COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC 2024 JOINT INTEGRATED RESOURCE PLAN OF LOUISVILLE GAS AND ELECTRIC COMPANY AND KENTUCKY UTILITIES COMPANY	))))	CASE NO. 2024-00326

<u>O R D E R</u>

The Commission initiated this proceeding for the Commission Staff to conduct a review of the 2024 Integrated Resource Plan (IRP) filed jointly by Louisville Gas and Electric Company (LG&E) and Kentucky Utilities Company (KU) (jointly, LG&E/KU), pursuant to 807 KAR 5:058. Attached as an Appendix to this Order is the Commission Staff's Report summarizing Commission Staff's review of the IRP. This Commission Staff's Report is being entered into the record of this case pursuant to 807 KAR 5:058, Section 11(3).

Based on the evidence of record, the Commission finds that the Commission Staff's Report represents the final substantive action in this matter. The final administrative action will be an Order closing the case and removing it from the Commission's docket. That Order will be issued after the period for comments on the Commission Staff's Report has expired.

IT IS THEREFORE ORDERED that:

1. The Commission Staff's Report on LG&E/KU's 2024 IRP represents the final substantive action in this matter.

2. An Order closing this case and removing it from the Commission docket shall be issued after the period for comments on the Commission Staff's Report has expired.

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PUBLIC SERVICE COMMISSION

Chairman

Commissioner

Commissioner

ATTEST:

Executive Director

ENTERED
JUL 31 2025
AB
KENTUCKY PUBLIC SERVICE COMMISSION

APPENDIX

AN APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2024-00326 JUL 31 2025

FIFTY FOUR PAGES TO FOLLOW

Kentucky Public Service Commission

Commission Staff's Report on the

2024 Joint Integrated Resource Plan

of Louisville Gas and Electric Company and

Kentucky Utilities Company

Case No. 2024-00326

[July 2025]

SECTION 1

INTRODUCTION

In 1990, the Kentucky Public Service Commission (Commission) promulgated 807 KAR 5:058 to create an integrated resource planning process to provide for review of the long-range resource plans of Kentucky's jurisdictional electric generating utilities by Commission Staff. The Commission's goal was to ensure that all reasonable options to meet projected load were being examined in order to provide ratepayers a reliable supply of electricity that is cost-effective.[1]

Louisville Gas and Electric Company (LG&E) and Kentucky Utilities Company (KU, jointly LG&E/KU) are investor-owned utilities and subsidiaries of the PPL Corporation (PPL). LG&E/KU file their Joint 2024 Integrated Resource Plan (2024 IRP or IRP) on October 18, 2024. LG&E serves approximately 436,000 electric customers with KU serving approximately 573,000 electric customers.[2] The 2024 IRP reflects LG&E/KU's resource plan for meeting its customers projected electricity requirements for the 2024 through 2039 planning period.

In filing their 2024 IRP, LG&E/KU stated that the IRP represents a snapshot of an ongoing resource planning process using current business assumptions. LG&E/KU cautioned that prior to making any "final strategic decisions" LG&E/KU would support any request with "specific analyses."[3] LG&E/KU stated that instead the goal of their resource planning process was "to provide safe, reliable, and low-cost service to their customers while complying with all laws and regulations."[4] LG&E/KU stated that energy was vital to the Commonwealth because Kentucky was "the 8th most electricity-intensive U.S. state in 2022 as measured by the ratio of electricity consumption and state gross domestic product."[5]

Table 5-1 in Volume 1 of LG&E/KU's 2024 IRP detailed its current generation resources.[6] As a brief overview, LG&E/KU currently own and operate 29 fully dispatchable resources (11 coal units, 1 Natural Gas Combined Cycle (NGCC) unit, 14 large-frame Single Cycle Combustion Turbine (SCCT); and 3 small frame SCCTs). These dispatchable units provide approximately 7,612 MW of summer capacity and 7,909 MW of winter capacity. Additionally, LG&E/KU own and operate approximately 16

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[1] *See* Admin. Case No. 308, *An Inquiry into Kentucky's Present and Future Electric Needs and the Alternatives for Meeting Those Needs* (Ky. PSC Aug. 8, 1990), Order at 1–3. *See also* 807 KAR 5:058.

[2] 2024 IRP Volume 1, Section 5(1)(a) at 5-1. Additionally, LG&E also serves approximately 335,000 gas customers.

[3] 2024 IRP Volume 1 at 2.

[4] 2024 IRP Volume 1.

[5] 2024 IRP Volume 1, Section 5(1)(a) at 5-1.

[6] 2024 IRP Volume 1, Section 5(1).

renewable resources (4 solar farms, 11 hydro units, and 1 wind unit) which provide roughly 147 MW of summer and winter capacity. Finally, LG&E/KU also have two limited-duration programs; the curtailable service rider (CSR) and the demand conservation program (DCP) which account for approximately 170 MW of summer capacity and 150 MW of winter capacity.[7]

LG&E/KU submitted its 2024 IRP to the Commission on October 18, 2024. On October 30, 2024, the Commission issued an Order establishing a procedural schedule for this proceeding. The procedural schedule established a deadline for requesting intervention, two rounds of data requests to LG&E/KU, an opportunity for intervenors to file written comments, and an opportunity for LG&E/KU to file a response to any intervenor comments. Additionally, a hearing was set in this matter, and was held on May 13 and 14, 2025.

The following parties filed for, and were granted, intervention in this matter: (1) Attorney General of the Commonwealth of Kentucky, by and through the Office of Rate Intervention (Attorney General); Kentucky Industrial Utility Customers (KIUC); The Sierra Club (Sierra Club); the Kentucky Coal Association (KCA); and Mountain Association (MA), Kentuckians for the Commonwealth (KFTC), Kentucky Solar Energy Society (KYSES), and Metropolitan Housing Coalition (MHC) (collectively Joint Intervenors). Intervenor comments in response to Commission Staff's Report are due on or before August 22, 2025.

A number of individual public comments were submitted to the Commission regarding LG&E/KU's IRP filing. Those comments are publicly available on the Commission's website.[8] Commission staff have reviewed all comments.

The purpose of this report is to review and evaluate LG&E/KU's 2024 IRP in accordance with 807 KAR 5:058, Section 11(3), which requires Commission Staff to issue a report summarizing its review of each IRP filing made with the Commission and make suggestions and recommendations to be considered by a utility in its next IRP filing.

Commission Staff recognizes that resource planning is a dynamic, ongoing process and that all IRP filings, including this one, represent a snapshot in time. Specifically, Commission Staff's goals are to ensure that, among other things, the following:

- All resource options are adequately and fairly evaluated;
- Critical data, assumptions, and methodologies for all aspects of the plan are adequately documented and are reasonable; and

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[7] 2024 IRP, Volume 1, Section 5(1)(a), table 5-2.

[8] https://psc.ky.gov/Case/ViewCaseFilings/2024-00326/Public.

- The report includes an incremental component, noting any significant changes from LG&E/KU's most recent IRP filed in 2021.

The remainder of this report is organized as follows:

- Section 2: Load Forecasting—reviews LG&E/KU's projected load growth and load forecasting methodology.

- Section 3: Demand-Side Management and Energy Efficiency (DSM/EE)—summarizes LG&E/KU's evaluation of DSM opportunities.

- Section 4: Supply-Side Resource & Integration Assessment—focuses on supply-side resources available to meet LG&E/KU's load requirements and environmental compliance planning while looking holistically as to how those resources are integrated.

- Section 5: Reasonableness and Recommendations—discusses Commission Staff's position regarding the reasonableness of the IRP and its assumptions and includes Commission Staff's recommendations.

SECTION 2

LOAD FORECASTING

INTRODUCTION

This section reviews LG&E/KU's load forecasting methodology and projected load and peak demand for the planning period. This section also reviews the parties' comments regarding LG&E/KU's load and demand forecast. Commission Staff's discussion of and recommendations regarding LG&E/KU's load and demand forecasting are discussed in the final section of this report.

LOAD FORECASTING METHODOLOGY

LG&E/KU's integrated planning process began with the development of forecasts of hourly energy requirements or "load." LG&E/KU defined their energy requirement as the sum of electricity sales and transmission and distribution losses.[9] LG&E/KU determined their energy requirements by forecasting monthly energy sales by customer class, aggregating the sales forecasts by company, and adjusting for transmission and distribution losses.[10]

Forecasts of energy sales were made separately for LG&E and KU and later combined to form the Class Energy Sales Forecast. LG&E's forecasts were for retail customers in Kentucky only; whereas KU's forecasts were comprised of forecasts for Kentucky retail customers, Virginia retail customers (KU ODP), and wholesale municipal customers.[11]

Econometric and statistically adjusted end use ("SAE") models were used to forecast energy sales for most rate classes, but specific information regarding the prospective energy requirements of certain large customers was used to forecast energy sales for those customers. The models utilized macroeconomic data, historical and customer specific data, weather data (20-year normal degree days), and end use data to

[9] 2024 IRP, Vol. I, Section 5 at 6.

[10] 2024 IRP, Vol. I, Section 5 at 7.

[11] 2024 IRP, Vol. II, Section 4 at 9.

obtain sales forecasts, though the specific method used, and data relied on differed by customer class. [12]

Residential sales were forecast as the product of the forecasted number of customers and the average energy use per customer. Average use per residential customer was forecast using an SAE model, which defined energy use per customer as a function of energy use by heating equipment, cooling equipment, and other equipment.[13] These variables included heating and cooling degree days, appliance saturation levels, appliance and equipment efficiencies, income, population, household members and electricity prices.[14] LG&E/KU's forecast incorporated both customer-initiated energy efficiency, historical and current Demand-Side Management and energy efficiency ("DSM-EE") impacts, and the Inflation Reduction Act (IRA) in the EIA/Itron projections of end-uses.[15] LG&E/KU's Electric Vehicle ("EV") sales forecast was allocated entirely to the residential class.[16] The number of residential customers was modeled as a function of the number of forecasted households or population in each company's service territory.[17]

The Commercial and Industrial (C&I) forecasts comprised several separate forecasts with customers grouped by rate schedule. The General Service energy sales forecasts used SAE models that were similar to that used for the residential use-per-customer forecast and were a function of heating and cooling equipment and other nonweather sensitive equipment and binary variables.[18] The KU and LG&E Secondary Service forecasts were a function of weather, end-use intensity projections, and binary variables that account for anomalies in the historical data.[19] The KU ODP Secondary Service forecast was a function of energy used by heating equipment, cooling equipment,

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[12] See 2024 IRP, Vol. II, Electric Sales and Demand Forecast Process at 6 (showing that the data relied on for modeling included state macroeconomic and demographic data from S&P Global, national macroeconomic data from S&P Global; weather data from National Oceanic and Atmospheric Administration (NOAA); appliance saturations and structural variables from Energy Information Administration (EIA) and Itron; data regarding elasticities of demand from EIA and historical trends; billing sales and customer count history from the CCS Billing System; monthly net metering and qualifying facility customers and private solar costs from internal billing information and the National Renewable Energy Laboratory (NREL), and S&P Global; and data regarding electrical vehicle adoption and charging shapes from S&P Global, NREL, Bloomberg New Energy Finance, the Electric Power Research Institute, EIA, and Kelley Blue Book).

[13] 2024 IRP, Vol. II, Electric Sales and Demand Forecast Process at 10.

[14] 2024 IRP, Vol. II, Electric Sales and Demand Forecast Process at 10.

[15] 2024 IRP, Vol. II, Electric Sales and Demand Forecast Process at 10.

[16] 2024 IRP, Vol. II, Electric Sales and Demand Forecast Process at 15.

[17] 2024 IRP, Vol. II, Electric Sales and Demand Forecast Process at 10.

[18] 2024 IRP, Vol. II, Electric Sales and Demand Forecast Process at 12; *see also* Appendix A to the Electric Sales and Demand Forecast Process.

[19] 2024 IRP, Vol. II, Electric Sales and Demand Forecast Process at 12-13.

and other equipment as well as economic variables and other binary variables to account for anomalies in the historical data.[20] The KU All Electric Schools forecast were a function of end-use intensity projections, weather, and monthly binaries in addition to binary variables to account for anomalies in the historical data.[21] The KU ODP School Service forecast was a function of a constant, a variable to capture energy efficiency trends, weather, and monthly binaries in addition to binary variables to account for anomalies in the historical data.[22] The KU ODP Municipal Pumping forecast was a trend analysis of recent sales. The KU Primary Service forecast was a function of an economic variable, monthly binaries, and a binary variable to capture Covid-related usage changes.[23] The LG&E Primary service forecast was a function of an economic variable and monthly binaries.[24] Both the KU and LG&E Primary service forecasts are adjusted as necessary based upon individual customer supplied information. The LG&E Special Contract forecast, the KU Fluctuating Load Service forecast, and the KU Retail Transmission Service (RTS") forecast were primarily based upon individual customer forecasts. The RTS mining customer forecasts are a function of a mining index variable, a lag dependent variable, and a binary variable to capture Covid-related usage changes.[25] The LG&E RTS forecast is based upon individual customer forecasts. For those LG&E RTS customers not forecast individually, the forecast was a function of historical monthly usage. The KU ODP Industrial forecast was a function of weather and mining production indices.[26]

LG&E/KU developed separate forecasts for EV charging and Lighting sales using recent sales trends.[27] KU forecasted wholesale municipal sales using the individual municipal customer forecasts. Each municipal customer generated its own forecast, which is then reviewed by KU and compared to the customer's historical trend.[28]

LG&E/KU's forecast reflected the adoption of Distributed Solar Generation as a reduction in forecasted sales. LG&E/KU developed the net metering distributed solar generation forecast based on a consumer choice model, driven by various economic and financial inputs, including the retail price for electricity, the levelized cost of energy (LCOE) for solar installations, disposable personal income, monthly binaries, and the

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[20] 2024 IRP, Vol. II, Electric Sales and Demand Forecast Process at 13.

[21] 2024 IRP, Vol. II, Electric Sales and Demand Forecast Process at 12.

[22] 2024 IRP, Vol. II, Electric Sales and Demand Forecast Process at 12-13.

[23] 2024 IRP, Vol. II, Electric Sales and Demand Forecast Process at 13.

[24] 2024 IRP, Vol. II, Electric Sales and Demand Forecast Process at 13.

[25] 2024 IRP, Vol. II, Electric Sales and Demand Forecast Process at 13.

[26] 2024 IRP, Vol. II, Electric Sales and Demand Forecast Process at 14.

[27] 2024 IRP, Vol. II, Electric Sales and Demand Forecast Process at 14.

