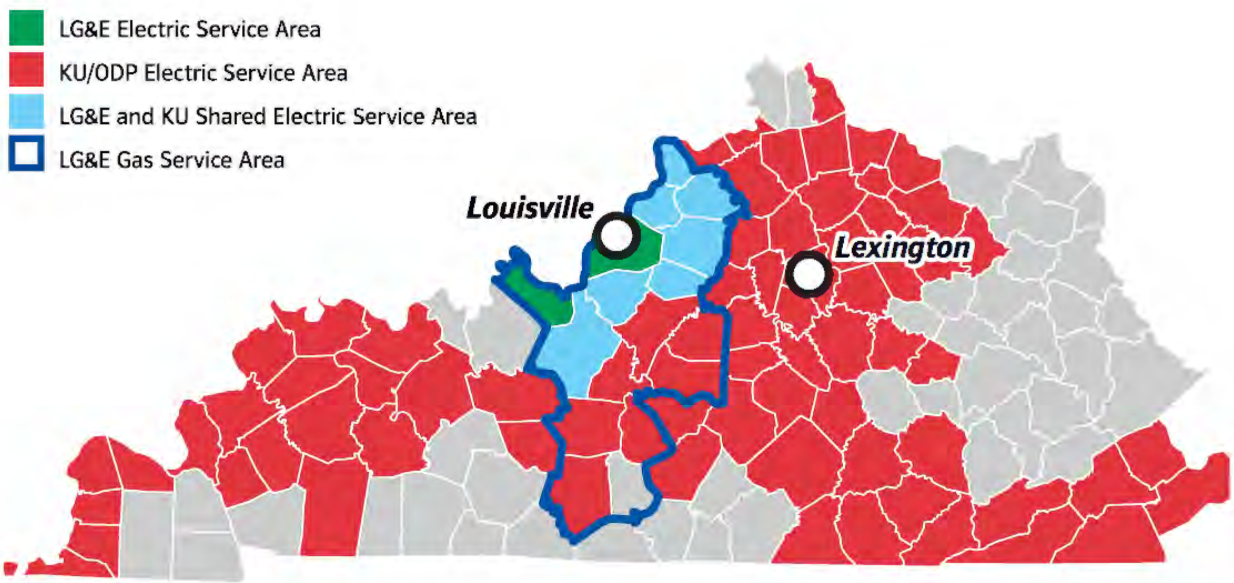
John Wolfe, VP Electric Distribution

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 more than 1.3 million customers and have consistently ranked among the best companies for customer service in the United States. LG&E serves almost 330,000 natural gas and 425,000 electric customers in Louisville and 16 surrounding counties. KU serves more than 560,000 customers in 77 Kentucky counties and five counties in Virginia, where KU operates under the name Old Dominion Power Company (see Figure 5-1). In addition, KU provides wholesale power to two municipalities in Kentucky.

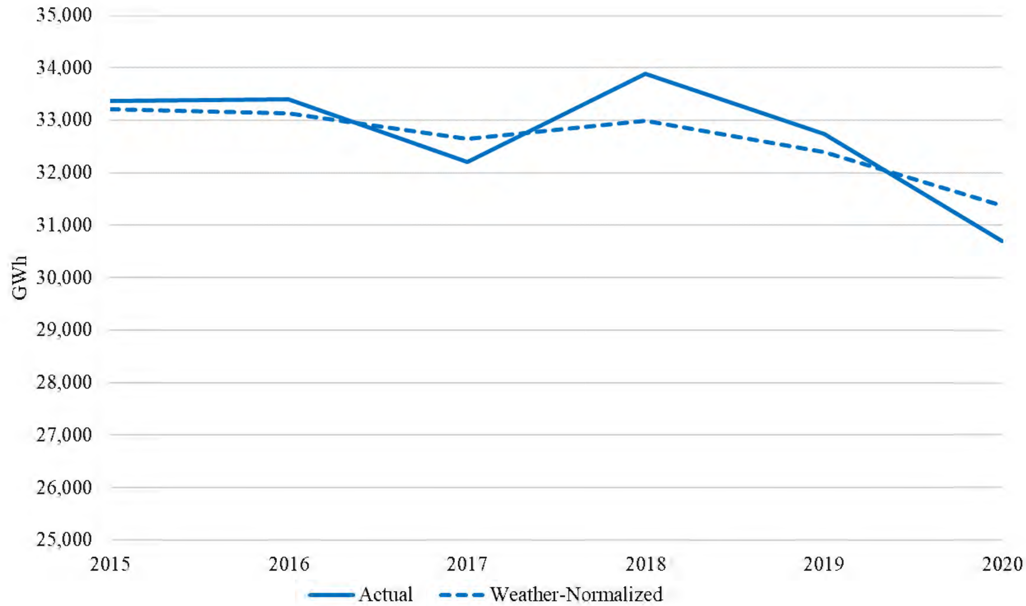
Figure 5-1: LG&E and KU Service Territory Map



Reliable, low-cost electricity is critically important to the Commonwealth's economy. As a leading manufacturer of automobiles, steel, and other products, Kentucky was the 7th most electricity-intensive U.S. state in 2019, as measured by the ratio of electricity consumption and state gross domestic product.

Figure 5-2 shows actual and weather-normalized energy requirements in the LG&E and KU service territories since 2015. Prior to 2020, energy requirements were slightly declining as increased consumption from the addition of new customers was more than offset by mining sector declines, industrial production efficiency improvements, and efficiency improvements in residential and commercial end-uses. Energy requirements declined significantly in 2020 due to the COVID-19 pandemic but are forecasted to recover to the slightly declining trend observed prior to the pandemic (see Section 5.(3)).

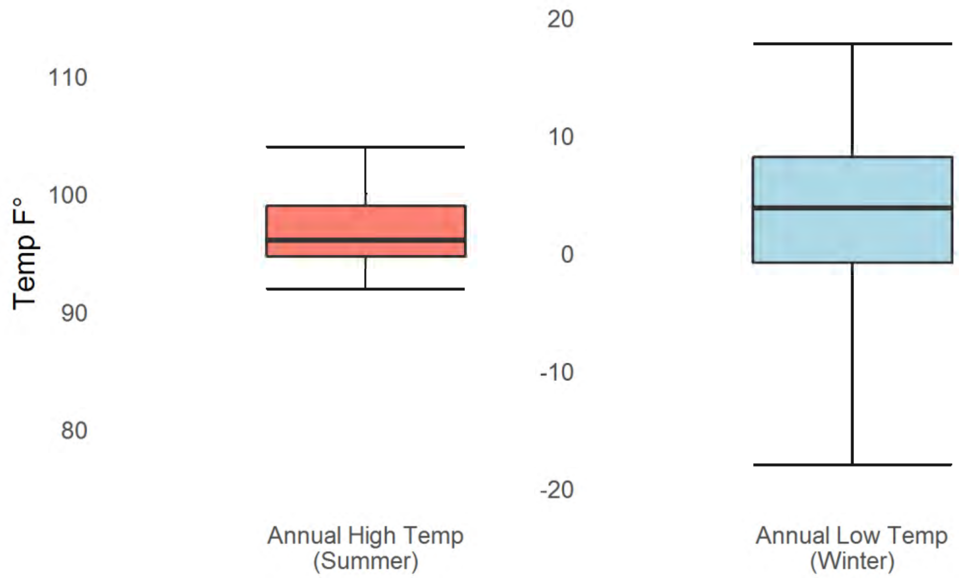
Figure 5-2: LG&E and KU Energy Requirements, 2015-2020[1]



Temperatures in Kentucky can range from below zero degrees Fahrenheit to above 100 degrees Fahrenheit. Figure 5-3 shows the distribution of annual high and low temperatures in Louisville over the last 48 years. From 1973 to 2020, the median annual high temperature was 96.1 degrees Fahrenheit and the median annual low temperature was 3.8 degrees Fahrenheit. Additionally, the variability of low temperatures in the winter is significantly greater than the variability of high temperatures in the summer.

[1] Energy provided to the municipal customers that departed in 2019 is removed from the history.

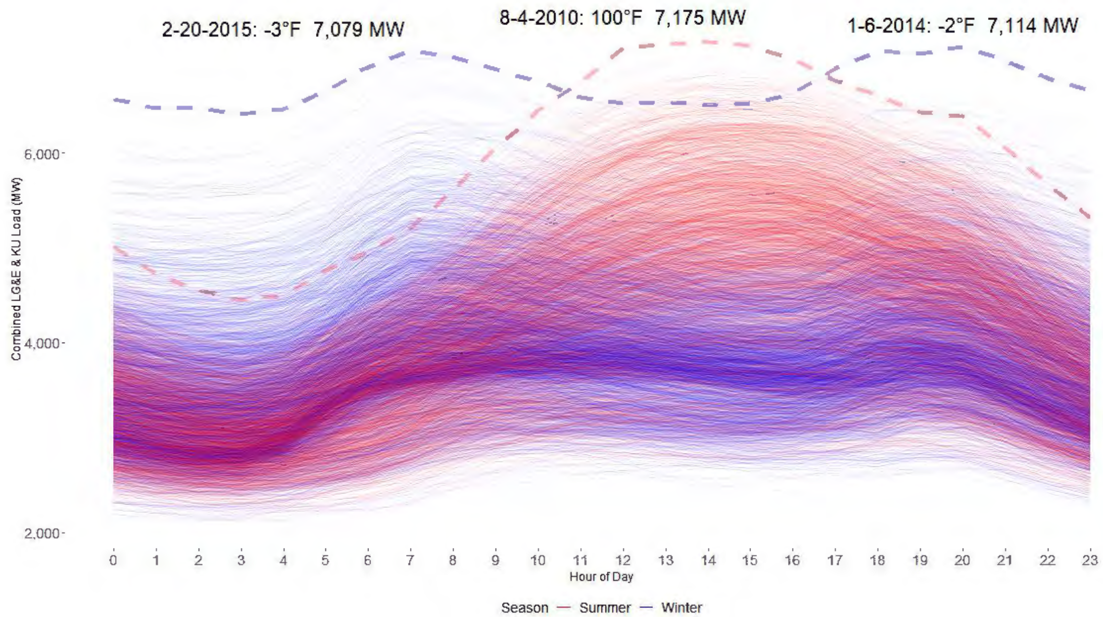
Figure 5-3: Louisville Annual High and Low Temperature Distributions (1973-2020)[2]



Due to the potential for cold winter temperatures and the increasing penetration of electric heating, the Companies are somewhat unique because annual peak demands can occur in both the summer and 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 5-4 contains the Companies' hourly load profiles for every day from 2010 through 2020. 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 can occur in the mornings or evenings. 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.

[2] The limits of the box in the boxplots reflect the 25th and 75th percentiles while the "whiskers" represent the maximum and minimum.

Figure 5-4: Hourly Load Profiles, 2010-2020



System demands from one moment to the next can be almost as volatile as average demands from one hour to the next. Figure 5-5 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 5-5: Four-Second Demands, 5:00-7:00 PM on January 6, 2014

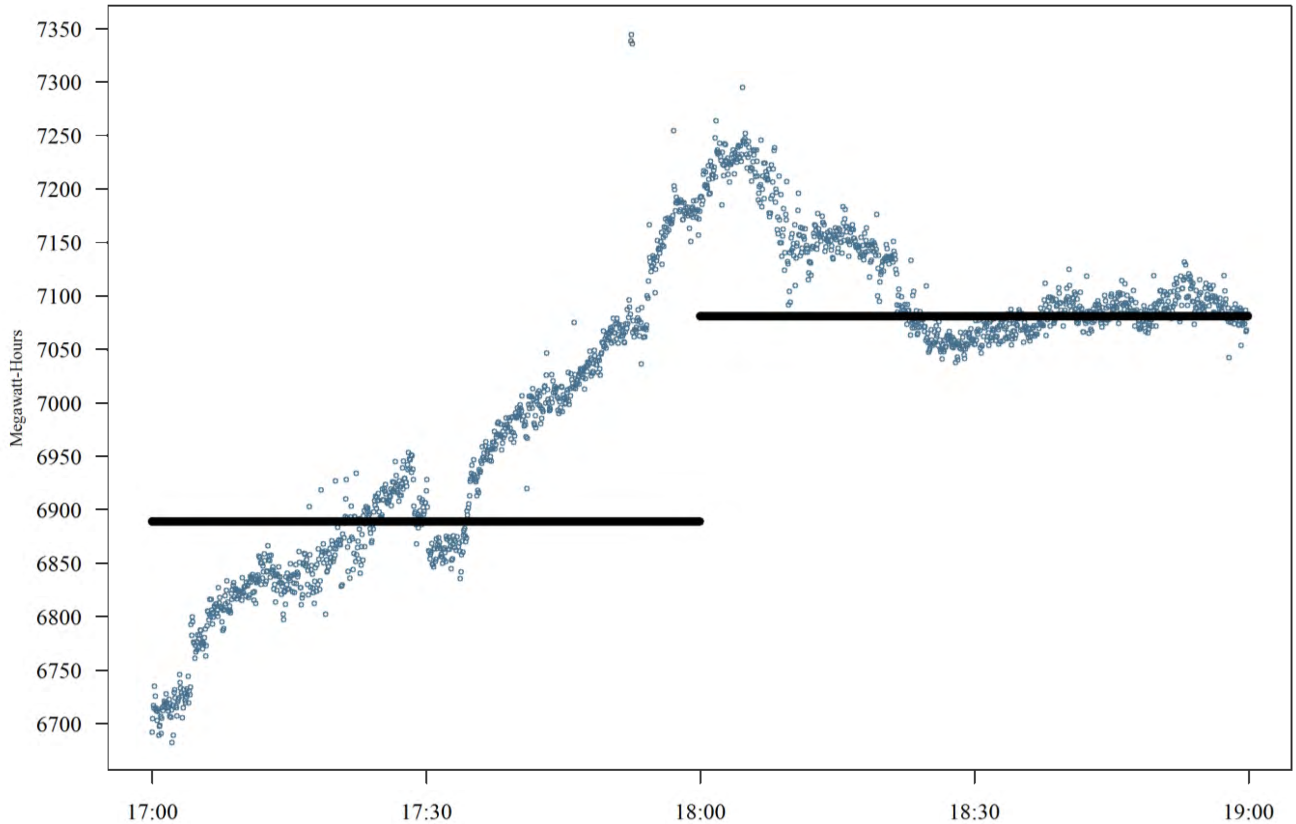


Table 5-1 contains a summary of the Companies' dispatchable, non-dispatchable, and demand-side management resources.[3] Different types of generation resources play different roles in serving customers. Dispatchable resources include baseload and peaking resources. The Companies' baseload resources are 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.[4] The Companies' non-dispatchable resources are renewable resources and 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.

[3] A detailed listing of the Companies' generation resources is included in Table 8-3.
[4] 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 2021

			Total Net Capacity (MW)	
Resource	**Number of Units**	**Unit Size (Range in Net Summer Capacity, MW)**	**Summer**	**Winter**
Dispatchable Generation				
Coal[5]	11	297 - 549	4,867	4,910
Natural Gas Combined Cycle ("NGCC")	1	662	662	683
Large-Frame SCCT	14	121 - 159	2,007	2,253
Small-Frame SCCT[6]	4	12 – 23	61	71
Non-Dispatchable Generation				
Solar[7]	2	0.3 – 8	9	0
Hydro	11	8 - 10.5	96	72
Total Generation Resources	**42**	**0.3 - 549**	**7,702**	**7,989**
Demand-Side Management Resources				
Curtailable Service Rider	N/A	N/A	127	127
Demand Conservation Program	N/A	N/A	63	0
Total Demand-Side Resources	**N/A**	**N/A**	**190**	**127**

Table 5-2 contains a listing of the Companies' generating stations. With the exception of the Companies' share of OVEC, all of the generating stations in Table 5-2 are located in Kentucky.[8] In addition to these generation resources, the Companies operate an electric grid consisting of almost 28,000 miles of electric transmission and distribution lines.

[5] Includes the Companies' share of Ohio Valley Electric Corporation ("OVEC").
[6] Small-frame SCCTs comprise Paddy's Run 12, Zorn 1, and Haefling 1 & 2. All of the Companies' other SCCTs are large-frame SCCTs. Zorn 1 is planned to be retired by the end of 2021.
[7] Includes Brown Solar and the first four arrays of the Companies' Simpsonville Solar (Solar Share) facility.
[8] A detailed listing of the Companies' generation portfolio is contained in Section 8.(3).(b).

Table 5-2: LG&E and KU Generating Stations, Net Summer Capacity (MW), Sep. 2021[9]

Generating Station	Coal	NGCC	Large-Frame SCCT	Small-Frame SCCT	Solar	Hydro	Total
E.W. Brown	412		906		8	32	1,358
Cane Run		662					662
Ghent	1,919						1,919
Mill Creek	1,465						1,465
Trimble County	919		954				1,873
Paddy's Run			147	23			170
Haefling				24			24
Zorn				14			14
Ohio Falls						64	64
OVEC	152						152
Simpsonville Solar					1		1
Total	**4,867**	**662**	**2,007**	**61**	**9**	**96**	**7,702**

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. This 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 2018 Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company dated July 2020 (Case No. 2018-00348) 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 Models and Methods

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

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

Energy Requirements

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.[10]

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").

[10] 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")	Monthly Net Metering/Qualifying Facility Customers, Private Solar Costs
Electric Vehicles ("EV")	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

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

As mentioned previously, different types of resources play different roles in serving customers' energy requirements. 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 dispatchable and non-dispatchable resource options for evaluation in the long-term resource planning analysis. The Companies did not directly evaluate new demand-side management ("DSM") programs in this IRP. Instead, the IRP identifies opportunites for new DSM programs that will be evaluated based on data and DSM pilot programs associated with the implementation of AMI.

Resource cost estimates are based on the "Moderate" case forecast from the National Renewable Energy Laboratory's ("NREL's") 2021 Annual Technology Baseline ("ATB"). Resources with similar roles in serving customers were compared based on their levelized cost of energy. A complete summary of this analysis is included in Volume III ("2021 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 electricity 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. In past IRPs, the results of this analysis were communicated in the context of a summer peak reserve margin. However, as more solar generation is integrated into the Companies' generation portfolio and included in the calculation of summer reserve margin, a summer reserve margin will have less meaning as an indicator of the portfolio's ability to reliably serve customers in all hours.[11] Therefore, the results of this analysis are communicated in the context of a summer and winter peak reserve margin. The mathematics – like past reserve margin analyses – assess the Companies' ability to reliably serve customers in all hours.

Figure 5-6 illustrates the costs and benefits of adding capacity to a generation portfolio.[12] As capacity is added, reliability and generation production costs decrease (i.e., the generation portfolio becomes more reliable) but fixed capacity costs increase.[13] In their reserve margin analysis, the Companies evaluate these costs and benefits over a range of generation portfolios with different reserve margins. The reserve margin for the generation portfolio where the sum of (a) capacity

[11] Solar generation is not available to serve the Companies' winter peak, which occurs at night.

[12] 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.

[13] 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.

costs and (b) reliability and generation production costs is minimized is the economic reserve margin.

Figure 5-6: Costs and Benefits of Generation Capacity (Illustrative)

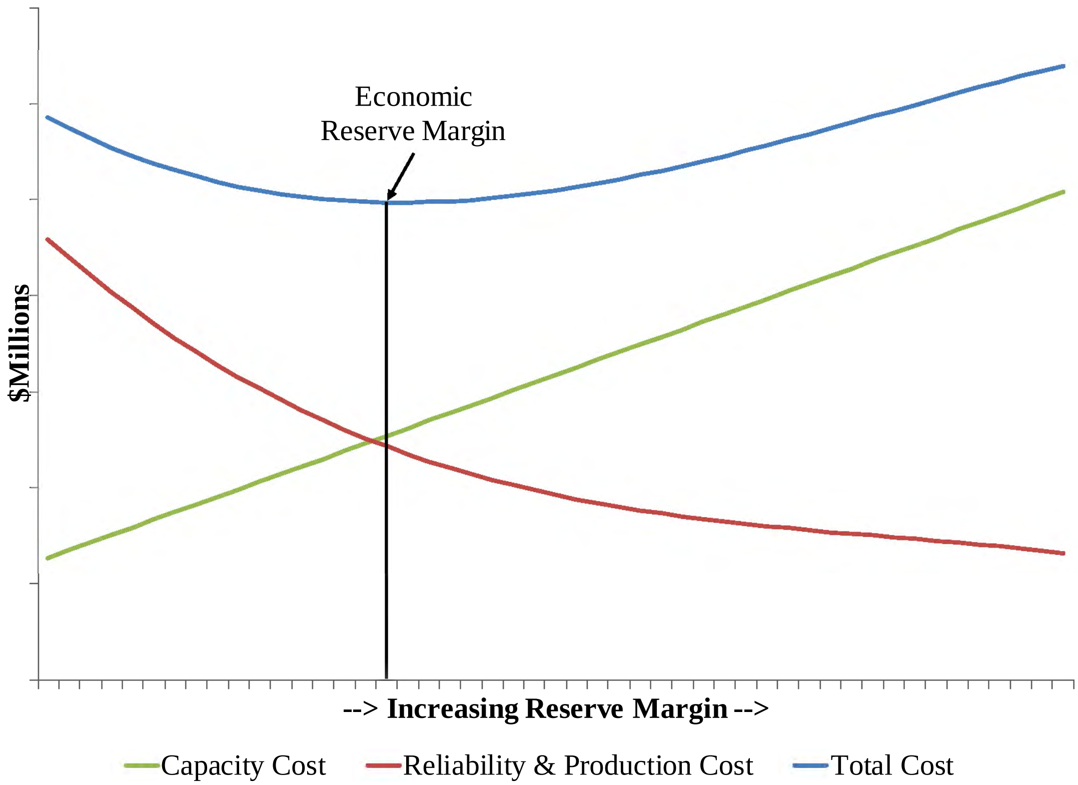
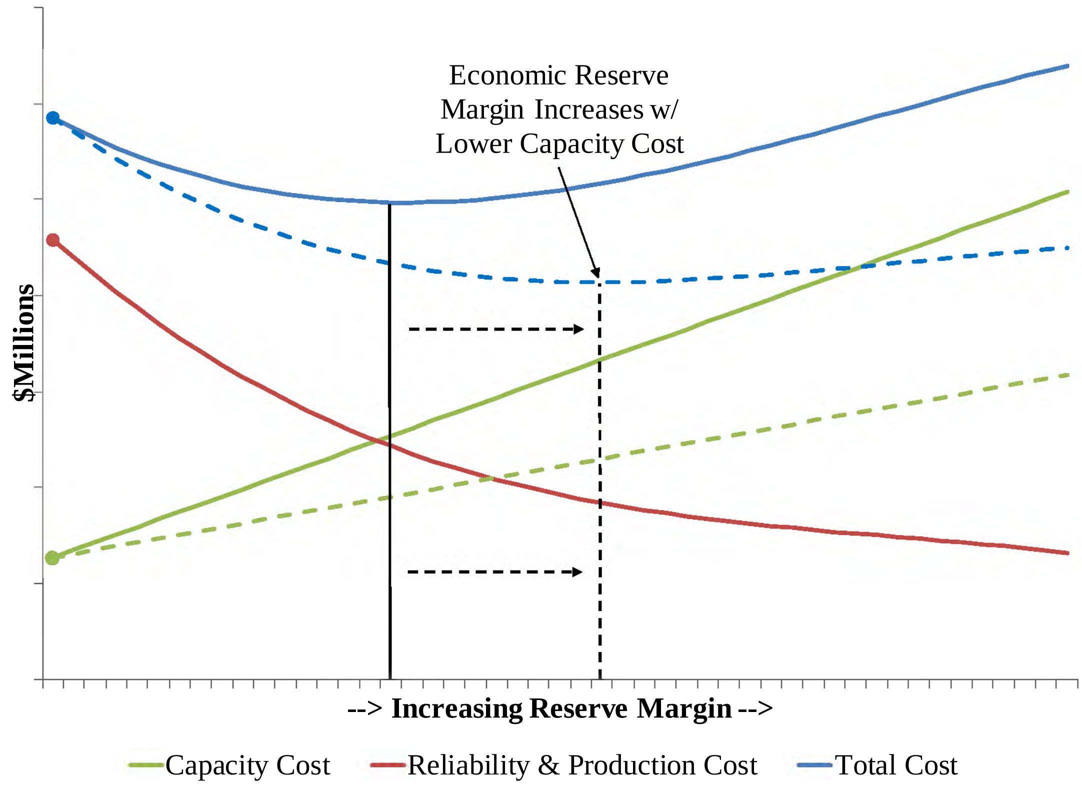


Figure 5-7 includes an alternative capacity cost scenario (dashed green line) for capacity with the same dispatch cost and reliability characteristics. The large dots mark the minimum of the range of reserve margins that is being evaluated. In this scenario, reliability and generation production costs 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 is reduced to zero.[14]

[14] In Figure 5-7, 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 5-7: 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.

In the 2021 IRP base energy requirements forecast, the Companies' forecasted reserve margin in 2025 is 25.7 percent in the summer and 32.8 percent in the winter. 3.4 percent of the summer reserve margin reflects the assumed availability of the Rhudes Creek solar facility (100 MW nameplate) and an additional 160 MW of Green Tariff Option 3 solar that is assumed to come online in 2025, but the availability of these resources is uncertain.[15]

Figure 5-8 contains distributions of the average and minimum Brown Solar generation under peak load conditions in June through September. Based on the array's average generation over the hour,

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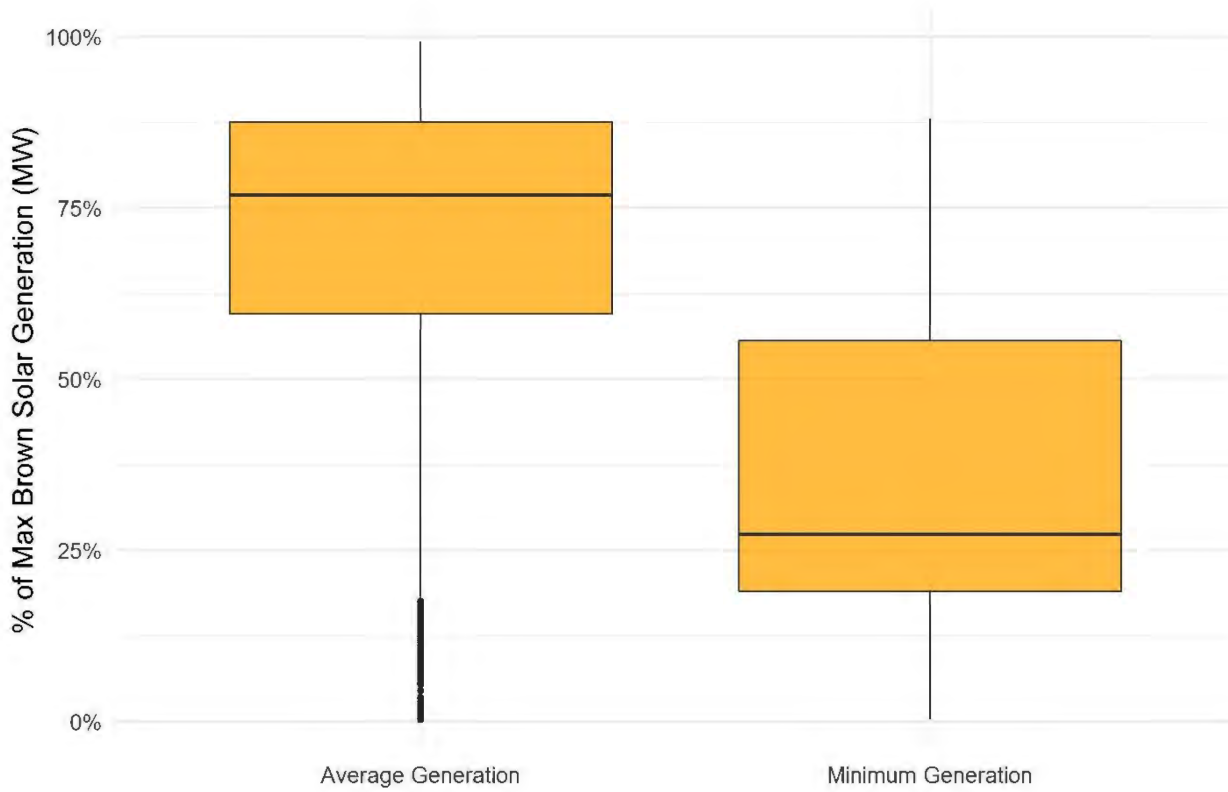
[15] None of this capacity is available to serve winter peak because the Companies' winter peak occurs at night. On October 13, 2021, the Companies announced plans to enter into a 125 MW solar PPA to exclusively serve five customers participating in the Companies' Green Tariff Option 3. The PPA was not finalized until October 11, 2021, after all participating customers committed to their desired allocation of the PPA. Given the proximity of this date to the October 19, 2021 IRP filing date, the IRP could not be updated to reflect the lower capacity.

between 60 and 88 percent of Brown Solar is available during peak hours.[16] However, based on minimum generation during the hour, between 19 and 56 percent is available. Because the Companies plan generation to serve load in every moment, the distribution of minimum generation is an important consideration and reflects the intermittent nature of solar generation.[17]

Figure 5-8: Distribution of Average and Minimum Brown Solar Generation (June-September; Hours Beginning 1:00 and 2:00 PM EST with System Load > 5,790 MW; 2016-2021)[18]



Based on the distributions in Figure 5-8, the Companies evaluated an optimal summer reserve margin with and without solar generation. To evaluate a range of reserve margins, the Companies evaluated the retirement of existing marginal resources as well as the addition of 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.

