COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC 2021 JOINT INTEGRATED RESOURCE PLAN OF LOUISVILLE GAS AND ELECTRIC COMPANY AND KENTUCKY UTILITIES COMPANY	))))	CASE NO. 2021-00393

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

The Commission initiated this proceeding for Commission Staff to conduct a review of the 2021 Integrated Resource Plan (IRP) filed by Louisville Gas and Electric Company and Kentucky Utilities Company (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. Pursuant to 807 KAR 5:058, Section 11(3), the Commission Staff's Report, attached to this Order as an Appendix, shall be entered into the record of this case.

IT IS THEREFORE ORDERED that the Commission Staff's Report, attached as an Appendix to this Order, shall be entered into the record of this matter.

PUBLIC SERVICE COMMISSION

Chairman

Vice Chairman

Commissioner

ENTERED

SEP 16 2022 rcs

KENTUCKY PUBLIC
SERVICE COMMISSION

ATTEST:

Executive Director

APPENDIX

AN APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2021-00393 DATED SEP 16 2022

SEVENTY PAGES TO FOLLOW

Kentucky Public Service Commission

Commission Staff's Report on the

2021 Integrated Resource Plan

of Louisville Gas and Electric Company

and Kentucky Utilities Company

Case No. 2021-00393

September 16, 2022

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) (collectively, LG&E/KU or the Companies) filed their 2021 Integrated Resource Plan (2021 IRP) on October 19, 2021. The Companies are subsidiaries of the PPL Corporation (PPL) and provide retail electric service to about 950,000 customers in Kentucky and Virginia, and wholesale electric service to two municipalities in Kentucky.[2] LG&E/KU's 2021 IRP reflects their resource plan for meeting their customers' electricity requirements for the 2021 to 2036 planning period.

LG&E/KU stated that the 2021 IRP is a snapshot of their established annual resource planning process and is based on current business assumptions and assessment of risks.[3] The Companies stated that their resource planning process begins with the development of an hourly energy requirements forecast that forms the basis of their resource plan.[4] The planning process then generally consists of the following: (1) screening of demand-side and supply-side resource options; (2) assessment of target reserve margin criterion; and (3) development of long-term resource plan.[5] The Companies asserted that their resource plan is developed with the goal of meeting the future energy requirements of their customers at the lowest reasonable cost.[6]

On November 12, 2021, an Order was entered establishing a procedural schedule for the review of LG&E/KU's 2021 IRP. The procedural schedule established a deadline for requesting intervention, two rounds of requests for information to LG&E/KU, and an opportunity for intervenors to file written comments regarding the IRP and indicated that a hearing and additional comments from intervenors and LG&E/KU would be scheduled. On April 13, 2021, the procedural schedule was amended to extend the period during

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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] 2021 IRP, Vol. I, Section 5 at 1.

[3] 2021 IRP, Vol. I, Section 5 at 7.

[4] 2021 IRP, Vol. I, Section 5 at 7.

[5] 2021 IRP, Vol. I, Section 5 at 10.

[6] 2021 IRP, Vol. I, Section 5 at 7.

which intervenors were permitted to file comments and to allow LG&E/KU the opportunity to file comments in response to intervenor comments before any hearing was scheduled.

The Attorney General of the Commonwealth of Kentucky, by and through the Office of Rate Intervention (Attorney General), Sierra Club, Southern Renewable Energy Association (SREA), and Kentucky Industrial Utilities Customers (KIUC) were permitted to intervene in this matter pursuant to 807 KAR 5:001. Metropolitan Housing Coalition, Kentuckians for the Commonwealth, Kentucky Solar Energy Society, and Mountain Association (Joint Intervenors), who are represented by the same counsel, were permitted to jointly intervene in this matter.

LG&E/KU responded to two rounds of request for information from intervenors and Commission Staff. Intervenors filed written comments regarding the LG&E/KU's 2021 IRP and the Companies filed comments responding to intervenor comments. A hearing was held on July 12, 2022, and July 13, 2022. Following the hearing, LG&E/KU responded to post-hearing requests for information, and the parties were given the opportunity to file simultaneous post-hearing comments and response comments. Members of the general public were given the opportunity to provide oral comments at the hearing and written comments at any time throughout this case.

After reviewing the information submitted in this case, Commission Staff prepared this report summarizing Commission Staff's review and evaluation of LG&E/KU's 2021 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 and to make suggestions and recommendations to be considered in future IRP filings. Commission Staff's goals, when reviewing and evaluating this IRP, are to ensure that:

- 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

- The report includes an incremental component, noting any significant changes from LG&E/KU's most recent IRP filed in 2018.

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: summarizes LG&E/KU's evaluation of DSM opportunities.

- Section 4 Supply-Side Resource Assessment and Integration: focuses on supply-side resources available to meet LG&E/KU's load requirements and environmental compliance planning. This section also discusses LG&E/KU's overall assessment of supply-side and demand-side options and their integration into an overall resource plan.

- 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 Section 5 of this report.

LOAD FORECAST METHODOLOGY

LG&E/KU's integrated planning process began with the development of forecasts of hourly energy requirements or "load." The Companies defined their energy requirement as the sum of electricity sales and transmission and distribution losses.[7] The Companies 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.[8]

Forecasts of energy sales were made separately for LG&E and KU. 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.[9]

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 is 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 obtain sales forecasts,[10] though the specific method used, and data relied on differed by customer class.