[28] 2024 IRP, Vol. II, Electric Sales and Demand Forecast Process at 14.

price paid for energy exported to the grid.[29] Regarding the investment tax credit phase-out discussed in the IRA, the LCOE variable included the changes in the model. [30] The forecast is a blend of two models, a near-term and long-term. Additionally, there is a forecast of behind-the-meter (BTM) qualifying facilities. This forecast is based upon the historical trend in BTM qualifying facility adoptions as well as current capacity-per-installation levels.[31]

For most forecasts, energy sales are converted from a "billed" basis to a "calendar" basis. Since customers billed-period energy overlaps more than one calendar month, billed energy was allocated to calendar months based on when the energy was consumed. LG&E/KU allocated the weather sensitive portion of consumed energy based upon heating and cooling degree days and the nonweather sensitive portion was allocated based on the number of specific billing days.[32] To determine annual energy requirements, LG&E/KU then sum the calendar-month energy sales forecast volumes and transmission sales and losses.[33]

HOURLY ENERGY REQUIREMENTS METHODOLOGY

LG&E/KU converted their forecasted load to an hourly energy-requirements forecast to develop resource expansion plans and a forecast of generation production costs. To start, LG&E/KU summed calendar-month forecast volumes independent of distributed generation and incremental EV load by company, transmission and distribution losses, and calendar-month forecast volumes for LG&E, KU and ODP service territories. LG&E/KU then developed load duration curves for each company and each month based on 10 years of historical hourly energy requirements. LG&E/KU then normalized the load duration curves by averaging hour-energy and month-energy ratios by month, rank and company. Then, LG&E/KU allocated total forecast monthly energy-requirements by company to hours using the normalized load duration curves. LG&E/KU then adjusted the hourly forecasts to ensure forecasted peaks are consistent with weather-normalized historical peaks and any changes in forecasted energy requirements. Finally, LG&E/KU adjusted the hourly energy requirements forecast to reflect the forecasted impact of distributed solar generation and electric vehicle load.[34]

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[29] 2024 IRP, Vol. II, Electric Sales and Demand Forecast Process at 15.

[30] 2024 IRP, Vol. II, Electric Sales and Demand Forecast Process at 15.

[31] 2024 IRP, Vol. II, Electric Sales and Demand Forecast Process at 15.

[32] 2024 IRP, Bol. II, Electric Sales and Demand Forecast Process at 17.

[33] 2024 IRP, Vol. II, Electric Sales and Demand Forecast Process at 18.

[34] 2024 IRP, Vol. II, Energy Sales and Demand Forecast Process at 19.

WEATHER-YEAR FORECASTS METHODOLOGY

LG&E/KU produced the 51 hourly energy-requirement forecasts for each year of the forecast based on actual weather in each of the last 51 years (1973 through 2023).[35] LG&E/KU developed a model to forecast hourly energy-requirements as a function of temperature and calendar variables. LG&E/KU produce two versions; a version where the forecast years are all identically shaped from a calendar perspective, and a version where forecast years match the calendar as it occurs.[36] The former version allows for a consistent load distribution across multiple years to assess reserve margin requirements, while the latter allows for accurate assessment of weather likelihood and is useful for analysis of minimum fuel burn requirements.[37]

LG&E/KU first adjusted all hours of the weather-year forecast so that the mean of monthly energy-requirements equals monthly energy-requirements in the mid energy forecast, excluding inputs with distinct load shapes. Then, LG&E/KU reviewed historical data to account for extreme points of weather and increase or decrease these points based on LG&E/KU's system load response. LG&E/KU then added or subtracted inputs with distinct load shapes, such as EV charging and distributed generation, on an hourly basis. All hours of the weather-year forecast are adjusted again, so that the mean of monthly energy-requirements in the weather-year forecast equals monthly energy-requirements in the mid energy forecast, including inputs with distinct load shapes. LG&E/KU then adjusted the mean of seasonal peaks of the weather-year forecast to equal seasonal peaks forecast using normal weather.[38] Finally, LG&E/KU adjusted all hours of the weather-year forecast so that the mean of seasonal energy-requirements equals seasonal energy-requirements in the mid energy forecast, including distinct load shapes.

KEY ASSUMPTIONS AND UNCERTAINTIES

A key assumption driving the forecasts is normal weather. LG&E/KU used a 20-year normal weather assumption in its energy requirements forecast. Additional weather-year model forecasts were developed to support LG&E/KU' reserve margin analysis and other generation reliability studies. The model created forecasts of hourly energy requirements in each year of the forecast period based on hourly temperatures from the prior 51 calendar years and calendar variables from the forecast period. Consistency between the base energy forecasts and the weather-year forecast was ensured by

[35] 2024 IRP, Vol. II, Energy Sales and Demand Forecast Process at 19.

[36] 2024 IRP, Vol. II, Energy Sales and Demand Forecast Process at 19.

[37] 2024 IRP, Vol. II, Energy Sales and Demand Forecast Process at 19.

[38] 3 Seasons are defined as winter (November, December, January, February), summer (June, July, August, September), and shoulder (March, April, May, October) in this context.

adjusting the mean of the weather-year forecast to the mean of the monthly energy requirements forecast.[39]

Other key assumptions centered around economic data. Based on the data used by LG&E/KU, Kentucky currently expects a real economic growth rate of 2.3 percent for 2024, which is similar to the U.S. economy. Average annual growth rates of 1.2 percent and 1.5 percent were expected for the 2025-2029 period and 2030-2039 period, respectively. LG&E/KU stated that the same downside risks that are present for the U.S. economic expansion are also potential headwinds for the Kentucky economy.[40]

With regards to Kentucky's economic development, Electric Power Research Institute (EPRI) projects data center electric generation consumption growth in the United States to climb from 4.6 percent to 9.1 percent.[41] LG&E/KU considers three economic development load growth scenarios, labeled High, Mid, and Low. While LG&E/KU expect economic development load growth to occur throughout the planning period, data center load growth was the predominant driver as shown by the load growth modeled in each of the planning scenarios. Specifically, the High scenario assumed 1,750 MW of data center load and additional smaller projects.[42] The Mid scenario assumed 1,050 MW of data center load and a relatively small economic development project.[43] Lastly, the Low scenario assumed zero data center load and one small project, which result in insignificant growth.[44] Additionally, the Low scenario assumed that a couple of large customers would leave the service territory later in the 2030s.

Customer growth was expected to remain strong with the Kentucky housing market experiencing rapid growth. S&P Global forecasts total housing in Kentucky to be the eighteenth highest in the United States during 2024.[45] Additionally the growth rate for 2024-2039 averages tenth in the United States.

Electricity pricing was also a consideration in the load forecasts. The load forecasting process contemplated short-run price elasticity of demand via SAE models.[46] Forecast models incorporate class-specific estimates of price elasticity between -0.1 and

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[39] 2024 IRP, Vol. II, Energy Sales and Demand Forecast Process at 19.

[40] 2024 IRP, Vol. I, Section 5 at 18.

[41] 2024 IRP, Vol. I, Section 7 at 12.

[42] 2024 IRP, Vol. I, Section 7 at 12.

[43] 2024 IRP, Vol. I, Section 5 at 16.

[44] 2024 IRP, Vol. I, Section 5 at 16.

[45] 2024 IRP, Vol. I, Section 5 at 19.

[46] 2024 IRP, Vol. I, Section 5 at 19.

-0.15, which are supported by estimates from both the EIA and Itron.[47] Electricity prices are assumed to increase by 2.3 percent per year.[48] Notably, the Low scenario acts as a proxy for higher electricity pricing as it assumes a decline in sales due to the negative price elasticities incorporated into the forecasting models.[49]

LG&E/KU included the IRA in its modeling by forecasting energy efficiency improvements. The IRA is expected to impact load through distributed solar generation, energy efficient appliances, or electrification through EVs and heat pumps.[50] LG&E/KU's Mid load forecast assumed nearly 1,500 GWh of reductions through advanced metering infrastructure (AMI) related conservation, distributed generation resources, and energy efficiency effects by 2032.[51] Forecasted end-use efficiency improvements are explicitly incorporated in residential and commercial forecasts through the SAE modeling.[52] In the Mid forecast, energy efficiency improvements reduced residential and commercial sales by over 7.5 percent by 2039. By 2032, the Mid load forecast assumed residential and commercial use-per-customer will decrease by an additional 6 percent and 9 percent from 2023 levels, respectively. Additionally, the energy efficiency assumptions in the forecast resulted in summer peak demand reductions of 230 MW and winter peak demand reductions of 171 MW in 2032.[53]

LG&E/KU's load forecasts accounted for expected distributed generation resources, including both qualifying facilities and net metering customers. About 99.8 percent of LG&E/KU's distributed generation resources are solar, the remaining 0.2 percent non-solar resources are wind and hydro.[54] LG&E/KU's analysis of distributed energy resources assumed customers will choose the most economically advantageous form of distributed generation. The analysis assumed that customers will determine what is most economically favorable primarily based on a distributed energy resource's LCOE.[55] The High solar (Low load) scenario assumes net metering continues indefinitely, whereas the Low and Mid solar scenarios assume that net metering capacity is capped at 1 percent of the LG&E/KU's annual peak load in 2025.[56] LG&E/KU do not, however, account for distributed battery storage in the forecasts due to low rates of energy storage

[47] 2024 IRP, Vol. I, Section 7 at 17.

[48] 2024 IRP, Vol. I, Section 5 at 19.

[49] 2024 IRP, Vol. I, Section 5 at 19.

[50] 2024 IRP, Vol. I, Section 7 at 15.

[51] 2024 IRP, Vol. I, Section 7 at 15.

[52] 2024 IRP, Vol. I, Section 7 at 16.

[53] 2024 IRP, Vol. I, Section 7 at 16.

[54] 2024 IRP, Vol. I, Section 5 at 20, and footnote 27.

[55] 2024 IRP, Vol. I, Section 7 at 19.

[56] 2024 IRP, Vol. I, Section 5 at 20.

adoptions.[57] LG&E/KU stated that it did not have access to data concerning how customers are using battery storage. LG&E/KU was also unsure to what extent non-net metering customers have adopted battery storage as there is no mechanism to track it outside of net metering.[58] The distributed generation forecast assumed the level of battery storage increases with customer growth.

The future penetration of EVs is a key uncertainty as it has the potential to increase day-light energy requirements. The estimated number of EVs in LG&E/KU's service territories grew by an average of 43 percent per year, from 1,415 to 12,284 EVs between 2017 and 2023.[59] EVs-in-operation were forecasted in the Mid forecast to increase to over 130,000 by the end of 2039. [60] The primary factors impacting total electricity consumption by EVs are the number of EVs and the distance driven per vehicle, though the timing of EV charging is at least equally important.[61] The EV forecast does not account for potential supply chain issues or incentives passed or in the process of being passed in other states.[62]

Additionally, LG&E/KU accounted for space heating electrification[63] in its load forecast. The High load forecast assumes that space heating electrification penetration will increase more rapidly than in the Mid load forecast.[64]

The Impact of environmental regulations remains a key uncertainty in the IRP. Since LG&E/KU's 2021 IRP, the U.S. Environmental Protection Agency (EPA), finalized three impactful regulations: the 2023 Good Neighbor Plan relating to the 2015 National Ambient Air Quality Standards for Ozone (Ozone NAAQS); the 2024 updates to the Effluent Limitation Guidelines (ELG); and the 2024 Clean Air Act Section 111(b) and (d) Green House Gas Rules (GHG Rules).[65] To address the uncertainty, LG&E/KU modeled four different environmental regulatory scenarios: (1) no new regulations scenario; (2) an Ozone NAAQS-only scenario; (3) an Ozone NAAQS and ELG scenario (the chosen scenario); and (4) a scenario in which all three regulations become enforceable. [66]

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[57] 2024 IRP, Vol. I, Section 5 at 21, and footnote 29.

[58] 2024 IRP, Vol. I, Section 7 at 20.

[59] 2024 IRP, Vol. I, Section 5 at 21.

[60] 2024 IRP, Vol. I, Section 7 ay 27.

[61] 2024 IRP, Vol. I, Section 5 at 22.

[62] 2024 IRP, Vol. I, Section 7 at 28.

[63] Space heating electrification refers to the switch from natural gas heat pumps to electric heat pumps.

[64] 2024 IRP, Vol. I, Section 5 at 22.

[65] 2024 IRP, Executive Summary at 6.

[66] 2024 IRP, Executive Summary at 6.

SIGNIFICANT CHANGES SINCE THE 2021 IRP

There have been several significant changes since LG&E/KU's 2021 IRP and relevant comparisons to the 2022 CPCN. To begin with, overall energy requirements are increasing. Winter peak and summer peak are both forecasted with significant increases from the 2021 IRP to the 2024 IRP. Additionally, LG&E/KU's commercial and industrial classes are forecasted to experience large increases in sales due to potential data center load and growth in the auto manufacturing sector, including BOSK.[67]

Energy requirements in the 2024 IRP are 31.7 percent higher by 2032 due to the addition data centers and the first phase of Blue Oval SK Battery Park (BOSK), as compared to the 2021 IRP.[68] Notably, when compared to the 2022 CPCN, energy requirements are slightly lower through 2027 due to the delay of the second phase of BOSK but significantly higher between 2028-2039.[69] Winter peak demands in the 2024 IRP are nearly 1,400 MW higher than the 2021 IRP and over 900 MW higher than modeled in the 2022 CPCN proceeding starting in 2032. [70] In the 2024 IRP, summer peak demand is more than 1,150 MW higher than the 2021 IRP and nearly 800 MW higher than the 2022 CPCN in 2032.[71]

LG&E/KU'S COMBINED BASE CASE ENERGY FORECAST

The base case energy forecast for LG&E/KU exhibited overall positive growth in energy requirements for the 2024-2039 forecast period, with slight decreases in energy requirements from 2032 to 2039. KU's total energy requirements, including company use and losses, maintained a relatively flat curve, with the highest energy requirement being at 21,057 GWh in 2026 and slowly decreasing to 20,460 GWh in 2039.[72] Conversely, LG&E shows a steady increase in energy requirements, ranging from 11,909 GWh in 2024 to 20,483 GWh in 2039.[73] On a combined company basis, energy requirements range from 31,913 GWh in 2024, increasing to 41,199 GWh in 2032, and then slowly decreasing to 40,943 GWh in 2039.[74] The table below shows LG&E/KU's combined forecasted energy GWh sales by class after DSM program effects.

[67] 2024 IRP, Vol. I, Section 6 at 3.

[68] 2024 IRP, Vol. I, Section 6 at 1.

[69] 2024 IRP, Vol. I, Section 6 at 1.

[70] 2024 IRP, Vol. I, Section 6 at 1.

[71] 2024 IRP, Vol. I, Section 6 at 2.

[72] 2024 IRP, Vol. I, Section 7 at 8.

[73] 2024 IRP, Vol. I, Section 7 at 9.

[74] 2024 IRP, Vol. I, Section 7 at 8-9, Table 7-19, Table 7-20.