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[16] 60 and 88 percent are the 25th and 75th percentile values of the distribution.
[17] The Companies will closely monitor the variability of the Rhudes Creek and additional Green Tariff Option 3 solar facilities as they are added to the generation portfolio. Because these facilities are much larger than Brown Solar, their variability may be less as a percent of total output than Brown Solar.
[18] 5,790 MW is the 90th percentile load value for these hours. The limits of the box in the boxplots reflect the 25th and 75th percentiles while the "whiskers" represent the maximum and minimum.

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 ("2021 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 over a range of forecasted energy requirements and fuel prices. Each of these inputs is discussed in the following section.

For each energy requirements and fuel price case, the Plexos model from Energy Exemplar was used to identify the least-cost generation portfolio for serving customers at the end of the IRP planning period. The analysis considered all costs for new and existing resources, and it optimized the portfolio to minimize energy and new capacity costs. An annual resource plan was then developed for each case to meet minimum reserve margin requirements (i.e., 17 percent in the summer and 26 percent in the winter) throughout the planning period. To assess the potential for new DSM programs, the PROSYM production cost model from ABB was used to model annual production costs for the resource plan in the base energy requirements, base fuel case. A complete summary of this analysis is included in Volume III ("2021 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. Long-Term Energy Requirements Forecast

A discussion of the base, high, and low energy requirements forecasts is included in Section 5.(3).

2. Energy Requirements for Reliability Planning

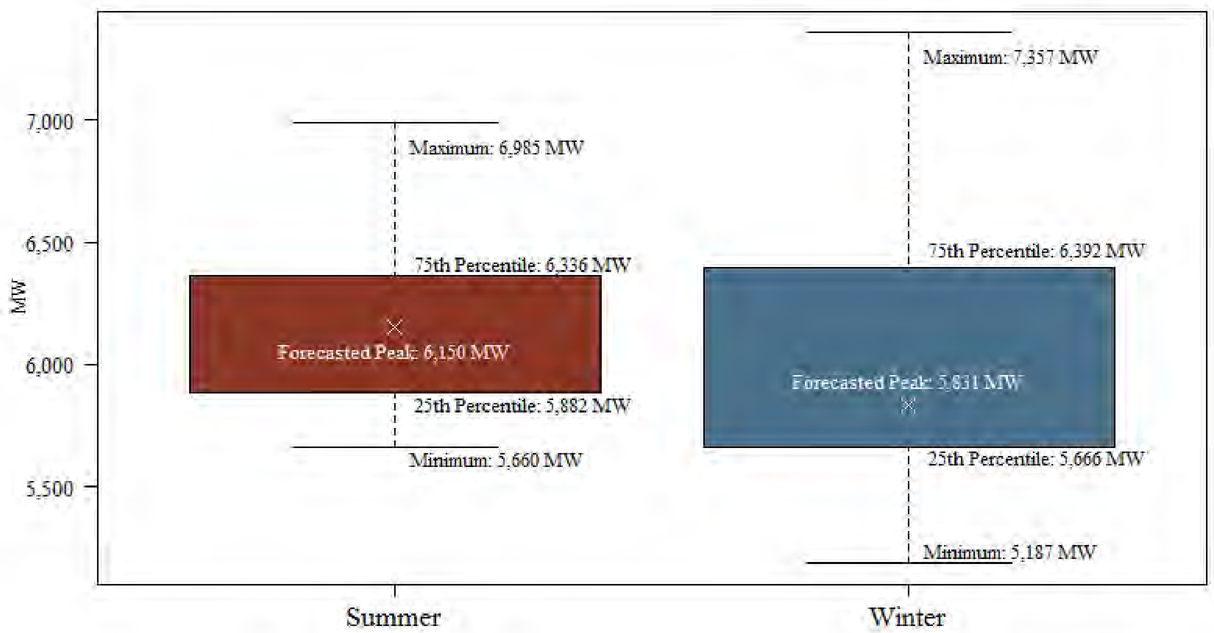
The Companies develop their long-term base, high, and low energy requirements forecasts with the assumption that weather will be average or "normal" in every year.[19] While this is a reasonable assumption for long-term resource planning, weather from one year to the next is never the same. For this reason, to support the Companies' Reserve Margin Analysis, the Companies produced 48 hourly energy requirement forecasts for 2025 based on weather in each of the last 48 years.

Figure 5-9 and Figure 5-10 contain distributions of the Companies' summer and winter peak demands for 2025 based on these "weather year" forecasts. The values in Figure 5-9 labeled "Forecasted Peak" (i.e., 6,150 MW in the summer and 5,942 MW in the winter) are the Companies'

[19] The Companies use 20 years of historical weather data to develop their normal weather forecast. Weather does not explain any differences between the base, high, and low energy requirements forecasts.

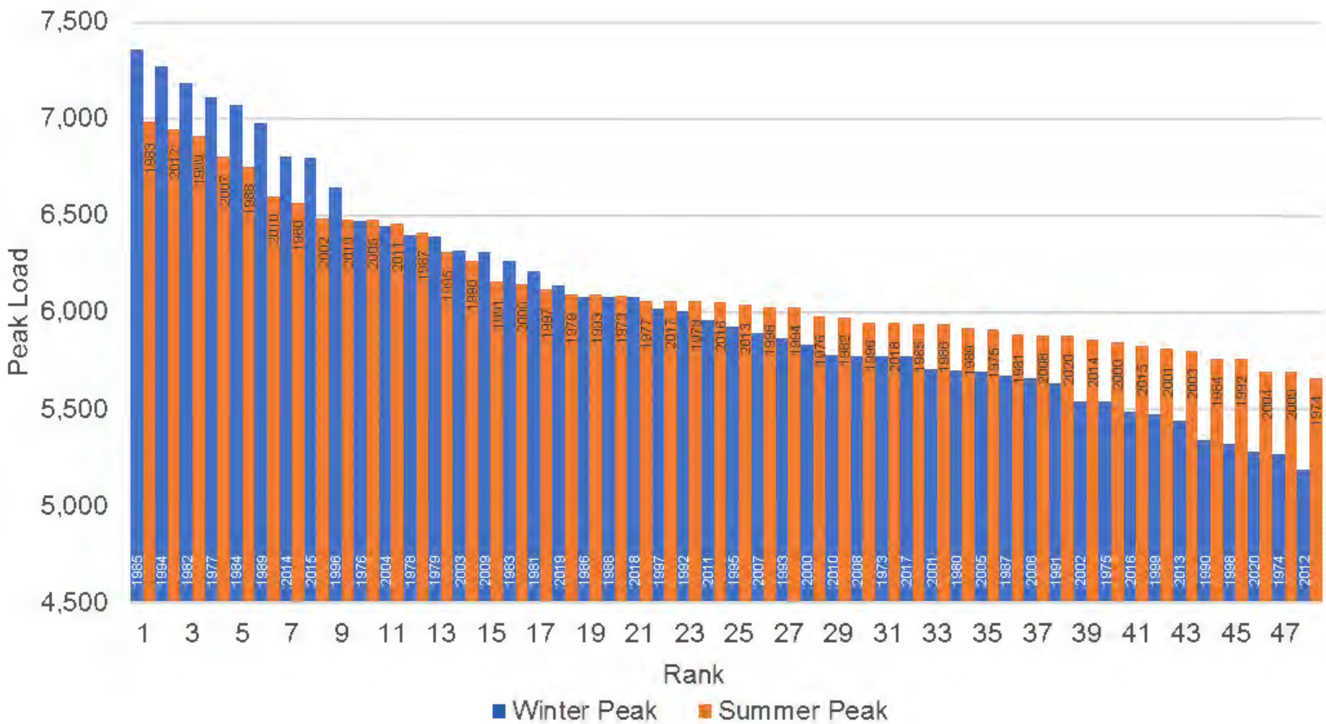
forecasts of summer and winter peak based on average peak weather conditions over the past 20 years. In Figure 5-10, the year labels indicate the weather years on which the seasonal peaks are based. While the Forecasted Peak is higher in the summer, the variability in peak demands is much higher in the winter.[20] This is largely due to the wider range of low temperatures that can be experienced in the winter and because electric heating systems with heat pumps consume 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 5-9: Distribution of Summer and Winter Peak Demands, 2025



[20] The distributions in Figure 5-9 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 127 MW in 2025. The maximum winter peak demand (7,357 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.

Figure 5-10: Distributions of Summer and Winter Peak Demands, 2025[21]



3. State and Federal Regulations

The 2020 ECR analysis demonstrated that installing the water treatment capacity needed to simultaneously operate all four coal units at the Mill Creek station and comply with the amended Effluent Limit Guidelines ("ELG") is not least-cost. In addition, there is some likelihood that a cooling tower will eventually be needed for Mill Creek Unit 1 to comply with Clean Water Act 316(b) regulations. For these reasons, the 2021 IRP assumes Mill Creek 1 will be retired in 2024, the Mill Creek station's deadline for ELG compliance.

After the Companies complete projects that are currently in progress to comply with the EPA's Coal Combustion Residual Rule ("CCR Rule") and amended ELG, all of the Companies' generating units will be in compliance with known state and federal regulations. All of the Companies' coal units are equipped with fabric filter baghouses ("baghouses") and flue-gas desulfurization equipment ("FGD"). After Mill Creek Unit 1 is retired, all but two coal units (Mill Creek Unit 2 and Ghent Unit 2) will be equipped with selective catalytic reduction ("SCR").

Significant changes in environmental regulations since the 2018 IRP are discussed in Section 6. Based on these changes and the analysis summarized in Exhibit LEB-2 in Case Nos. 2020-00349 and 2020-00350, the 2021 IRP assumes Mill Creek 2 and Brown 3 will be retired in 2028. Based on the current debate regarding new laws and regulations to reduce CO_2 emissions that is mainly

[21] The year labels indicate the weather year on which the seasonal peaks are based.

focused on stimulating the addition of "clean energy resources" or setting "clean energy standards," all other CO_2-emitting units are assumed to retire at the end of their book depreciation lives.

4. Generating Unit Operating Life

Table 5-4 lists the units that are assumed to retire during the IRP planning period (2022-2036). Due to their age and inefficiency, the Companies' remaining small-frame SCCTs (Haefling 1-2 and Paddy's Run 12) are assumed to retire by 2025.[22] The retirement year for each of Brown 8-11 and Ghent 1-2 is the end of the unit's book depreciation 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.

Table 5-4: Assumed Retirement Years

Generating Unit	Summer Net Capacity	Retirement Year
Mill Creek 1	300	2024
Haefling 1-2	24	2025
Paddy's Run 12	23	2025
Mill Creek 2	297	2028
Brown 3	412	2028
Ghent 1	475	2034
Ghent 2	485	2034
Brown 9	121	2034
Brown 8	121	2035
Brown 10	121	2035
Brown 11	121	2036

5. 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 5-5. 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

[22] The Companies' small-frame SCCTs do not undergo major maintenance, and the Companies plan to retire these units once a maintenance event renders them uneconomic to repair. Since the 2018 IRP, the Companies have retired Cane Run 11 and Paddy's Run 11 in this manner, and expect to retire Zorn before the end of 2021.

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, and the Companies must supply, electricity every hour of the year, yet no generating unit can be available at all times. 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 over 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 available units 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.

6. Fuel and Emission Prices

Table 5-5 contains the coal and natural gas 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.

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

Year	Natural Gas[23]			Coal[24]		
	Low	Mid	High	Low	Mid	High
2022	[redacted]					
2023						
2024						
2025						
2026						
2027						
2028						
2029						
2030						
2031						
2032						
2033						
2034						
2035						
2036						

Currently, there is no price associated with CO_2 emissions and no law or regulation is being seriously discussed that would explicitly put a price on such emissions. Instead, much focus recently has been on addressing CO_2 emissions indirectly via a Clean Energy Standard rather than through a CO_2 price or cap and trade scheme. During the Obama administration, the Clean Power Plan sought to reduce CO_2 emissions via state-administered programs that focused on either emission rates or mass reductions rather than through a CO_2 price. The Companies have no basis for assuming that a price on CO_2 emissions will or will not be part of part of any such regulations. For these reasons, the 2021 IRP does not evaluate resource expansion plans with an assumed price for CO_2 emissions.

[23] The natural gas price forecast reflects forecasted Henry Hub market prices. In 2022 through 2024, base natural gas prices are the forecast commodity prices at Henry Hub based on NYMEX market prices as of July 14, 2021. In subsequent years, the base forecast is interpolated to reach EIA's High Oil and Gas Resource case from its 2021 Annual Energy Outlook ("AEO") in 2050. The low Henry Hub price forecast begins with 2020's actual spot price and escalates at half of the compound annual growth rate between 2021 and 2050 of the 2021 AEO's EIA's High Oil and Gas Supply case. The high Henry Hub gas price forecast reflects a smoothed version of the EIA's reference case forecast from its 2021 AEO.

[24] The coal price forecast reflects Illinois Basin coal prices. In the first five years of the forecast, the base market price is a blend of prices based on coal bids received but not under contract and forecasts from independent third-party consultants. Beyond the fifth year, prices are increased at the annual growth rate reflected in the EIA's 2021 AEO High Oil and Gas Supply case for "All Coals, Minemouth" price forecast. The high and low coal price forecasts reflect the historical relationship of changes in natural gas and ILB coal prices.

7. Generation Technology Costs

The generation cost forecasts utilized in this analysis are based on the "Moderate" case forecast from NREL's 2021 ATB, which can be accessed at https://atb.nrel.gov/. See Section 5.(4) for a summary of the technologies evaluated in this IRP.

5.(3) Energy Requirements Forecast

Base Energy Requirements Forecast[25]

The Companies developed base, high, and low forecasts of energy requirements to evaluate resource planning decisions under multiple energy requirement scenarios. Table 5-6 contains the Companies' base energy requirements forecast for the 15-year planning period. From 2021 to 2036, the Companies' energy requirements forecast is slightly declining, as energy efficiency gains are assumed to offset the impact of new customer growth.

Table 5-6: Base Energy Requirements Forecast (GWh)

Year	KU	LG&E	Combined Companies
2021	19,976	12,253	32,229
2022	19,893	12,344	32,238
2023	19,807	12,273	32,079
2024	19,771	12,273	32,045
2025	19,634	12,205	31,839
2026	19,521	12,127	31,648
2027	19,423	12,109	31,532
2028	19,410	12,109	31,519
2029	19,309	12,061	31,370
2030	19,245	12,034	31,279
2031	19,216	12,027	31,243
2032	19,242	12,041	31,283
2033	19,181	12,015	31,196
2034	19,150	12,022	31,172
2035	19,155	12,033	31,188
2036	19,212	12,077	31,289

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 5-7 contains monthly energy requirements for 2025 as well as the percentage of total energy requirements consumed during nighttime hours.

[25]On September 27, 2021, Ford announced plans to add twin electric vehicle battery plants. Given the proximity of the announcement to the October 19, 2021 IRP filing date, the IRP could not be updated to explicitly include the new load. With the new load, the Companies do not anticipate needing additional generation capacity prior to 2028.

Table 5-7: Monthly Energy Requirements, 2025 (MWh)

	KU	LG&E	Combined Companies	CC Night
Jan	1,946	1,030	2,976	58%
Feb	1,717	908	2,624	54%
Mar	1,632	910	2,542	50%
Apr	1,409	858	2,268	41%
May	1,503	995	2,498	37%
Jun	1,603	1,144	2,747	33%
Jul	1,778	1,294	3,072	34%
Aug	1,778	1,267	3,045	37%
Sep	1,535	1,043	2,578	44%
Oct	1,464	909	2,374	50%
Nov	1,513	872	2,385	58%
Dec	1,756	974	2,729	57%
Total	19,634	12,205	31,839	46%

Table 5-8 contains the Companies' base summer and winter peak demand forecasts under average or "normal" peak weather conditions.[26] From 2021 to 2036, the compound annual growth rate ("CAGR") for peak winter demands is less negative than the CAGR for peak summer demands due to assumed increases in electric heating penetration and the lack of distributed solar contribution during winter peaks.

[26] The variability and potential deviation from normal in summer and winter peaks is displayed in Figure 5-9.

Table 5-8: Base Summer and Winter Peak Demand Forecast (MW)

Year	Summer	Winter
2021	6,168	5,765
2022	6,229	5,898
2023	6,201	5,874
2024	6,179	5,859
2025	6,150	5,831
2026	6,113	5,806
2027	6,088	5,790
2028	6,067	5,777
2029	6,055	5,758
2030	6,056	5,750
2031	6,033	5,736
2032	6,035	5,738
2033	6,029	5,726
2034	6,020	5,715
2035	6,023	5,719
2036	6,026	5,737
CAGR	-0.16%	-0.03%

Key Forecast Assumptions and Uncertainties

The following is a discussion of key energy requirement forecast assumptions and uncertainties.

1. Weather

The Companies develop their base, high, and low energy requirements forecasts with the assumption that weather will be average or "normal" in every year. The Companies use 20 years of historical weather data to develop their normal weather forecast. In other words, weather does not explain any differences between the base, high, and low energy requirements forecasts.

2. Economic Assumptions

Economic assumptions in the Companies' base energy requirements are taken from IHS Markit's May 2021 U.S. Economic Outlook.[27] For the U.S. overall, IHS Markit projects real economic growth of 6.7 percent during 2021. This would result in a 3.0 percent larger economy in 2021 as compared to pre-pandemic 2019 levels. For the 2022-2026 timeframe, real GDP is forecasted to increase at an average annual rate of 2.6 percent, above the 2010-2019 between-recession (Great Recession and the COVID-19 pandemic) average of 2.3 percent.

The spread of the COVID-19 Delta variant is the biggest near-term risk to the U.S. economy. Another risk to the outlook is inflation, which has surged in recent months due largely to supply shortages amid an increase in consumer demand. If extremely strong inflation proves to not be

[27] See Volume II ("IHS Market U.S. Economic Outlook – May 2021").

transitory, the Federal Reserve may have to raise rates more quickly than anticipated, potentially slamming the brakes on the current economic recovery.

In Kentucky, IHS projects real economic growth of 6.5 percent during 2021, comparable to the U.S. level. For the 2022-2026 period, the state's economy is expected to increase at an average pace of 1.9 percent, above the between-recession average of 1.5 percent. Over the longer term from 2027-2036, IHS projects growth to average 1.8 percent. The same downside risks that are present for the U.S. economic expansion also present potential headwinds for the Kentucky economy.

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.

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. The Companies continue to incorporate 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, electric vehicle adoption, distributed energy resources, demographics, and economic conditions in the service territory.

Barring unexpected tax or policy changes, electricity base prices are not anticipated to increase until later in the business planning period.[28] 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 means in which residential or commercial customers would make such changes to reduce their consumption in the long-run would most likely be through more efficient end-uses and installation

[28] Fuel prices change each month based on the Companies' actual cost of fuel. Fuel markets have historically experienced periods of price volatility which would be reflected in customer bills through the fuel adjustment clause.

of distributed generation, which are both contemplated in Figure 5-12 and Figure 5-13. Customer growth would likely weaken as compared to what the service territory has experienced over the past decade. Large customers in highly competitive industries would be more likely to move their business elsewhere or find ways to significantly reduce their demand. Given these factors and what has been mentioned in the paragraphs immediately above, the low load scenario displayed in Table 5-13 can also act as a more specific proxy for a high electricity price scenario.

4. Customer Growth

A key upside scenario for Kentucky's economy is rapid growth in the state's housing market. IHS Markit is forecasting total housing starts in Kentucky to be the second highest in the United States during 2021. Further, the forecasted 2021-2036 growth rate averages ninth in the US as compared to the average rate over the previous ten years. The growth has been centered in and around the state's largest metro areas of Louisville and Lexington, a trend that is expected to continue.

Another area ripe for customer growth is the manufacturing sector. Kentucky has a number of advantages in this sector, as it is the home to a number of large auto manufacturers, centrally located in the United States, has a large pool of experienced labor to draw from, and benefits from relatively low-cost electricity prices. The addition of any new large accounts in the service territory would be a boon for sales to the industrial sector, and would likely spur new commercial and residential growth in the area.[29]

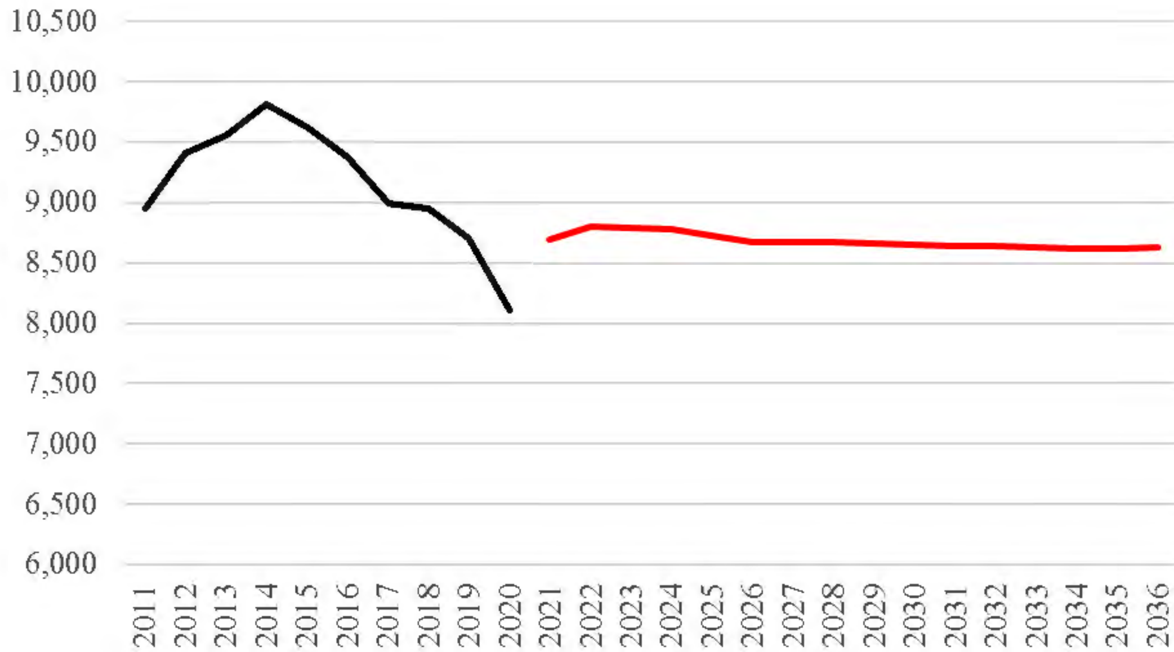
5. Energy Efficiency

Over the past decade, customers in all classes 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 5-11 contains a plot of industrial sales through 2036. Prior to 2020 when sales dropped significantly due to reduced operations from COVID-19 and the lingering economic impacts, industrial sales were declining on average. As discussed in the 2018 IRP, this is due in part to energy efficiency improvements by industrial customers during that period. In some cases, customers have leveraged energy efficiency measures to expand their operations without increasing load. Industrial sales are forecasted to recover through 2022 and then decline slightly thereafter despite continued economic growth as efficiency improvements offset production increases.

[29] On September 27, 2021, Ford announced plans to add twin electric vehicle battery plants. Given the proximity of the announcement to the October 19, 2021 IRP filing date, the IRP could not be updated to explicity include the new load. With the new load, the Companies do not anticipate needing additional generation capacity prior to 2028.

Figure 5-11: Industrial Sales, 2011-2036



Forecasted end-use efficiency improvements are explicitly incorporated in the residential and commercial energy requirements forecasts. As mentioned in the previous IRP, heat pumps and central air conditioners have become more efficient in recent history and continue to drive efficiency improvements through the forecast period. Additionally, the light emitting diode ("LED") has revolutionized the lighting market and significantly reduced electricity consumption for lighting.[30] The base energy requirements forecast assumes the penetration of LEDs will continue to increase throughout the forecast period.

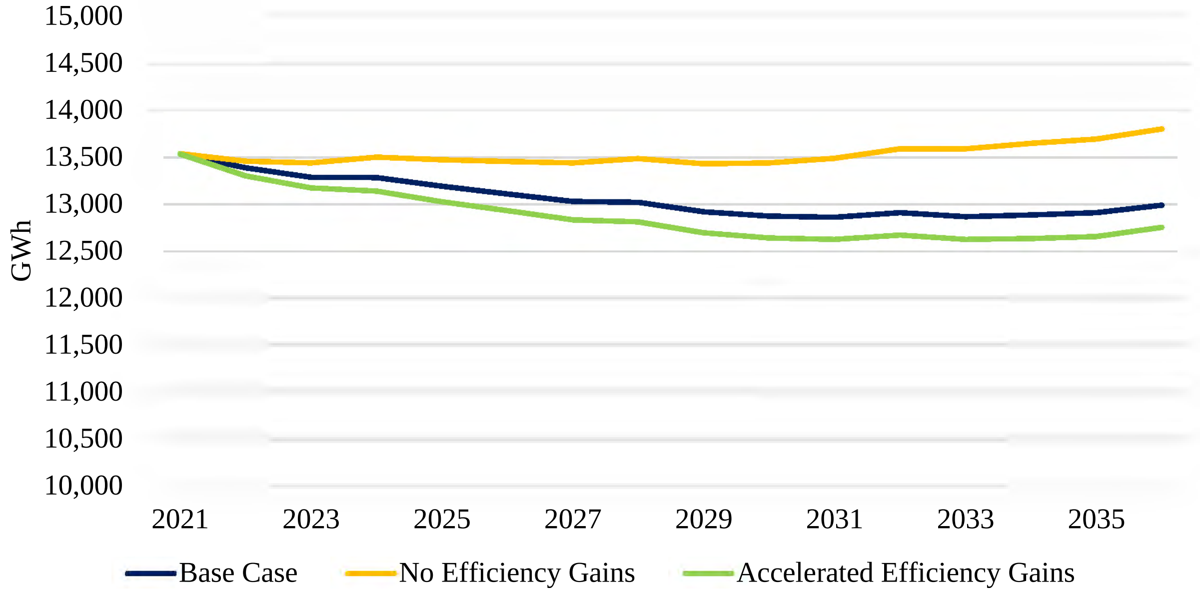
Table 5-11 and Table 5-12 show the use-per-customer ("UPC") declines of each new cohort. Not surprisingly, the more recently the home was built, the more efficient it is. These residential UPC reductions are in both LG&E and KU service territories despite the increased incidence of electric heating. Indeed, much of this is attributed to the most efficient lighting and other end-uses possible at the time being installed in these homes in addition to a more efficient housing structure in terms of insulation and windows.

Figure 5-12 shows the impact of energy efficiency improvements on the residential and small commercial sales forecasts. By 2036, energy efficiency improvements in the base forecast reduce residential and commercial sales by over 6 percent compared to a case where end-use efficiencies are assumed to remain unchanged. These improvements include the impact of company-sponsored Demand Side Management – Energy Efficiency ("DSM-EE") programs. With "accelerated efficiency gains," end-use efficiencies are assumed to reach 2050 levels by 2035. The impact of

[30] A 60-watt equivalent LED consumes 9 watts per 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.

this assumption is relatively small compared to the energy efficiency improvements in the base forecast.

Figure 5-12: Impact of Energy Efficiency Improvements on Residential and Small Commercial Sales Forecast[31]



6. Distributed Generation

Distributed generation includes generation from net metering customers and qualifying facilities. The economics of distrbuted solar depends on several factors: electricity usage patterns and their correlation to solar irradiance (i.e., the extent to which solar generation reduces consumption from the grid), the availability of investment tax credits ("ITC"), the capital and annual operating cost of solar, the retail energy rate charged by the utility to the end user, and the energy rate paid by the utility for any excess energy that is pushed onto the grid.

Table 5-9 contains the capital and annual operating cost of private solar in 2022 and 2030 according to NREL's 2020 ATB, as well as the total project cost expressed as a levelized cost of energy ("LCOE") over a 30 year life.[32] The economics of private solar in 2022 depend on the availability of the ITC and are expected to improve significantly over time.

[31] With accelerated efficiency gains, end-use efficiencies are assumed to reach 2050 levels by 2035.
[32] The Companies' distributed generation forecast reflects cost assumptions from NREL's 2020 ATB. NREL's 2021 ATB was not available when the forecast was developed.

Table 5-9: Cost of Private Solar in 2022 and 2030

Installation year	ITC	Capital cost ($/kW, nominal)	Annual O&M ($/kW-year, nominal)	LCOE ($/kWh)
2022	26%	2,533	19.00	0.0913
	0%	2,533	19.00	0.1176
2030	26%	1,427	10.69	0.0514
	0%	1,427	10.69	0.0662

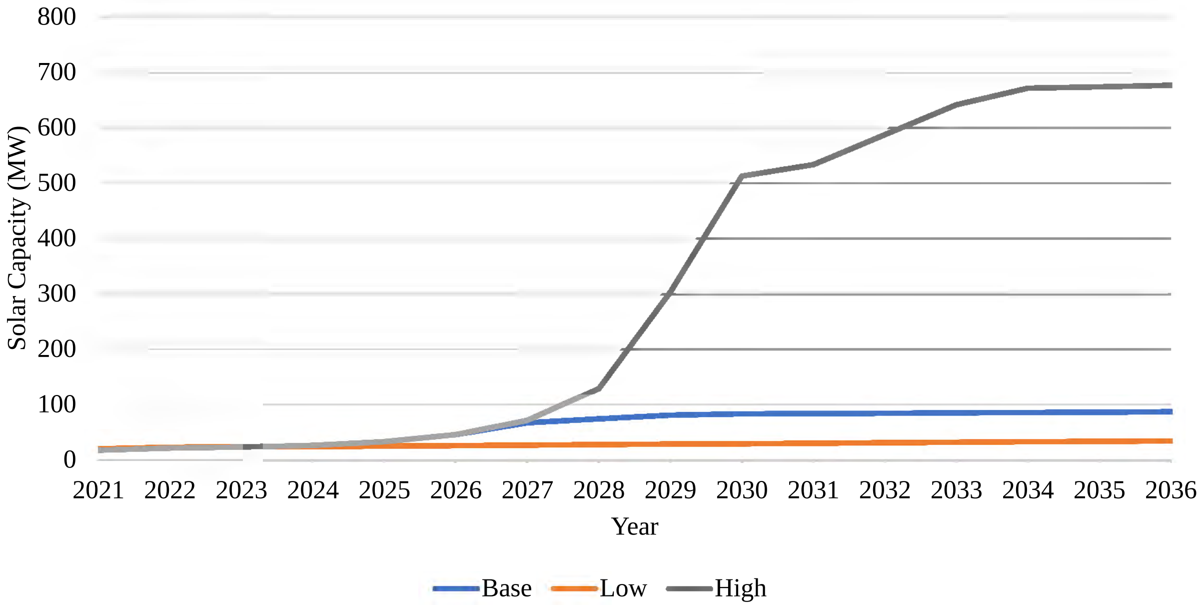
Table 5-10 shows the prices needed for excess energy exported to the grid in order to meet total project costs. By 2030, regardless of whether an ITC is available, the price required to cover the cost of the solar array is zero if 40 percent or less of the solar generation is pushed to the grid.

Table 5-10: Price Needed for Energy Exported to Grid to Meet Total Project Costs ($/kWh)

	2022	2030	
Percent energy pushed to grid	**26% ITC**	**26% ITC**	**No ITC**
20%	0.02814	-0.21598	-0.14202
30%	0.05448	-0.10456	-0.05525
40%	0.06764	-0.04884	-0.01186
50%	0.07554	-0.01542	0.01417
60%	0.08081	0.00687	0.03152
70%	0.08457	0.02279	0.04392
80%	0.08739	0.03473	0.05322
90%	0.08959	0.04401	0.06045

Figure 5-13 contains the Companies' base, low, and high distributed solar generation forecasts. All net metering forecasts were created using a consumer choice model, in which the ratio of net-metering customers to total residential customers is predicted by the avoided cost-to-LCOE ratio, which is weighted by the potential universe of net-metering customers per company. The avoided-cost-to-LCOE ratio is computed as a function of the above economic factors.

Figure 5-13: Distributed Generation Forecast Scenarios



The base distributed solar generation forecast assumes retail rate paid for excess generation, instantaneous netting of usage and generation, and a continuation of the federal ITC for residential customers.[33] After 2021, net metering customer growth returns to levels experienced before mid-2019 when growth increased due to the passing of Kentucky House Bill 100 and the then-planned expiration of the ITC. The base forecast scenario is capped at 1% of the Company's single hour peak load for the previous year, which explains the mostly flat trend after mid-2027 when the 1% peak is reached. Minimal growth seen after 2027 is due to the continued linear growth of qualifying facilities customers.

Compared to the base scenario, customer growth in the low scenario is the same but the size of new net metering installations is smaller as customers size their arrays to limit excess solar energy pushed back to the grid. In the high scenario, a new federal law is assumed to eliminate the 1% cap on total installed net metering capacity. As a result, the high scenario is identical to the base scenario through 2027 and then continues to grow thereafter. The steep increase in capacity seen from 2028-2030 in the high scenario is due to quickly falling capital costs coupled with the ITC. After 2030, the capacity costs for installing solar decline much less rapidly, resulting in slower capacity growth as compared to the previous few years. Capacity growth flattens out further after 2034 due to the assumed end of the 10-year ITC.

Figure 5-14 and Figure 5-15 show the impact of distributed solar generation on peak energy requirements in the base and high forecast scenarios, respectively. The impact is small in the base forecast but much larger in the high forecast.

[33] On September 24, 2021, the KY PSC issued its final order concerning the Companies' NMS-2 compensation rates and netting interval for new net metering customers. Given the proximity of the announcement to the October 19, 2021 IRP filing date, the forecast could not be updated to reflect the new rates and monthly netting.

Figure 5-14: Hourly Forecast Profile for August 27th, 2036 (Base Solar Scenario)

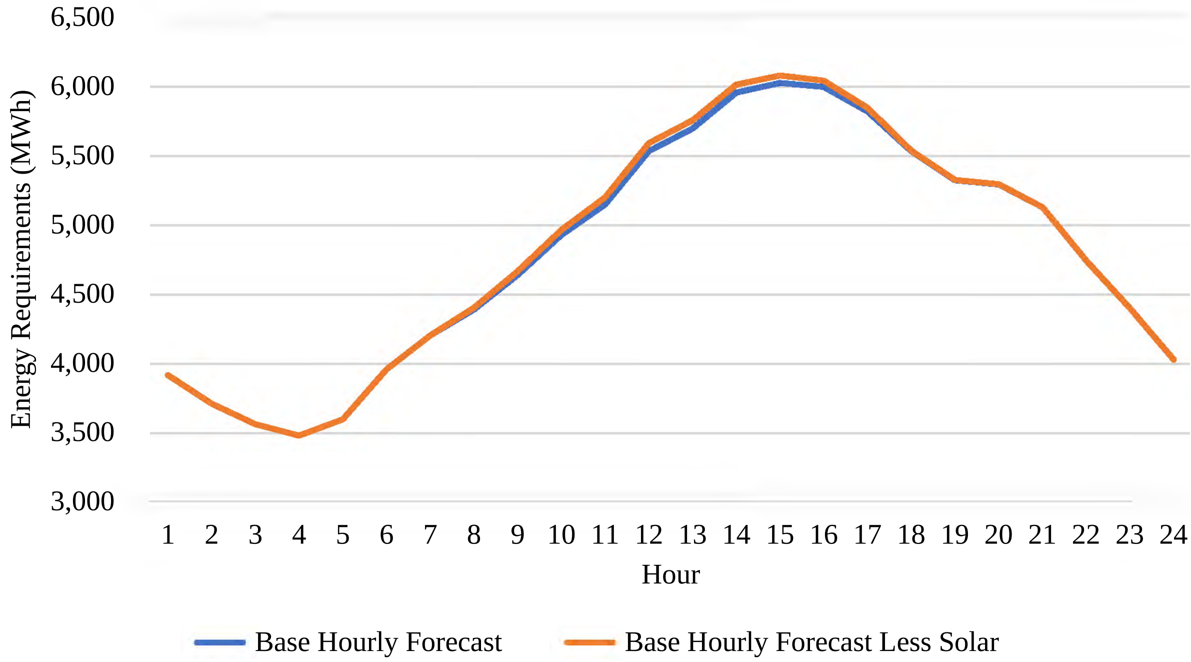
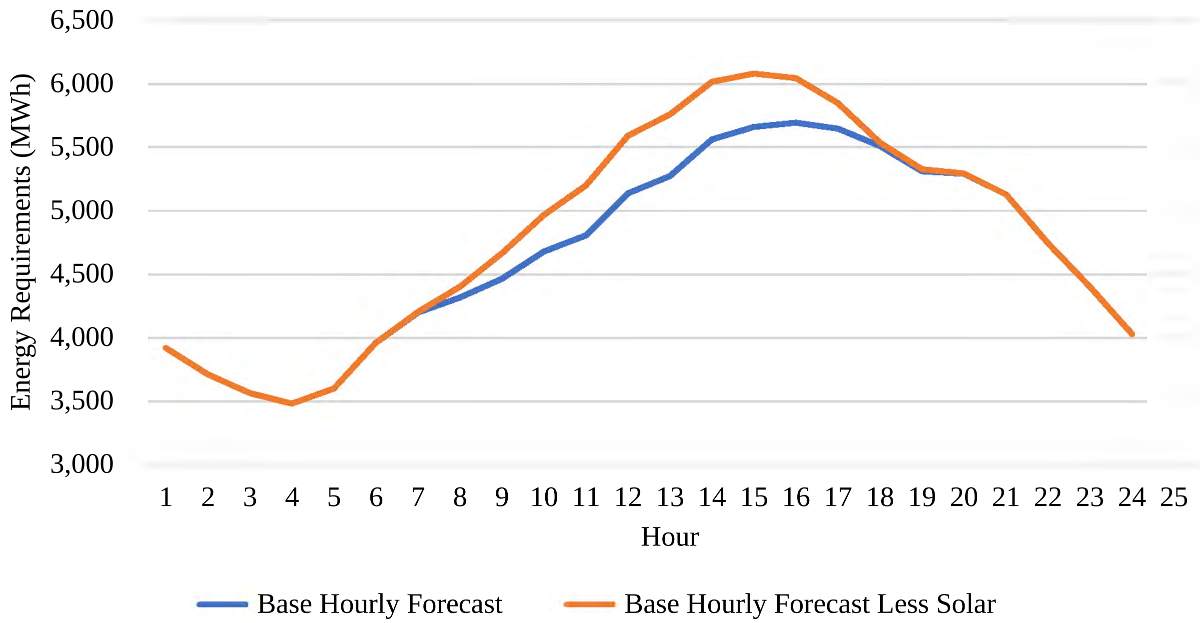


Figure 5-15: Hourly Forecast Profile for August 27th, 2036 (High Solar Scenario)

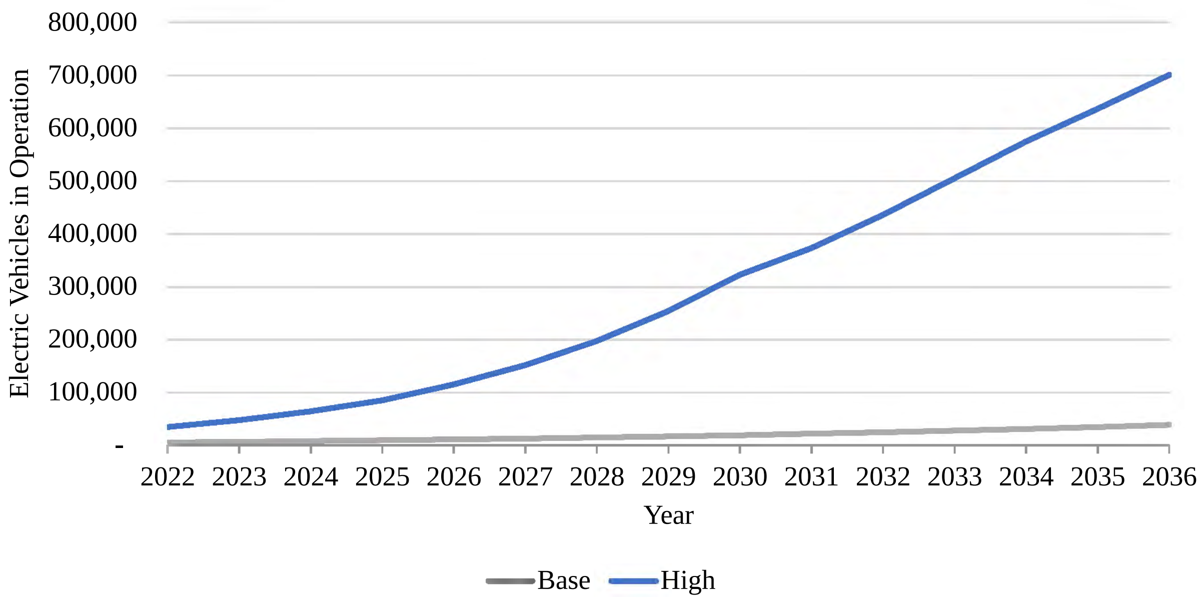


7. Electric Vehicles

Figure 5-16 shows the base and high forecasts for the number of electric vehicles ("EV") in the Companies' service territories. From 2017 to 2020, the estimated number of EVs in operation in the LG&E and KU service territories increased 164% from 1,415 to 3,737. EV vehicles-in-operation are forecast in the base scenario to increase to over 38,000 by the end of 2036. Like distributed solar generation, the future penetration of EVs is a key forecast uncertainty. The model used to forecast the number of EVs in the serice territory takes into account historical adoption of EVs, battery pack prices, the comparison of EV to internal combustion engine ("ICE") car costs, and the total number of cars possible in the service territory, but is unable to account for sudden technological innovation that could cause a dramatic shift from historical adoption patterns. The base scenario forecast was blended to match the Energy Information Administration's ("EIA") forecast for Kentucky by 2050.

Consistent with the executive order signed by President Biden in August 2021, the high scenario assumes EVs account for 50% of new vehicle sales by 2030. The high scenario is an accelerated version of Bloomberg New Energy Finance's ("BNEF") forecast for EV adoption in Kentucky, which assumes EVs account for 50% of new vehicle sales by 2033. For reference, the forecast predicts the total number of cars in Kentucky by 2036 to be around 1.66 million, with roughly 40% of those cars being EVs.

Figure 5-16: Electric Vehicles in Operation, 2021 - 2036



The primary factors impacting electricity consumption by EVs are the number of EVs in the Companies' service territories and the distance driven per vehicle. However, resource planning considerations for EVs focus less on these factors and more on the way customers charge their vehicles. The timing of charging for EVs is an important consideration. If EVs are charged overnight when energy requirements would otherwise be low, the vehicles can likely be charged with the Companies' existing dispatchable generation assets. Contrarily, if EVs are charged early in the evenings (e.g., when customers get home from work), EV charging could exacerbate summer and winter peak energy requirements and potentially create the need for additional peaking capacity or load control programs (see Figure 5-17 and Figure 5-18).

Figure 5-17: Managed and Natural EV Charging Profiles Compared to Summer Peak on August 27th, 2036

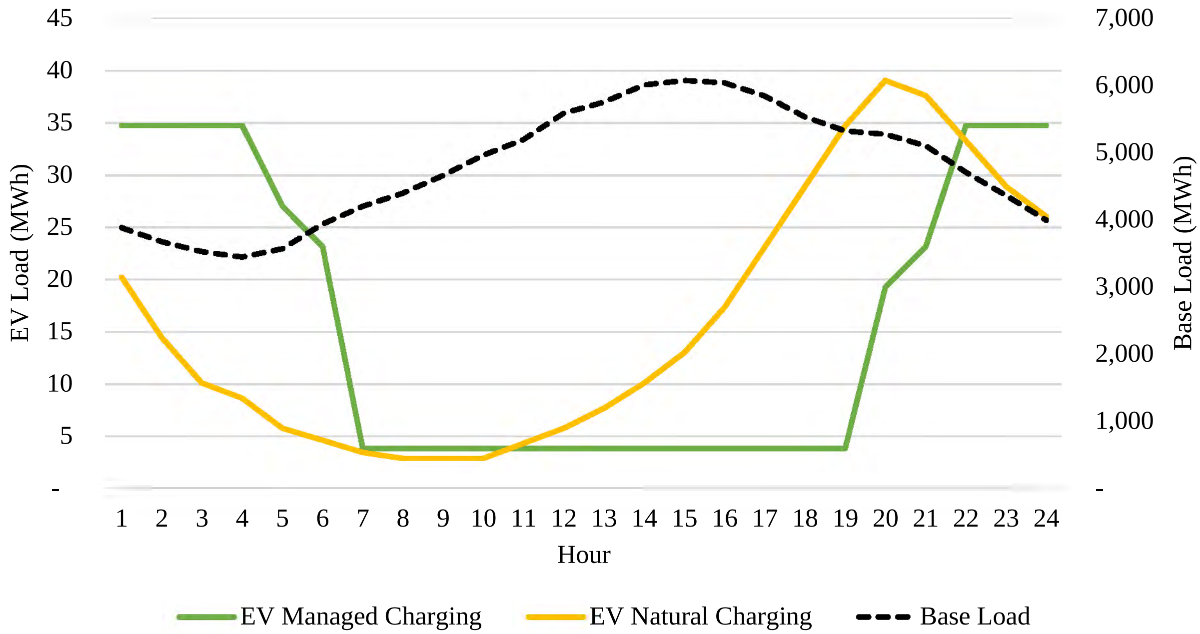
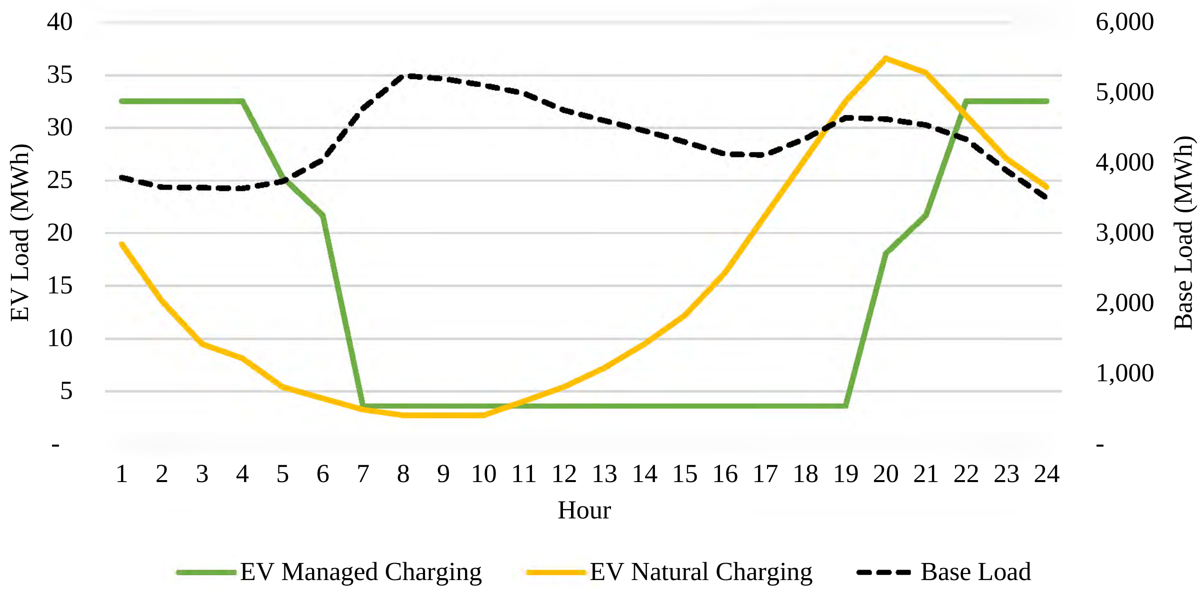


Figure 5-18: Managed and Natural EV Charging Profiles Compared to Winter Peak on January 16th, 2036



In Figure 5-17 and Figure 5-18, the natural charging profile coincides with the Companies' summer and winter peak demands, but the managed charging profile shifts EV charging to later in the evening when load is lower. As the generation fleet moves away from dispatchable resources toward more intermittent resources, EV charging times may need to shift to periods of the days when the intermittent resources are available.

8. *Space Heating Electrification*

Compared to residential customers added through 2010, a greater percentage of residential customers added since 2010 have electric space heating (see Table 5-11 and Table 5-12). In the KU service territory, about 60 percent of all residential customers added through 2010 have electric space heating, but more than 70 percent of new customers added since 2010 have electric space heating. This increase is even more pronounced in the LG&E service territory where 35 to 50 percent of customers added since 2010 have electric space heating versus only 21 percent of customers added through 2010.

Table 5-11: KU Electric Heating Penetration

Cohort	Estimated Electric Heating Penetration	Average Billed kWh in 2020	Customers
<= 2010	59%	13,583	390,288
2011	76%	14,212	4,169
2012	77%	13,826	3,973
2013	77%	13,649	4,314
2014	75%	13,733	3,547
2015	74%	13,300	3,570
2016	74%	12,600	4,264
2017	71%	12,004	4,839
2018	72%	12,027	4,073
2019	69%	11,608	4,034

Table 5-12: LG&E Electric Heating Penetration

Cohort	Estimated Electric Heating Penetration	Average Billed kWh in 2020	Customers
<= 2010	21%	11,138	332,675
2011	34%	11,819	2,488
2012	35%	13,206	2,135
2013	39%	12,987	2,552
2014	42%	11,858	3,242
2015	44%	11,789	3,284
2016	45%	11,739	3,210
2017	44%	10,865	3,823
2018	42%	10,843	3,630
2019	47%	10,108	3,598

All other things equal, customers with a higher electric heating penetration would be expected to consume more electricity annually, but this has not been the case for customers added in recent years. For example, as seen in Table 5-11 and Table 5-12, despite a higher electric heating penetration, the average consumption in 2020 for customers added in 2019 (11,608 kWh for KU and 10,108 kWh for LG&E) 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 5-19 compares the monthly use-per-customer in 2019 for three customer cohorts. Compared to customers added through 2010, newer customers have significantly lower usage in the summer months and more similar usage in the winter months.

Figure 5-19: Monthly Average Use-Per-Customer by Estimated Housing Vintage

High and Low Energy Requirement Forecasts

The Companies' high and low energy requirements forecasts are summarized in Table 5-13 with the base energy requirements forecast. Compared to the base case forecast, the high case reflects an electrification scenario in which gas furnaces are replaced with electric heat pumps over time in both new and existing homes. Additionally, electric vehicles grow more quickly than in the base case and account for 50% of new car sales in the service territory by 2030. The high case also includes 180 MW of industrial load growth with a high load factor. Finally, the high case assumes customers grow 50% faster than in the base case (0.6% versus 0.4%) beginning in 2024.

Conversely, the low case assumes 180 MW of industrial load leaves the service territory and customer growth is 50% slower than in the base case (0.2% versus 0.4%) beginning in 2022. In addition, the low case assumes a new federal law eliminates the 1% cap on net metering capacity.[34]

[34] On September 27, 2021, Ford announced plans to add twin electric vehicle battery plants. Given the proximity of the announcement to the October 19, 2021 IRP filing date, the IRP could not be updated to explicitly include the new

Table 5-13: Energy Requirements Forecasts, Combined Companies (GWh)

Year	Base	High	Low
2021	32,229	32,239	32,229
2022	32,238	32,271	31,939
2023	32,079	32,152	31,719
2024	32,045	32,980	30,951
2025	31,839	33,039	30,702
2026	31,648	33,816	29,788
2027	31,532	34,019	29,595
2028	31,519	34,387	29,427
2029	31,370	34,651	28,980
2030	31,279	35,036	28,549
2031	31,243	35,425	28,444
2032	31,283	35,968	28,353
2033	31,196	36,358	28,144
2034	31,172	36,866	28,043
2035	31,188	37,368	28,005
2036	31,289	38,001	28,064

Figure 5-20 shows the disaggregated impact of each high and low case assumption on the base energy requirements forecast. In the low case, the loss of industrial load has the largest impact on the forecast throughout the planning period. In the high case, the new industrial load explains the majority of the difference between the high and base case forecasts initially, but higher EV adoption and space heating electrification have larger impacts by the end of the planning period. The high case assumes LG&E residential and small commercial customers gradually become more like KU customers in the winter heating months due to space heating electrification. This transition is assumed to occur over a 15-year period beginning in 2024. Therefore, by 2026 (three years into the 15-year transition), the high case assumes that the difference between LG&E and KU use-per-customer is reduced by 20% (3/15).[35] The timing of this transition was selected to evaluate the effects of a significant increase in electric space heating by the end of the IRP analysis period. Absent a new law or mandate, this transition is unlikely to begin in 2024.

load. The addition of this load makes the low case less likely. However, with the new load, the Companies do not anticipate needing additional generation capacity prior to 2028.

[35] Compared to LG&E residential customers, use-per-customer for KU residential customers is currently nearly 70% higher in January.