Class Energy Sales Forecast (GWh)[75]

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Residential	10,195	10,145	10,115	10,097	10,119	10,065	10,047	10,061	10,118	10,105	10,131	10,166	10,246	10,256	10,309	10,368
Commercial	7,562	7,511	7,445	8,255	9,380	10,756	13,015	15,288	15,856	15,764	15,723	15,687	15,696	15,624	15,601	15,578
Industrial	8,641	9,621	9,805	9,826	9,822	9,797	9,791	9,781	9,788	9,756	9,740	9,732	9,749	9,732	9,730	9,731
Total C/I	11,230	12,185	12,327	12,305	12,269	12,201	12,155	12,115	12,100	12,035	11,994	11,967	11,972	11,932	11,916	11,903
Public Authority	1,514	1,501	1,487	1,476	1,469	1,459	1,453	1,445	1,442	1,433	1,427	1,423	1,423	1,418	1,416	1,414
Utility Use and Lighting	11,224	11,184	11,145	11,986	13,155	14,550	16,841	19,153	19,773	19,713	19,711	19,717	19,782	19,743	19,767	19,792
Sales for Resale	362	381	382	392	393	393	394	394	395	396	396	397	398	398	398	398
Total KU Kentucky	18,131	19,056	19,167	19,132	19,100	18,986	18,922	18,876	18,884	18,794	18,756	18,736	18,780	18,729	18,730	18,739
Virginia	646	649	644	640	637	631	626	621	618	613	609	605	602	597	593	589
Total Sales	29,975	30,863	30,931	31,732	32,866	34,141	36,362	38,625	39,250	39,095	39,051	39,033	39,139	39,044	39,066	39,095
Utility Use and Losses	1,234	1,256	1,252	1,245	1,239	1,217	1,210	1,202	1,201	1,193	1,176	1,173	1,173	1,143	1,140	1,138
Total GWh	31,913	32,808	32,868	33,668	34,806	36,058	38,292	40,569	41,199	41,033	40,971	40,949	41,057	40,930	40,949	40,943

PEAK LOAD FORECAST

On a combined basis in the base case, LG&E/KU are a dual-peaking utility. Historically, LG&E/KU have been a summer-peaking utility, however, LG&E/KU's system peaks recently occur in the winter.[76] KU's summer peak exhibits a steady incline from 3,554 MW in 2024 to 3,687 MW in 2028, then declines to 3,584 MW in 2039.[77] LG&E's summer peak ranges from 2,561 MW in 2024 to 3,564 MW in 2039, with the highest forecasted peak at 3,600 MW in 2032.[78] The combined winter peak, as shown in the table below, displays a steady increase from 6,015 MW in 2024 to a consistent 7,117 MW from the 2034-2039 period.

[75] 2024 IRP, Vol. I, Section 7 at 8-9, Table 7-19, Table 7-20.

[76] 2024 IRP, Vol. I, Section 5 at 16.

[77] 2024 IRP, Vol. I, Section 7 at 9, Table 7-21.

[78] 2024 IRP, Vol. I, Section 7 at 9, Table 7-22.

Combined Summer and Winter Coincident Peak Demand after DSM (MW)[79]

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Summer	6,115	6,228	6,242	6,365	6,474	6,686	6,931	7,215	7,201	7,200	7,178	7,171	7,161	7,159	7,158	7,148
	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	36/37	37/38	38/39
Winter	6,015	6,146	6,150	6,227	6,347	6,471	6,733	7,002	7,135	7,123	7,121	7,118	7,117	7,118	7,118	7,117

HIGH AND LOW ENERGY AND DEMAND REQUIREMENT FORECASTS

In addition to the base-case scenario forecast, LG&E/KU produced a High and Low scenario energy and demand requirement forecasts. Relative to the base-case scenario, the high energy scenario assumes electric vehicles grow more quickly than in the base-case, reaching 15 times current levels by 2039; residential customers grow 50 percent faster than in the base-case forecast (0.83 percent versus 0.55 percent) beginning in 2024; energy efficiency and distributed generation grow more slowly than in the base-case scenario; and space heating electrification is adopted more quickly than assumed in the base-case forecast.[80] The high energy scenario assumes increased economic development load due to data center customers entering the service territory, with roughly 700 MW of additional data center growth.[81] The base-case energy requirements over the forecast period increase from 31,913 GWh to 40,943 GWh.[82] Similarly, the peak demand forecast in the base-case scenario increases from 6,115 MW for summer peak and 6,015 MW for winter peak to 7,149 MW and 7,117 MW, respectively over the forecast period.[83] However, under the high growth scenario, over the forecast period, energy requirements rise from 32,090 GWh to 49,320 GWh and the peak demand rises from 6,155 MW for summer peak and 6,047 MW for winter peak to 8,248 MW and 8,148 MW, respectively.[84]

In contrast to the base-case scenario, the low energy scenario assumes no data center customers join the service territory, and 100 MW of industrial load leaves the service territory in the 2030s.[85] In the low energy scenario, residential customer growth is 50 percent slower than in the base-case forecast (0.27 percent versus 0.55 percent) and a new federal or state law eliminates the 1 percent cap on net metering capacity.[86] Additionally, space heating electrification occurs more slowly than assumed in the base-

[79] 2024 IRP, Vol. I, Section 7 at 9, Table 7-21, Table 7-22.

[80] 2024 IRP, Vol. I, Section 7 at 34.

[81] 2024 IRP, Vol. I, Section 7 at 13.

[82] 2024 IRP, Vol. I, Section 7 at 34, Table 7-27.

[83] 2024 IRP, Vol. I, Section 7 at 36, Table 7-28.

[84] 2024 IRP, Vol. I, Section 7 at 34 and 36, Table 7-27, Table 7-28.

[85] 2024 IRP, Vol. I, Section 7 at 34.

[86] 2024 IRP, Vol. I, Section 7 at 34.

case forecast. Under the low growth scenario, energy requirements decline from 31,727 GWh to 30,051 GWh and peak demand declines from 6,087 MW for the summer and 5,982 MW in the winter to 5,668 MW and 5,803 MW, respectively over the forecast period.[87] Note that the loss of the 100 MW of industrial load accelerates the decline over the forecast period. The tables below show the energy and demand scenario forecast results.

Combined Energy Requirements Forecast (GWh)[88]

Year	Base	High	Low
2024	31,913	32,090	31,727
2025	32,808	33,092	32,452
2026	32,867	33,251	32,339
2027	33,668	34,455	32,086
2028	34,806	37,372	31,882
2029	36,057	41,270	31,516
2030	38,292	45,114	31,262
2031	40,569	48,392	31,049
2032	41,200	49,142	30,678
2033	41,033	49,039	30,409
2034	40,971	49,057	30,551
2035	40,949	49,096	30,261
2036	41,057	49,284	30,301
2037	40,930	49,118	30,158
2038	40,949	49,263	30,120
2039	40,943	49,320	30,051

Combined Demand Scenario Forecast (MW)[89]

	Low Load Scenario		Base Load Scenario		High Load Scenario	
Year	Summer	Winter	Summer	Winter	Summer	Winter
2024	6,087	5,982	6,115	6,015	6,155	6,047
2025	6,160	6,078	6,228	6146	6,285	6,203
2026	6,135	6,049	6,242	6,150	6,318	6,228
2027	6,081	6,029	6,365	6,227	6,532	6,327
2028	6,022	5,991	6,474	6,347	6,913	6,600
2029	5,976	5,952	6,686	6,471	7,439	7,059
2030	5,930	5,924	6,931	6,733	7,833	7,551
2031	5,886	5,896	7,216	7,003	8,222	7,984
2032	5,844	5,876	7,201	7,135	8,218	8,142
2033	5,802	5,856	7,201	7,123	8,217	8,141
2034	5,766	5,836	7,179	7,121	8,216	8,141
2035	5,729	5,816	7,171	7,118	8,215	8,140

[87] 2024 IRP, Vol. I, Section 7 at 34 and 36, Table 7-27, Table 7-28.

[88] 2024 IRP, Vol. I, Section 7 at 34, Table 7-27.

[89] 2024 IRP, Vol. I, Section 7 at 36, Table 7-28.

2036	5,714	5,813	7,161	7,118	8,235	8,140
2037	5,699	5,809	7,160	7,118	8,240	8,148
2038	5,683	5,806	7,158	7,118	8,239	8,148
2039	5,668	5,803	7,149	7,117	8,248	8,148

RESPONSES TO 2021 STAFF RECOMMENDATIONS

LG&E/KU responded to the recommendations regarding load forecasting in the Commission's Staff Report addressing LG&E/KU's 2021 IRP as indicated below.

- The report recommended that LG&E/KU expand their discussion of the reasonableness of underlying assumptions including supporting documentation listing known facts. LG&E/KU stated that they provided additional supporting documentation of the load forecasting process in Volume II, as well as expanded the discussion of reasonableness for each forecast in Volume I, Section 7.

- The report recommended that LG&E/KU continue to monitor and incorporate anticipated changes in Energy Efficiency impacts in forecasts and sensitivity analyses. In addition, the report recommended that LG&E/KU should not assume that current DSM-EE programs will not be renewed to model increased participation in current programs up to their current limits. LG&E/KU stated that forecasted end-use efficiency improvements are explicitly incorporated in residential and commercial forecasts through the statistically adjusted end-use modeling approach. LG&E/KU's Mid load forecast includes nearly 1,500 GWh of reductions by 2032 from customer-initiated energy efficiency improvements, AMI-related conservation load reduction and ePortal savings, distributed generation, and the energy efficiency effects of LG&E/KU' proposed 2024-2030 DSM-EE Program Plan as well as new programs beyond 2030.

- The report recommended that LG&E/KU expand its discussion of Distributed Energy Resources to identify resources other than distributed solar that could potentially be adopted by customers and explain how and why those resources are expected to affect load, if at all. LG&E/KU stated that resources other than distributed solar are not anticipated to materially affect load and therefore, the load forecast explicitly assumes all distributed generation additions will be solar for the IRP period.

- The report recommended that LG&E/KU expand its discussion of the projected adoption of distributed solar and its effect on load to include separate discussions of assumptions, methodology, and projections for residential, commercial, and industrial customers and separate discussions of assumptions, methodology, and projections for customers interconnected under LG&E/KU's net metering tariffs, qualifying facilities tariffs, and other similar tariffs. LG&E/KU stated that Qualifying Facilities customers were forecast separately from the net metering customers. The economics of distributed solar depend on several factors: electricity usage patterns and their correlation to solar irradiance, 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. Additionally, for customers that have demand charges (such as PS customers) and therefore have much lower energy rates, it is more challenging to cost-justify net metering. PS customers have the opposite effect of RS and GS in that their weighted average compensation improves the more they can sell back to the grid.

- The report recommended that LG&E/KU analyze and discuss whether and the extent to which customers that would have taken service under Net Metering Service-2 tariff would continue to interconnect Distributed Energy Resources even if they received no credit for energy sent back into the system because the 1 percent cap had been reached when they sought to connect. LG&E/KU stated that it did not analyze a situation in which NMS-2 customers would receive no compensation for exported energy because it would be inconsistent with their SQF tariff provisions to provide no compensation for such energy. Instead, LG&E/KU modeled providing customers SQF compensation for exported energy after reaching the 1 percent capacity level.

INTERVENOR COMMENTS

As stated in the introduction, a number of parties intervened in this proceeding. Those parties, whose comments are summarized below in no particular order, participated in discovery, and attended the Commission led hearing in this case. Their comments were drafted following the hearing, and the conclusion of formal discovery as determined in the Commission's procedural schedule. Commission Staff notes that while it found the intervenors participation in the IRP helpful, Commission Staff has not adopted the view of any intervenors.

The Attorney General

While the Attorney General's office did not file post-hearing comments it did file comments during the pendency of this proceeding. Specifically, the AG commented that LG&E/KU should "ensure that they are maximizing the lifespan of existing resources."[90] That, LG&E/KU observe Kentucky law when deciding to retire any existing resources,

[90] The Attorney General's Comments on LG&E/KU's Joint 2024 IRP at 3.

taking care that retirement decisions "are not driven by the policy goals of its corporate parent."[91] And, that LG&E/KU ensure that it insulates ratepayers from costs associated with the expected data center load growth in the IRP.[92]

Kentucky Industrial Utility Customers

As with the Attorney General, KIUC also did not file post-hearing comments, but its initial comments included the following two recommendations:

> First, LG&E/KU should be required to seek Commission approval of a separate tariff for new data centers similar to Kentucky Power's proposal. That new tariff should require long-term contracts with strong minimum bill provisions. The long-term contracts should be signed before construction of new generation or storage begins. Second, the Companies should expand their Curtailable Service Rider ("CSR") programs and update the interruptible credits in their next rate cases.[93]

Southern Renewable Energy Association

SREA, likewise, did not file post-hearing comments but in its initial comments SREA made the following seven recommendations, and requested that LG&E/KU: :

- Develop robust and transparent processes for projecting large load growth development in the Companies' service territories, fully considering the potential load flexibility provisions (via customer-sited backup generation or managed load) that data centers may be able to provide. Consider that the customers who develop and own data centers often have aggressive company clean energy goals and thus delineate certain preferences to the resource types and mix that data center loads must be served with, which are overwhelmingly non-carbon emitting generation in the longer-term.

- Model additional sensitivity cases that include (1) non-zero solar capacity contributions in the winter, (2) non-zero wind capacity contributions in both summer and winter, (3) an appropriate derating factor to the assumed 100 percent capacity contributions of "fully dispatchable" thermal resources, and (4) coincident forced outages on thermal facilities during extreme winter weather events.

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[91] The Attorney General's Comments on LG&E/KU's Joint 2024 IRP at 4.

[92] The Attorney General's Comments on LG&E/KU's Joint 2024 IRP at 7.

[93] KIUC's Comments on LG&E/KU's Joint 2024 IRP at 5.

- Issue competitive solicitation requests for proposals of renewable energy and energy storage systems to test market assumptions and implement IRP plans.

- Enable greater opportunities for customers to enable zero-emissions generation beyond the Green Tariff Option #3.

- Consider the value of leveraging market purchases via imports and quantify the realistic cost savings and resiliency benefits that could be provided by imports from neighboring regions.

- Consider the full scope of the economic value of resources beyond just the resource adequacy value.

- Integrate improved, proactive local and regional transmission planning to (1) improve access to low-cost capacity and energy purchases that reduce expensive overbuilding of resources within the service territories; (2) improve reliability by leveraging geographic diversity benefits through greater access to neighboring regions, and (3) to perform holistic planning across generation and transmission to develop cost-effective fully integrated generation and transmission plans.[94]

Kentucky Coal Association

In KCA's own words, it summarized its recommendations as follows:

- Given the issues KCA raised in its initial IRP comments combined with the items raised in these comments, the IRP cannot be relied upon for supporting a Certificate of Public Convenience and Necessity (CPCN).

- LG&E/KU' forecast load growth is not firm as while there are Data Center prospects, LG&E/KU have not entered into any agreements to provide electrical service. LG&E/KU are just beginning to negotiate a Data Center Rate with the Commission. The filing made by LG&E/KU on May 30, 2025 does not adequately protect traditional ratepayers if there is a default.

- The outlook for CCGT's has changed since the filing of the IRP due to many factors including cost inflation, tariffs, supply chain constraints, and increased CCGT demand. LG&E/KU acknowledged they will be challenged to meet the construction dates put forward in their IRP. LG&E/KU need to re-evaluate the cost and timing of the preferred plan given these changes.
- KCA recommended LG&E/KU incorporate third party fuel price forecasts into the analysis. Intercompany mathematical correlation of LG&E/KU

[94] SREA's Comments on LG&E/KU's Joint 2024 IRP at 4-5.

historical coal to gas purchases to forecast fuel price for long range planning should be compared to industry accepted third party forecasts to determine reasonableness and support credibility of the fuel price assumptions used by LG&E/KU.