Figure 5-20: High and Low Case Energy Requirements Differences (GWh)

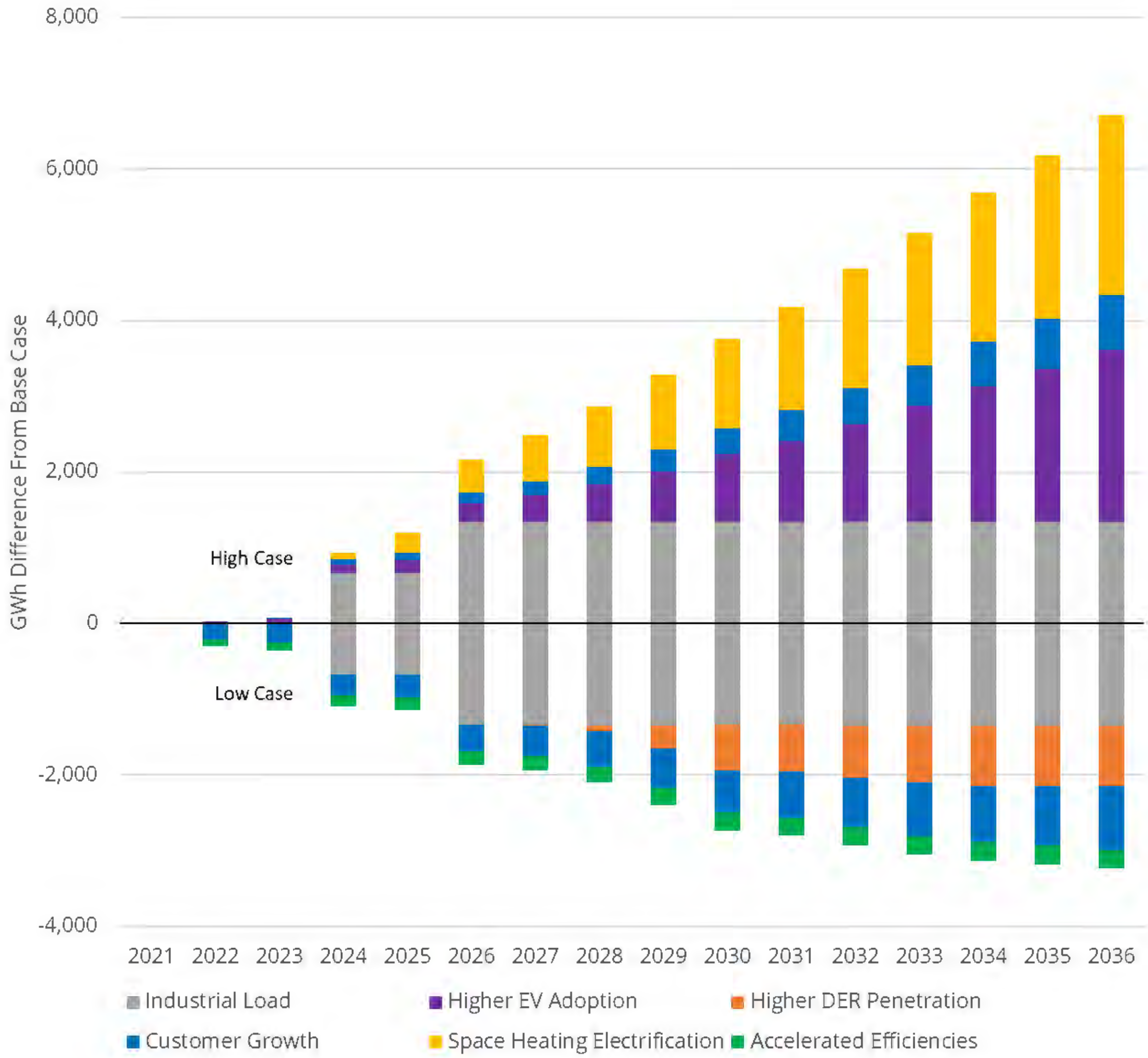


Table 5-14 summarizes the base, high, and low forecasts for summer and winter peak demands. In addition, Figure 5-21 and Figure 5-22 show the disaggregated impact of each high and low case assumption on the base summer and winter peak demand forecasts, respectively. In both the low and high forecasts, the Companies eventually become winter peaking under normal weather conditions. In the high scenario, while EV charging is assumed to be managed, the greater adoption of electric space heating and EVs causes the winter peak to exceed the summer peak by 2027. In the low scenario, greater adoption of distributed generation causes the summer peak to trend lower over the IRP period such that the winter peak is higher than the summer peak by the end of the IRP period. The summer peaks have an unbalanced downside risk due to distributed generation while the winter peaks have unbalanced upside risk due to space heating electrification. In 2026, the increase in space heating accounts for 233 MW of the total 481 MW difference between the high and base winter peak demands.

Table 5-14: Peak Demand Forecasts, Combined Companies (MW)

	Summer			Winter		
Year	**Base**	**High**	**Low**	**Base**	**High**	**Low**
2021	6,168	6,168	6,168	5,765	5,765	5,765
2022	6,229	6,230	6,175	5,898	5,899	5,839
2023	6,201	6,204	6,134	5,874	5,875	5,804
2024	6,179	6,265	6,024	5,859	6,030	5,693
2025	6,150	6,248	5,975	5,831	6,120	5,656
2026	6,113	6,294	5,849	5,806	6,287	5,535
2027	6,088	6,283	5,800	5,790	6,395	5,502
2028	6,067	6,270	5,731	5,777	6,494	5,472
2029	6,055	6,271	5,602	5,758	6,590	5,444
2030	6,056	6,280	5,564	5,750	6,769	5,430
2031	6,033	6,291	5,445	5,736	6,854	5,395
2032	6,035	6,312	5,448	5,738	6,961	5,395
2033	6,029	6,315	5,362	5,726	7,076	5,367
2034	6,020	6,330	5,364	5,715	7,211	5,325
2035	6,023	6,350	5,361	5,719	7,334	5,337
2036	6,026	6,379	5,321	5,737	7,648	5,364

Figure 5-21: High and Low Case Summer Peak Differences (MW)

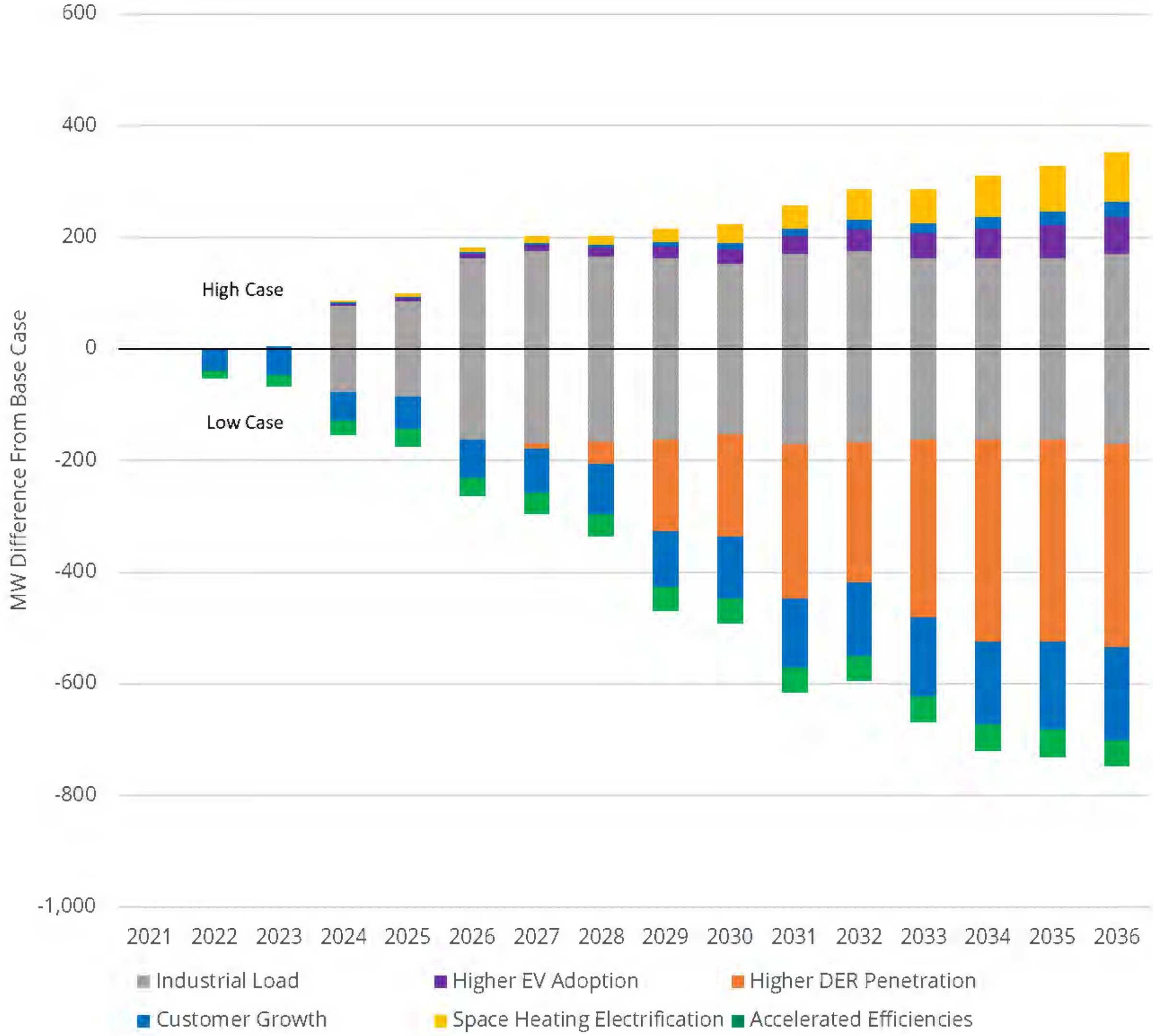
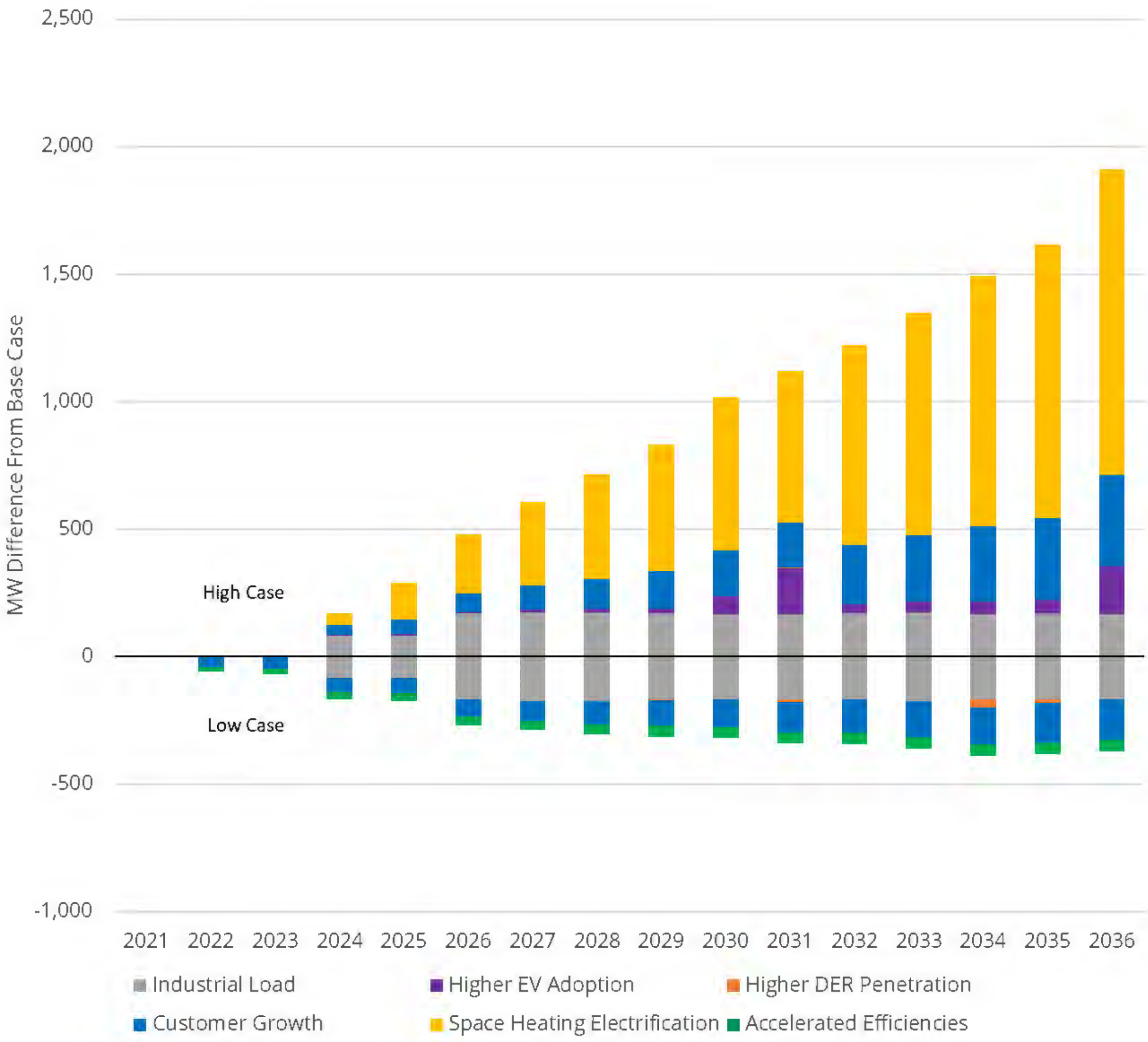


Figure 5-22: High and Low Case Winter Peak Differences (MW)



5.(4) Resource Plan

Resource Screening Analysis

Table 5-15 and Table 5-16 list the dispatchable and non-dispatchable resource options that were selected for evaluation in the Long-Term Resource Planning Analysis.[36] These resources set the foundation for a clean energy transition. Non-dispatchable resources include wind and utility-scale solar resources located in Kentucky. Dispatchable resources include large-frame simple-cycle combustion turbines ("SCCT"), natural gas combined cycle combustion turbines with carbon capture and sequestration ("NGCC w/ CCS"), and 4-hour and 8-hour battery storage. Based on

[36] 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.

the Biden administration's energy policy and the national focus on moving to clean energy, the current environment does not support the installation of NGCC without CCS due to its CO_2 emissions. SCCT was evaluated to support reliability as the industry transitions to resources with increasing intermittency.

Table 5-15: Dispatchable Resources (2022 Installation; 2022 Dollars)

	SCCT	NGCC w/CCS	Battery Storage	
			4-hour	**8-hour**
Summer Capacity (MW)[37]	220	513	1+	1+
Winter Capacity (MW)[37]	248	539	1+	1+
Heat Rate (MMBtu/MWh)[38]	9.7	7.2	N/A	N/A
Capital Cost ($/kW)[38]	885	2,304	1,274	2,300
Fixed O&M ($/kW-yr)[38]	22	69	32	58
Firm Gas Cost ($/kW-yr)[39]	22	22	N/A	N/A
Variable O&M ($/MWh)[38]	5.24	6.08	N/A	N/A
Fuel Cost ($/MWh)	27.45	20.23	N/A	N/A

Table 5-16: Non-Dispatchable Resources (2022 Installation; 2022 Dollars)

	KY Solar	KY Wind
Summer Capacity (MW)[40]	100+	100+
Winter Capacity (MW)[40]	100+	100+
Contribution to Summer Peak	79%	24%
Contribution to Winter Peak	0%	32%
Net Capacity Factor[38]	25.1%	27.4%
Capital Cost ($/kW)[38]	1,305	1,325
Fixed O&M ($/kW-yr)[38]	23	44
Investment Tax Credit	26%	N/A
Production Tax Credit ($/MWh)[41]	N/A	15

The Companies did not evaluate combined cycle with hydrogen or nuclear resources in the Long-Term Resource Planning Analysis, but these technologies could eventually play an important role in decarbonization and the integration of renewables. In addition, the Companies did not directly

[37] NREL's 2021 ATB did not specify capacity values. The capacities shown are representative of typical installations. The Companies modeled battery storage resources in 100 MW increments.
[38] Source: NREL's 2021 ATB (https://atb.nrel.gov/). The Companies inflated NREL's cost forecasts, which were provided in real 2019 dollars, to nominal dollars at 2% annually.
[39] Firm gas transportation costs are based on the cost of firm gas transportation for Cane Run 7 and the Trimble County SCCTs.
[40] NREL's 2021 ATB did not specify capacity values. The capacities shown are representative of typical installations. The Companies modeled solar and wind resources in 100 MW increments.
[41] Production Tax Credit of $15/MWh included for the first 10 years of wind resources.

evaluate new demand-side management ("DSM") programs in this IRP. Instead, the IRP identifies potential opportunites for new DSM programs that will be evaluated based on data and DSM pilot programs associated with the implementation of AMI.

Compared to assumptions in the 2018 IRP, the capital costs of wind and battery technologies for a 2022 installation have decreased and the capital cost of solar resources has increased; however, capital costs for all three technologies are expected to decline through 2030, and are lower than capital costs in the 2018 IRP by the end of the IRP planning period. Fixed operating and maintenance costs have increased significantly from the 2018 IRP for all evaluated technologies with the exception of wind resources.

Target Reserve Margin Range

Using the same methodology as the 2018 IRP, the 2021 IRP reserve margin analysis evaluates (a) annual capacity costs and (b) annual reliability and generation production costs for 2025 over a range of generation portfolios with different reserve margins to identify the optimal generation mix for customers.[42] 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 retirements of one or more Brown 11N2 simple-cycle combustion turbines ("SCCTs"), Mill Creek 2, and Brown 3.[43] Similarly, to determine if adding resources would cost-effectively improve reliability, the Companies compared the costs and benefits of adding new SCCT capacity and solar to the generation portfolio.

The results of the 2021 analysis show that the Companies' existing resources are economically optimal for meeting system reliability needs in 2025. 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; the reliability and generation production cost benefit for each of the Companies' marginal resources exceeds the costs that would be saved by retiring these units. Table 5-17 compares the 2018 IRP and 2021 IRP summer margin ranges. The minimum of the summer reserve margin range is unchanged, and the maximum of the range in the 2021 IRP is slightly lower due primarily to a decrease in the assumed variability of summer peak demands.

Table 5-17: Summer Target Reserve Margin Ranges

	Summer Range (%)
2018 IRP	17 – 25
2021 IRP	17 – 24

The high end of the 2021 IRP summer reserve margin range (24 percent) is the reserve margin for the generation portfolio that meets the 1-in-10 loss-of-load event ("1-in-10 LOLE") physical reliability guideline. The winter reserve margin for the same generation portfolio – computed as

[42] 2025 is the first year of the planning period that reflects the planned retirement of Mill Creek 1 and the assumed retirements of the small-frame SCCTs. As the Companies' analyses show, they do not anticipate needing additional generation capacity prior to 2028.
[43] The Brown 11N2 SCCTs comprise Brown 5, Brown 8, Brown 9, Brown 10, and Brown 11. The analysis assumes Mill Creek 1 will be retired in 2024, and the Companies' small-frame SCCTs will be retired by 2025.

a function the forecasted winter peak demand under normal weather conditions – is 35 percent. The low end of the summer reserve margin range is determined by estimating the increase in load that would result in the addition of generation resources. Based on the 2021 IRP analysis, the reliability and production cost benefits from adding new SCCT capacity would more than offset the cost of the capacity if the Companies' load increased by 300 MW. With this load increase, the Companies' summer reserve margin would be approximately 17 percent, and the winter reserve margin would be 26 percent. Therefore, the Companies' target reserve margin range is 17 to 24 percent in the summer and 26 to 35 percent in the winter.

Long-Term Resource Plan

Table 5-18 lists the Companies' forecasted summer and winter reserve margins in the base, high, and low load forecast scenarios and reflects the assumed retirements in Table 5-4 as well as the addition of Rhudes Creek Solar in 2023 (100 MW nameplate) and an additional 160 MW of Green Tariff Option 3 solar in 2025.[44]

Table 5-18: Forecasted Summer and Winter Reserve Margins[45]

	Base Load Scenario		High Load Scenario		Low Load Scenario	
Year	**Summer**	**Winter**	**Summer**	**Winter**	**Summer**	**Winter**
2022	21.6%	37.3%	21.6%	37.3%	22.7%	38.7%
2023	23.4%	37.9%	23.3%	37.9%	24.8%	39.6%
2024	23.8%	38.2%	22.1%	34.3%	27.0%	42.3%
2025	25.7%	32.8%	23.7%	26.5%	29.3%	36.9%
2026	26.4%	33.4%	22.8%	23.2%	32.1%	39.9%
2027	26.9%	33.8%	23.0%	21.1%	33.2%	40.8%
2028	15.6%	21.7%	11.9%	8.3%	22.4%	28.5%
2029	15.8%	22.1%	11.8%	6.7%	25.2%	29.2%
2030	15.8%	22.3%	11.7%	3.9%	26.0%	29.5%
2031	16.2%	22.6%	11.4%	2.6%	28.8%	30.3%
2032	16.2%	22.5%	11.1%	1.0%	28.7%	30.3%
2033	16.3%	22.8%	11.0%	-0.6%	30.7%	31.0%
2034	-1.6%	3.7%	-6.4%	-17.8%	10.5%	11.3%
2035	-5.6%	-1.0%	-10.5%	-22.8%	6.0%	6.1%
2036	-7.7%	-3.5%	-12.8%	-27.6%	4.5%	3.2%

The Companies developed least-cost resource plans over three energy requirements and three fuel price scenarios with the resources in Table 5-15 and Table 5-16. Table 5-19 lists the least-cost resource plans from this analysis. Each plan was developed in consideration of the need to reliably

[44] On October 13, 2021, the Companies announced plans to enter into a 125 MW solar PPA to exclusively serve five customers participating in the Companies' Green Tariff Option 3. The PPA was not finalized until October 11, 2021, after all participating customers committed to their desired allocation of the PPA. Given the proximity of this date to the October 19, 2021 IRP filing date, the IRP could not be updated to reflect the lower capacity.

[45] Values reflect the assumed retirements in Table 5-4 as well as the addition of Rhudes Creek Solar in 2023 (100 MW nameplate) and an additional 160 MW of Green Tariff Option 3 solar in 2025.

serve customers in the summer and winter months and considers, for example, the availability of renewable resources under summer and winter peak load conditions.

Table 5-19: New Generation in Least-Cost Resource Plan Summary

Years	Load Scenario	Fuel Price Scenario	Gas	Solar	Wind	Batteries
2026-2030	Base	Base	2 SCCTs[46]	500 MW	0 MW	0 MW
		High	2 SCCTs	1,000 MW	0 MW	0 MW
		Low	2 SCCTs	300 MW	0 MW	0 MW
	High	Base	6 SCCTs	1,500 MW	0 MW	100 MW
		High	5 SCCTs	1,500 MW	0 MW	300 MW
		Low	7 SCCTs	500 MW	0 MW	0 MW
	Low	Base	0 SCCTs	500 MW	0 MW	0 MW
		High	0 SCCTs	1,000 MW	0 MW	0 MW
		Low	0 SCCTs	0 MW	0 MW	0 MW
2031-2036	Base	Base	4 SCCTs	1,600 MW	0 MW	200 MW
		High	0 SCCTs	2,400 MW	300 MW	1,100 MW
		Low	5 SCCTs	0 MW	0 MW	0 MW
	High	Base	0 SCCTs	2,400 MW	100 MW	2,500 MW
		High	0 SCCTs	2,200 MW	1,900 MW	2,000 MW
		Low	10 SCCTs	600 MW	0 MW	0 MW
	Low	Base	4 SCCTs	700 MW	100 MW	200 MW
		High	2 SCCTs	1,600 MW	100 MW	700 MW
		Low	5 SCCTs	0 MW	0 MW	0 MW

Despite a wide range of load and fuel scenarios, some consistent results emerged. Solar and SCCTs are the predominant resource technology choices until the retirement of Ghent 1 and Ghent 2 in 2034. Battery storage is favored in cases with high renewable penetration. The replacement of Ghent 1 and Ghent 2 is expected to rely on renewable resources for energy in most scenarios and either SCCTs or battery storage for capacity. And NGCC with CCS is not cost-competitive with solar combined with SCCTs or battery storage in any of the scenarios modeled in this analysis. In the base load, base fuel price case, peaking resources are primarily used to meet peak load needs and operate at low capacity factors. Successful deployment of DSM programs could reduce or defer the need for peaking resources, particularly for battery storage because their modular nature allows for more custom project sizes.

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

[46] A SCCT is assumed to have a summer capacity of 220 MW and a winter capacity of 248 MW. In the high load scenario, SCCT capacity is first added in 2026 to address winter reliability concerns associated with a higher penetration of electric space heating. In the base load scenario, SCCT capacity is first added in 2028 to address the reserve margin need resulting from the retirements of Mill Creek 2 and Brown 3.

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 their 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 addition of Rhudes Creek solar and the retirement of Mill Creek 1 and Zorn 1, no changes or additions to the Companies' generation resources are planned for the next three years. As AMI is implemented, the Companies plan to evaluate new DSM mechanisms that leverage AMI data and communications through the development of pilot programs. The Companies will closely evaluate the these programs to assess their ability to avoid or defer the need for supply-side resources as well as engage customers. In addition, when Rhudes Creek Solar comes online, the Companies will closely monitor its generation to better understand its output under peak load conditions.

The Companies will continue to monitor developments in renewable technology, battery storage, and carbon capture and sequestration, 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 regulations aimed at reducing CO_2 emissions. 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.[47] 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.

[47] On September 27, 2021, Ford announced plans to add twin electric vehicle battery plants. Given the proximity of the announcement to the October 19, 2021 IRP filing date, the IRP could not be updated to explicitly include the new load. With the new load, the Companies do not anticipate needing additional generation capacity prior to 2028.

6 Significant Changes

The following sections summarize significant changes since the 2018 IRP was filed in October 2018.

Load Forecast

As mentioned previously, energy requirements in the LG&E and KU service territories have been slightly declining over the past five years. Increased consumption from the addition of new customers has been offset by mining sector declines, 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.

Table 6-1 compares the 2021 IRP and 2018 IRP energy requirements forecasts for the combined companies. Energy requirements in the 2021 IRP forecast are only slightly lower through 2025, but the differences increase gradually thereafter. The major reasons pertain to continued improvements in end-use efficiencies, as mentioned above, and load reductions associated with conservation voltage reduction ("CVR") after AMI is fully implemented. Beginning in 2022, total energy requirements in the 2021 IRP forecast are only 234 GWh lower, but show a negative growth rate (-0.2 percent) through the end of the 15-year IRP planning period.

Table 6-1: Combined Company Energy Requirements Forecast (GWh)

Year	2021 IRP	2018 IRP	Change
2021	32,229	32,506	(277)
2022	32,238	32,472	(234)
2023	32,079	32,460	(381)
2024	32,045	32,535	(490)
2025	31,839	32,502	(663)
2026	31,648	32,507	(859)
2027	31,532	32,511	(979)
2028	31,519	32,550	(1,031)
2029	31,370	32,503	(1,133)
2030	31,279	32,477	(1,198)
2031	31,243	32,486	(1,243)
2032	31,283	32,521	(1,238)
2033	31,196	32,486	(1,290)
2034	31,172	32,488	(1,316)
2035	31,188	32,487	(1,299)
2036	31,289	32,518	(1,229)
2021-2036 CAGR	-0.20%	0.00%	

Table 6-2 compares the 2021 IRP and 2018 IRP peak demand forecasts for the combined companies. In the 2021 IRP, summer peak demand is only 109 MW lower in 2022 and 303 MW lower in 2036. Winter peak demands in the 2021 IRP are only 72 MW lower in 2022 and 431 MW lower in 2036.

Table 6-2: Summer and Winter Peak Demand Forecasts (MW)

	Summer			Winter		
Year	2021 IRP	2018 IRP	Change	2021 IRP	2018 IRP	Change
2021	6,168	6,350	(182)	5,765	5,975	(210)
2022	6,229	6,338	(109)	5,898	5,970	(72)
2023	6,201	6,337	(136)	5,874	5,967	(93)
2024	6,179	6,325	(146)	5,859	5,973	(114)
2025	6,150	6,330	(180)	5,831	5,991	(160)
2026	6,113	6,344	(231)	5,806	6,013	(207)
2027	6,088	6,351	(263)	5,790	6,028	(238)
2028	6,067	6,352	(285)	5,777	6,048	(271)
2029	6,055	6,357	(302)	5,758	6,068	(310)
2030	6,056	6,355	(299)	5,750	6,084	(334)
2031	6,033	6,353	(320)	5,736	6,101	(365)
2032	6,035	6,343	(308)	5,738	6,114	(376)
2033	6,029	6,339	(310)	5,726	6,128	(402)
2034	6,020	6,335	(315)	5,715	6,146	(431)
2035	6,023	6,334	(311)	5,719	6,156	(437)
2036	6,026	6,329	(303)	5,737	6,168	(431)
2022-2036 Avg	-0.16%	-0.02%		-0.03%	0.21%	

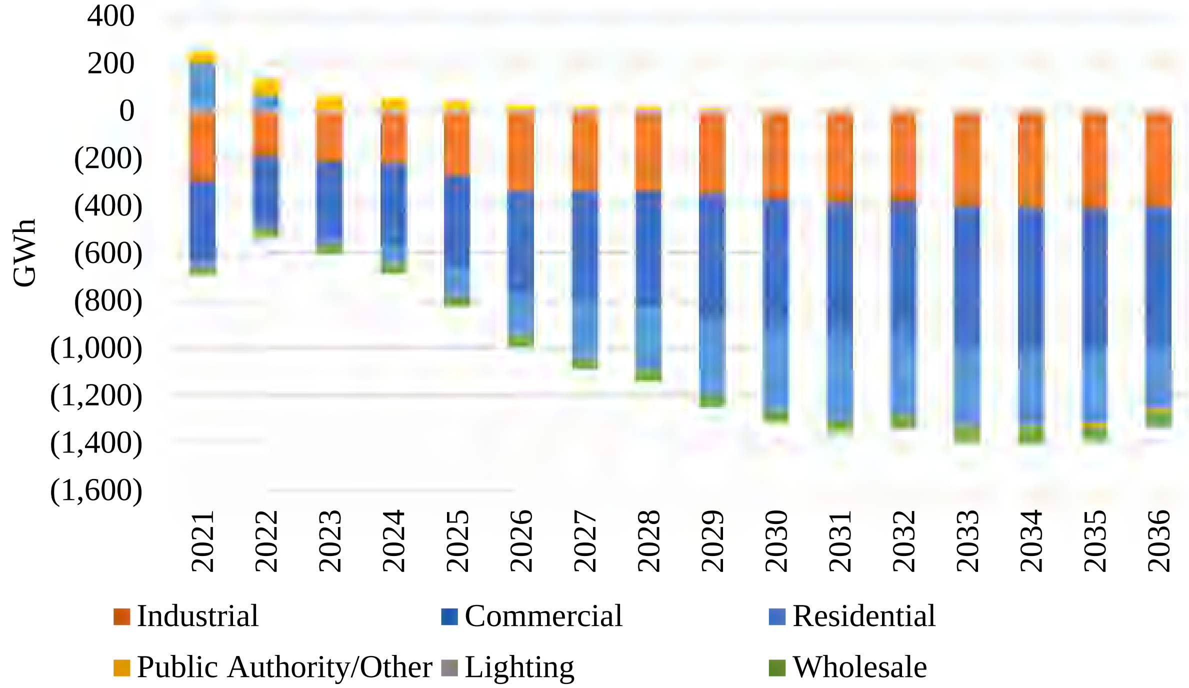
Table 6-3 shows the changes in sales forecasts for KU, LG&E, and the Combined Companies. The majority of the change in the Combined Companies' sales comes from the KU service territory, which has been impacted most by industrial losses and the decline in rural customers. Sales in both service territories are slightly declining as efficiency gains are expected to more than offset the impact of growing numbers of customers.

Table 6-3: Energy Sales Forecast (GWh)

	KU			LG&E			Combined Companies		
Year	**2021 IRP**	**2018 IRP**	**Change**	**2021 IRP**	**2018 IRP**	**Change**	**2021 IRP**	**2018 IRP**	**Change**
2021	18,696	18,910	(214)	11,403	11,634	(231)	30,099	30,544	(445)
2022	18,620	18,875	(255)	11,489	11,638	(149)	30,109	30,513	(404)
2023	18,539	18,855	(316)	11,422	11,647	(225)	29,961	30,502	(541)
2024	18,507	18,894	(387)	11,423	11,673	(250)	29,930	30,567	(637)
2025	18,380	18,866	(486)	11,371	11,670	(299)	29,751	30,536	(785)
2026	18,279	18,862	(583)	11,299	11,682	(383)	29,578	30,544	(966)
2027	18,194	18,860	(666)	11,286	11,693	(407)	29,480	30,553	(1,073)
2028	18,184	18,880	(696)	11,286	11,717	(431)	29,470	30,597	(1,127)
2029	18,091	18,857	(766)	11,241	11,714	(473)	29,332	30,571	(1,239)
2030	18,032	18,845	(813)	11,216	11,715	(499)	29,248	30,560	(1,312)
2031	18,005	18,842	(837)	11,209	11,727	(518)	29,214	30,569	(1,355)
2032	18,029	18,858	(829)	11,232	11,747	(515)	29,261	30,605	(1,344)
2033	17,972	18,835	(863)	11,209	11,741	(532)	29,181	30,576	(1,395)
2034	17,967	18,834	(867)	11,215	11,748	(533)	29,182	30,582	(1,400)
2035	17,971	18,832	(861)	11,226	11,755	(529)	29,197	30,587	(1,390)
2036	18,024	18,851	(827)	11,267	11,774	(507)	29,291	30,625	(1,334)
2022-2036 Average	-0.24%	-0.02%		-0.08%	0.08%		-0.18%	0.02%	

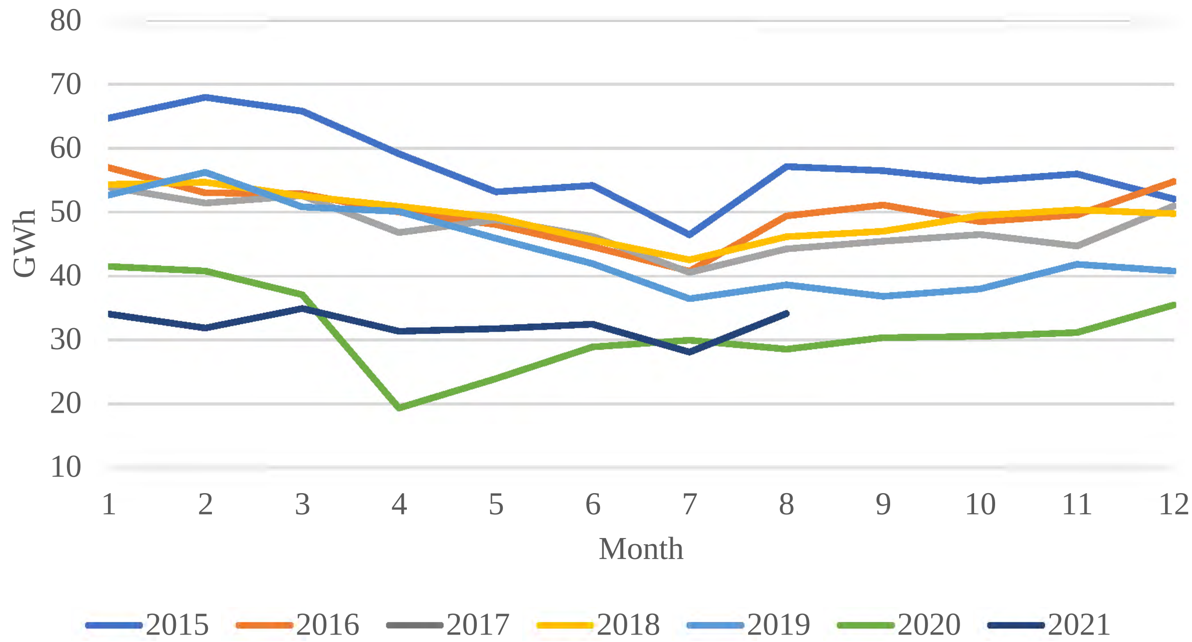
Figure 6-1 shows sales forecast changes from the 2018 IRP by class. By far the largest change to the Companies' projections are in the commercial and industrial classes. While both the industrial and commerical classes experienced material declines in 2020 as a result of the COVID-19 pandemic, a quicker pace of efficiency gains is the primary reason for the changes over the next 15 years. For the commercial class, forecasted energy efficiency gains are based on energy intensity projections from the EIA for the major commercial end-uses. The declines in industrial load as compared to the previous IRP are more indicative of efficiency gains offsetting expected sales growth as opposed to an outright projection for declining sales. In recent years, many of the Companies' largest customers have leveraged newer technologies and process improvements to expand operations without increasing load. Load reductions associated with CVR impact primarily the residential and commercial classes.

Figure 6-1: 2021 IRP GWh Changes from 2018 IRP By Class



In addition to commercial and industrial efficiency gains, sales to the mining sector have declined and are forecasted to continue to decline at a faster pace than forecasted in the 2018 IRP. Figure 6-2 shows monthly sales to the coal mining sector since 2015. Prior to the pandemic, sales to the coal mining sector had declined more than 35% from first quarter 2015 levels.

Figure 6-2: Sales to the Coal Mining Sector



Generation Capacity Needs

Table 6-4 contains a summary of summer peak demand and resources from the 2018 IRP. When the 2018 IRP was filed, the Companies' generation capacity was projected to decrease by 437 MW in 2019 due to the retirements 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. With no planned retirements, the Companies did not have a need for new capacity through the end of the 15-year planning period (2033).

Table 6-4: Summer Peak Demand 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[48]	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[49]	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%**

Table 6-5 and Table 6-6 contain summaries of peak demand and resources from the 2021 IRP. Generation Resources in 2022 reflect the retirements of Brown 1 and 2, the expiration of the Bluegrass Agreement, and the retirement of Zorn 1, which is still planned for 2021.[50] Mill Creek 1 will be retired in 2024, and the Companies' small-frame SCCTs are assumed to be retired by 2025. Because Mill Creek 1 and 2 cannot operate simultaneously during the ozone season due to NOx limits, one of the units (300 MW) is assumed to be unavailable in the summer from 2022 to 2024. The Rhudes Creek solar facility (100 MW nameplate) is assumed to come online in 2023 and an additional 160 MW of Green Tariff Option 3 solar is added in 2025.[51] None of this capacity is available to serve winter peak because the Companies' winter peak occurs at night. Approximately 79% of the new solar capacity is assumed to be available to serve summer peak but the availability of solar is uncertain due to its intermittent fuel source. The Companies' target reserve margin range is 17 to 24 percent in the summer and 26 to 35 percent in the winter. Based on those reserve margin ranges, the Companies anticipate being capacity sufficient until at least 2028, when the Companies will have a small reserve margin deficit in the summer and a larger reserve margin deficit in the winter after the assumed retirements of Mill Creek 2 and Brown 3.

[48] 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.
[49] 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.
[50] Generation resources have a higher capacity in the winter primarily because natural gas units can produce more power at lower ambient air temperatures.
[51] On October 13, 2021, the Companies announced plans to enter into a 125 MW solar PPA to exclusively serve five customers participating in the Companies' Green Tariff Option 3. The PPA was not finalized until October 11, 2021, after all participating customers committed to their desired allocation of the PPA. Given the proximity of this date to the October 19, 2021 IRP filing date, the IRP could not be updated to reflect the lower capacity.

Table 6-5: Summer Peak Demand and Resource Summary (MW, 2021 IRP)

	2022	2023	2024	2025	2028	2034	2035	2036
Gross Peak Load	6,522	6,500	6,485	6,461	6,378	6,331	6,334	6,337
Non-Dispatchable DSM	-294	-300	-305	-311	-311	-311	-311	-311
Net Peak Load	6,229	6,201	6,179	6,150	6,067	6,020	6,023	6,026
Generation Resources	7,688	7,688	7,688	7,688	7,688	7,688	7,688	7,688
CSR	127	127	127	127	127	127	127	127
DCP	61	60	58	56	52	45	44	43
Retirements/Additions								
Coal[52]	-300	-300	-300	-300	-1,009	-1,969	-1,969	-1,969
Large-Frame SCCTs[53]	0	0	0	0	0	-121	-363	-484
Small-Frame SCCTs[54]	0	0	0	-47	-47	-47	-47	-47
New Solar[55]	0	79	79	204	204	204	204	204
Total Supply	7,576	7,653	7,651	7,728	7,015	5.927	5,684	5,562
Reserve Margin	1,348	1,452	1,472	1,578	947	-93	-339	-465
Reserve Margin %	21.6%	23.4%	23.8%	25.7%	15.6%	-1.6%	-5.6%	-7.7%

[52] The Companies assume that Mill Creek 1 and 2 cannot be operated simultaneously during ozone season due to NOx limits, which results in a reduction of available summer capacity through 2024. This analysis assumes that Mill Creek 1 is retired in 2024, Mill Creek 2 and Brown 3 are retired in 2028, and Ghent 1-2 are retired in 2034.
[53] This analysis assumes that Brown 9 is retired in 2034, Brown 8 and 10 are retired in 2035, and Brown 11 is retired in 2036.
[54] This analysis assumes that Haefling 1-2 and Paddy's Run 12 are retired in 2025.
[55] This analysis assumes 100 MW of solar capacity is added in 2023, and an additional 160 MW of solar capacity is added in 2025. Capacity values reflect 78.6% expected contribution to summer peak capacity.

Table 6-6: Winter Peak Demand and Resource Summary (MW, 2021 IRP)

	2022	2023	2024	2025	2028	2034	2035	2036
Net Peak Load	5,898	5,874	5,859	5,831	5,777	5,715	5,719	5,737
Generation Resources	7,973	7,973	7,973	7,973	7,973	7,973	7,973	7,973
CSR	127	127	127	127	127	127	127	127
DCP	0	0	0	0	0	0	0	0
Retirements/Additions								
Coal[52]	0	0	0	-300	-1,013	-1,978	-1,978	-1,978
Large-Frame SCCTs[53]	0	0	0	0	0	-138	-404	-532
Small-Frame SCCTs[54]	0	0	0	-55	-55	-55	-55	-55
New Solar[56]	0	0	0	0	0	0	0	0
Total Supply	8,100	8,100	8,100	7,744	7,031	5,928	5,662	5,534
Reserve Margin	2,201	2,226	2,240	1,913	1,254	213	-57	-203
Reserve Margin %	37.3%	37.9%	38.2%	32.8%	21.7%	3.7%	-1.0%	-3.5%

Supply-Side and Demand-Side Resources

Since the 2018 IRP was filed in October 2018, the Companies retired Brown 1 and 2 (272 MW) in February 2019 and their capacity purchase and tolling agreement with Bluegrass Generation (165 MW) expired in April 2019. In addition, two of the Companies' small-frame SCCTs, Cane Run 11 and Paddy's Run 11, were retired in November 2019 and March 2021, respectively.

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"). The Companies have recently initiated a new DSM Planning process to cover the years of 2023 – 2025. The primary driver of this is the higher than expected customer participation in the Nonresidential Rebates Program resulting in more rebates paid to customers than forecasted. Also, with the most recent Rate Case Orders, the Companies have been asked to review some additional programming options including: On-bill Financing, Peak-Time Rebates, AMI related customer offerings, as well as any additional low-cost offerings that could be provided for low-income customers. The Companies expect to file an updated DSM Filing in 2022 due to the higher than expected customer demand for the Nonresidential Rebate program and to address possible pilots for some of the programs noted above.

The latest DSM Filing (i.e., the 2019-2025 DSM-EE Program Plan) incorporated changes in the Companies' approach to working with industrial customers by making nonresidential programs available to all commercial and industrial customers. Industrial customers are included in the Companies' DSM rate recovery mechanism, and are eligible for all nonresidential programs offerings, unless they meet the Companies' opt-out criteria and follow the Companies' opt-out process. The Companies have established seven-year electricity savings goals of 214,667 MWh

[56] This analysis assumes 100 MW of solar capacity is added in 2023, and an additional 160 MW of solar capacity is added in 2025. Capacity values reflect zero expected contribution to winter peak capacity as specified in section 5.(4).

of electric energy savings and 557,143 CCF of gas savings as part of their 2019 – 2025 DSM Filing.

Environmental Regulations

Significant changes to environmental regulations since the 2018 IRP are briefly summarized in the following sections. Section 8.(5).(f) contains a more complete discussion of current environmental regulations.

Clean Air Interstate Rule / Cross-State Air Pollution Rule

On March 15, 2021, the EPA published the Revised Cross State Air Pollution Rule ("CSAPR") Update rule to address non-attainment issues with the 2008 ozone National Ambient Air Quality Standards ("NAAQS") in the northeastern states. Currently, certain areas of the United States are not meeting the 2008 ozone standard (75 parts per billion or "ppb"). Based on EPA's analysis, electric generating units in Kentucky and 11 other states have an impact on the affected non-attainment areas, causing them to exceed a screening threshold. Based on that analysis, the Revised CSAPR Update rule significantly reduces the nitrogen oxide ("NO_x") allowances issued to Kentucky and the 11 other states. The reduced allocation of allowances may result in the replacement of the Companies' non-SCR-equipped units. Additionally, trading of the reduced number of NOx allowances will be restricted to a new "Group 3" trading group consisting of just the 12 affected states.

The Companies will continue to operate and maintain the affected facilities in compliance with the Revised CSAPR Update requirements and will continue to follow EPA's development of any regional transport rules to address the 2015 ozone NAAQS. Because this Revised CSAPR Update rule was deemed necessary to meet the 2008 ozone NAAQS (75 ppb), it is reasonable to expect that even greater NO_x reductions will be necessary to meet the 2015 ozone NAAQS (70 ppb).

National Ambient Air Quality Standards ("NAAQS") – Ozone and $PM_{2.5}$

On December 23, 2020, following requirements to review NAAQS every five years, EPA issued a final decision to retain the 2015 NAAQS for ozone (70 ppb) and $PM_{2.5}$ (12.0 µg/m^3). Non-attainment designations to the 2015 ozone NAAQS are expected in late 2021 or early 2022. EPA will perform ozone transport modeling to assess regional impacts to non-attainment areas. The ozone transport modeling results may drive a new ozone regional transport rule that further reduces regional ozone emissions through reduced NOx credit allocations. Similar actions occurred when, on March 15, 2021, EPA published the Revised CSAPR Update rule (mentioned above) to address non-attainment issues with the 2008 ozone standard. Modeling, rulemaking, and compliance preparation may result in ozone reduction requirements around 2027 for the 2015 ozone NAAQS.

The Companies' Mill Creek Generating Station is located in Jefferson County, which is currently classified as marginal non-attainment for the 2015 Ozone NAAQS. By regulation, the Jefferson County marginal non-attainment area had until August 13, 2021 to reach attainment or risk being redesignated to moderate non-attainment. In 2020 and 2021, the Louisville Metro Air Pollution Control District ("LMAPCD") imposed, via an Agreed Board order, an additional 15-ton total daily NO_x emissions limitation on the Mill Creek Generating Station for the months of May through October in an effort to meet the August 2021 deadline. Despite the Companies' efforts while meeting this limit, there were exceedances of the 70 ppb ozone standard in the Jefferson County area during the 2020 ozone season. LMAPCD has stated that Jefferson County was not "in compliance" with the 2015 Ozone NAAQS by August 2021 due to those exceedances in 2020. LMAPCD currently anticipates being reclassified to moderate non-attainment in 2022. If that happens, major sources in Jefferson County may be required to implement NO_x Reasonable Available Control Technology ("RACT") by March 1, 2023. In the interim, the Companies expect that the ozone season NO_x limit for the Mill Creek Generating Station will remain in place pending development of the NO_x RACT standard. Therefore, the Companies will likely be limited to operating either Mill Creek Unit 1 or Mill Creek Unit 2 (but not both) during the ozone season (i.e., April through October) until Mill Creek Unit 1 retires in 2024.

Upon reclassification to moderate non-attainment with the 2015 Ozone NAAQS, the Jefferson County area will have a moderate non-attainment compliance date of August 3, 2024. The State Implementation Plan ("SIP") must be amended to include the RACT standards by April 2024. The NO_x emission reduction associated with the implementation of RACT at Mill Creek Generating Station is expected to be similar to the mode of operation at Mill Creek during the summers of 2020 and 2021.

Continued non-attainment past the 2024 compliance date will result in Kentucky reevaluating RACT for the Jefferson County area to further reduce NO_x emissions or cause the non-attainment area to be reclassified to serious non-attainment. Such a reclassification would require additional NO_x emission reductions, which must be demonstrated by August 2027. If serious non-attainment is reached, Mill Creek 2 would likely be retired as an alternative to installing additional NO_x controls, such as selective catalytic reduction ("SCR"), to achieve those reductions.

Prior to EPA's proposal to retain the 2015 standards, many environmental groups and members on EPA's Clean Air Scientific Advisory Committee presented data for lowering the standards to 65 – 68 ppb for ozone and 10-11 $\mu g/m^3$ for $PM_{2.5}$. By regulation, both standards should be reevaluated again in 2025. As of this IRP, there are reasons to expect both standards will be lowered following a reevaluation prior to 2025. The Jefferson County area is likely not to meet either standard. Therefore, even if Jefferson County has achieved attainment of the 70 ppb ozone standard by August 2024, it is likely that the standard would be lowered in 2025, and, once again, the Jefferson County area will be determined to be non-attainment for ozone. Such a determination will start the process of establishing a new RACT and implementing further NO_x reductions at all sources in the Jefferson County area. Additionally, many other areas in Kentucky could likely be non-attainment for a lower $PM_{2.5}$ NAAQS. If this occurred, the Commonwealth of Kentucky would need to begin the process of determining what needs to be done to achieve attainment and make changes to the State Implementation Plan to address those needs. The Companies will continue to follow these NAAQS developments and implement any needed changes to ensure compliance.

Regional Haze

Since the 2018 IRP, the second planning period (2018-2028) of the Regional Haze rule began. The Companies' Mill Creek Generating Station Units 3 and 4 have permit limits based on reviews performed during the first planning period to meet the visibility criteria of the rule for impacts on Mammoth Cave National Park. From the Commonwealth of Kentucky's review, the Companies will not have to take any further actions for the second Regional Haze planning period. However, EPA's requirements for implementation of the third planning period of the Regional Haze regulation will likely be published in 2028 for states to model sources impacting visibility in national parks. Even though the Commonwealth of Kentucky is below the glide path required for showing progress toward the rule's goal by 2064, the Companies may be requested to evaluate visibility/regional haze impacts of operations on Class 1 areas like Mammoth Cave National Park because EPA has stated that being below the glide path does not negate the need to evaluate impacts and possibly install controls. The Companies will continue to follow these issues and implement any needed changes to ensure compliance.

Greenhouse Gases

On June 19, 2019, EPA issued the final Affordable Clean Energy ("ACE") rule to replace the 2015 Clean Power Plan ("CPP"). However, on January 19, 2021, the U.S. Court of Appeals for the D.C. Circuit court vacated the ACE rule and remanded it to EPA for further proceedings consistent with the court's opinion.[57] As of the date of this IRP, EPA is still formulating how to address the court decision.

In 2021, President Joe Biden's administration has placed a high priority on climate change and GHG issues. President Biden fulfilled a campaign promise and had the United States rejoin the Paris Agreement. The Paris Agreement is a legally binding international treaty on climate change that nearly 200 countries adopted in 2015. As part of meeting the Paris Agreement's goals, President Biden set new targets for the United States to achieve a 50-52% reduction from 2005 levels of economy-wide net GHG emissions in 2030. A goal was also set for reaching net zero emissions economy-wide by no later than 2050. Additionally, in response to President Biden's Executive Order 13990 "Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis", EPA is considering rulemaking proposals to address sources of climate- and health-impacting emissions. EPA states that these efforts include investigating the possibility of lowering the GHG NSPS levels for new, modified, and reconstructed electric generating units, including new NGCC units, as well as developing strategies to achieve reductions in GHG emissions from existing power plants. Depending on how far those efforts are taken, carbon capture, utilization, and sequestration ("CCUS") technologies may be needed to achieve desired reductions.

The Companies will continue to follow all these GHG issues and assess their impacts on operating facilities.

[57] *American Lung Ass'n v. E.P.A.*, 985 F.3d 914 (D.C. Cir. 2021).

Environmental Justice

There is not a specific regulation or guidance document issued by EPA that addresses environmental justice. However, President Biden has made the topic a key focus of his administration. In 2021, EPA began emphasizing the use of their environmental justice screening tool ("EJ Screen") when community or project stakeholders have concerns about impacts on a community regarding issues related to environmental justice. However, as of the date of this IRP, there is no prescribed guidance on data interpretation nor any defined actions that should be taken based on the data provided by use of EJ Screen. Therefore, the Companies will continue to utilize existing siting processes until change is prompted by local, state, or federal drivers.

Although not actively utilizing the EPA's EJ Screen, the Companies consider environmental and economic factors in assessing and planning development activity. These factors are consistent with our mission and values of being environmentally conscious, investing in our community, and providing safe and reliable service at the lowest reasonable cost. Environmentally, properties are assessed for endangered species, biodiversity, impact to water resources, and cultural and heritage related concerns to comply with applicable legal requirements. Economic least-cost drivers tend to minimize the number of residential customer impacts and often drive projects toward public, commercial, and agricultural properties. The Companies have a history of community engagement and public meetings to support development activities.

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

	2016	2017	2018	2019	2020
Residential	426,230	429,411	431,617	434,374	438,537
Commercial	80,674	81,236	81,572	82,544	83,029
Industrial	2,842	2,662	2,421	1,795	1,737
Public Authority	1,456	1,454	1,444	1,166	1,188
Public Street and Highway Lighting	7,646	7,751	7,935	8,462	8,627
Virginia Retail	28,221	28,122	27,933	27,790	27,804
Req. Sales for Resale	11	10	11	6	3
Total Customers	547,080	550,646	552,933	556,137	560,925

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

	2016	2017	2018	2019	2020
Residential	356,424	359,658	362,112	365,910	371,301
Commercial	42,914	43,574	44,002	44,329	44,921
Industrial	580	573	567	558	547
Street Lighting	672	680	655	639	625
Public Authority	4,154	4,253	4,375	4,417	4,449
Total Customers	404,744	408,738	411,711	415,853	421,843

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

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

	2016	2017	2018	2019	2020
SYSTEM BILLED SALES:					
Recorded	20,549	19,897	21,077	19,556	17,752
Weather Normalized	20,632	20,393	20,504	19,188	18,116
SYSTEM USED SALES:					
Recorded	20,757	19,984	20,916	19,385	17,834
Weather Normalized	20,602	20,291	20,373	19,236	18,325
ENERGY REQUIREMENTS:					
Recorded	22,073	21,257	22,291	20,696	18,964
Weather Normalized	21,918	21,564	21,748	20,547	19,455
SALES BY CLASS:					
Residential	6,048	5,698	6,320	6,080	5,968
Commercial	3,849	3,778	4,011	4,100	3,723
Industrial	6,635	6,499	6,429	6,101	5,663
Lighting	43	44	42	36	28
Public Authorities	1,571	1,508	1,565	1,539	1,426
Requirement Sales for Resale	1,876	1,755	1,792	826	368
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KENTUCKY Retail	20,022	19,282	20,159	18,682	17,176
VIRGINIA Retail	735	702	757	703	658
SYSTEM LOSSES	1,294	1,256	1,356	1,287	1,106
Utility Use	22	17	19	24	24
ENERGY REQUIREMENTS	22,073	21,257	22,291	20,696	18,964
Weather Normalized:					
Residential	5,947	5,929	6,008	5,960	6,338
Commercial	3,833	3,809	3,886	4,081	3,790
Industrial	6,635	6,501	6,429	6,101	5,663
Lighting	43	44	42	36	28
Public Authorities	1,569	1,512	1,538	1,532	1,446
Requirement Sales for Resale	1,856	1,788	1,731	829	371
VIRGINIA Retail	719	708	739	697	689

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

	2016	2017	2018	2019	2020
SYSTEM BILLED SALES:					
Recorded	11,919	11,503	12,057	11,738	11,059
Weather Normalized	11,763	11,667	11,626	11,544	11,142
SYSTEM USED SALES:					
Recorded	11,948	11,527	12,062	11,656	11,007
Weather Normalized	11,811	11,690	11,650	11,450	11,195
ENERGY REQUIREMENTS:					
Recorded	12,570	12,066	12,626	12,298	11,562
Weather Normalized	12,433	12,229	12,214	12,092	11,750
SALES BY CLASS:					
Residential	4,215	4,004	4,370	4,229	4,122
Commercial	3,943	3,854	3,949	3,830	3,518
Industrial	2,640	2,562	2,606	2,500	2,359
Public Authorities	1,131	1,087	1,120	1,083	998
Lighting	19	20	17	14	10
TOTAL LG&E SALES	11,948	11,527	12,062	11,656	11,007
SYSTEM LOSSES	600	518	541	620	533
Utility Use	22	21	23	22	22
ENERGY REQUIREMENTS	12,570	12,066	12,626	12,298	11,562
WEATHER NORMALIZED SALES BY CLASS:					
Residential	4,083	4,138	4,076	4,078	4,256
Commercial	3,940	3,873	3,860	3,788	3,560
Industrial	2,641	2,569	2,606	2,500	2,359
Public Authorities	1,128	1,090	1,091	1,070	1,010
Lighting	19	20	17	14	10

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

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

	2016	2017	2018	2019	2020
SUMMER					
Actual*	3,642	3,641	3,610	3,671	3,565
	2015/2016	**2016/2017**	**2017/2018**	**2018/2019**	**2019/2020**
WINTER					
Actual*	4,148	3,771	4,516	4,098	3,693

*Excluding departed municipal customers

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

	2016	2017	2018	2019	2020
SUMMER					
Actual	2,524	2,589	2,618	2,607	2,504
	2015/2016	**2016/2017**	**2017/2018**	**2018/2019**	**2019/2020**
WINTER					
Actual	1,808	1,797	1,909	1,882	1,658

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

	2016	2017	2018	2019	2020
SUMMER					
Actual*	6,166	6,230	6,228	6,278	6,069
	2015/2016	**2016/2017**	**2017/2018**	**2018/2019**	**2019/2020**
WINTER					
Actual*	5,956	5,567	6,425	5,980	5,351