- LG&E/KU acknowledge that their parent, PPL Inc., is committed to net-zero carbon emissions by 2050. LG&E/KU have not incorporated this commitment in their analyses. The analyses for carbon emitting sources should address the 2050 net-zero commitment by assuming closure of carbon emitting assets, the purchase/cost of carbon offsets beyond 2050, and/or PPL's commitment to not seek recovery of stranded and replacement costs.[95]

<u>Sierra Club</u>

Sierra Club stated in regard to LG&E/KU's load forecasting, that LG&E/KU's approach to handling speculative data center load growth raised concerns.[96] Specifically, Sierra Club stated that LG&E/KU have no means of knowing whether inquiries from customers are duplicative of other load-serving entities.[97] Sierra Club notes that it does not oppose the uses of varying levels of new customers in load forecasting, however, given the uncertainty of data center load growth, Sierra Club believes it is important for LG&E/KU to not dismiss forecasts that assume lower levels of growth or no growth at all.[98]

Sierra Club provided the following comments regarding LG&E/KU's load forecasts, especially as they related to large-load data center evaluations:

- The Commission should not approve the construction of new resources that are intended to serve large customers without establishing protections for existing ratepayers that would guarantee costs caused by these new loads are paid by the new load and prevent early exit from said large-load agreements without a stranded cost allocation to those large loads.

- LG&E/KU's operational decisions regarding Mill Creek 3 and 4 are primarily what cause the need for a second NGCC under the mid-load scenario. But LG&E/KU' plan to advance the second NGCC to 2031 is not adequately justified by LG&E/KU as it is based on speculative load growth. While

[95] KCA's Post-Hearing Comments on LG&E/KU's 2024 IRP at 1-2.

[96] Sierra Club's Post Hearing Comments on the Louisville Gas and Electric Company and Kentucky Utilities Company's 2024 Joint Integrated Resource Plan (Sierra Club's Post Hearing Comments on LG&E/KU's 2024 IRP) (filed June 16, 2025) at 5.

[97] Sierra Club's Post Hearing Comments on LG&E/KU's 2024 IRP at 5.

[98] Sierra Club's Post Hearing Comments on LG&E/KU's 2024 IRP at 6.

LG&E/KU characterize this as a "no regrets" decision because of load growth inquiries, its puts unnecessary risk on existing ratepayers to build a new power plant for need that may never materialize.

- LG&E/KU should have evaluated whether it was the lower-cost alternative to convert Ghent 2 to run on natural gas compared to its proposed retrofit with an SCR. Former coal-fired power plants that were converted to run on gas achieve a NOx emissions rate at or below the targeted emission rate that LG&E/KU hope to achieve at Ghent 2 during ozone season with an SCR, so the Company should have considered conversion as an alternative. Energy Futures Group modeled such a scenario and found that it had a lower present value revenue requirement (PVRR) cost than the retrofit alternative. Moreover, it had a significantly cheaper PVRR when a reasonable, less speculative amount of load growth was assumed.

- LG&E/KU' interconnection process for new load does not appear to shield existing customers from serious risks to the operational security and reliability of the grid that large loads may introduce and urgently needs to be reformed before new customers are interconnected.

Additionally, Sierra Club offered a number of more general considerations which it believed would aid Commission Staff in future CPCN proceedings predicated on large-load data center projections such as those being considered in this IRP.[99]

Joint Intervenors

For its part, Joint Intervenors provided the following critiques of LG&E/KU's IRP. Specifically Joint Intervenors asserted that LG&E/KU were dismissive of the AEC Report critique of adequately modeling DSM program savings past 2030.[100] Joint Intervenors stated that the IRP did not adequately address what the assumptions for "new programs beyond 2030" would be, how savings potential was determined, how budget levels change year-to-year, or the estimated savings attributable to program activities after 2030.[101] Additionally, Joint Intervenors stated that LG&E/KU did not model DSM/EE program savings potential on equal footing with supply-side counterparts.[102] Joint Intervenors stated that LG&E/KU continue to identify and propose new supply-side

[99] Sierra Club's Post-Hearing Comments on LG&E/KU's 2024 IRP at 8-13.

[100] Joint Intervenors' Post Hearing Comments on Louisville Gas and Electric Company and Kentucky Utilities Company's 2024 Joint Integrated Resource Plan (Joint Intervenors' Post Hearing Comments on LG&E/KU's 2024 IRP) (filed June 16, 2025) at 12.

[101] Joint Intervenors' Post Hearing Comments on LG&E/KU's 2024 IRP at 13.

[102] Joint Intervenors' Post Hearing Comments on LG&E/KU's 2024 IRP at 13-14.

resource investments, without allowing demand-side management potential to get the same level of updating and reanalysis.[103]

Joint Intervenors stated that similarly to LG&E/KU's 2021 IRP, the 2024 IRP did not include an updated vintage potential study.[104] Joint Intervenors added that it has been two IRP filings and the development of a new DSM/EE portfolio without a "reasonably updated picture of energy savings potential for one million Kentucky electric customers."[105]

Additionally, Joint Intervenors stated that LG&E/KU's constraints on renewables, including potential renewable demand response programs, as part of modeling, limited those resources' potential to be chosen by the model.[106] [107] Joint Intervenors also noted that regarding load growth related to data centers LG&E/KU should put forth clear evidence and justification for their assumptions regarding new large load customers.[108] Additionally noting that the risks to ratepayers from an unsupported and inaccurate load forecast is excessively high when LG&E/KU rely on projections as a basis to support their resource decisions and rate calculations.[109]

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[103] Joint Interventors' Post Hearing Comments on LG&E/KU's 2024 IRP at 14.

[104] Joint Intervenors' Post Hearing Comments on LG&E/KU's 2024 IRP at 14.

[105] Joint Intervenors' Post Hearing Comments on LG&E/KU's 2024 IRP at 14.

[106] Joint Intervenors' Post Hearing Comments on LG&E/KU's 2024 IRP at 15.

[107] Joint Intervenors' Post Hearing Comments on LG&E/KU's 2024 IRP at 17.

[108] Joint Intervenors' Post Hearing Comments on LG&E/KU's 2024 IRP at 18.

[109] Joint Intervenors' Post Hearing Comments on LG&E/KU's 2024 IRP at 19.

SECTION 3
DEMAND-SIDE MANAGEMENT AND ENERGY EFFICIENCY

INTRODUCTION

Depending on the circumstances, the IRP regulation permits demand-side resources to be assessed as options that could be selected to meet projected load or be assessed based on their projected effects on load.[110] This section briefly describes LG&E/KU's existing DSM/EE programs, summarizes how existing programs were reflected in the IRP, and discusses DSM/EE programs LG&E/KU reviewed to meet projected load. This section also reviews LG&E/KU's response to Commission Staff's recommendations regarding DSM/EE in its 2021 IRP and the parties' comments specifically regarding LG&E/KU's DSM/EE programs. Commission Staff's discussion of and recommendations regarding LG&E/KU's DSM/EE forecasting are in the final section of this Report.

2024-2030 DSM/EE PROGRAM PLAN

LG&E/KU's 2024-2030 DSM/EE Program Plan was approved in Case No. 2022-00402.[111] The 2024-2030 DSM/EE Program Plan currently includes the following approved programs:[112]

1. Income-Qualified Solutions: WeCare for Homeowners & Renters and WeCare for Property Owners & Managers;
2. Business Solutions: Business Rebates and Small Business Audit & Direct Install; and
3. Connected Solutions: Residential & Small Nonresidential Demand Conservation, Bring Your Own Device, Optimized EV Charging, and Online Marketplace, and Business Demand Response.

Additionally, LG&E/KU's 2024-2030 DSM/EE Program Plan includes the following programs to be offered starting in 2025 and 2026:[113]

1. Starting in 2025: Peak Time Rebates and Residential Online Audit & Rebates.
2. Starting in 2026: Appliance Recycling and Business Midstream Lighting.

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[110] *See* 807 KAR 5:058, Section 7(3).

[111] Case No. 2022-00402, E*lectronic Joint Application of Kentucky Utilities Company and Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity and Site Compatibility Certificates and Approval of a Demand Side Management Plan and Approval of Fossil Fuel-Fired Generating Unit Retirements* (Ky. PSC Nov. 11, 2024), Order at 173.

[112] 2024 IRP, Vol. I, Section 8 at 21.

[113] 2024 IRP, Vol. I, Section 8 at 21.

The following paragraphs contain descriptions of the programs included 2024-2030 DSM/EE Program Plan[114]:

WeCare for Homeowners and Renters is an education and weatherization program which is designed to reduce energy consumption of income-qualified residential customers. The program provides energy audits, energy education, and weatherization and energy efficient measures to qualified participants.

WeCare for Property Owners and Managers is an education and weatherization program which is designed to reduce energy consumption for property owners with income-qualified tenants. Similarly to the WeCare for Homeowners and Renters, the program provides energy audits, energy education, and weatherization to qualified participants.

Business Rebates provides non-residential customers with financial incentives to replace inefficient equipment with more energy-efficient equipment. The incentives are for one-to-one replacement, custom energy efficient measures, LEED certifications, and new construction or major renovation projects.

Small Business Audit and Direct Install provides in-person energy audits to qualified small businesses. The program also provides the installation of energy-saving products that help reduce energy usage and lower energy bills.

Residential and Small Nonresidential Demand Conservation is a program that cycles central air conditioning units, water heaters, and pool pumps of participants through a switch installed in the equipment. The switch is controlled by LG&E/KU when a signal is sent for it to cycle over a specified “event period.” Participants receive an event-based incentive for allowing LG&E/KU to cycle the enrolled equipment during peak demand periods.

Bring Your Own Device is an event-based program that utilizes smart wi-fi enabled thermostats and wi-fi enabled electric water heaters as a load control resources. This program enables LG&E/KU to directly manage summer and winter loads during hours of peak demand.

Optimized EV Charging allows LG&E/KU to manage load through issuing signals to qualified EVs and EV supply equipment to affect the timing and level of EV charging.

Online Marketplace provides a marketplace for residential and small business participants to purchase discounted smart thermostats, smart plugs, and smart strips. The Online Marketplace also provides a link to enroll in the Bring Your Own Device program when purchasing a smart thermostat.

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[114] 2024 IRP, Vol. I, Section 8 at 21-24.

Business Demand Response reduces demand during peak event periods by the amount a large business participant elects to nominate. Participants who demonstrate a load reduction receive monetary incentives at the end of a 12-month term. LG&E/KU provides software to allow participants to monitor load reduction during the event period and throughout all other days of the term.

Peak Time Rebates is designed as an event-based demand response resource that rewards residential and small business participants who reduce energy consumption during periods of high demand. LG&E/KU will notify participants in advance of peak demand events. The program will utilize AMI data to calculate rewards for the participants based on the energy reduction during each event. This program is planned to begin in 2025.

Residential Online Audits and Rebates is a program designed to provide web-based, self-guided assessments of participant's homes. The audit will pull participant-specific AMI interval data to provide an accurate picture pf the participant's disaggregated energy use. After completing the audit, the participant will receive feedback on energy-use behavior, energy saving tips, and other associated recommendations. This program is planned to begin in 2025.

Appliance Recycling is designed to offer residential and small business participants with residential-sized appliances an opportunity to safely discard and recycle inefficient refrigerators and freezers. Participants will receive a one-time rebate. This program aims to reduce energy consumption and demand by incentivizing participants to recycle aging appliances and upgrading to more efficient equipment. This program is planned to begin in 2026.

Business Midstream Lighting is designed to provide lighting incentives to distributors who stock and sell qualifying high-efficiency lighting equipment. This program is planned to begin in 2026.

LG&E/KU solicited input from its DSM Advisory Group and identified three new program measures for the 2024 IRP analysis.[115] The proposed measures are presented below:[116]

- Bring Your Own Device: a new measure for residential and small business participants to enroll in participant-owned, dispatchable residential-style batter energy storage systems;

- Bring Your Own Device: a new measure for residential participants to enroll in participant-owned, whole home dispatchable back-up generators; and

[115] 2024 IRP, Vol. I, Section 8 at 21.

[116] 2024 IRP, Vol. I, Section 8 at 21.

- Business Demand Response: allowing small business customers (with a measured base demand from 50 kW to 200 kW) to qualify for the program.

LG&E/KU stated that the Bring Your Own Device enhancements are expected to be: (1) cost effective; (2) provide around-the-clock energy reduction or dispatchable demand reduction, and (3) provide a participant with the ability to opt-out during a low-level event.[117] However, the enhancements to the Business Demand Response program will have the option to opt-out of any event and load reduction based on the participant's unique load reduction plan.

DSM/EE PROGRAM ENERGY AND DEMAND IMPACTS

The load changes for the 2024-2030 DSM/EE Program Plan were embedded in the load forecast for energy and demand. The following table summarizes the peak demand impact in MWs of LG&E/KU's current DSM/EE programs:[118]

Program	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Optimized EV Charging	0.6	0.9	1.2	1.8	2.4	3	3.452	3.968	4.564	5.248	6.036	6.94	7.288	7.652	8.036
Peak Time Rebates	4.42	8.84	17.68	31.45	31.45	31.45	31.45	31.45	31.45	31.45	31.45	31.45	31.45	31.45	31.45
Demand Conservation - AC	36.26	32.58	29.27	26.32	23.64	21.25	19.13	17.21	15.50	13.95	12.55	11.30	10.18	9.15	8.24
Demand Conservation - Water Heaters	0.95	0.84	0.73	0.64	0.57	0.51	0.46	0.41	0.37	0.33	0.30	0.27	0.24	0.22	0.20
Demand Conservation - Pool Pumps	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
BYOD - Smart Water Heaters	0.000	0.005	0.008	0.011	0.017	0.025	0.032	0.040	0.050	0.055	0.060	0.066	0.073	0.080	0.088
BYOD - Smart Thermostats - Cooling Season	2.783	5.850	10.444	16.674	22.903	29.133	32.024	35.242	38.761	42.632	46.905	51.581	56.759	62.440	68.674
BYOD - Smart Thermostats - Heating Season	0.840	1.679	2.744	4.246	5.748	7.250	7.970	8.770	9.646	10.609	11.673	12.836	14.125	15.539	17.090
BYOD - Smart Wall HVAC Units (Room AC)	0.000	0.005	0.008	0.011	0.017	0.025	0.032	0.040	0.049	0.054	0.060	0.066	0.072	0.080	0.088
BYOD - Energy Storage*	0.00	0.00	0.48	0.64	0.80	0.97	1.13	1.29	1.45	1.61	1.77	1.93	2.09	2.25	2.41
BYOD - Whole Home Generator*	0.00	0.00	0.20	0.40	0.60	0.80	1.00	2.00	3.00	4.00	4.00	5.00	5.00	6.00	6.00
Business Demand Response (year-round) > 200 kW Base Demand	36	45	56	67	79	79	87	95	105	105	105	105	105	105	105
Business Demand Response (year-round) > 50 kW and < 200 kW Base Demand*	0.00	0.00	0.00	0.68	1.02	1.36	1.70	2.04	2.72	3.06	3.40	3.40	3.40	3.40	3.40
Forecasted Total - Cooling Season	81.36	93.73	115.76	145.76	162.12	167.21	176.96	188.90	202.65	207.12	211.27	216.74	221.29	227.46	233.32
Forecasted Total - Heating Season	42.21	56.13	78.05	106.36	120.73	123.54	133.29	144.77	157.61	160.77	163.12	166.36	168.16	171.11	173.21

* Measure or Program is not currently part of the 2024-2030 DSM/EE portfolio

The values in 2025-2030 were included in the cost-effectiveness analysis for Case No. 2022-00402, whereas the values for 2031-2039 were updated assuming program continuation and the referenced program enhancements.[119]

[117] 2024 IRP, Vol. I, Section 8 at 21.