*Excluding departed municipal customers

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

	2016	2017	2018	2019	2020
Energy Sales (GWh)	18,920	18,165	18,979	17,539	16,111
Coincident Peak Demand (MW)	3,490	3,469	4,373	3,518	3,432

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

	2016	2017	2018	2019	2020
Energy Sales (GWh)	11,415	11,001	11,522	11,154	10,511
Coincident Peak Demand (MW)	2,462	2,530	1,868	2,541	2,479

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

	2016	2017	2018	2019	2020
Energy Sales (GWh)	1,102	1,116	1,181	1,142	1,064
Coincident Peak Demand (MW)	152	172	142	154	132

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

	2016	2017	2018	2019	2020
Energy Sales (GWh)	532	525	542	502	497
Coincident Peak Demand (MW)	62	59	41	66	26

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

Table 7-12: KU Annual Energy Losses

	2016	2017	2018	2019	2020
Annual Energy Loss (GWh)	1,294	1,256	1,356	1,287	1,106
Loss Percent of Energy Requirements	6.2%	6.3%	6.5%	6.6%	6.2%

Table 7-13: LG&E Annual Energy Losses

	2016	2017	2018	2019	2020
Annual Energy Loss (GWh)	600	518	541	620	533
Loss Percent of Energy Requirements	4.8%	4.3%	4.3%	5.0%	4.6%

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)

	2016	2017	2018	2019	2020
Energy Savings (GWh)	996	1,096	1,166	1,255	1,338
Demand Savings (MW)	427	466	491	508	537

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)

	2016	2017	2018	2019	2020
Residential	14,190	13,269	14,643	13,997	13,609
Commercial	47,711	46,506	49,171	49,670	44,840
Industrial	2,334,624	2,441,397	2,655,514	3,398,886	3,260,219
Public Authority	1,078,984	1,037,139	1,083,795	1,319,897	1,200,337
Utility Use & Other	5,624	5,677	5,293	4,254	3,246

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

	2016	2017	2018	2019	2020
Residential	11,826	11,133	12,068	11,557	11,102
Commercial	92,059	88,447	89,746	86,399	78,315
Industrial	4,551,724	4,471,204	4,596,120	4,480,287	4,312,614
Public Authority	272,268	255,584	256,000	245,189	224,320
Utility Use and Other	28,274	29,412	25,954	21,909	16,000

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

	2016	2017	2018	2019	2020
Total Residential	29%	28%	30%	31%	33%
Commercial	19%	19%	19%	21%	21%
Industrial	32%	32%	31%	31%	32%
Public Authority	8%	8%	7%	8%	8%
Utility Use and Other	0%	0%	0%	0%	0%
Virginia Retail	4%	4%	4%	4%	4%
Req. Sales for Resale	9%	9%	9%	4%	2%
Total Company	100%	100%	100%	100%	100%

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

	2016	2017	2018	2019	2020
Residential	35%	35%	36%	36%	37%
Commercial	33%	33%	33%	33%	32%
Industrial	22%	22%	22%	21%	21%
Public Authority	9%	9%	9%	9%	9%
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)

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Residential	6,057	5,954	5,912	5,920	5,882	5,856	5,830	5,838	5,796	5,784	5,785	5,817	5,801	5,814	5,832	5,879
Commercial	3,903	3,901	3,876	3,863	3,835	3,804	3,776	3,762	3,736	3,713	3,697	3,691	3,672	3,662	3,655	3,654
Industrial	6,125	6,152	6,153	6,137	6,095	6,065	6,049	6,051	6,042	6,029	6,024	6,026	6,013	6,010	6,009	6,016
Total C/I	10,029	10,054	10,029	10,000	9,931	9,870	9,825	9,813	9,779	9,742	9,722	9,717	9,685	9,672	9,664	9,670
Public Authority	1,501	1,509	1,505	1,497	1,486	1,478	1,472	1,470	1,467	1,462	1,460	1,459	1,455	1,454	1,452	1,453
Utility Use and Lighting	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34	34
Sales for Resale	393	394	395	396	397	398	399	400	400	401	402	403	403	403	403	403
Total Kentucky	18,014	17,945	17,875	17,847	17,730	17,636	17,560	17,555	17,476	17,424	17,402	17,430	17,379	17,378	17,385	17,439
Virginia	683	675	665	660	650	643	635	629	615	608	603	600	593	589	586	585
Total KU Calendar Sales	18,696	18,620	18,539	18,507	18,380	18,279	18,194	18,184	18,091	18,032	18,005	18,029	17,972	17,967	17,971	18,024
Utility Use and Losses	1,280	1,273	1,267	1,264	1,254	1,243	1,229	1,226	1,218	1,213	1,212	1,213	1,209	1,184	1,184	1,187
Total Requirements	19,976	19,893	19,807	19,771	19,634	19,521	19,423	19,410	19,309	19,245	19,216	19,242	19,181	19,150	19,155	19,212

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

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Residential	4,149	4,101	4,073	4,074	4,053	4,037	4,021	4,025	4,005	4,001	4,007	4,030	4,029	4,044	4,062	4,095
Commercial	3,737	3,784	3,764	3,755	3,736	3,716	3,696	3,689	3,670	3,653	3,642	3,639	3,624	3,617	3,611	3,614
Industrial	2,489	2,564	2,549	2,560	2,552	2,522	2,545	2,549	2,544	2,542	2,541	2,544	2,539	2,538	2,537	2,541
Public Authority	1,018	1,029	1,025	1,023	1,019	1,013	1,013	1,013	1,011	1,009	1,008	1,008	1,006	1,005	1,005	1,006
Utility Use and Lighting	11	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Total LG&E Calendar	11,403	11,489	11,422	11,423	11,371	11,299	11,286	11,286	11,241	11,216	11,209	11,232	11,209	11,215	11,226	11,267
Utility Use and Losses	851	855	851	851	835	828	823	823	820	818	818	808	806	807	807	810
Requirements	12,253	12,344	12,273	12,273	12,205	12,127	12,109	12,109	12,061	12,034	12,027	12,041	12,015	12,022	12,033	12,077

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

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

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Summer	3,620	3,668	3,628	3,614	3,596	3,570	3,545	3,539	3,530	3,529	3,514	3,508	3,532	3,506	3,506	3,509
	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**	**33/34**	**34/35**	**35/36**
Winter	3,967	4,042	4,021	4,015	4,037	3,986	3,980	3,959	3,946	3,959	3,971	3,940	3,924	3,928	3,919	3,949

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

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Summer	2,548	2,561	2,572	2,566	2,554	2,543	2,543	2,528	2,526	2,528	2,519	2,527	2,497	2,515	2,516	2,518
	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**	**33/34**	**34/35**	**35/36**
Winter	1,797	1,856	1,853	1,844	1,794	1,820	1,810	1,818	1,812	1,790	1,765	1,798	1,802	1,787	1,800	1,788

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	2021	755	623	523	369	382	463	550	536	406	364	457	628	6,057
	2022	722	606	511	364	376	457	544	531	403	362	454	624	5,954
Commercial	2021	339	307	310	290	321	338	367	366	329	314	297	326	3,903
	2022	343	309	314	292	321	336	365	364	327	312	295	323	3,901
Industrial	2021	491	466	506	497	529	529	548	554	527	521	481	476	6,125
	2022	507	473	505	497	534	517	550	552	532	524	483	479	6,152
Total C/I	2021	830	774	816	787	851	867	915	920	856	836	778	802	10,029
	2022	850	782	819	789	855	853	915	916	859	836	778	802	10,054
Public Authority	2021	124	117	121	116	126	129	135	138	129	125	117	123	1,501
	2022	128	118	122	118	128	127	135	138	129	125	117	123	1,509
Utility Use and	2021	4	3	3	3	2	2	2	2	3	3	3	4	34
Other (Lighting)	2022	4	3	3	3	2	2	2	2	3	3	3	4	34
Sales for Resale	2021	36	31	32	28	32	35	37	37	31	30	31	33	393
	2022	36	31	32	28	32	35	37	37	32	30	31	33	394
Total Kentucky	2021	1,749	1,547	1,494	1,304	1,393	1,496	1,639	1,634	1,425	1,358	1,385	1,590	18,014
	2022	1,740	1,541	1,487	1,302	1,393	1,475	1,633	1,624	1,425	1,356	1,383	1,585	17,945
Virginia	2021	86	72	65	48	44	45	48	49	43	48	60	76	683
	2022	85	72	65	48	44	44	48	48	42	47	59	74	675
Total KU Calendar	2021	1,835	1,619	1,559	1,351	1,437	1,540	1,687	1,682	1,468	1,406	1,445	1,665	18,696
	2022	1,825	1,613	1,552	1,350	1,437	1,519	1,681	1,672	1,467	1,403	1,441	1,660	18,620
Requirements	2021	1,982	1,745	1,660	1,429	1,522	1,648	1,810	1,810	1,561	1,488	1,537	1,785	19,976
	2022	1,971	1,738	1,653	1,427	1,523	1,625	1,803	1,798	1,559	1,484	1,533	1,779	19,893

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	2021	377	314	289	246	308	419	498	481	347	263	271	337	4,149
	2022	366	308	285	243	304	414	493	477	344	262	269	336	4,101
Commercial	2021	297	274	286	276	311	338	373	374	328	302	281	298	3,737
	2022	309	280	295	285	320	343	374	373	328	301	280	296	3,784
Industrial	2021	195	189	200	196	207	217	232	232	219	212	192	197	2,489
	2022	209	195	201	208	225	222	235	232	220	215	200	203	2,564
Public Authority	2021	82	77	80	78	85	89	97	96	89	84	78	82	1,018
	2022	85	78	81	80	88	90	97	96	89	84	79	82	1,029
Utility Use and Other	2021	1	1	1	1	1	1	1	1	1	1	1	1	11
	2022	1	1	1	1	1	1	1	1	1	1	1	1	10
Total LG&E Calendar	2021	952	855	856	795	911	1,063	1,201	1,184	984	862	824	915	11,403
	2022	970	862	863	817	938	1,069	1,199	1,178	982	862	829	919	11,489
Requirements	2021	1,023	909	913	845	978	1,152	1,311	1,290	1,057	919	876	980	12,253
	2022	1,041	918	921	867	1,007	1,159	1,309	1,283	1,055	919	882	984	12,344

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 8-12 and Table 8-13. 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.(3) 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 Companies develop 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 5-13 and Table 5-14).

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 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 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 and Table 8-2 contain the Companies' summer and winter peak demand and resource summaries in the base energy requirements, base fuel case.

Table 8-1: Summer Resource Summary (MW, Base Energy Requirements, Base Fuel)

	2022	2023	2024	2025	2028	2034	2035	2036
Gross Peak Load	6,522	6,500	6,485	6,461	6,378	6,331	6,334	6,337
Non-Dispatchable DSM	-294	-300	-305	-311	-311	-311	-311	-311
Net Peak Load	6,229	6,201	6,179	6,150	6,067	6,020	6,023	6,026
Generation Resources	7,688	7,688	7,688	7,688	7,688	7,688	7,688	7,688
CSR	127	127	127	127	127	127	127	127
DCP	61	60	58	56	52	45	44	43
Retirements/Additions								
Coal[58]	-300	-300	-300	-300	-1,009	-1,969	-1,969	-1,969
Large-Frame SCCTs[59]	0	0	0	0	0	-121	-363	-484
Small-Frame SCCTs[60]	0	0	0	-47	-47	-47	-47	-47
New SCCTs	0	0	0	0	440	1,320	1,320	1,320
New Solar[61]	0	79	79	204	597	1,855	1,855	1,855
New Wind[62]	0	0	0	0	0	0	0	0
New Battery Storage	0	0	0	0	0	0	100	200
Total Supply	7,576	7,653	7,651	7,728	7,848	8,897	8,754	8,732
Reserve Margin	1,348	1,452	1,472	1,578	1,780	2,877	2,732	2,706
Reserve Margin %	21.6%	23.4%	23.8%	25.7%	29.3%	47.8%	45.4%	44.9%

[58] The Companies assume that Mill Creek 1 and 2 cannot be operated simultaneously during ozone season due to NOx limits, which results in a reduction of available summer capacity through 2024. This analysis assumes that Mill Creek 1 is retired in 2024, Mill Creek 2 and Brown 3 are retired in 2028, and Ghent 1-2 are retired in 2034.
[59] This analysis assumes that Brown 9 is retired in 2034, Brown 8 and 10 are retired in 2035, and Brown 11 is retired in 2036.
[60] This analysis assumes that Haefling 1-2 and Paddy's Run 12 are retired by 2025.
[61] Solar capacity values reflect 78.6% expected contribution to summer peak capacity.
[62] Wind capacity values reflect 24.2% expected contribution to summer peak capacity.

Table 8-2: Winter Resource Summary (MW, Base Energy Requirements, Base Fuel)

	2022	2023	2024	2025	2028	2034	2035	2036
Net Peak Load	5,898	5,874	5,859	5,831	5,777	5,715	5,719	5,737
Generation Resources	7,973	7,973	7,973	7,973	7,973	7,973	7,973	7,973
CSR	127	127	127	127	127	127	127	127
DCP	0	0	0	0	0	0	0	0
Retirements/Additions								
Coal[58]	0	0	0	-300	-1,013	-1,978	-1,978	-1,978
Large-Frame SCCTs[59]	0	0	0	0	0	-138	-404	-532
Small-Frame SCCTs[60]	0	0	0	-55	-55	-55	-55	-55
New SCCTs	0	0	0	0	496	1,488	1,488	1,488
New Solar[63]	0	0	0	0	0	0	0	0
New Wind[64]	0	0	0	0	0	0	0	0
New Battery Storage	0	0	0	0	0	0	100	200
Total Supply	8,100	8,100	8,100	7,744	7,527	7,416	7,250	7,222
Reserve Margin	2,201	2,226	2,240	1,913	1,750	1,701	1,531	1,485
Reserve Margin %	37.3%	37.9%	38.2%	32.8%	30.3%	29.8%	26.8%	25.9%

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 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.

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

Reliable operation of the Companies' generation fleet is key to the delivery of safe, cost-effective electric service to our customers. The Companies employ several strategies to ensure this reliability in the long term by keeping equipment in optimal operating condition, as well as in the short-term in extreme weather conditions. The Companies' generating assets have routinely exceeded Equivalent Forced Outage Rate (EFOR) expectations for many years, demonstrating a record of reliable operation. Additionally, the Companies' knowledgeable and experienced work force understands how to operate and maintain assets in a proven, cost effective, and reliable

[63] Solar capacity values reflect zero expected contribution to winter peak capacity.
[64] Wind capacity values reflect 31.9% expected contribution to winter peak capacity.

manner. Within this section, information is presented to detail the Companies' practices to maintain generation equipment reliability into the future.

Fleetwide Operational Reliability

Fuel (coal) can be readily inventoried at each of the Companies' coal-fired generation stations, mitigating short-term supply risks that exist with coal and other fuel sources. Such risks could include natural gas pipeline interruptions due to cyber-attacks or weather, delayed or interrupted rail and barge transportation due to snow, ice, or high river conditions, and ice or snow accumulation on solar panels and wind turbines. Typically, sufficient fuel is inventoried at each coal-fired facility to provide for 30 days of operation. The Companies' fleet of coal-fired and natural gas-fired generation reliably responds to meet customer demands for electricity, and can be dispatched according to demands in opposition to variable energy resources such as solar and wind.

In addition to freeze protection systems on plant equipment referenced later in this section, each plant maintains a Cold Weather Preparation Guideline document. These documents are based on industry standards for seasonal readiness. The guidelines include check lists for relevant areas of the plant, and fuel acquisition and delivery guidelines for severe winter conditions, both coal and gas. The plans are discussed each year in the 4th quarter at each location. Checklist actions to be taken when temperatures reach freezing include cooling tower preparation, portable heater deployment, material handling preparation, monitoring of water intakes, and instrument line checks. Actions and checklists are reviewed after each winter to ensure operations were not affected due to freezing conditions, and changes are made accordingly.

Currently, the generation fleet is in the process of implementing an Operational Technology (OT) Cyber Security Governance Program over the next several years. It is a collaborative process that incorporates a detailed phased roadmap encompassing the following risk-reducing mitigation strategies: governance; asset and change management; network segmentation; access control; anti-virus, patch, and vulnerability management; disaster recovery and business continuity; network monitoring; and system hardening. Each strategy provides a level of defense in depth for the fleet that equates to concurrent and continuous cyber security functions, which are cyber-industry best practices for identifying, protecting against, detecting, responding to, and recovering from cyber attacks.

The Companies are active participants in research with the Electric Power Research Institute (EPRI). Working with EPRI provides valuable technical insights that help the Companies continue their record of reliable operation. An example of a current effort with EPRI includes review of the low-load limitations of each unit in the Companies' fleet. As the utility industry adapts to increased deployment of variable energy resources (wind and solar), reliable and flexible operation of our existing assets will serve to ensure reliable service to our customers. This review includes site interviews with plant staff to determine the key equipment limitations that impact turndown of each unit. The Companies also participate in EPRI research programs aligned with mechanical, electrical, and cyber reliability of our generating assets.

Maintenance Schedules and Practices

Maintenance schedules are coordinated across the Companies' generation fleet such that the outages will have the least economic impact to the customers and the Companies and will maximize fleet reliability. Outages are scheduled in lower-load seasons so they can return to service at their most reliable and efficient to serve during peak demand periods with minimum economic impact.

The Companies continue to plan multi-week boiler outages biennially to keep the units in the fleet running efficiently during the maintenance interval. Generally, units are scheduled off for one week of maintenance in the other years. The Companies continue to target seven- to eight-year maintenance intervals for major turbine overhauls. As equipment inspections during these outages reveal potential issues, affected components can be repaired or replaced as needed. When equipment enhancements are available, they are analyzed and installed when determined to be the most prudent option.

Predictive Maintenance (PdM) is a practice geared to prevent failure and reduce maintenance costs by monitoring the condition of operating equipment, identifying issues, and recommending proactive maintenance practices prior to equipment failure. Alternative approaches would consider running equipment to failure or performing maintenance on time-based intervals. These approaches would result in increased cost and decreased reliability. The technologies that are primarily used to monitor equipment condition are vibration analysis, oil sample analysis, thermography, and electrical motor testing. Abnormal conditions like looseness, misalignment, imbalance, and bearing failure can be diagnosed with vibration data, and can support root cause failure analyses. Oil samples are collected from plant equipment and analyzed in a lab to look for early indications of an equipment problem. Oil analysis can help identify issues such as excessive wear, water ingression, temperature excursions, or breakdown of critical compounds that are necessary for proper lubrication. Thermography is another technology that is used to identify issues with mechanical or electrical equipment. Identifying areas where insulation has been damaged can be an easy way to troubleshoot a problem before the equipment fails.

Controls Systems, Generators, Exciters, and Electrical Systems

Technologically advanced controls continue to be one of the most proven applications for maintaining the efficiency and reliability 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 Paddy's Run CT 13 and Brown CTs 5-11, as well as control software upgrades on Cane Run 7, Trimble County CTs 5-10, and Ghent 1-4.

Each unit has a generator step up (GSU) transformer and associated auxiliary transformers to feed the switchyard, supplying power to the grid and to the plant for auxiliary usage. These transformers have cooling systems that are installed to ensure that the oil or gas that fills the transformer does not overheat, especially in extreme summer conditions. Remote monitoring of these cooling systems is being expanded on all GSUs and certain auxiliary transformers in the fleet. Instrumentation is being installed to remotely monitor and detect failures in transformer bushings by detecting increased temperature and resistance in the components and detecting any oil degradation in oil-filled transformers through dissolved gas analysis.

Other turbine and generator maintenance and improvements include generator inspections for Mill Creek 2 and 4, Trimble County 2, and Cane Run 7, new static exciters on Paddy's Run 13 and Cane Run 7 CTs and ST, and a new static frequency converter for Brown CT5.

Freeze protection is installed on critical systems that could experience sub-freezing temperatures during winter operation. Examples of freeze protection include resistive heating, insulation, motor heaters, and weather-resistant enclosures. Extreme minimum design temperatures have been and continue to be specified in site conditions for all new construction projects. Additionally, plant operating personnel monitor and evaluate freeze-protection systems during winter months to ensure that equipment is properly protected, especially when extreme cold is anticipated. Upgrades and enhancement to freeze-protection systems are planned and executed as needed.

Turbines and Boiler Feed Pumps

Another proven area to maintain efficiency in generating stations is restoring degraded turbines through regular turbine overhauls. A worn or degraded turbine fails to extract the maximum possible energy from the steam, thus decreasing the station efficiency. Turbine overhauls include inspecting the rotors for any issues such as excessive wear or cracking, 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 in the steam path to return the efficiency of the turbine to at or near design values. Major turbine overhauls are planned on a seven-to-eight-year cycle for all units within the Companies' generation fleet.

Similar to turbine degradation, boiler feed pump degradation also robs the steam/water cycle of efficiency. These pumps are driven by small steam turbines or electric motors, and if worn, additional power is required to produce the required flow. In the case of turbine driven pumps, the turbine is overhauled as well to restore its efficiency. Feed pump and drive turbine overhauls are planned throughout the fleet on regular intervals to maintain reliability.

Boilers/HRSGS/Air Heaters/Combustion Components

The Companies have made recent improvements in boiler reliability and in preventing tube leaks that cause forced outages. Continued inspection, repair, and replacement of boiler tubes will allow the fleet to maintain this improved reliability and reduced outage rate. All of the boilers in the fleet have scheduled strategic tube replacements to ensure continued maximum availability and reliability. The heat recovery steam generators (HRSGs) on Cane Run 7 are scheduled to undergo cleaning with CO_2 blasting and inspections. Specialty cleaning is needed on the HRSGs due to the finned tubing and lack of access for traditional cleaning methods. Insulation and lagging on the HRSGs and associated piping are routinely evaluated to ensure reliability in winter operation because they are outside units.

Burners are routinely inspected and repaired to ensure that coal is burned as efficiently as possible. Air heaters extract energy from the exiting flue gas and transfer it to the combustion air entering the boiler and pulverizers so that the combustion is more efficient. The baskets in the air heaters serve as the heat transfer medium and need to be replaced periodically to maintain reliable operation, as well as optimize heat transfer efficiency. The Companies inspect burners, pulverizers, and air heater baskets during planned maintenance outages, and plan for major replacements or overhauls as needed to ensure reliable operation.

HEP/Feedwater Systems

High Energy Piping (HEP) systems that carry steam to and from the boiler are subject to high stress due to the temperatures and pressures at which these systems operate. As such, it is important to inspect them periodically using visual and NDE techniques to identify cracking and other failure mechanisms before they pose a risk to operational safety and unit reliability. HEP inspections are planned for all units in the Companies' fleet on three- to five-year intervals. These inspections also identify and address insulation issues to ensure the most efficient energy transfer from the steam, and to ensure proper protection from ambient conditions.

Feedwater heaters use extraction steam from the turbine to heat the boiler feed water prior to entering the boiler. Preheating the boiler feedwater using extraction steam improves the thermal efficiency of the steam cycle. However, feedwater heaters can develop leaks, which causes inefficient operation and can force a unit to be taken offline for repairs. The Companies have taken steps to mitigate heaters with common failure mechanisms and continue to conduct repairs or replacements as needed.

Environmental Control Systems

SCRs (selective catalytic reactors) reduce NO_x emissions in the flue gas via ammonia injection and reaction with a catalyst. SCR catalysts must be in proper operating condition to remove NO_x and fully consume the ammonia. Any unused ammonia, referred to as ammonia slip, can form ammonium bisulfate (ABS) on downstream components. ABS formation leads to additional ash buildup and associated maintenance issues. The Companies regularly test this catalyst and maintain a long-range plan for replacement to ensure reliable operation of the SCRs.

Precipitators and pulse jet fabric filters (PJFFs) remove particulate from the flue gas downstream of the boiler. The precipitators remove particulate by collecting it on electrically charged plates. Electrical components are upgraded and replaced as needed to ensure reliable particulate removal. The PJFFs act as filters and collect particulate in a series of bags that are then emptied into hoppers. The bags and their support cages require periodic replacement to ensure compliance with environmental regulations. All PJFFs in the fleet will undergo bag and cage replacements on a 6-year cycle (based on measured bag condition) during the plan period.

Compliance with new effluent limit guidelines (ELG) has required each affected plant to build new physical/chemical water treatment systems that are currently in service. Projects for biological treatment of FGD wastewater are planned at affected plants. Freeze protection on these systems will ensure that they function reliably and efficiently in winter conditions.

Condensers/Cooling Towers/Circulating Water Pumps

Cooling towers are used to cool the circulating water that absorbs energy from the turbine exhaust in the steam condenser. Towers are inspected periodically to ensure fill and fans (for mechanical draft towers) are in proper working order. In freezing conditions, water can freeze in the tower fill, causing damage and loss of efficiency. In these conditions, operational practices would shut off cooling tower fans or bypass the tower periodically to prevent ice from damaging the tower and impacting reliability. The Companies continue to repair and rebuild towers to ensure maximum operational reliability and to ensure freeze protection/bypassing capabilities are available. Four towers have been recently rebuilt and other rebuilds are being evaluated. Fill replacement is scheduled for Trimble County 1 and being evaluated on other towers in fleet. Gearbox repairs and maintenance for cooling tower fans are planned for all mechanical draft towers. Proper gearbox maintenance and attention to lubrication prevents any operational issues in hot weather conditions. Condensers are cleaned manually during maintenance outages to remove debris left by the circulating water in the tubes and on the tube sheets in the water boxes.

Combustion Turbines

Significant efforts to maintain the reliability and efficiency of the Companies' combustion turbine fleet continue in the plan. Hot Gas Path Inspection (HGPI) outages occur at scheduled intervals on combustion turbines based on hours of operation and number of starts. This type of outage includes complete inspection and any necessary repairs from the air inlet section to the exhaust section, and includes all compressor, combustor, and turbine components. HGPIs are scheduled, based on hours of operation, on Trimble County 8 and 10, EW Brown 7, 8, 9, and 10, Paddy's Run 13, and Cane Run 7-1 and 7-2. The remaining CTs have recently undergone HGPI outages and would only do so again in the plan period based on operating hours. Cane Run 7-1 and 7-2 will also be getting an insulation upgrade to prevent loss of energy to the surrounding atmosphere. Combustion turbines are designed to operate outside in peak ambient conditions. As such, the freeze protection on instruments and piping is routinely inspected, repaired, and upgraded as needed. Inlet cooling systems allow more air to be passed through the CT when the inlet temperature increases. These systems are maintained and inspected to provide the most efficient cooling for summer peak operations. Inlet filtration keeps debris from accumulating on and fouling the compressor section. The filters are cleaned periodically to ensure proper air flow to the compressor. Compressors are also washed as needed when operational data indicates a loss of efficiency due to fouling.

Hydroelectric Units

Dix Dam is undergoing and will continue to undergo improvements that will maintain the reliability of the plant going forward. These improvements include face slab repair and structural improvements of the parapet wall.

Ohio Falls will similarly continue to undergo improvements to maintain the reliability of the units. These projects include trash rack guide repairs, repairs to the powerhouse façade and replacement of the roof, and improvements to the plant service water piping.

Distribution

LG&E and KU develop annual and long-term distribution system operations, maintenance, and investment plans designed to provide safe, reliable, resilient, secure and high-quality electric service to customers at a fair cost. Evolving customer expectations, acceleration of behind-the-meter distributed energy resources (DER), advancement in behind-the-meter technologies, and increased system threats are amplifying associated challenges and necessitating more robust system planning processes and tools, greater utilization of data analytics and science, and more strategic investments in grid modernization, hardening, and security.

Distribution's reliability and resiliency planning processes place emphasis on data collection and analytics, prioritization of system improvement opportunities, and identification and execution of investment strategies which provide for top quartile reliability performance and assure voltage at the point of delivery satisfies regulatory requirements. Focused investments in modernization and hardening of the distribution system over the last ten-years have resulted in downward trends in service interruption frequencies (19% lower) and durations (26% lower). During three of the last four years, customers experienced the lowest average interruption frequency in the combined companies' history. Similarly, customers experienced their lowest average interruption durations during two of the last four years.

The greatest contribution to improved reliability in recent years has been the advancement of distribution automation (DA) since 2017. The installation of more than 1,750 Supervisory Control and Data Acquisition (SCADA) connected reclosers on the distribution system, and deployment of an advanced distribution management system (ADMS) and distribution SCADA have enabled automated detection of fault conditions, isolation of faults, and expedited service restoration, helping to minimize impacts of faults on the distribution grid. Through September 2021, more than 38 million customer interruption minutes and 256,500 customer service interruptions have been avoided directly as a result of the DA program.

In addition to the DA program, LG&E and KU have completed, and continue to execute, numerous 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. Because of this, capicty investment needs have waned, allowing for increased focus on system reliability, resiliency and aging infrastructure replacement investments. Projects that improve reliability performance of poorer performing circuits and mitigate the effects major equipment failure have received the most emphasis in recent years. Advanced data analytics tools and resources are now allowing LG&E and KU to more wisely invest in areas of concern based on outage history, geo-spatial characteristics, and environmental factors.

During 2010, LG&E and KU initiated a Pole Inspection and Treatment Program (PITP). Since the program started, the Companies have inspected more than 636,000 wood poles, retreated more than 200,000 wood poles with preservative, and replaced more than 25,000 defective poles.

Moving forward, the Companies will continue to invest in grid modernization to increase the flexibility of the distribution system andsupport integration of DER, and meet the capacity demands associated with accelerating electrification of customer end use devices and vehicles. Key future investments include:

- Advanced metering infrastructure (AMI) will be deployed by LG&E and KU between 2021 and 2026. Associated technology will enable the Companies to collect more detailed information about distribution system components, interconnected DER, and customer load characteristics.
- Enhanced distribution line-device voltage controls and supporting information systems are being deployed on the distribution system between 2020 and 2030 as part of a volt/VAR optimization (VVO) program designed to optimize system efficiencies through reducing system losses and voltage drop. VVO will also support implementation of conservation voltage reduction (CVR), the intentional lowering of distribution system voltages on targeted system components to reduce overall system demand and produce direct energy savings for customers.

To plan for system capacity needs, LG&E and KU have long leveraged industry accepted practices for forecasting load requirements on distribution components. Substation transformer loads are monitored nearly continuously, and peak loads are tracked and recorded on an hourly basis. This information is used to create ten-year peak load forecasts for the purpose of targeting more detailed system capacity studies and developing alternatives for addressing forecasted capacity constraints. The contribution of all connected load and distributed energy resources are currently included in load forecasts at the distribution substation transformer level. These forecasts, along with other key system information, are 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 the LG&E and KU service areas do not have a large amount of distributed generation today, the total capacity of these resources continues to grow as prices for inverter-based generation resources fall. Due to its capacity value, the net impacts from connected distributed generation are considered when developing the ten-year load forecasts for planning purposes. Many of the grid enhancements previously mentioned (DA, VVO, AMI, etc.) provide greater situational awareness about the locational and timing benefits and dependability of interconnected DER resources.

The Companies also continue to learn from utility industry leaders and plan their systems to accommodate future distributed generation and renewables integration. This industry purview includes utilities at all points of the maturity curve respective to distributed energy resource integration levels, not just those with high rates of DER interconnections. Additionally, LG&E and KU continue to participate in industry forums and studies which are developing more robust system modeling tools that are forecasted to enable more efficient integration and optimization of distributed energy resources into the distribution grid, as well as processes to incorporate non-wires solutions when addressing future capacity constraints. Furthermore, these industry forums help the Companies stay abreast of developments in inverter technologies and industry regulations and standards which govern the operation and integration of DERs, to assure optimization of distributed resources at local and aggregate levels. The Companies continue to evolve their distributed energy resource integration framework based on associated best practices and tools. The integration framework assures that the Companies can: maintain high levels of system reliability and power quality, model and understand locational value/impacts on the distribution system, and leverage interconnected distributed energy resources to deal with system constraints and improve operational efficiencies.

As customer adoption and interconnection requests of DER increase, LG&E and KU will implement a fully online DER interconnection application portal to manage associated administrative processes. The online portal will provide a streamlined and quicker interconnection process for customers and installers. Additionally, it will automate many tasks that are performed manually today. By linking to various internal databases and modeling tools, the companies will be able to conduct hosting capacity analyses and publish study results near real-time in the portal.

Finally, 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 received approval for DSM programs in Case No. 2017-00441 in October 2018. From this order, the Companies were able to continue some programs while also ending other programs. The following programs have continued 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. Additional discussion of the Companies' demand-side management programs is contained in Section 8.(3).(e). An in-depth description and discussion of current 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 5-15 in Section 5.(4). A complete summary of this analysis is included in Volume III ("2021 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 8-3 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 8-3: KU and LG&E Existing and Planned Electric Generation Facilities

Plant	Unit	Location	Status	Operation Date	Facility Type	Net Capability (MW)[1]		Entitlement		Fuel Type	Fuel Storage Capacity	Upgrades Derates, Retirements
						2021/22 Winter	2022 Summer	KU	LGE			
Dispatchable Resources												
Cane Run	7	Louisville	Existing	2015	Turbine	683	662	78%	22%	Gas	None	2055
Dix Dam	1-3	Burgin	Existing	1925	Hydro	31.5	31.5	100%		Water	None	2041
E.W. Brown	3	Burgin	Existing	1971	Steam	416	412	100%		Coal (Rail)	350,000 Tons	2028
	5			2001	Turbine	130	130	47%	53%	Gas	2,200,000 Gal.	2041
	6			1999		171	146	62%	38%			2039
	7			1999		171	146					2039
	8			1995		128	121	100%		Gas / Oil		2035
	9			1994		138	121					2034
	10			1995		138	121					2035
	11			1996		128	121					2036
Ghent	1	Ghent	Existing	1974	Steam	479	475	100%		Coal (Barge)	1,200,000 Tons	2034
	2			1977		486	485					2034
	3			1981		476	481					2037
	4			1984		478	478					2037
Haefling	1-2	Lexington	Existing	1970	Turbine	28	24	100%		Gas	None	2025
Mill Creek	1	Louisville	Existing	1972	Steam	300	300		100%	Coal (Barge & Rail)	1,000,000 Tons	2024
	2			1974		297	297					2028
	3			1978		394	391					2039
	4			1982		486	477					2039
Paddy's Run	12	Louisville	Existing	1968	Turbine	28	23		100%	Gas	None	2025
	13			2001		175	147	47%	53%			2041
Trimble County	1	Near Bedford	Existing	1990	Steam	493 (370)[2]	493 (370)[2]	0%	75%	Coal (Barge)	1,000,000 Tons (HS) 250,000 Tons (PRB)	2045
	2			2011		760 (570)[2]	732 (549)[2]	61%	14%			2066
	5-6			2002	Turbine	358	318	71%	29%	Gas	None	2042
	7-10			2004		716	636	63%	37%			2044
Zorn	1	Louisville	Existing	1969	Turbine	16	14		100%	Gas	None	2021
New SCCTs	1-2	TBD	Planned	2028	Turbine	496	440	64%	36%	Gas	TBD	None
	3-6			2034		992	880					
New Battery Storage	1	TBD	Planned	2035	Battery Storage	100	100	64%	36%	Battery Storage	None	None
	2			2036		100	100					
Non-Dispatchable Resources												
E.W. Brown	Solar	Burgin	Existing	2016	Solar	0	8	61%	39%	Solar	None	None
Ohio Falls	1-8	Louisville	Existing	1928	Hydro	40	64		100%	Water	None	2045
Simpsonville Solar	1	Simpsonville	Existing	2019	Solar	0	1.6[4]	[3]	[3]	Solar	None	None
Rhudes Creek Solar	1	Hardin Co	Planned	2023	Solar	0	79	70%	30%	Solar	None	2043
Green Tariff Op3 Solar	1	TBD	Planned	2025	Solar	0	126	70%	30%	Solar	None	2045
New Solar	1	TBD	Planned	2028	Solar	0	393	64%	36%	Solar	None	None
	2			2034		0	1,258					

[1] The ratings for non-dispatchable resources 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] Simpsonville Solar's ownership percentages will be determined by the composition of KU and LG&E customers.
[4] Four of Simpsonville Solar's eight phases are complete. The remaining phases will be constructed as customers fully subscribe, for a total of approximately 3 MW (AC).

Table 8-4: Capacity Factors

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Brown 3	23%	29%	27%	30%	26%	25%	26%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Brown 5, 8-11	2%	2%	2%	2%	2%	3%	3%	7%	6%	5%	2%	2%	3%	2%	3%	5%
Brown 6-7	5%	4%	6%	6%	7%	8%	5%	6%	4%	4%	5%	4%	2%	8%	6%	6%
Brown Solar	19%	19%	19%	19%	19%	19%	19%	19%	19%	19%	19%	19%	19%	19%	19%	19%
Cane Run 7	84%	82%	80%	77%	88%	87%	89%	76%	89%	88%	87%	81%	85%	83%	72%	81%
Dix Dam 1-3	29%	32%	32%	32%	32%	32%	32%	32%	32%	32%	32%	32%	32%	32%	32%	32%
Ghent 1	61%	62%	72%	64%	59%	65%	64%	66%	58%	64%	66%	64%	66%	N/A	N/A	N/A
Ghent 2	61%	62%	67%	55%	63%	60%	55%	63%	62%	58%	61%	63%	62%	N/A	N/A	N/A
Ghent 3	65%	61%	62%	58%	57%	53%	56%	61%	60%	56%	58%	59%	60%	59%	59%	58%
Ghent 4	55%	53%	58%	46%	47%	45%	48%	47%	49%	51%	49%	50%	51%	53%	54%	54%
Haefling 1-2	0.1%	0.3%	0.1%	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
Mill Creek 1	59%	69%	68%	80%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Mill Creek 2	35%	30%	31%	36%	79%	76%	80%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Mill Creek 3	61%	63%	55%	73%	68%	74%	63%	76%	69%	77%	71%	76%	71%	71%	64%	72%
Mill Creek 4	71%	61%	69%	73%	81%	80%	72%	74%	82%	69%	81%	76%	81%	70%	77%	71%
Ohio Falls 1-8	30%	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%	31%	32%	31%
Paddy's Run 12	0.3%	0.3%	0.1%	0.2%	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 13	6%	7%	3%	3%	3%	1%	1%	4%	3%	3%	3%	3%	4%	4%	4%	4%
Trimble County 1	65%	74%	74%	77%	68%	76%	75%	79%	75%	78%	72%	78%	67%	78%	74%	78%
Trimble County 2	76%	69%	61%	65%	64%	59%	67%	69%	68%	67%	66%	67%	66%	60%	66%	65%
Trimble Co 5-10	12%	17%	13%	12%	12%	10%	11%	12%	8%	11%	9%	11%	12%	14%	17%	14%
Zorn 1	0.1%	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
Simpsonville Solar	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%
New SCCTs	N/A	N/A	N/A	N/A	N/A	N/A	N/A	20%	22%	21%	20%	18%	19%	21%	23%	21%
New Solar	N/A	N/A	26%	25%	26%	26%	26%	27%	27%	27%	27%	27%	27%	27%	27%	27%
New Battery Storage	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	0.4%	0.6%

Table 8-5: Equivalent Availability Factors

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Brown 3	83%	85%	85%	85%	83%	83%	83%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Brown 5, 8-11	92%	84%	86%	87%	87%	87%	84%	85%	87%	87%	87%	88%	88%	88%	88%	88%
Brown 6-7	94%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	92%	92%	92%	92%	92%
Brown Solar	19%	19%	19%	19%	19%	19%	19%	19%	19%	19%	19%	19%	19%	19%	19%	19%
Cane Run 7	89%	85%	85%	78%	89%	89%	91%	78%	91%	89%	91%	84%	87%	91%	78%	89%
Dix Dam 1-3	95%	94%	94%	94%	94%	94%	94%	94%	94%	94%	94%	94%	94%	94%	94%	94%
Ghent 1	78%	81%	89%	89%	83%	89%	87%	87%	80%	87%	89%	89%	89%	N/A	N/A	N/A
Ghent 2	88%	85%	85%	80%	87%	89%	80%	89%	89%	83%	89%	89%	87%	N/A	N/A	N/A
Ghent 3	90%	87%	83%	89%	85%	80%	87%	89%	89%	83%	89%	87%	89%	89%	89%	89%
Ghent 4	85%	87%	87%	87%	89%	85%	87%	80%	89%	87%	89%	89%	89%	87%	89%	89%
Haefling 1-2	75%	50%	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
Mill Creek 1	82%	88%	86%	90%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Mill Creek 2	50%	39%	39%	39%	90%	87%	90%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Mill Creek 3	86%	90%	83%	92%	85%	92%	80%	92%	83%	92%	87%	92%	87%	92%	80%	92%
Mill Creek 4	93%	80%	92%	83%	92%	95%	83%	83%	92%	80%	92%	87%	92%	87%	92%	87%
Ohio Falls 1-8	39%	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%	33%
Paddy's Run 12	74%	50%	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
Paddy's Run 13	93%	90%	90%	90%	92%	59%	55%	90%	90%	90%	92%	92%	92%	92%	92%	92%
Trimble County 1	77%	90%	87%	90%	80%	90%	87%	90%	87%	90%	85%	90%	77%	90%	85%	90%
Trimble County 2	82%	80%	74%	81%	81%	74%	81%	81%	81%	81%	81%	81%	81%	74%	81%	81%
Trimble Co 5-10	52%	91%	91%	91%	87%	91%	93%	90%	85%	91%	93%	93%	93%	93%	93%	93%
Zorn 1	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	N/A
Simpsonville Solar	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%	20%
New SCCTs	N/A	N/A	N/A	N/A	N/A	N/A	N/A	95%	95%	95%	95%	95%	95%	95%	95%	95%
New Solar	N/A	N/A	26%	25%	26%	26%	26%	27%	27%	27%	27%	27%	27%	27%	27%	27%
New Battery Storage	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	100%	100%

Table 8-6: Average Heat Rate (MMBtu/MWh)

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Brown 3	12.0	11.7	12.1	12.0	12.1	12.0	12.1	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Brown 5, 8-11	15.1	14.8	15.1	14.2	14.6	14.8	14.9	15.6	15.8	15.9	15.6	15.6	15.7	16.3	15.5	15.6
Brown 6-7	11.1	11.3	11.1	10.9	11.0	11.0	11.0	11.1	11.2	11.2	11.4	11.4	11.4	11.1	11.2	11.1
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	6.8	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7
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	10.8	10.7	10.6	10.8	10.7	10.7	10.7	10.7	10.7	10.7	10.8	10.8	10.7	N/A	N/A	N/A
Ghent 2	10.6	10.5	10.5	10.6	10.5	10.6	10.6	10.6	10.6	10.6	10.6	10.6	10.6	N/A	N/A	N/A
Ghent 3	10.5	10.5	10.4	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.6	10.6	10.6
Ghent 4	10.7	10.7	10.7	10.8	10.7	10.8	10.7	10.7	10.8	10.8	10.8	10.8	10.7	10.8	10.8	10.8
Haefling 1-2	N/A	17.8	17.8	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
Mill Creek 1	10.5	10.5	10.5	10.5	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Mill Creek 2	10.6	10.6	10.6	10.5	10.5	10.5	10.5	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Mill Creek 3	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	10.6
Mill Creek 4	10.4	10.4	10.4	10.4	10.3	10.3	10.4	10.3	10.3	10.4	10.3	10.4	10.4	10.4	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 12	N/A	17.7	17.7	17.7	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 13	10.9	11.1	10.9	10.7	10.7	11.0	10.6	11.4	12.2	12.0	12.1	11.8	11.8	11.4	11.5	11.5
Trimble County 1	10.4	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3
Trimble County 2	9.2	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
Trimble Co 5-10	11.1	11.0	11.0	10.8	10.9	10.9	10.9	11.1	11.3	11.3	11.3	11.3	11.4	11.4	11.5	11.4
Zorn 1	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
Simpsonville 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
New SCCTs	N/A	N/A	N/A	N/A	N/A	N/A	N/A	10.4	10.5	10.5	10.5	10.6	10.6	10.7	10.7	10.7
New 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
New Battery Storage	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 8-7: Cost of Fuel ($/MMBtu)

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Brown 3	[redacted]															
Brown 5, 8-11	[redacted]															
Brown 6-7	[redacted]															
Brown Solar	[redacted]															
Cane Run 7	[redacted]															
Dix Dam 1-3	[redacted]															
Ghent 1	[redacted]															
Ghent 2	[redacted]															
Ghent 3	[redacted]															
Ghent 4	[redacted]															
Haefling 1-2	[redacted]															
Mill Creek 1	[redacted]															
Mill Creek 2	[redacted]															
Mill Creek 3	[redacted]															
Mill Creek 4	[redacted]															
Ohio Falls 1-8	[redacted]															
Paddy's Run 12	[redacted]															
Paddy's Run 13	[redacted]															
Trimble County 1	[redacted]															
Trimble County 2	[redacted]															
Trimble Co 5-10	[redacted]															
Zorn 1	[redacted]															
Simpsonville Solar	[redacted]															
New SCCTs	[redacted]															
New Solar	[redacted]															
New Battery Storage	[redacted]															

Table 8-8: Capital Costs

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
New SCCTs																
$/kW								703						766		
$M								329						717		
New Solar																
$/kW								1,048						986		
$M								524						1,577		
New Battery Storage																
$/kW															1,009	1,016
$M															101	102

Capital cost assumptions in Table 8-8 are in nominal "overnight" dollars and are based on the "Moderate" case forecast in NREL's 2021 ATB.

Table 8-9: Production Costs

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Variable and Fixed O&M Costs ($M)[65]	[redacted]															
Average Variable Production Costs (cents/kWh)																
Total Electricity Production Costs (cents/kWh)																

[65] Variable and fixed operating and maintenance costs include the cost of fuel.

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

Table 8-10 provides a forecast of the Companies' electricity transactions.

Table 8-10: Electricity Purchases and Sales (GWh, Base Energy Requirements Forecast)

	2021	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
OVEC	971	958	550	567	628	601	613	597	600	606	593	603	606	616	615	609
Market Purchases	9	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Off-System Sales	-279	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

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

Table 8-11 shows the forecasted capacity and energy purchases from non-utility sources.

Table 8-11: Electricity Purchases from Non-Utility Sources

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Qualifying Facilities																
Capacity (MW)	5	6	6	7	7	8	9	9	10	11	11	12	12	13	14	14
Energy (GWh)	6	7	8	9	10	10	11	12	13	13	14	15	16	17	17	18

8.(3).(e) Demand-Side Management Programs

The following sections describe the Companies' approved DSM-EE programs. Through September 2021, the Companies' DSM-EE programs have produced cumulative energy and gas savings of approximately 1,410 GWh and 7.5 million Ccf, along with a cumulative gross demand reduction of over 486 MW. The Companies' DSM-EE programs have been a tremendous success. The 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.

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 is captured, communicated, and stored which allows customers to monitor their interval usage through the portal. Through the AMI project the Companies' plans are that current customers under the DSM AMS program will be able to continue receiving their benefits through access to MyMeter portral uninterrupted.

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.

<u>Nonresidential Rebates Program</u>

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 allowed 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 8-12 summarizes the annual incremental energy impact and the summer and winter peak demand of the Companies' DSM programs. Table 8-13 summarizes the cumulative energy impact and the summer and winter peak demand of the Companies' DSM programs.

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

DSM Energy Reduction (GWh)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
AMS Customer Service Offering	0.0	0.0	0.0	0.0	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	0.0	0.0	0.0	0.0	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	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	0.0	0.0	0.0
Large Nonresidential Demand Conservation	0.0	0.0	0.0	0.0	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	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	0.0	0.0	0.0
Program Development and Administration	0.0	0.0	0.0	0.0	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	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	0.0	0.0	0.0

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

DSM Summer Peak Demand Reduction (MW)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
AMS Customer Service Offering	0.0	0.0	0.0	0.0	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	(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	0.0	0.0	0.0
WeCare	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	0.0	0.0	0.0
Large Nonresidential Demand Conservation	0.0	0.0	0.0	0.0	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	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	0.0	0.0	0.0
Program Development and Administration	0.0	0.0	0.0	0.0	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	(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	0.0	0.0	0.0

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

DSM Winter Peak Demand Reduction (MW)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
AMS Customer Service Offering	0.0	0.0	0.0	0.0	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	0.0	0.0	0.0	0.0	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	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	0.0	0.0	0.0
Large Nonresidential Demand Conservation	0.0	0.0	0.0	0.0	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	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	0.0	0.0	0.0
Program Development and Administration	0.0	0.0	0.0	0.0	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	5.6	5.6	5.7	5.7	5.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Table 8-13: KU and LG&E Demand Side Management Energy and Demand Impacts (Cumulative)

DSM Energy Reduction (GWh)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
AMS Customer Service Offering	0.0	0.0	0.0	0.0	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	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	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	90.9	90.9	90.9
Large Nonresidential Demand Conservation	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	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	660.9	660.9	660.9
Program Development and Administration	0.0	0.0	0.0	0.0	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 for Active Programs	633.3	663.9	694.6	725.3	755.9	755.9	755.9	755.9	755.9	755.9	755.9	755.9	755.9	755.9	755.9	755.9

Table 8-13: KU and LG&E Demand Side Management Energy and Demand Impacts (Cumulative) Continued

DSM Summer Peak Demand Reduction (MW)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
AMS Customer Service Offering	0.0	0.0	0.0	0.0	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	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	118.7	118.7	118.7
WeCare	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	7.1	7.1	7.1
Large Nonresidential Demand Conservation	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	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	215.9	215.9	215.9
Program Development and Administration	0.0	0.0	0.0	0.0	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 for Active Programs	373.9	372.2	370.8	369.8	369.2	369.2	369.2	369.2	369.2	369.2	369.2	369.2	369.2	369.2	369.2	369.2

Table 8-13: KU and LG&E Demand Side Management Energy and Demand Impacts (Cumulative) Continued

DSM Winter Peak Demand Reduction (MW)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
AMS Customer Service Offering	0.0	0.0	0.0	0.0	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	0.0	0.0	0.0	0.0	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	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	7.1	7.1	7.1
Large Nonresidential Demand Conservation	0.0	0.0	0.0	0.0	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	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	215.9	215.9	215.9
Program Development and Administration	0.0	0.0	0.0	0.0	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 for Active Programs	200.1	205.8	211.5	217.2	223.0	223.0	223.0	223.0	223.0	223.0	223.0	223.0	223.0	223.0	223.0	223.0

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

The projected costs provided in Table 8-14 reflect the latest approved DSM-EE Program Portfolio.

Table 8-14: DSM Program Costs ($M)

Program Expenses ($M)	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**Total**
AMS Customer Service Offering	4.6	0.7	0.6	0.7	0.5	0.5	0.5	7.6
Residential and Small Nonresidential Demand Conservation	3.6	2.4	2.6	2.4	2.4	2.4	2.3	18.1
WeCare	6.3	6.3	6.3	6.7	6.4	6.4	6.4	44.8
Large Nonresidential Demand Conservation	0.9	0.8	0.8	1.0	0.9	0.9	0.9	6.2
Nonresidential Rebates	2.8	2.9	2.8	2.5	2.5	2.6	2.6	18.7
Program Development and Administration	0.7	0.7	0.7	0.8	0.8	0.8	0.8	5.3
Total Programs	**18.9**	**13.8**	**13.8**	**14.1**	**13.5**	**13.6**	**13.0**	**100.7**

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

As stated in the 2017 DSM-EE filing, Exhibit GSL-1, Table F, the Companies project that the portfolio of programs will reduce demand by 179 MW through 2025 as well as achieve energy savings of approximately 215 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 8-15 and Table 8-16 summarize the Companies' forecasted loads and resource capacities and the corresponding reserve margins for the summer and winter seasons.

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

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Gross Peak Load	6,456	6,522	6,500	6,485	6,461	6,424	6,399	6,378	6,366	6,368	6,344	6,346	6,340	6,331	6,334	6,337
DSM	-288	-294	-300	-305	-311	-311	-311	-311	-311	-311	-311	-311	-311	-311	-311	-311
Net Peak Load	**6,168**	**6,229**	**6,201**	**6,179**	**6,150**	**6,113**	**6,088**	**6,067**	**6,055**	**6,056**	**6,033**	**6,035**	**6,029**	**6,020**	**6,023**	**6,026**
Existing Capability[66]	7,702	7,702	7,702	7,702	7,702	7,702	7,702	7,702	7,702	7,702	7,702	7,702	7,702	7,702	7,702	7,702
CSR	127	127	127	127	127	127	127	127	127	127	127	127	127	127	127	127
DCP	63	61	60	58	56	55	53	52	50	49	48	47	46	45	44	43
Retirements/Additions																
Coal	-300	-300	-300	-300	-300	-300	-300	-1,009	-1,009	-1,009	-1,009	-1,009	-1,009	-1,969	-1,969	-1,969
Large-Frame SCCTs	0	0	0	0	0	0	0	0	0	0	0	0	0	-121	-363	-484
Small-Frame SCCTs	0	-14	-14	-14	-61	-61	-61	-61	-61	-61	-61	-61	-61	-61	-61	-61
New SCCTs	0	0	0	0	0	0	0	440	440	440	440	440	440	1,320	1,320	1,320
New Solar	0	0	79	79	204	204	204	597	597	597	597	597	597	1,855	1,855	1,855
New Battery Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100	200
Total Supply	**7,592**	**7,576**	**7,653**	**7,651**	**7,728**	**7,727**	**7,725**	**7,848**	**7,846**	**7,845**	**7,844**	**7,843**	**7,842**	**8,897**	**8,754**	**8,732**
Reserve Margin	1,424	1,348	1,452	1,472	1,578	1,614	1,637	1,780	1,791	1,789	1,811	1,808	1,813	2,877	2,732	2,706
Reserve Margin %	**23.1%**	**21.6%**	**23.4%**	**23.8%**	**25.7%**	**26.4%**	**26.9%**	**29.3%**	**29.6%**	**29.5%**	**30.0%**	**30.0%**	**30.1%**	**47.8%**	**45.4%**	**44.9%**

[66] Existing capability excludes CSR and DCP and includes OVEC's capacity, which 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 8-16: Winter Peak Demand and Resource Summary (MW)

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Gross Peak Load	6,053	6,192	6,173	6,165	6,142	6,117	6,101	6,088	6,069	6,061	6,047	6,049	6,037	6,026	6,030	6,048
DSM	-288	-294	-300	-305	-311	-311	-311	-311	-311	-311	-311	-311	-311	-311	-311	-311
Net Peak Load	**5,765**	**5,898**	**5,874**	**5,859**	**5,831**	**5,806**	**5,790**	**5,777**	**5,758**	**5,750**	**5,736**	**5,738**	**5,726**	**5,715**	**5,719**	**5,737**
Existing Capability[67]	7,973	7,973	7,973	7,973	7,973	7,973	7,973	7,973	7,973	7,973	7,973	7,973	7,973	7,973	7,973	7,973
CSR	127	127	127	127	127	127	127	127	127	127	127	127	127	127	127	127
DCP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Retirements/Additions																
Coal	0	0	0	0	-300	-300	-300	-1,013	-1,013	-1,013	-1,013	-1,013	-1,013	-1,978	-1,978	-1,978
Large-Frame SCCTs	0	0	0	0	0	0	0	0	0	0	0	0	0	-138	-404	-532
Small-Frame SCCTs	0	0	0	0	-55	-55	-55	-55	-55	-55	-55	-55	-55	-55	-55	-55
New SCCTs	0	0	0	0	0	0	0	496	496	496	496	496	496	1,488	1,488	1,488
New Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Battery Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100	200
Total Supply	**8,100**	**8,100**	**8,100**	**8,100**	**7,744**	**7,744**	**7,744**	**7,527**	**7,527**	**7,527**	**7,527**	**7,527**	**7,527**	**7,416**	**7,250**	**7,222**
Reserve Margin	2,335	2,201	2,226	2,240	1,913	1,939	1,954	1,750	1,770	1,778	1,791	1,789	1,801	1,701	1,531	1,485
Reserve Margin %	**40.5%**	**37.3%**	**37.9%**	**38.2%**	**32.8%**	**33.4%**	**33.8%**	**30.3%**	**30.7%**	**30.9%**	**31.2%**	**31.2%**	**31.5%**	**29.8%**	**26.8%**	**25.9%**

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

Table 8-17 summarizes the Companies' forecasted energy requirements.