[118] 2024 IRP, Vol. I, Section 8 at 26, Table 8-16.

[119] 2024 IRP, Vol. I, Section 8.

RESPONSES TO 2021 STAFF RECOMMENDATIONS

In the 2021 IRP Commission Staff Report made the following recommendations regarding LG&E/KU's DSM/EE programs.[120]

- That LG&E/KU should identify and assess all potentially cost-effective demand-side resource options. LG&E/KU included three potentially cost-effective demand-side resource enhancements within the IRP.

- That any changes to demand-side resources should be discussed in full including a transparent analysis of the cost and benefits inputs. LG&E/KU did not provide a cost-benefit analysis regarding the three potential program expansions included in the IRP. LG&E/KU stated that there has not been a sufficient review or any development regarding these measures needed to conduct the cost-benefit analysis.

- That LG&E/KU should describe and discuss all new demand-side resources that they considered, and if a resource was considered but ultimately not included in any model or formal assessment, LG&E/KU should explain each basis for excluding the resource. LG&E/KU included three potential program enhancements in the modeling, as well as an extension of the existing CSR-2 program in the Resource Assessment model.

- That LG&E/KU should continue the stakeholder process through the DSM Advisory Group and strive to include recommendations and inputs from the stakeholders in its demand-side resource assessment. LG&E/KU stated that LG&E/KU solicited input from the DSM Advisory Group to include three potential program enhancements for the analysis in this IRP.

- That LG&E/KU should consider making AMI usage data that is more closely aligned to real-time data available to customers and should consider peak time rebate programs, time-of-use rates, and prepay options for AMI customers. LG&E/KU stated that AMI usage data is available to customers through the MyMeter tool. Additionally, LG&E/KU stated that the launch of a Peak Time Rebate program is scheduled for January 2025 as approved in Case No. 2022-00402.

- That LG&E/KU consider and model more aggressive options to increase use of the curtailable service rider and demand conservation program. LG&E/KU stated that in Case No. 2022-00402, LG&E/KU received approval for program enhancements to the Nonresidential Demand Response program, which included a higher incentive paid, year-round program availability, and a target to achieve an enrolled capacity level of nearly 80 MW. Additionally, the Bring Your Own Device program is offered as an alternative program that provides similar benefits to

[120] 2021 IRP.

participants. Furthermore, LG&E/KU stated that the Curtailable Service Rider is a non-DSM rider that will continue to be utilized in accordance with the published tariff.

- That LG&E/KU should consider DSM/EE programs specifically designed to shift EV charging from peak periods. LG&E/KU stated that in January 2024, as part of the approved 2024-2030 DSM/EE Plan, LG&E/KU launched an Optimized EV Charging program.

- That that LG&E/KU continue to identify energy efficiency opportunities for large customers and continue to offer incentives that encourage them to adopt or maintain energy-related technologies, sustainability plans, and long-range energy planning. LG&E/KU stated that in Case No. 2022-00402, LG&E/KU included an expanded Business Solutions offering to assist non-residential participants in identifying and implementing energy efficient measures. Additionally, LG&E/KU stated that LG&E/KU expanded and reopened the Business Demand Response Program for large customers.

- That LG&E/KU should continue to define and improve procedures to evaluate, measure, and verify both actual costs and benefits of energy savings based on the actual dollar savings and energy savings. LG&E/KU stated that LG&E/KU contracts with a third-party partner to perform independent EM&V studies of its DSM/EE programs.

- That LG&E/KU should file to expand or revise its current 2019-2025 DSM/EE Plan if its ongoing resource assessments indicate that doing so is the least-cost option for meeting its projected load. LG&E/KU submitted a new DSM/EE Plan in December 2022 for 2024-2030 in Case No. 2022-00402. The DSM/EE Plan was approved in November 2023.

INTERVENOR COMMENTS

Joint Intervenors

Joint Intervenors stated that LG&E/KU did not evaluate increased energy or demand savings on par with supply-side resources.[121] Additionally, Joint Intervenors stated that LG&E/KU did not evaluate expanded DSM/EE potential.[122] Joint Intervenors asserted that it is not clear whether LG&E/KU will file updates to the 2024-2030 DSM/EE plan.[123]

[121] Joint Intervenors' Initial Comments on Louisville Gas and Electric Company and Kentucky Utilities Company's 2024 Joint Integrated Resource Plan (Joint Intervenors' Initial Comments on LG&E/KU's 2024 IRP) (filed Mar. 7, 2025) at 35.

[122] Joint Intervenors' Initial Comments on LG&E/KU's 2024 IRP at 36.

[123] Joint Intervenors' Initial Comments on LG&E/KU's 2024 IRP at 36.

LG&E/KU RESPONSES TO INTERVENOR COMMENTS

LGE/KU stated that the 2024-2030 DSM/EE Program Plan is in the early stages of implementation.[124] LG&E/KU asserted that the IRP reasonably accounts for demand-side resources and energy efficiency savings.[125]

[124] LG&E/KU's Response to Intervenor Comments (filed Apr. 4, 2025) at 13.

[125] LG&E/KU's Response to Intervenor Comments at 14.

SECTION 4

SUPPLY & INTEGRATION

In this Section, Staff reviews, summarizes, and comments on LG&E/KU's evaluation of existing and future supply and demand-side resources. In addition, there is a discussion on LG&E/KU's environmental compliance plan. The resource planning and portfolio production cost modeling in this IRP was conducted against the backdrop of the Commission's November 6, 2023 Order in Case No. 2022-00402.[126] In that Order among other things, the Commission approved multiple new supply side and demand side management and energy efficiency (DSM-EE) resources, the retirement of Mill Creek Units 1 and 2, a new natural gas combined cycle (NGCC) unit (Mill Creek 5) with an expected in-service date at the end of 2027, a new 125 MW four hour battery storage system (BESS), the Mercer and Marion county solar facilities, and four solar power purchase agreements (PPAs).[127]

Environmental Regulation Compliance and Planning

Acid Deposition Control Program

The Acid Deposition Control Program was established under Title IV of the Clean Air Act (CAA) 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 1980 levels in the 48 contiguous states.[128] With further reductions in SO_2 and NO_X aided by rules such as the Clean Air Interstate Rule, Mercury Air Toxics Standards (MATS), and the Cross-State Air Pollution Rule (CSAPR), LG&E/KU continue to comply with the Acid Deposition Control Program through allowance surrendering.[129]

Cross-State Air Pollution Rule/Good Neighbor Plan

The 2021 Revised Cross-State Air Pollution Rule (Revised CSAPR) was the result of efforts to bring affected geographic areas into attainment status with the 2008 ozone National Ambient Air Quality Standards (NAAQS) at 75 parts per billion (ppb). The

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

[127] Case No. 2022-00402, (Ky. PSC Nov. 6, 2023), final Order at 178-180.

[128] IRP Vol.1 at 8-37.

[129] IRP Vol.1 at 8-37. Note that the Clean Air Interstate Rule was implemented in 2009/2010, MATS in 2012, and CSAPR was initially implemented in 2015, updated in 2017, and revised in 2021.

Revised CSAPR rule established a new NO_X ozone season Group 3 trading program for Kentucky and 11 other states.[130] Consequently, LG&E/KU's ozone season NO_X allocations were reduced by 7 percent in 2021 and 15 percent in 2022 going forward compared to the previous 2020 CSAPR allocations. In addition, the Revised CSAPR rule converted LG&E/KU's 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. LG&E/KU self-comply with this rule through the application of emissions controls and intracompany emission allocation transfers.[131]

At the time the EPA was working on the Revised CSAPR, it was working on regulations to address NO_X emission reduction requirements for Kentucky and other affected areas to achieve and maintain compliance with the 2015 ozone NAAQS (i.e., Good Neighbor Plan) requirement of 70 ppb. On June 5, 2023, the Good Neighbor Plan was published in the Federal Register establishing August 4, 2023, as the effective date for the new rule. As finalized, the Good Neighbor Plan rule sought to accomplish its compliance goals in part by revising and tightening the existing CSAPR NO_X allowance trading program with revised NO_X emissions budgets for fossil fuel-fired power plants in affected states beginning in the 2023 ozone season (May through September).[132] As a result of the new, more stringent, requirements, the Good Neighbor Plan effectively required non-SCR-equipped coal units to cease operating, or operate only at very minimal levels, during each year's ozone season beginning in 2026.[133] Regardless of the outcomes from the continuing litigation, the EPA is obligated to drive attainment of the 2015 Ozone NAAQS. Given local non-attainment in Louisville-Jefferson County, Kentucky's significant impact to downwind states, and the lack of Reasonably Achievable Control Technology on some units, LG&E/KU have exposure to further NO_X reductions in support of attainment.[134]

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. The EPA issued revisions to the MATS rule on April 25, 2024, which lowered some hazardous air pollution emission standards, required the use of monitoring systems instead of emissions testing when determining

[130] IRP Vol. 1 at 8-37.

[131] IRP Vol.1 at 8-37 – 8-37.

[132] IRP Vol.1 at 8-38.

[133] IRP Vol.1 at 8-38 – 8-39.

[134] IRP Vol.1 at 8-39.

compliance with particulate matter ("PM") as a surrogate for related hazardous air pollution emission limits, and removed one of the two definitions for the term "startup."[135]

Non-mercury metal continuous emission monitoring system are not certified or accepted by EPA and PM monitoring may be used as a surrogate. As a surrogate for compliance to the revised MATS non-mercury hazardous air pollutants, the filterable PM emission limit was reduced from 0.030 lb/mmBtu to 0.010 lb/mmBtu on a 30-boiler-operating-day average and requires use of PM continuous emissions monitoring systems ("PM CEMS").[136] Even though the MATS revisions do not directly impact LG&E/KU, because all of LG&E/KU' MATS-rule-affected units have been using PM CEMS for compliance since the MATS rule was originally published, the reductions result in a significant reduction in compliance margin and a significant increase in compliance risk. Further, with this lower limit, the required PM CEMS quality assurance activities are now harder to achieve.[137] One of the criteria for successful confirmation of the quality of a PM CEMS correlation curve is that annual testing must demonstrate test results stay within 25% of the PM emission limit from the correlation curve. Therefore, the emissions limit reduction (0.03 to 0.01) results in 66% tighter PM test criteria. LG&E/KU are assessing the use of non-mercury hazardous air pollution traps monitoring equipment that is unaffected by the PM test criteria to minimize compliance risk and enhance compliance margin.[138] The MATS rule revision removed the second startup definition which allowed for a four-hour window of startup operations that would not impact the determination of compliance with emission limits. However, LG&E/KU' affected units have been using the rule's first startup definition and are therefore not impacted by this revision.[139]

Hazardous Air Pollutant Regulations/Combustion Turbines

In March 2004, EPA promulgated National Emissions Standards for Hazardous Air Pollutants (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.[140] Many, but not all, of LG&E/KU's combustion turbines are in this category. However, in August 2004, EPA stayed a portion of the rule pertaining to the types of combustion turbines LG&E/KUs employs. On March 9, 2022, EPA published amendments to 40 CFR

[135] IRP Vol.1 at 8-40.

[136] IRP Vol.1 at 8-40.

[137] IRP Vol.1 at 8-40.

[138] IRP Vol.1 at 8-40.

[139] IRP Vol.1 at 8-40. Like the Good Neighbor Plan, the MATS rule is being litigated. See IRP Vol.1 at 8-40–8-41 for a discussion of the litigation timeline.

[140] IRP Vol.1 at 8-41.

63, Subpart YYYY that lifted the stay. All lean premix gas-fired turbines and diffusion flame gas-fired turbines that began construction or reconstruction after January 2003 at major sources of HAPS needed to comply with the 91ppb formaldehyde limit and other operating limitations.[141] As of March 9, 2022, the two combustion turbines at LG&E/KU' Cane Run Unit 7 were the only ones that began construction after January 2003. However, the Cane Run facility is designated as an area source, not a major source of hazardous air pollutants (HAPS). Therefore, LG&E/KU have not been affected by the amendments to 40 CFR 63, Subpart YYYY.[142]

On July 15, 2024, construction began on Mill Creek Unit 5 natural gas-fired combined cycle facility (MC5), which will use one combustion turbine. The Mill Creek Generating Station will continue to be designated as a major source of HAPS and as of the date of this IRP, the MC5 combustion turbine is the only combustion turbine affected by the requirements of 40 CFR 60, Subpart YYYY.

National Ambient Air Quality Standards

SO_2

The primary SO_2 NAAQS remains set at 75 ppb as set in 2010. All areas in which LG&E/KU operate are in attainment with the primary SO_2 NAAQS.[143] On April 3, 2024, EPA proposed to revise the secondary NAAQS for oxides of sulfur (SO_x) to an annual standard at a level between 10 and 15 ppb, averaged over 3 years (compared to the current 3-hour standard set at 500 ppb). EPA sets secondary standards to protect the public welfare against adverse effects including ecological effects such as damage to vegetation.[144] LG&E/KU' areas of operation are currently in attainment with the primary SO_2 NAAQS.[145]

NO_x/NO_2

On November 16, 2018, the Kentucky Department of Air Quality (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 requested that the EPA approve the demonstration for Kentucky to fully implement the 2010 1-hour oxides of nitrogen ("NO_2") NAAQS.[146] The EPA has not acted on that request. On April 3, 2024, the EPA

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141 IRP Vol.1 at 8-41.

142 IRP Vol.1 at 8-41.

143 IRP Vol.1 at 8-42.

144 IRP Vol.1 at 8-42.

145 IRP Vol.1 at 8-42.

146 IRP Vol.1 at 8-42.

proposed to retain the current secondary NO_2 NAAQS at an annual average of 53 ppb. LG&E/KU are not expecting any impacts on operating facilities from primary or secondary NO_2 NAAQS issues.[147]

Ozone

The current (i.e., 2015) primary and secondary ozone NAAQS requirement remains at 70 ppb. On September 8, 2022, the Louisville Metro Air Pollution Control District (LMAPCD) in conjunction with KDAQ submitted a request to EPA to redesignate the Louisville-Jefferson County, Kentucky marginal non-attainment area to attainment for the 2015 8-hour ozone NAAQS based on certified ozone monitoring data from 2019 through 2021.[148] Conversely, on September 15, 2022, EPA finalized actions on non-attainment designations for the 2015 ozone NAAQS. In that action, 25 “marginal” non-attainment areas (including the Louisville-Jefferson County area) were reclassified as “moderate” non-attainment areas. With that new status, the moderate non-attainment areas had a deadline to attain the standards by August 3, 2024. Also, in parallel action on April 18, 2023, in response to the September 8, 2022, LMAPCD request, the EPA proposed to finalize the redesignation of the Louisville-Jefferson County, KY area to attainment status. The comment period on that proposal ended on May 18, 2023, and EPA has not finalized the redesignation of the Louisville-Jefferson County, KY area to attainment status.[149]

The Louisville-Jefferson County area has indicated non-attainment status with the 2015 8-hour ozone standard based on monitored ozone levels from 2021 through 2023 and thereby may be in danger of not achieving attainment status by the August 2, 2024 deadline which could put the Louisville-Jefferson County area into a “serious” non-attainment designation area.[150] On August 21, 2023, the EPA announced plans to review the ozone NAAQS prior to its five year review deadline. The EPA’s Clean Air Scientific Advisory Committee has previously suggested lowering the ozone standard to 65-68 ppb. So even as efforts were being made to bring areas into attainment with the 70 ppb ozone standard, it is possible that the standard would be lowered, and once again those areas would be determined to be non- attainment for ozone.[151] From 2020 through retirement of either Mill Creek Unit 1 or Unit 2, the LMAPCD has imposed 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 aid the ozone non-attainment area achieve attainment status.[152] However, LG&E/KU have not consistently

[147] IRP Vol.1 at 8-42.

[148] IRP Vol.1 at 8-42.

[149] IRP Vol.1 at 8-42.

[150] IRP Vol.1 at 8-42–8-43.

[151] IRP Vol.1 at 8-43.

[152] IRP Vol.1 at 8-43.

achieved the 70 ppb ozone standard in the Jefferson County area. Based on that information and the potential bump up of the Louisville-Jefferson County, on- attainment area to serious status, it is unclear what other efforts may be requested of LG&E/KU operations to help the area reach attainment status.[153]

Particulate Matter (PM) / PM2.5

The EPA published in the Federal Register March 6, 2024, effective May 6, 2024 a revision of the primary annual PM2.5 standard by lowering the level from 12.0 μg/m^3 to 9.0 μg/m^3. On March 6, 2024, several states, including Kentucky, filed a petition for review in the D.C. Circuit challenging the revision.[154] The EPA, with input from states and tribes, has two years to designate area in attainment or non- attainment of the standard. The Louisville-Jefferson County area could likely be designated non-attainment for the new PM2.5 standard. LG&E/KU's operations in or near that area could be requested to aid in achieving attainment status. As a result of installation of pulse jet fabric filters across LG&E/KU' fleet, concerns with the changes to PM/PM10/PM2.5 NAAQS could be minimized since the equipment is considered a best available control technology for coarse and fine particulates.[155] On April 3, 2024, EPA proposed to retain the current secondary NAAQS for PM2.5 at an annual average of 15 μg/m^3. LG&E/KU anticipate no actions are needed regarding maintaining compliance with the secondary PM2.5 NAAQS.[156]

Regional Haze

The second planning period (2019-2028) of the Regional Haze rule continues.[157] On July 11, 2024, the Commonwealth of Kentucky's Energy and Environment Cabinet held a public hearing to discuss a draft of the Regional Haze SIP for Kentucky's Class I area for the Second Planning Period. If the EPA accepts the Regional Haze SIP, LG&E/KU will not have to take any further restrictions during 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[158]. Even though Kentucky is below the glide path required for showing progress toward the rule's goal by 2064, LG&E/KU

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[153] IRP Vol.1 at 8-43.

[154] IRP Vol.1 at 8-43.

[155] IRP Vol.1 at 8-44.

[156] IRP Vol.1 at 8-44.

[157] IRP Vol.1 at 8-44.

[158] IRP Vol.1 at 8-44.

may be requested to evaluate visibility or regional haze impacts of operations on Class 1 areas like Mammoth Cave National Park.[159]

Greenhouse Gases (GHG)

On May 9, 2024, EPA published its final version of the rule regulating GHGs from Electric Generating Units (EGUs).[160] The rule finalized the following: (1) repeal of the Affordable Clean Energy (ACE) rule; (2) emission guidelines for GHG emissions from existing fossil fuel-fired steam EGUs under Section 111(d) of the CAA; (3) revisions of the GHG New Source Performance Standards (NSPS) from new and reconstructed fossil fuel-fired stationary combustion turbines; and (4) revisions to the standards of performance for coal-fired EGUs which undertake a large modification (i.e., increases the unit's hourly emissions rate by more than 10 percent). The EPA did not finalize emission guidelines for GHG emissions from existing fossil fuel-fired stationary combustion turbines. For those existing stationary turbines, EPA developed a non-rulemaking regulatory docket to gather more information for a rulemaking to be proposed at a later date.[161]

As finalized, the emission guidelines for GHG emissions from existing fossil fuel-fired steam EGUs and coal-fired EGUs that undertake a large modification require:[162]

1. For existing coal-fired EGUs that intend to operate beyond December 31, 2038, the EGU must achieve an 88.4 percent reduction in its annual GHG emissions by January 1, 2032. EPA identified the best system of emission reduction ("BESR") to achieve that reduction is the installation of carbon capture and storage ("CCS") systems with a 90 percent capture efficiency.

2. For existing coal-fired EGUs that intend to permanently cease operations before January 1, 2039, the EGU must achieve a 16 percent reduction in its annual GHG emissions by January 1, 2030. EPA identified the BSER to achieve that reduction is the co-firing of natural gas at a level of 40 percent of the unit's annual heat input.

3. For existing coal-fired EGUs that intend to permanently cease operations prior to January 1, 2032, the EGU would be exempt from applicability of the rule. The planned retirements would be identified in the state implementation plan ("SIP") and federally enforceable.

[159] IRP Vol.1 at 8-44.

[160] IRP Vol.1 at 8-45. For a discussion of the legal history of the GHG rule Vol 1 at 8-45.

[161] IRP Vol.1 at 8-45.

[162] IRP Vol.1 at 8-45–8-46.

4. For existing natural gas- and oil-fired steam EGUs that operate at an annual capacity factor of greater than 45 percent, the EGU must achieve a presumptive GHG emission standard of 1,400 pounds CO_2 per megawatt hour of gross electrical output (lb CO_2/MWh-gross).

5. For existing natural gas- and oil-fired steam EGUs that operate at an annual capacity factor between greater than eight percent and less than or equal to 45 percent, the EGU must achieve a presumptive GHG emission standard of 1,600 lb CO_2/MWh-gross.

6. For existing natural gas- and oil-fired steam EGUs that operate at an annual capacity factor of less than or equal to eight percent, the oil-fired EGU must achieve a presumptive GHG emission standard of 170 pounds CO_2 per million British thermal units of heat input (lb CO_2/MMBtu), while the natural gas-fired EGU must achieve 130 lb CO_2/ MMBtu.

For new and reconstructed fossil fuel-fired stationary combustion turbines, the following standards apply:[163]

1. If the EGU operates at a greater than 40 percent capacity factor, the EGU must achieve highly efficient generation and achieve a 12-operating month average emission rate of 800 lb CO_2/MWh-gross if rated for greater than or equal to 2,000 MMBtu per hour (MMBtu/hr) or a 12-operating month average emission rate between 800 and 900 lb CO_2/MWh-gross if rated for less than 2,000 MMBtu/hr. Additionally, by January 1, 2032, the EGU must use CCS with 90 percent capture to achieve an emission rate of 100 lb CO_2/MWh-gross.

2. If the EGU operates at greater than or equal to 20 percent and less than or equal to 40 percent capacity factor, the EGU must achieve highly efficient best operating and maintenance practices to achieve a 12-operating month average emission rate of 1,170 lb CO_2/MWh-gross.

3. If the EGU operates at less than 20 percent capacity factor, the EGU must use lower emitting fuels (e.g., natural gas) and achieve a 12-operating month average emission rate of less than 160 lb CO_2/MMBtu.

When the IRP was filed there were multiple ongoing legal challenges to the rule that remain unresolved.[164]

[163] IRP Vol.1 at 8-45–8-46.

[164] See the IRP Vol.1 at 8-47 for a discussion of the legal history to date.

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

Section 316(b) of the Clean Water Act requires the reduction of adverse environmental impact upon aquatic populations by using Best Available Control Technology (BACT) for water withdrawn from a water source for cooling purposes. Section 316(b) became effective on October 14, 2014, and it addressed both impingement and entrainment impacts for aquatic species.[165] All coal-fired generating units meet the impingement standard by utilizing the closed-cycle cooling compliance option, except LG&E/KU' Mill Creek Unit 1. However, due to the retirement of Mill Creek Unit 1 in 2024, no additional 316(b) compliance actions are necessary for the Mill Creek coal units.[166]

Clean Water Act: Steam Electric Power Generating Effluent Limitation Guidelines

The EPA's final rule for effluent limitation guidelines (ELG) became effective on January 4, 2016. The revised regulations required 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 included greatly reduced discharge limits from FGD wastewaters on mercury, arsenic, selenium, and nitrates.[167] Since then, the ELG rule has been amended multiple times and the 2024 ELG rule became effective on July 8, 2024. The 2024 rule sets a compliance period of as-soon-as-possible but no-later-than December 31, 2029.[168]

The 2024 revised regulations require major changes to wastewater treatment systems at existing coal-fired plants that generate FGD Wastewater (FGDW), Bottom Ash Transport Wastewater (BATW), Combustion Residual Leachate (CRL), and Legacy Wastewater (LWW). The regulations impose a prohibition on the discharge of FGDW, BATW, and CRL by no later than December 31, 2029. The new regulations also direct permitting authorities to set Best Professional Judgment (BPJ) limits for LWW. The rule expands the Notice of Planned Participation (NOPP) retirement subcategory to include units retiring before January 1, 2034. Upon utilizing the NOPP provision, the final rule retains the 2020 rule requirements for FGD wastewater and BA transport water and the pre-2015 BPJ-based BAT requirements for CRL rather than requiring the new, more stringent zero-discharge requirements for these waste-streams. After the permanent cessation of coal combustion, however, EGUs in this subcategory must meet limitations on arsenic and mercury based on chemical precipitation for CRL.[169]

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[165] IRP Vol.1 at 8-47.

[166] IRP Vol.1 at 8-48.

[167] IRP Vol.1 at 8-48.

[168] IRP Vol.1 at 8-48.

[169] IRP Vol.1 at 8-48.

Coal Combustion Residuals

The 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.[170] LG&E/KU initiated the closure of 19 surface impoundments using in-place closure and closure by removal methods. The physical closure process has been completed for 17 of the impoundments with the remaining two slated for physical completion in 2025. Of the closures undertaken by LG&E/KU, ten were performed using in-place methods.[171]

Since 2015, the rule has been modified by the EPA, the most recent of which on May 8, 2024. This modification expanded the scope of the regulation to include Legacy CCR surface impoundments and CCR management units (CCRMU). The addition of CCRMUs broadens LG&E/KU's exposure to the rule at each of its owned current and former generating facilities because of the past beneficial use of CCR, especially for fill materials. Many of the known CCRMU locations are now beneath buildings or infrastructure which will create challenges during the investigative process and may inhibit the closure process for individual CCRMUs if the removal of CCRs is necessary for rule compliance.[172]

EXISTING CAPACITY

The 2024 IRP assumed that most of the resource retirements and additions will either be deployed or occur as planned. By 2028 and including LG&E/KU's 158 MW share of the coal fired generation from the Ohio Valley Electric Corporation (OVEC) station, LG&E/KU expect to have 3,672 MW of gas fired generation and 4,313 MW of coal fired generation (7,985 MW winter 7,619 and summer capacity rating combined). In addition, LG&E/KU expect to have, 134 MW of hydroelectric generation (72 MW winter and 104 MW summer capacity), 240 MW of Company owned solar (201 MW winter capacity) and 518 MW solar PPA (434 MW winter capacity) and 125 MW of BESS (125 MW winter and summer capacity).[173] By 2028, LG&E/KU will have retired Mill Creek Units 1 and 2, Haefling Units 1 and 2, and Paddy's Run Unit 12.

RESOURCE ASSESSMENT AND ACQUISITION PLAN

In order to develop an optimal long term resource plan, LG&E/KU undertook an analysis of potential new demand and supply side resources, reassessed its reserve margin criteria, and then developed its optimal plan. LG&E/KU's IRP objective was to create a resource portfolio that reliably serves customers in all hours of the year under a

[170] IRP Vol.1 at 8-48.

[171] IRP Vol.1 at 8-49.

[172] IRP Vol.1 at 8-49.

[173] IRP Executive Summary at 2 and Vol. 3 Resource Adequacy Analysis, Table 3 at 12..

wide range of weather conditions at the lowest reasonable cost.[174] In addition to the changes to the load forecast, discussed previously, there were two additional considerations in the development of the optimal resource portfolio. First is that new supply side resource costs have increased, with the costs of simple cycle combustion turbines and NGCCs increasing significantly.[175] Second, the impact of environmental regulations is a key source of uncertainty. Though the subject of court challenges, three new significant environmental regulations have been finalized since the 2021 IRP: "the 2023 Good Neighbor Plan relating to the 2015 NAAQS for ozone. Ozone NAAQS; the 2024 updates to the ELG; and the 2024 Clean Air Act Section 111(b) and (d) GHG Rules."[176] LG&E/KU modeled four different environmental regulatory scenarios to better understand the potential impacts of the new rules: "(1) a No New Regulations scenario in which none of the recent regulations becomes enforceable, and only existing enforceable environmental regulations continue throughout the IRP planning horizon; (2) an Ozone NAAQS-only scenario; (3) an Ozone NAAQS and ELG scenario; and (4) a scenario in which all three of the recent major regulations (or their equivalents) become enforceable."[177]

<u>GENERATION TECHNOLOGY OPTIONS</u>

Multiple generation technologies were evaluated for inclusion as potential resources. Fully Dispatchable Resources included gas fired SCCTs, NGCCs and small modular nuclear reactors (SMRs). Used primarily for peaking purposes, SCCTs are relatively inexpensive on a $/kW basis and can be easily fitted with environmental controls. SCCT costs were based on the National Renewable Energy Laboratory 2024 Annual Technology Bulletin (NREL 2024 ATB).[178] NGCC's using the same amount of fuel can produce up to 50 percent more energy than SCCTs, can respond to significant load swings and can be cycled overnight. NGCC costs were based on LG&E/KU' recent cost estimates and assumptions for the Brown 12 NGCC unit developed in Case No. 2022-00402. The NREL 2024 ATB was used to escalate cost assumptions.[179] Nuclear generation generally faces multiple challenges including very high capital costs, inability to ramp quickly up or down, economic competitiveness in energy markets, permitting, waste disposal and public perceptions. SMRs are not yet fully commercially available, though research is ongoing. SMR assumptions and costs include an Inflation Reduction Act (IRA) 40 percent tax credit with the energy community bonus for new SMR resources

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[174] IRP Vol.3 Technology Update at 9.

[175] IRP Executive Summary at 5-6 and Table 2 at 6.

[176] IRP Executive Summary at 6.

[177] IRP Executive Summary at 6. At the time the IRP was filed, LG&E/KU believed that (3) Ozone NAAQS and ELG scenario was most likely and that (1) No New Regulations was least likely. However, LG&E/KU acknowledged that the upcoming elections could change the regulatory landscape.

[178] IRP Vol.3 Technology Update at 15.