[67] Existing capability excludes CSR and DCP and includes OVEC's capacity, which 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 8-17: Energy Requirements Summary (GWh, Base Energy Requirements Forecast)

	2021	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
Energy Requirements	32,040	32,233	32,079	32,045	31,838	31,648	31,532	31,518	31,370	31,280	31,244	31,284	31,196	31,348	31,323	31,481
Energy by Fuel Type																
Coal	24,354	24,174	24,689	24,823	23,568	23,607	23,237	21,690	21,227	21,007	21,342	21,653	21,272	15,535	15,802	15,909
Gas	6,612	6,696	6,211	6,026	6,639	6,436	6,686	7,036	7,354	7,479	7,126	6,843	7,138	9,214	8,917	8,966
Oil	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hydro	355	387	388	388	388	388	388	388	388	387	387	388	388	369	373	371
Solar	16	17	241	240	615	615	608	1,806	1,802	1,800	1,795	1,798	1,793	5,614	5,615	5,626
Battery Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	4	11
Firm Purchases from Other Utilities																
OVEC	971	958	550	567	628	601	613	597	600	606	593	603	606	616	615	609
Firm Purchases from Non-Utility Sources	6	7	8	9	10	10	11	12	13	13	14	15	16	17	17	18
Reductions/Increases in Energy from DSM	-288	-294	-300	-305	-311	-311	-311	-311	-311	-311	-311	-311	-311	-311	-311	-311

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

Table 8-18 shows the Companies' forecasts of total generation required to meet load and total energy input by primary fuel type.

Table 8-18: Generation and Energy Input by Fuel Type (Base Energy Requirements Forecast)

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Coal																
Energy (GWh)	24,354	24,174	24,689	24,823	23,568	23,607	23,237	21,690	21,227	21,007	21,342	21,653	21,272	15,535	15,802	15,909
Fuel Burn (000 Tons)	10,837	10,824	11,261	11,340	10,804	10,977	10,810	10,011	9,798	9,707	9,861	10,005	9,827	7,166	7,275	7,333
Fuel Burn (MMBtu)	253,677	251,290	257,311	258,966	245,464	246,241	242,173	224,003	219,256	217,199	220,729	223,940	219,993	160,065	162,324	163,657
Gas																
Energy (GWh)	6,612	6,696	6,211	6,026	6,639	6,436	6,686	7,036	7,354	7,479	7,126	6,843	7,138	9,214	8,917	8,966
Fuel Burn (000 MCF)	49,260	49,831	45,397	43,768	47,888	46,201	48,121	56,250	56,271	57,799	53,407	52,103	54,412	76,805	76,122	74,091
Fuel Burn (MMBtu)	52,318	52,967	48,223	46,486	50,851	49,029	51,093	59,271	59,319	60,978	56,412	55,062	57,514	80,547	79,784	77,741
Oil																
Energy (GWh)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Fuel Burn (000 Gallons)	24	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Fuel Burn (MMBtu)	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hydro																
Energy (GWh)	355	387	388	388	388	388	388	388	388	387	387	388	388	369	373	371
Solar																
Energy (GWh)	16	17	241	240	615	615	608	1,806	1,802	1,800	1,795	1,798	1,793	5,614	5,615	5,626
Battery Storage																
Energy (GWh)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	4	11

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 a complete summary of this analysis is included in Volume III ("2021 IRP Reserve Margin 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 electric vehicles. 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, the University of Kentucky, and other research 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. Solar generation can, for example, go from 100% of capacity to 10% of capacity within 90 seconds, highlighting the intermittent performance of solar. Monitoring solar output during winter months has revealed important modelling cases to ensure that a portfolio can withstand the worst times of solar generation and maintain reliable service. 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 at https://lge-ku.com/live-solar-generation.

Energy Storage

R&D is researching energy storage technologies regarding cost, performance, and advanced control techniques. The Companies operate Kentucky's first and largest utility-scale energy storage system — a 1-megawatt, 2-megawatt-hour lithium-ion battery, which is co-located with E.W. Brown Solar, allowing the Companies to explore how batteries can mitigate the inherent intermittency of solar power. The battery research site has testing bays for three separate megawatt-scale energy storage systems and was 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 battery is operated around the clock, charging during the day when solar power is available and discharging at night. During daylight hours, the system can perform solar-support functions including power smoothing. The Companies have also used this battery system to simulate reducing or limiting peak demand. Other advanced functions are Auto Volt-Var, during which the battery supplies or absorbs reactive power to maintain grid voltage at a reference value, and Auto Frequency Watt, in which the battery rapidly charges or discharges to reduce grid frequency variation. The battery's function is constantly monitored via a real-time battery performance dashboard to maintain awareness of hundreds of conditions remotely. Through partnership with local universities, the Companies are also performing system modeling and developing applications for combining intermittent renewable generation with energy storage. Over the past three years, nine academic papers and presentations based on data retrieved from the E.W. Brown Solar Dashboard and E.W. Brown 1-megawatt, 2-megawatt-hour battery have been used in dozens of internationally published academic papers.

Vegetation Management

Land use is one of the greatest challenges to increasing renewable energy generation from sources of solar and wind. In the spring of 2020, R&D began a novel project to research the use of sheep for vegetation management around solar panels rather than conventional groundskeeping with lawn mowers and weed eaters. The E.W. Brown Generating Station is home to a 35-acre field of solar panels that needs to be maintained and mowed to keep the solar panels up and running. Mowing is both challenging and time-consuming because of row width and panel height. During the growing season, a flock of Shetland and Katahdin sheep from nearby Shaker Village are rotated through fenced paddocks at the E.W. Brown solar facility. The stocking density, vegetation preference, and rotation schedule are all part of the learnings for utilizing the sheep for vegetation management at a larger scale. Farmers from Shaker Village oversee the care of the flock, including veterinary services and shearing. The project has demonstrated that sheep grazing can be an effective form of vegetation management and that land used for solar generation can simultaneously be used for agricultural purposes.

Carbon Capture Research

The Companies are global leaders in carbon capture research and operate one of the two carbon capture systems in operation at power plants in the United States today. Since 2006, the Companies have directly invested more than $4 million in the University of Kentucky's Center for Applied Energy Research (UK CAER) decarbonization research. Leveraging funding from the Companies with a $14.5 million U.S. Department of Energy ("DOE") grant in 2011, the team installed a carbon capture slip-stream pilot demonstration system at the Companies' E.W. Brown plant. The post-combustion process takes a small portion of the flue gas and uses an amine-based solvent to capture carbon dioxide. Since 2014, University of Kentucky researchers have used this system to run tests for U.S. Department of Energy-funded research projects and have generated 118 publications and have had 17 U.S. patents issued for their work with another four patents pending. The site is operational and currently working on mimicking natural-gas flue gas to address the challenges of carbon capture at natural gas plants. The learnings from the research could be significant for adapting carbon capture systems for use with natural gas combined cycle power plants. Along with post-combustion carbon capture, the Companies are working with UK CAER on direct air carbon capture that captures carbon dioxide from the air, regenerates the capture solvent, and produces hydrogen as a beneficial byproduct.

Data Analytics

R&D has developed modeling capabilities to analyze the minute-to-minute impacts of intermittent renewable generation on the Companies' transmission and generation systems. The model is driven by years of data from the Companies' distribution, transmission, and generation assets, including the E.W. Brown solar and energy storage facilities, and publicly available weather data. Valuable insights have been gained from the model including methods for increasing the Companies' intermittent renewable hosting capacity. The model shows that the Companies can increase intermittent renewable capacity and minimize the negative impacts on reliability by adding natural gas combined cycle with carbon capture and storage or battery energy storage and by dispersing renewable capacity across the service territory. With this model, the Companies can also understand one of the greatest challenges to increasing renewable energy—land use—which has been quantified across thousands of simulated portfolios with varying amounts of intermittent renewable capacity.

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. The Companies have also installed solar electric vehicle chargers and have been testing their functionality. Each station has backup battery storage that can charge EVs for two full charges in case of bad weather and poor solar collection. The solar chargers are also fitted with switches that can control where the energy for charging comes from in case solar is not optimal. The switch will move the charge over to the connected energy grid to ensure the EV can fully charge. The Companies also have twenty non-solar public electric vehicle charging stations across the state that are monitored and the data analyzed to inform future charging installation decisions. Through a partnership with EPRI, the Companies also monitor activities at other utilities for novel system adaptations for additional electric load from electric transportation.

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 sulfur dioxide ("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 further reductions in SO_2 and NO_x aided by rules such as the Clean Air Interstate Rule (2009/2010), Mercury Air Toxics Standards (2012), and the Cross-State Air Pollution Rule (initially implemented in 2015, updated in 2017, and revised in 2021), the Companies continue to comply with the Acid Deposition Control Program through allowance surrendering.

Clean Air Interstate Rule / Cross-State Air Pollution Rule

As an update to the 2018 IRP, the Cross-State Air Pollution Rule ("CSAPR") Update Rule (finalized on September 7, 2016) was replaced with the Revised CSAPR Update Rule (finalized on March 15, 2021). The Revised CSAPR Update Rule became effective on June 29, 2021.

Due to continuing ozone non-attainment issues primarily in the northeast, EPA analysis determined that emissions from Kentucky and 11 other states are significantly contributing to downwind ozone attainment issues. The Revised CSAPR Update rule establishes a new CSAPR NOx ozone season Group 3 trading program for just the 12 states identified in the rule. Within that Group 3 trading program, the Companies' ozone season NO_x allocations were reduced by 7% in 2021 and 15% in 2022 forward compared to the 2020 allocations of the CSAPR Update Rule. Additionally, the Revised CSAPR Update Rule converted the Companies' banked 2017 through 2020 Group 2 NO_x allowances to Group 3 allowances at an 8:1 ratio. That conversion was completed by August 13, 2021. Because the Revised CSAPR Update rule was deemed necessary to meet the 2008 (75 parts per billion "ppb") ozone NAAQS, it is reasonable to expect that even greater NO_x reductions will be necessary to meet the 2015 (70 ppb) ozone NAAQS. The Companies will continue to operate and maintain the affected facilities in compliance with the Revised CSAPR Update requirements and will continue to follow EPA's development of any regional transport rules to address the 2015 ozone NAAQS.

Hazardous Air Pollutant Regulations/Mercury and Air Toxics Standard

EPA developed final rules to establish national emission standards for hazardous air pollutants ("NESHAP") 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 2018 IRP, EPA issued an update to MATS on July 17, 2020 that revised some recordkeeping and reporting requirements, including the transition to a single electronic reporting system. The revision established that affected facilities' MATS data is to be reported through EPA's Emission Collection and Monitoring Plan System ("ECMPS") beginning on January 1, 2024. EPA is in the process of making changes to ECMPS to capture the required data and working with emission monitoring data acquisition and handling vendors to meet the deadline. The Companies' compliance has been managed per MATS-defined monitoring, testing, work practices, record keeping, and reporting, which have been incorporated into facility operating permits. The Companies will continue to follow these electronic reporting developments and implement any needed changes to internal processes to ensure MATS compliance.

Hazardous Air Pollutant Regulations/Combustion Turbines

In March 2004, EPA promulgated NESHAP for stationary combustion turbines. Stationary combustion turbines were identified as major sources for formaldehyde, toluene, benzene, and acetaldehyde. The final rule (40 CFR 63, Subpart YYYY) applied to stationary combustion turbines located at major sources of hazardous air pollutant emissions. Many, but not all, of the Companies' combustion turbines are in this category. The rule also had different requirements for existing (i.e., commenced construction on or before January 14, 2003) and new combustion turbines (i.e., commenced construction after January 14, 2003). However, in August 2004, EPA stayed a portion of the rule pertaining to the types of combustion turbines the Companies employ. Therefore, the Companies have not been affected by this rule.

On March 9, 2020, following a requirement to perform reviews of NESHAP rules every eight (8) years, EPA finalized revisions to the combustion turbine NESHAP rule. EPA maintained the same NESHAP limits (e.g., a formaldehyde limit of 91 ppb) after determining that the limits provided an ample margin of safety to protect public health and that no new cost-effective controls are available that could achieve further reductions. The revision clarifies that emissions during startup, shutdown, and malfunction operating periods should be included, and it added reporting requirements. However, the revision also did not lift the 2004 stay. EPA stated that more time was needed to review public comments and a petition to delist the stationary combustion turbines source category that was filed in August 2019. Therefore, the Companies' combustion turbines remain unaffected by this rule.

The Companies will continue to follow NESHAP developments. If EPA lifts the stay, emissions testing will be needed to prove compliance. If compliance is not determined, emission or operational controls may need to be investigated.

National Ambient Air Quality Standards

On January 20, 2021, President Biden signed Executive Order 13990, "Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis." The Executive Order requires federal agenices to review the action and policies of all federal agencies taken during the Trump administration to ensure compliance with the administration's environmental policies. Accordingly, EPA has announced efforts to review various NAAQS. The Companies are following these developments and will assess their impacts on operating facilities.

SO_2

As an update to the 2018 IRP, on March 18, 2019, EPA published a final action, which became effective on April 17, 2019, to retain the primary SO_2 NAAQS at 75 ppb as set in 2010. On October 3, 2019, EPA denied a 2017 petition, submitted by the Sierra Club, requesting that EPA object to Mill Creek Station's revised Title V operating permit. Additionally, effective September 8, 2020, EPA approved the redesignation of the Jefferson County metropolitan statistical area from non-attainment to attainment of the 2010 1-hour SO_2 primary NAAQS. In the same action, EPA approved the Commonwealth of Kentucky's plan for maintaining the attainment status and incorporated the plan into the Commonwealth's SIP.

NO_x/NO_2

As an update to the 2018 IRP, on November 16, 2018, the KDAQ proposed a revision to the State Implementation Plan ("SIP") that demonstrates the "Good Neighbor" provisions of the 2010 NO_2 NAAQS are being met and requests that EPA approve the demonstration for Kentucky to fully implement the 2010 1-hour NO_2 NAAQS. EPA has not yet acted on that request. The Companies are not expecting any impacts on operating facilities but will continue to follow these issues involving NO_2 NAAQS.

Ozone

As an update to the 2018 IRP, on January 9, 2019, KDAQ submitted an infrastructure SIP regarding the requirements of the 2015 8-hour ozone NAAQS. On June 1, 2020, EPA approved portions of that SIP submittal. On December 23, 2020, following requirements to review NAAQS every five years, EPA issued a final decision to retain the current (i.e., 2015) primary and secondary ozone NAAQS (both retained at 70 ppb). Non-attainment designations to the 2015 ozone NAAQS are expected in late 2021 or early 2022. EPA will perform ozone transport modeling to assess regional impacts to non-attainment areas. The ozone transport modeling results may drive a new ozone regional transport rule that further reduces regional ozone emissions through reduced NOx credit allocations. Similar actions occurred when, on March 15, 2021, EPA published the Revised CSAPR Update rule (mentioned previously) to address non-attainment issues with the 2008 ozone standard. Modeling, rulemaking, and compliance preparation may result in ozone reduction requirements around 2027 for the 2015 ozone NAAQS.

Following the issuance of President Biden's Executive Order 13990, it may be reasonable to expect that EPA will reevaluate the December 2020 decision to retain the ozone NAAQS. Prior to EPA's decision to retain the current standards, many environmental groups and members on EPA's Clean Air Scientific Advisory Committee presented data for lowering the ozone standards to 65 – 68 ppb. By regulation, the NAAQS should be reevaluated again in 2025, but Executive Order 13990 might cause EPA to review the standard earlier. The Jefferson County area is likely not to meet a lower standard. Therefore, even if Jefferson County has achieved attainment of the 70 ppb ozone standard by August 2024, it is possible that the standard would be lowered in 2025, and once again the Jefferson County area would be determined to be non-attainment for ozone. Such a determination will start the process of establishing a new RACT and implementing further NO_x reductions at all sources in the Jefferson County area.

The Companies' Mill Creek Generating Station is located in Jefferson County, which is currently classified as marginal non-attainment for the 2015 Ozone NAAQS. By regulation, the Jefferson County marginal non-attainment area had until August 13, 2021 to reach attainment or risk being redesignated to moderate non-attainment. In 2020 and 2021, the Louisville Metro Air Pollution Control District ("LMAPCD") imposed via an Agreed Board order, an additional 15-ton total daily NO_x emissions limitation on the Mill Creek Generating Station for the months of May through October in an effort to meet the August 2021 deadline. Despite the Companies' efforts while meeting this limit, there were exceedances of the 70 ppb ozone standard in the Jefferson County area during the 2020 ozone season. LMAPCD has stated that Jefferson County was not "in compliance" with the 2015 Ozone NAAQS by August 2021 due to those exceedances in 2020. LMAPCD currently anticipates being reclassified to moderate non-attainment in 2022. If that happens, major sources in Jefferson County may be required to implement NO_x Reasonable Available Control Technology ("RACT") by March 1, 2023. In the interim, the Companies expect that the ozone season NO_x limit for the Mill Creek Generating Station will remain in place pending development of the NO_x RACT standard. Therefore, the Companies will likely be limited to operating either Mill Creek Unit 1 or Mill Creek Unit 2 (but not both) during the ozone season (i.e., April through October) until Mill Creek Unit 1 retires in 2024.

Upon reclassification to moderate non-attainment with the 2015 Ozone NAAQS, the Jefferson County area will have a moderate non-attainment compliance date of August 3, 2024. The State Implementation Plan ("SIP") must be amended to include the RACT standards by April 2024. The NO_x emission reduction associated with the implementation of RACT at Mill Creek Generating Station is expected to be similar to the mode of operation at Mill Creek during the summers of 2020 and 2021.

Continued non-attainment past the 2024 compliance date will result in Kentucky reevaluating RACT for the Jefferson County area to further reduce NO_x emissions or cause the non-attainment area to be reclassified to serious non-attainment. Such a reclassification would require additional NO_x emission reductions, which must be demonstrated by August 2027. If serious non-attainment is reached, Mill Creek 2 would likely be replaced as an alternative to installing additional NO_x controls, such as selective catalytic reduction ("SCR"), to achieve those reductions.

The Companies will continue to follow these ozone NAAQS issues and assess their impacts on operating facilities.

PM / $PM_{2.5}$

As an update to the 2018 IRP, on December 7, 2020, EPA announced a decision to retain the existing primary and secondary PM NAAQS (for PM_{10}, and $PM_{2.5}$). Following President Biden's

Executive Order 13990, EPA announced, on June 10, 2021, they will reconsider the December 2020 decision. EPA indicated that they would be investigating tightening the standards. Many environmental groups and members on EPA's Clean Air Scientific Advisory Committee presented data for lowering the $PM_{2.5}$ limit to 10-11 $\mu g/m^3$. Depending on whether limits are lowered and how low the new levels are set, many areas across the country could be redesignated as non-attainment. If areas in Kentucky were redesignated, the state would need to begin the process of determining what needs to be done to achieve attainment and make changes to the State Implementation Plan to address those needs. As a result of installation of pulse jet fabric filters across the Companies' fleet, concerns with the changes to $PM/PM_{10}/PM_{2.5}$ NAAQS could be minimized since the equipment is considered a best available control technology for coarse and fine particulates. The Companies will continue to follow these issues involving PM NAAQS and assess their impacts on operating facilities.

Regional Haze

Since the 2018 IRP, the second planning period (2018-2028) of the Regional Haze rule began. The Companies' Mill Creek Generating Station Units 3 and 4 have permit limits based on reviews performed during the first planning period to meet the visibility criteria of the rule for impacts on Mammoth Cave National Park. From the Commonwealth of Kentucky's review, the Companies will not have to take any further restrictions for the second Regional Haze planning period. However, EPA's requirements for implementation of the third planning period of the Regional Haze regulation will likely be published in 2028 for states to model sources impacting visibility in national parks. Even though Kentucky is below the glide path required for showing progress toward the rule's goal by 2064 (i.e., Kentucky is making more than the required progress toward the goal), the Companies may be requested to evaluate visibility/regional haze impacts of operations on Class 1 areas like Mammoth Cave National Park because EPA has stated that being below the glide path does not negate the need to evaluate impacts and possibly install controls. The Companies will continue to follow these issues and implement any needed changes to ensure compliance.

Greenhouse Gases

As an update to the 2018 IRP, in December 2018, EPA published a proposal to revise the Greenhouse Gas New Source Performance Standards ("GHG NSPS"). Specifically, EPA proposed to find that the best system of emission reduction ("BSER") for newly constructed coal-fired electric generating units would no longer be partial carbon capture and storage ("CCS"), but instead would be to use the most efficient demonstrated steam cycle (e.g., supercritical steam conditions for large units and subcritical steam conditions for small units) in combination with the best operating practices. In January 2021, EPA finalized a portion of the proposal that provided a framework of criteria for making a significant contribution finding ("SCF") for regulating GHG emissions from a source category under CAA Section 111(b). EPA did not finalize the proposed revision to the BSER determination. On April 5, 2021, a court granted EPA's request for a voluntary vacatur and remand of the SCF final rule. EPA continues to review comments on the BSER portion of the 2018 proposal and whether any follow-up action is appropriate to address the SCF vacatur and remand. The Companies will continue to follow these GHG NSPS issues and assess their impacts on operating facilities.

Regarding existing sources, on August 21, 2018, EPA proposed the Affordable Clean Energy ("ACE") rule to replace the 2015 Clean Power Plan ("CPP"). On June 19, 2019, EPA issued the final ACE rule. With this rule, EPA also repealed the 2015 CPP rule and issued new implementing regulations for the ACE rule and future rules under section 111(d) of the Clean Air Act The final rule package did not include revisions to the New Source Review program as envisioned in the proposed ACE rule package. The finalized ACE rule established emission guidelines for states to develop plans to address greenhouse gas ("GHG") emissions from existing fossil fuel-fired power plants. ACE defined the best system of emissions reduction for GHG emissions from existing power plants as on-site, heat-rate efficiency improvements. The ACE rule contained a list of "candidate technologies" that states would need to consider in establishing standards of performance for individual existing plants. States were to determine which of these technologies would be appropriate for each plant and establish a standard of performance that reflected the degree of emission reduction from their application. However, on January 19, 2021, the U.S. Court of Appeals for the D.C. Circuit court vacated the ACE rule and remanded it to EPA for further proceedings consistent with the court's opinion.[68] As of the date of this IRP, EPA is still formulating how to address the court decision. The Companies will continue to follow these existing source GHG issues and assess their impacts on operating facilities.

In 2021, President Joe Biden's administration placed a high priority on climate change and GHG issues. President Biden fulfilled a campaign promise and had the United States rejoin the Paris Agreement. The Paris Agreement is a legally binding international treaty on climate change which was adopted by nearly 200 countries in 2015. As part of meeting the Paris Agreement's goals, President Biden set new targets for the United States to achieve a 50-52% reduction from 2005 levels of economy-wide net GHG emissions in 2030. A goal was also set for reaching net zero emissions economy-wide by no later than 2050. Additionally, in response to President Biden's Executive Order 13990, EPA is considering rulemaking proposals to address sources of climate- and health-impacting emissions. EPA states that these efforts include investigating the possibility of lowering the GHG NSPS levels for new, modified, and reconstructed electric generating units as well as developing strategies to achieve reductions in GHG emissions from existing power plants. Depending on how far those efforts are taken, carbon capture, utilization, and sequestration technologies may be needed to achieve desired reductions.

The Companies will continue to follow all these GHG issues and assess their impacts on operating facilities.

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 final version of the 316(b) regulations on August 15, 2014 that were effective on October 14, 2014. The regulation addresses both impingement and entrainment impacts for aquatic species. All coal-fired generating units meet the impingement standard by utilizing the closed-cycle cooling compliance option, except the Companies Mill Creek Unit 1. For the entrainment standard, only the combined units of Mill Creek Station will

[68] *American Lung Ass'n v. E.P.A.*, 985 F.3d 914 (D.C. Cir. 2021).

exceed the 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. The final report will be submitted in 2022. 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.

EPA published revisions to the rule on October 12, 2020 that included minor changes in limits for FGD Wastewater and an extension on Bottom Ash Transport Water Compliance. Permit modification applications were submitted on January 8, 2021 for the Companies Ghent, Mill Creek, Trimble County, and E.W. Brown electric generating facilities to incorporate new discharge limits into each facility's Kentucky Pollutant Discharge Elimination System ("KPDES") water discharge permit. On July 26, 2021, EPA announced a reconsideration of the 2020 revisions to the 2015 ELG standards with review to determine "whether more stringent limitations and standards are appropriate." The required public notice has been provided for the Mill Creek and Trimble County revised KPDES permits, which should be final by the end of 2021. The Ghent and E.W. Brown revised KPDES permits are expected in the first half of 2022. Additional treatment systems may be required in the future based on EPA's revisions to the ELG rule. EPA expects a finalized ELG rule in fall 2022.

Clean Water Act: Definition of Waters of the United States

On January 23, 2020, EPA finalized the Navigable Waters Protection Rule ("NWPR") to define the waters of the United States ("WOTUS"). The agency streamlined the definition to four categories: (i) territorial seas and traditional navigable waters; (ii) perennial and intermittent tributaries to those waters; (iii) certain lakes, ponds, and impoundments of jurisdictional waters; and (iv) wetlands adjacent to jurisdictional waters. Fourteen separate challenges were filed on the revised NWPR definition of WOTUS. EPA and United States Army Corps of Engineers ("US ACE") requested the courts to remand the rule without vacatur and announced on June 9, 2021 that they intended to revise the definition of WOTUS. On August 30, 2021, the U.S. District Court for the District of Arizona was the first court to issue an order to remand and vacate the NWPR based on "[t]he seriousness of the Agencies' errors in enacting the NWPR, the likelihood that the Agencies will alter the NWPR's definition of 'waters of the United States,' and the possibility of serious environmental harm if the NWPR remains in place upon remand." On September 3, 2021, EPA and US ACE announced that they have halted implementation of the NWPR and are interpreting the definition of WOTUS consistent with the pre-2015 regulatory regime until further notice. Based on preliminary communications from EPA and US ACE, the revised definitions of

WOTUS is expected to be broader than the NWPR and could create barriers for future construction permitting and compliance. A revised definition of WOTUS is expected in 2022.

Coal Combustion Residuals

After several years of review and public comment, EPA issued the coal combustion residuals ("CCR") regulation that was effective on October 14, 2015. The rule is a holistic program outlining federal standards for the storage, management, beneficial use, and long-term care of CCR managed in surface impoundments and landfills.

The Companies initiated closure of all 19 of its CCR surface impoundments as a result of the rule. These processes were accomplished using the rule's options of in-place closure and closure by removal methods. The Companies have completed the physical closure process on 14 of the former CCR surface impoundments.

While the Companies have made substantial progress with CCR Rule compliance in the six years since its effective date, the rule continues to evolve through additional rulemaking commitments made by EPA. Most potential future modifications to the rule, including expansion of the rule to include "legacy" impoundments, are unlikely to affect the CCR processes and measures the Companies have already completed. A potential future risk for the Companies involves the in-place closure of CCR surface impoundments where the bottom of the impoundment is, at least occasionally, in contact with groundwater. The EPA Administrator will have continued pressure to adopt a stronger position in opposition of closure in place.

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

In the development of the 2021 IRP, the Companies considered market forces and competition. This consideration is reflected in the appropriate sections of the IRP.

9 Financial Information

Annual revenue requirements and the present value of revenue requirements ("PVRR") are shown in Table 9-1 for the base energy requirements, base fuel price case. The discount rate used in the present value calculation is 6.41%. Annual revenue requirements include variable and fixed costs for both new and existing units and capital costs for new units.

Table 9-1: Annual Revenue Requirements (Base Energy Requirements, Base Fuel Case)

	2022	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
Revenue Requirements ($M)	1,028	1,010	1,001	1,016	1,045	1,083	1,178	1,179	1,195	1,218	1,244	1,277	1,522	1,502	1,555
PVRR ($M; 2021 Dollars)	3,821														
Base Energy Requirements (GWh)	32,233	32,079	32,045	31,838	31,648	31,532	31,518	31,370	31,280	31,244	31,284	31,196	31,348	31,326	31,492
cents/kWh	3.19	3.15	3.12	3.19	3.30	3.44	3.74	3.76	3.82	3.90	3.98	4.09	4.86	4.80	4.94