[179] IRP at 15.

and are based on the "Moderate" scenario in the NREL 2024 ATB.[180] Carbon Capture and Sequestration (CCS) technology was considered as a retrofit technology. However, due to the primary uncertainty surrounding CCS regarding the absence of a robust regional and national CO_2 transport and storage system, LG&E/KU did not include the CCS retrofit option in the 2024 IRP.[181]

The analysis included renewable resources including wind and solar. Wind technology is a proven scalable renewable option and both in-state and out-of-state wind options were evaluated.[182] Current capital costs for wind were not available, and LG&E/KU used the implied inflation rate for solar to the "moderate" capital cost estimate for wind in the NREL 2024 ATB.[183] Solar technology is a proven scalable technology. During summer peak, about 84 percent of solar capacity resource is assumed to be available.[184] The impact of the IRA was included in the analysis with a production tax credit of $30.25 per MWh with the energy community bonus for the first 10 years. The cost and assumptions for solar facilities were taken from LG&E/KU Mercer County solar facility project in Case No 2022-00402 and escalated using the NREL 2024 ATB.[185]

LG&E/KU evaluated limited duration resources including 4- and 8-hour BESS and dispatchable demand-side resource options based upon the most recent approved DSM program in Case No. 2022-00402. Three dispatchable programs were included in the modeling: Bring Your Own Device (BYOD) Energy Storage, BYOD Home Generators, Business Demand Response 50-200 kW. In addition, LG&E/KU modeled an extension of the Curtailable Service Rider (CSR-2) program assuming the current rate of $5.90 per kW-month.[186]

Other technologies considered, but not included for evaluation, include integrated gas combined cycle, coal-fired supercritical generation, hydro, pumped hydro storage, compressed air energy storage, geothermal, biopower, reciprocating engines, microturbines and fuel cell technology, circulating fluidized bed generation, waste to energy, and concentrated solar power. These technologies were not considered due to scalability, potential New Source Performance Standards (NSPS) impact, and high

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[180] IRP at 15-16.

[181] IRP at 18.

[182] IRP at 19-20. The analysis included impacts from the federal Inflation Reduction Act and included production tax credits of $30.50 per MWh for the first 10 years with the energy community bonus for solar resources and $27.50 per MWh for the first 10 years of new wind resources.

[183] IRP at 20. Note that wind resources were ultimately modeled as energy only for several reasons. LG&E/KU only received one response for wind resources in a previous request for proposal. In addition, transmission costs could not be estimated reliably because wind facilities locations were not known. Finally, even with firm transmission rights, there was still the risk that service would be interrupted in extreme circumstances, as was the case with MISO during Winter Storm Elliott.

[184] IRP at 19.

[185] IRP.

[186] IRP at 21-22.

capital, operating or maintenance costs.[187] Selected results from the preliminary generation screening analysis is presented in the table below. Footnotes inside the Tables are provided immediately following.[188]

	Dispatchable Resources			Renewable Resources			BESS		Dispatchable DSM[7]			
	SCCT	NGCC	SMR	KY Solar	KY Wind	IN Wind	4-Hour	8-Hour	BYOD Energy Storage	BYOD Home Generators	BDR 50-200 kW	CSR[6]
Summer Capacity (ICAP MW)	243	645	300	100+	100+	100+	100+	100+	0.89	0.85	1.45	100
Winter Capacity (ICAP MW)	258	660	300	100+	100+	100+	100+	100+	0.89	0.85	1.45	100
Capital Cost ($/kW)[1]	1,636	2,121	9,765	1,902	2,460	2,238	2,049	3,598	N/A	N/A	N/A	N/A
Fixed O&M ($/kW-yr)[2]	6.9	7.8	166	17	33	36	25	44	N/A	N/A	N/A	81
Variable O&M ($/MWh)[3]	N/A	0.23	3.17				N/A	N/A	N/A	N/A	N/A	N/A
Investment Tax Credit[4]	N/A	N/A	40%				50%	50%	N/A	N/A	N/A	N/A
Production Tax Credit ($/MWh)[5]				30.25	27.50	27.50						

(1) Capital cost is the overnight capital expenditure required to achieve commercial operation.
(2) Fixed operation and maintenance costs are operation and maintenance costs that do not vary with generation output. For SCCT and NGCC resources, fixed O&M includes fixed costs for a long term service agreement (LTSA).
(3) Variable operation and maintenance costs are operation and maintenance costs incurred on a per-unit-energy basis.
(4) In accordance with the current tax credits, LG&E/KU assumed nuclear SMR resources that are in-service by year 2039 would begin construction by year 2033 and receive the full credit; resources that are in-service in year 2040 would begin construction in 2034 and receive 75% of the credit; resources that are in-service in year 2041 would begin construction in 2035 and receive 50% of the credit; and resources that are in-service in year 2042 or later would begin construction in 2036 or later and not receive any tax credits. Further cost reductions may be possible by utilizing existing sites.
(5) In accordance with the current tax credits, LG&E/KU assumed solar, wind, and BESS resources that are in-service by year 2036 would begin construction by year 2033 and receive the full credit; resources that are in-service in year 2037 would begin construction in 2034 and receive 75% of the credit; resources that are in-service in year 2038 would begin construction in 2035 and receive 50% of the credit; and resources that are in-service in year 2039 or later would begin construction in 2036 or later and not receive any tax credits. Production tax credits are included for the first 10 years of each solar or wind resource.
(6) In accordance with the current tax credits, LG&E/KU assumed solar, wind, and BESS resources that are in-service by year 2036 would begin construction by year 2033 and receive the full credit; resources that are in-service in year 2037 would begin construction in 2034 and receive 75% of the credit; resources that are in-service in year 2038 would begin construction in 2035 and receive 50% of the credit; and resources that are in-service in year 2039 or later would begin construction in 2036 or later and not receive any tax credits. Production tax credits are included for the first 10 years of each solar or wind resource.
(7) Curtailable Service Rider (CSR) reflects an expansion of the existing CSR-2 program. Fixed O&M costs reflect the current CSR-2 tariff of $5.90/kW-mo inflated to 2030 dollars at 2.3 percent per year. Capacity contribution for CSR is assumed to be the same as capacity contribution for dispatchable DSM.

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187 IRP at 22-24.

188 IRP Tables 1-3 at 12-14. Selected statistics.

Also see IRP. Vol 3, Technology Update at 22. Though there are no new DSM programs, three potential program enhancements modeled. The Bring Your Own Device (BYOD) Energy Storage is an enhancement to the BYOD program to enroll customer-owned dispatchable residential style BESS. Similarly, the BYOD Home generators are for residential customers to enroll customer-owned whole home dispatchable back-up generation units. The Business Demand Response (BDR) 50-200 kW is the allowance of small business customers having a measured base demand of 50 to 200 kW to participate in the BDR program.

Resource Assessment and Generation Planning and Analysis

LG&E/KU used SERVM software to develop its minimum reserve margin constraints for resource planning, computing capacity contribution values for limited duration resources and to evaluate loss of load expectation (LOLE) values.[189] The PLEXOS resource planning model was used to develop least cost resource plans over a range of fuel price scenarios.[190] Once PLEXOS has identified which resources are best to include in a resource plan, a more detailed resource plan is developed using PROSYM. Using the same inputs as was used in PLEXOS, PROSYM develops an hourly chronological dispatch model.[191] A financial model developed in Excel is used to compare the present value revenue requirement (PVRR) of the different resource plans. Cost inputs include generation production costs, capital and fixed operating costs for new and existing resources, coal combustion residual (CCR) beneficial reuse (CCR sales), existing unit stay-open costs, environmental compliance costs, and new generation capital and stay-open costs.[192]

Multiple scenarios are considered as part of the comprehensive resource analysis. Based upon growing national interest in data centers and the number of current projects (which may or may not come to fruition in LG&E/KU' service territory), LG&E/KU developed three load scenarios. The Low load Forecast is assigned a low likelihood which includes no economic growth. The Mid and High Load Growth scenarios include 1,050 MW and 1,750 MW of new data center load by 2032 respectively.[193]

Four environmental scenarios were developed reflecting increasing levels of regulation over the forecast period.

- The No New Regulation scenario assumes the Good Neighbor Plan (related to the NAAQS for ozone, , 2024 ELG, and recent CAA Section 111(b) and (d) ("GHG") Rules or their equivalents do not take effect over the IRP planning period, and no new regulations are implemented through the end of the IRP planning period (2039).[194]

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[189] IRP Vol. 3 Resource Assessment at 27.

[190] IRP Vol. 3 Resource Assessment at 27.

[191] IRP Vol. 3 Resource Assessment at 28.

[192] IRP Vol. 3 Resource Assessment Table 8 at 28.

[193] IRP Vol. 3 Resource Assessment at 4.

[194] IRP Vol. 3 Resource Assessment at 5.

- The Ozone NAAQS scenario assumes the 2024 ELG and GHG Rules or their equivalents do not become effective during the IRP planning period, but the Good Neighbor Plan or its equivalent does become effective. In this case, because selective catalytic reduction (SCR) is a Reasonably Achievable Control Technology for ozone NAAQS compliance, LG&E/KU assume SCR will be needed to operate Ghent 2 in the ozone season (i.e., May through September) beyond 2030.[195]
- The Ozone NAAQS + ELG scenario assumes the Ozone NAAQS scenario plus the 2024 ELG or its equivalent will also become effective, but not the GHG Rules or their equivalents during the IRP planning period. LG&E/KU consider this environmental scenario to be most likely.[196]
- The Ozone NAAQS + ELG + GHG scenario adds to the previous plan plus the added assumption that the GHG Rules or their equivalents all become effective during the IRP forecast period. LG&E/KU assign a low likelihood to this scenario.[197]

Five fuel price scenarios were evaluated using the same methodology as employed and approved in Case No. 2022-00402.[198] LG&E/KU calculated a coal to gas ratio (CTG) variable using the long term relationship between forecast Illinois Basin coal prices and the high, Mid and Low Henry Hub natural gas price forecasts from the U.S. Energy Information Administration (EIA) 2023 Annual Energy Outlook (AEO2023).[199] The scenarios include: [200]

- Expected CTG Ratio
  - Low Gas, Mid CTG Ratio
  - Mid Gas, Mid CTG Ratio
  - High Gas, Mid CTG Ratio
- Atypical CTG Ratio
  - Low Gas, High CTG Ratio
  - High Gas, Low CTG Ratio

LG&E/KU note that the Mid CTG ratio is mean reverting over time. The High Gas to Mid CTG Ratio generally assumes some level of international demand is in effect over the forecast period, while the Low Gas to Mid CTG Ratio and Mid Gas to Mid CTG Ratio

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[195] IRP Vol. 3 Resource Assessment at 5.

[196] IRP Vol. 3 Resource Assessment at 5.

[197] IRP Vol. 3 Resource Assessment at 5.

[198] Case No. 2022-00402 *Electronic Joint Application of Kentucky Utilities Company and Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity and Site Compatibility Certificates and Approval of a Demand Side Management Plan* (filed Jan. 6, 2023).

[199] Case No. 2022-00402, (Ky. PSC Nov. 6, 2023), Order at 93-94 and the IRP Vol. 3 Resource Assessment at 5, 25 and 59-62.

[200] IRP Vol. 3 Resource Assessment at 58.

tend to reflect domestic price differences. The High Gas to Low CTG and Low Gas to High CTG reflect scenarios where coal and natural gas prices trends diverge.[201] The Mid CTG Ratio is LG&E/KU's expected CTG price ratio.[202]

MODELING

Stage One Analysis comprised of using PLEXOS to develop the most economical resource plans to serve customers across each load and environmental scenario. There were 12 scenarios in total, comprised of three load scenarios and four environmental scenarios across five fuel price scenarios resulting in 60 different resource plans. Each resource plan was evaluated with detailed production costs over each fuel price scenario to obtain the lowest cost plan for each load and environmental scenario across all fuel price scenarios.[203]

Stage One, Step Two Analysis reevaluated each of the resource plans with detailed production costs using PROSYM to determine with resource plan for a given load had the lowest present value revenue requirement (PVRR) on average across all fuel price scenarios.[204] LG&E/KU's Recommended Resource Plan is in the table below showing the years only in which a change occurs. In addition, the table contains the least cost resource plans across all fuel price scenarios for the Mid-load, Ozone NAAQS + ELG scenario and the High Load Ozone NAAQS + ELG scenario.[205]

Year	Least-Cost Resource Plans Ozone NAAQS + ELG		Recommended Resource Plan Ozone NAAQS + ELG Mid Load	Enhanced Solar Resource Plan Ozone NAAQS + ELG Mid Load
	Mid Load, Solar Cost Sensitivity	High Load		
2028	Add Dispatchable DSM	Add Dispatchable DSM +300 MW 4hr BESS	Add Dispatchable DSM +400 MW 4hr BESS; Add GH2 SCR	Add Dispatchable DSM +400 MW 4hr BESS; Add GH2 SCR +200 MW Solar
2029		Add 700 MW 4hr BESS		

[201] IRP Vol. 3 Resource Assessment at 59. Also see the Resource Assessment at pages 59-66 for a more in-depth discussion supporting the CTG Ratio.

[202] IRP at 61.

[203] IRP at 29. Specific resource plan results are presented in Tables 9-24 at 31-43.

[204] IRP at 43. Specific resource plan results are presented in Tables 25-28 at 44-48.

[205] IRP Vol. 1 Table 5-4 at 27 and Vol. 3 Resource Assessment Table 29 at 49.

2030	Retire BR3; Add GH2 SCR; +1 NGCC; ELG At GH, TC; +100 MW 4hr BESS	Add GH2 SCR; +1 NGCC; ELG At GH, TC	Add 1 NGCC; ELG At GH, TC	Add 1 NGCC; ELG At GH, TC +200 MW Solar
2031	Add 400 MW 4hr BESS	Retire BR3; +1 NGCC; +200 MW 4hr BESS	Add 1 NGCC	Add 1 NGCC
2032	Add 200 MW 4hr BESS	Add 200 MW 4hr BESS		Add 600 MW Solar
2035	Retire MC3-4; +1 NGCC; +200 MW 4hr BESS	Retire MC3-4; +1 NGCC; +1 SCCT	Retire MC3-4; Retire BR3; +500 MW 4hr BESS; 500 MW Solar	Retire MC3-4; Retire BR3; +500 MW 4hr BESS

The Recommend Resource Plan builds on the Least Cost Mid-load plan and is modified to account for the possibility of high load growth or CO_2. The Ghent 2 SCR and 400 MW BESS are accelerated to 2028, a second NGCC is accelerated to 2031, and the Brown Unit 3 retirement is delayed to 2035. Also, 500 MW of solar is added in 2035 after prices fall to hedge natural gas price volatility and future CO_2 regulation. The Recommended Resource Plan represents a “no regrets” plan in that the accelerated resources are needed by 2035 in winter high economic growth or CO2 regulations do not occur. In addition, the 500 MW of solar in 2035 is reflective of the likelihood that some level of solar will be least cost without CO_2 regulation.[206]

Below are resource summaries for LG&E/KU’s recommended resource plans for the winter and summer periods respectively.[207] All units are in MW and projections are based on the Ozone NAAQS plus ELG scenario, Mid Load Forecast. Table footnotes are provided immediately following the Summer Table.

Winter Plan	2025	2028	2029	2030	2031	2032	2035	2037	2039
Peak Load	6,146	6,347	6,471	6,733	7,003	7,135	7,118	7,118	7,117
Fully Dispatchable Generation Resources									
Existing Resources	7,909	7,977	7,977	7,977	7,977	7,977	7,977	7,977	7,977
Retirements/Additions									
Coal (1)	-300	-601	-601	-601	-601	-601	-1,897	-1,897	-1,897

[206] IRP Vol. 3 Resource Assessment at 49.

[207] IRP Vol. 1 Tables 8-2 and Table 8-3 at 8-2-8-3. Data is from select years over the forecast period. Also see Vol. 1 Table 6-5 at 6-6 for annual summer and winter reserve margins and capacity needs. Note that in these tables, the load forecast inherent in the calculations reflects the Mid Load forecast. In Vol. 1 Table 5-2 at 5-13, the Mid Load forecast shows an assumed addition of 1,050 MW of data center load, 150 MW of DG in 2032. See also IRP Vol. 3 Table 31 at 53. Commission Staff notes that after the planned retirement of Mill Creek Units 3 and 4 in 2035, there will be four years remaining on the book depreciable lives of the units

Small-Frame SCCTs [2]	-55	-55	-55	-55	-55	-55	-55	-55	-55
NGCC [3]	0	660	660	1,320	1,980	1,980	1,980	1,980	1,980
Total	7,554	7,981	7,981	8,641	9,301	9,301	8,005	8,005	8,005
Reserve Margin	22.9%	25.8%	23.3%	28.3%	32.8%	30.4%	12.5%	12.5%	12.5%
Renewable/Limited-Duration Resources									
Existing Resources	72	72	72	72	72	72	72	72	72
Existing CSR	115	115	115	115	115	115	115	115	115
Existing Disp. DSM [4]	45	110	124	125	135	145	158	160	163
Retirements/Additions									
Solar [5]	0	0	0	0	0	0	0	0	0
BESS [6]	0	465	465	465	465	465	890	890	890
Dispatchable DSM	0	1	2	3	3	5	8	9	10
Total	231	763	777	779	789	800	1,242	1,246	1,250
Total Supply	7,785	8,744	8,758	9,420	10,090	10,101	9,247	9,251	9,255
Total Reserve Margin	26.7%	37.8%	35.3%	39.9%	44.1%	41.6%	29.9%	30.0%	30.0%
Capacity Need [7]	143	-557	-411	-735	-1,057	-897	-65	-69	-74

Summer Plan	2025	2028	2029	2030	2031	2032	2035	2037	2039
Peak Load	6,228	6,474	6,686	6,931	7,216	7,201	7,171	7,160	7,149
Fully Dispatchable Generation Resources									
Existing Resources	7,612	7,618	7,618	7,618	7,618	7,618	7,618	7,618	7,618
Retirements/Additions									
Coal [1]	-300	-601	-601	-601	-601	-601	-1,881	-1,881	-1,881
Small-Frame SCCTs [2]	-47	-47	-47	-47	-47	-47	-47	-47	-47
NGCC [3]	0	645	645	1,290	1,935	1,935	1,935	1,935	1,935
Total	7,265	7,615	7,615	8,260	8,905	8,905	7,625	7,625	7,625
Reserve Margin	16.7%	17.6%	13.9%	19.2%	23.4%	23.7%	6.3%	6.5%	6.7%
Renewable/Limited-Duration Resources									
Existing Resources	106	107	107	107	107	107	107	107	107
Existing CSR	110	110	110	110	110	110	110	110	110
Existing Disp. DSM [4]	84	150	166	170	179	190	208	216	227
Retirements/Additions									
Solar [5]	0	201	201	201	201	201	619	619	619
BESS [6]	0	465	465	465	465	465	890	890	890
Dispatchable DSM	0	1	2	3	3	5	8	9	10
Total	300	1,034	1,051	1,056	1,065	1,078	1,942	1,952	1,963
Total Supply	7,565	8,649	8,666	9,316	9,970	9,983	9,567	9,577	9,588
Total Reserve Margin	21.5%	33.6%	29.6%	34.4%	38.2%	38.6%	33.4%	33.8%	34.1%
Capacity Need [7]	95	-686	-442	-791	-1,095	-1,125	-747	-770	-796

(1) Mill Creek 1 will be retired at the end of 2024. Mill Creek 2 will be retired after Mill Creek 5 is commissioned in 2027. The Recommended Resource Plan includes 4 MW auxiliary load for an SCR on Ghent 2 in 2028 and the retirement of Brown 3, Mill Creek 3, and Mill Creek 4 in 2035.

(2) This analysis assumes Haefling 1-2 and Paddy's Run 12 are retired in 2025.

(3) Mill Creek 5 is assumed in-service in 2027. The Recommended Resource Plan includes additional NGCC units in 2030 and 2031.

(4) Existing Dispatchable DSM reflects expected load reductions under normal peak weather conditions.

(5) This analysis assumes 120 MW of solar capacity is added in 2026, and another 120 MW of solar capacity is added in 2027. The Recommended Resource Plan includes an additional 500 MW of solar capacity in 2035. Capacity values reflect 83.7 percent expected contribution to summer peak capacity.

(6) Brown BESS is assumed in-service in 2026. The Recommended Resource Plan includes an additional 400 MW of 4-hour BESS capacity in 2028 and another 500 MW of 4-hour BESS capacity in 2035. Capacity values reflect 100 percent capacity contribution for Brown BESS and 85 percent capacity contribution for the additional 4-hour BESS.

(7) The summer capacity need is based on a 23 percent summer minimum reserve margin target. Positive values reflect a capacity deficit.

SECTION 5

REASONABLENESS AND RECOMMENDATIONS

INTRODUCTION

Some aspects of LG&E/KU's 2024 IRP, including some of the methodologies and assumptions used to produce the IRP, are reasonable and consistent with 807 KAR 5:058. However, there are areas in which LG&E/KU could improve its IRPs going forward, including issues with certain methodologies and assumptions that affected the reasonableness of the 2024 IRP. This section discusses the reasonableness of LG&E/KU's 2024 IRP and the issues and areas for improvement and makes recommendations for LG&E/KU's next IRP.

REASONABLENESS OF LOAD FORECASTING

Commission Staff notes from the outset, that LG&E/KU, along with many other utilities in the Commonwealth, and around the country, are faced with the potential for unprecedented load growth, materializing seemingly overnight. Moreover, the source of the projected load growth is arriving in large tranches and can ramp up far faster than LG&E/KU expects that it could build the necessary generation. Consequently, Commission Staff is sensitive to the complexities involved in identifying how much of the projected load growth LG&E/KU believe it is prudent to plan for, and when to include it in its models. There is necessarily a learning curve in identifying the appropriate process and best practices as data center load growth materializes in the service territories.

However, Commission Staff was concerned by the approach LG&E/KU took in evaluating prospective load to be modeled over the course of the planning year with regard to data centers. Specifically, Commission Staff's first concern is that LG&E/KU did not attempt to model load growth beyond 2032, despite the planning period extending through 2039. Still, Commission Staff's primary concerns revolve around how LG&E/KU determined which prospective customers to include in the model. While Commission Staff does not present in the context of this IRP a definitive process for LG&E/KU to implement, Commission Staff stresses the importance of LG&E/KU utilizing objective and replicable standards by which it evaluates all prospective data center load growth, or other comparable industrial or commercial load growth.. Therefore, Commission Staff recommends the following:

1. LG&E/KU establish objective standards to determine if and when significant additional load will be added to its service territory.

2. That LG&E/KU evaluate similarly situated utilities specifically with regards to data center load growth that actually materializes in those utilities' territories as a comparator to help LG&E/KU understand the data center landscape as LG&E/KU prepare to serve large-load customers.

3. More generally, Commission Staff also believe that LG&E/KU's next IRP process would benefit from not relying solely on a singular peak demand figure[208]. As this IRP proceeding demonstrated, all intervening parties presented concerns at various stages regarding how LG&E/KU arrived at its operating assumptions. While LG&E/KU acted reasonably in this IRP, Commission Staff does believe that a number of opportunities remain in which LG&E/KU can continue to improve. Therefore, Commission Staff recommends the following. That LG&E/KU's modeling includes a scenario that reflects a 48-hour peak demand period.

4. LG&E/KU should assign non-zero capacity values to solar resources in winter.

5. LG&E/KU should accelerate its transition to PLEXOS from PROSYM because the program is more up-to-date and has far greater processing speed and functionality, including producing multiple scenarios.

6. LG&E/Ku should utilize both traditional coal and gas pricing in its models as comparators to its Coal-to-Gas ratio adopted in Case No. 2022-00402.

7. LG&E/KU should appropriately lower the capacity factor of its thermal units to align with historical data instead of assigning a 100 percent capacity contribution to each unit.

8. LG&E/KU should estimate the retrofitting costs and either explicitly model or allow the model to economically select retrofitting all aging coal units in its fleet to operate on natural gas instead of having the model only assume new build resources.

9. LG&E/KU should begin comparing shorter weather time horizons of 5 and 10 years along with its traditional planning periods spanning 20 years. While more volatile, the comparison may alert LG&E/KU to trends quicker than the longer time horizon forecasts would.

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[208] While extending the peak demand analysis from a single figure to the 48-hour period suggested does not address all of intervenors concerns; its inclusion will likely aid all parties in understanding LG&E/KU's resiliency during extreme load events which may impact any potential generation portfolio.

REASONABLENESS OF DEMAND AND SUPPLY SIDE RESOURCE AND INTEGRATION ASSESSMENTS

While the IRP planning period extends 15 years, the forecasts produced by utilities have always been treated, as they must properly be, as snapshots in time. In essence, the IRP is meant to represent the utility's fundamental assumptions regarding its planning process at the time it submits the IRP for scrutiny. Because the IRP is separate from any specific application, the utility has the necessary freedom to explore scenarios in which it has less confidence than what is traditionally required in a CPCN proceeding. LG&E/KU's 2024 IRP exemplifies how that principle is operationalized. Unlike the 2021 IRP, or even the 2022 CPCN application, the 2024 IRP explores heretofore unseen load growth resulting from the Companies' ongoing discussions with prospective data center customers. Because no data center requiring the type of load that LG&E/KU envisions in this IRP has located in its territory, all of LG&E/KU's assumptions were necessarily speculative. Because the IRP is interested in understanding, directionally, how the Companies are operating and how it plans to evaluate its obligations to existing and prospective ratepayers, the speculative nature of the load relied on to create the resource portfolio is not inherently problematic, as long as inputs utilized by the Companies remained within some broad band of reasonableness.

This difference in approaches between IRP forecasts and forecasts produced to support CPCN proceedings has historically created very little friction. However, as LG&E/KU's last IRP and CPCN proceedings show, the uptick in cases involving requests for new generation have meant that load forecasts have often overlapped. This should not be inherently problematic, because at least notionally, the closer in time the models are the more characteristics they are likely to share if only because the data relied on will be similar. Consequently, Commission Staff is compelled to note that in Case No. 2021-00393 (LG&E/KU's most recent completed IRP) and Case No. 2022-00402 (LG&E/KU's most recent CPCN application), the load forecasts in both cases were meaningfully different and resulted in quite divergent resource portfolios, with the CPCN proceeding requesting more than was contemplated in the IRP proceeding. Again, the dissimilarity is not in itself concerning. However, Commission Staff notes the discrepancy in that case because the proximity between the filings raises the likelihood that the Companies were aware at the time of the IRP filing of circumstances which could require them to request approval for the more expansive resource portfolio presented in Case No. 2022-00402. Data center load growth projections only serve to exacerbate the potential problems of materially divergent IRP and CPCN forecasts, which can undermine the ultimate utility of the IRP in the short term. Therefore, Commission Staff urges LG&E/KU to be cognizant of this pitfall in its subsequent IRP filing and include all potential loads in the load forecast for which LG&E/KU can reasonably rely on.

In 2021, when LG&E/KU filed its most recent prior IRP, the load forecast assumed little growth, and consequently, the IRP centered heavily on energy efficiency programs. By 2022, as LG&E/KU filed its application in Case No. 2022-00402, circumstances appeared to have changed. LG&E/KU requested approval for billions in generation, alongside the closure of several aging coal generators. By 2024, with the filing of this

IRP, LG&E/KU signaled that instead of the modest growth expected in some areas, and contractions in others, LG&E/KU believed that economic development related load growth would require unprecedented build out of generation and transmission. Indeed, the reasonableness of its assumptions regarding that expected data center load growth (as discussed above) have been at the core of this IRP proceeding.

Understandably, in the context of gigawatts of expected growth, DSM/EE programs have a somewhat limited capacity to impact those forecasts, except at the margins. However, these programs continue to represent meaningful opportunities for ratepayers to control their energy costs and LG&E/KU must not lose sight of how important those programs may be to eligible customers. Moreover, those programs also represent real capacity headroom that must be properly accounted for in order to ensure that LG&E/KU has an accurate picture of its capacity and energy needs moving forward.

Turning specifically to Commission Staff's recommendations in its 2021 IRP and LG&E/KU's response to those recommendations, Commission Staff finds that LG&E/KU has largely taken positive steps in expanding its DSM/EE offerings. Specifically, Commission Staff was pleased to see LG&E/KU's continued relationship with its DSM advisory group and the fact that it presented three new proposals for enhancement, as well as LG&E/KU's business demand response program offerings and its EV studies.

Commission Staff would encourage LG&E/KU to continue studying and expanding its DSM/EE programs to ensure that LG&E/KU and ratepayers are operating in the most reasonably efficient ways possible. Specifically, Commission Staff believes that LG&E/KU could more accurately assess the value of potential programs and so Commission Staff recommends the following:

1. That LG&E/KU assign a capacity value to current and future dispatchable DSM/EE programs and model current and future DSM/EE programs against supply side resources so that it can accurately evaluate when it needs to construct new generation.

2. That for current and future DSM/EE programs and DER, LG&E/KU assign non-zero capacity values to those resources on par, or close to on par, with supply side resources.

In changing the way LG&E/KU evaluates DSM/EE programs, Commission Staff hopes that LG&E/KU will have better information with which to evaluate its needs and protect ratepayers from increased costs resulting from new generation until those resources are required.

More generally, Commission Staff also notes that the ever-changing regulatory landscape creates increasingly complex factors to consider. Specifically, tax programs and environmental compliance have recently experienced tectonic movement. Given the potential loss of savings and costs associated with those items, it is imperative that LG&E/KU begin formally evaluating its resources and programs accounting for the potential that expectations regarding costs and savings could materially change in very short timeframes. Consequently, Commission Staff believes that the following recommendations will aid LG&E/KU and Commission Staff in preparing for and evaluating LG&E/KU' next IRP:

1. LG&E/KU should investigate whether capacity and energy are available with transmission upgrades to serve large load customers who want to come online before 2032.

2. LG&E/KU should utilize the objective standard recommended above to rerun its models and resources, accounting for any necessary transmission upgrades to allow for the economic selection of imported capacity and energy resources instead of solely modeling reliance on constructing and operating new generation. This could include the joint ownership of a capacity resource where capacity economies of scale would make joint ownership economical.

3. LG&E/KU should investigate and present the costs of extending the service life of its current generation units. Then, where reasonably practical, allow the model to economically select unit life extensions as a potential short term resource option toward obtaining its least economic generation portfolio.

4. LG&E/KU should investigate the cost of new renewable resources without tax advantages. As part of the analysis Commission Staff would recommend that LG&E/KU determine whether other load, or transmission upgrades, could serve the load at less cost to ratepayers.

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