[7] 2021 IRP, Vol. I, Section 5 at 8.

[8] 2021 IRP, Vol. I, Section 5 at 8-9; *see also* 2021 IRP Vol. I, Section 5 at 34-35.

[9] 2021 IRP, Vol. II, Section 4 at 7.

[10] *See* 2021 IRP, Vol. II, Electric Sales and Demand Forecast Process at 5 (showing that the data relied on for modeling included state macroeconomic and demographic data from IHS Market and the Kentucky Data Center; national macroeconomic data from IHS Markit; weather data from the National Oceanic and Atmospheric Administration (NOAA); appliance saturations and structural variables, e.g. dwelling size, age, and type, 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 data regarding electrical vehicle adoption and charging shapes from IHS Markit, NREL, Bloomberg New Energy Finance, and the Electric Power Research Institute).

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. These variables were functions of heating and cooling degree days, appliance saturation levels, appliance and equipment efficiencies, income, population, household members and electricity prices.[11] LG&E/KU's Electric Vehicle (EV) sales forecast were also allocated as an increase in the residential sales forecasts.[12] The number of residential customers was modeled as a function of the number of forecasted households or population in each company's service territory.[13]

The Commercial and Industrial (C&I) forecasts are made up of 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 forecasts and were a function of heating and cooling equipment and other nonweather sensitive equipment and binary variables.[14] The KU, LG&E and KU ODP Secondary service forecasts were a function of weather, economic variables, cooling efficiencies, end-use intensity projections, and binary variables.[15] The KU All Electric Schools forecast were a function of weather, the number of KU All Electric School customers and binary variables. The KU ODP School Service forecast was a function of weather, the number of KU ODP School Service customers and binary variables. The KU ODP Municipal Pumping forecast was a trend analysis of recent sales. Both the KU and LG&E Primary forecasts were functions of an economic variables and 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 and economic variables. 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, sales and mining production indices.[16]

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[11] 2021 IRP, Vol. II, Electric Sales and Demand Forecast Process at 7-8; *see also* LG&E/KU's Response to Staff's First Information Request (Response to Staff's First Request), Item 40(b), Appendix A to the Electric Sales and Demand Forecast Process (providing a detailed explanation of the individual variables).

[12] 2021 IRP, Vol. II, Electric Sales and Demand Forecast Process at 8.

[13] 2021 IRP, Vol. II, Electric Sales and Demand Forecast Process at 8.

[14] 2021 IRP, Vol. II, Electric Sales and Demand Forecast Process at 9; *see also* Response to Staff's First Request), Item 40(b), Appendix A to the Electric Sales and Demand Forecast Process.

[15] 2021 IRP, Vol. II, Electric Sales and Demand Forecast Process at 9-10. Note that these customers receive service on the KU Power Service (PS) rate schedule, the LG&E and ODP customers receive service on the PS and Time Of Day Secondary rate schedule.

[16] 2021 IRP, Vol. II, Electric Sales and Demand Forecast Process at 8-11.

LG&E/KU developed separate forecasts for EV charging and Lighting sales using recent sales trends.[17] 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.[18]

LG&E/KU reflected the adoption of Distributed Solar Generation as a reduction in forecasted sales. It stated that the economics of Distributed Solar Generation depends on electricity usage patterns and the correlation to solar irradiance, the federal investment tax credit, the capital and annual operating cost of solar, and the retail rate paid by the consumer and the rate paid by the utility for excess generation.[19] The forecast was based on a consumer choice model and is a function of retail energy prices, instantaneous netting of usage, and the levelized cost of energy for solar installations. The forecasted sizes of new solar installations were based on recent trends in the residential service, general service, and the primary service rate classes and allocated as a reduction to the forecasted sales for those rate classes.[20]

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. The Companies 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.[21] To determine annual energy requirements, LG&E/KU then sum the calendar-month energy sales forecast volumes and transmission sales and losses.[22]

HOURLY ENERGY REQUIREMENTS METHODOLOGY

LG&E/KU converted their forecasted load to an hourly energy-requirements forecast to develop their resource expansion plans. To start, the Companies developed load duration curves for each company and each month based on 10 years of historical hourly energy requirements. The Companies then allocated their monthly energy requirements to hours based on those load duration curves, and assigned hourly energy requirements to specific hours in each month based on the ordering of days and weekends in the month. The Companies 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

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[17] 2021 IRP, Vol. II, Electric Sales and Demand Forecast Process at 12.

[18] 2021 IRP, Vol. II, Electric Sales and Demand Forecast Process at 11.

[19] 2021 IRP, Vol. I, Section 5 at 27.

[20] 2021 IRP, Vol. I, Section 5 at 29 and 33, FN33; 2021 IRP Vol. II, Electric Sales and Demand Forecast Process at 12. Note that due to the proximity of the IRP filing the Companies did not update the forecasts to account for the Commission's new NMS-2 rates or the netting interval.

[21] 2021 IRP, Vol. II, Electric Sales and Demand Forecast Process at 14.

[22] 2021 IRP, Vol. II, Electric Sales and Demand Forecast Process at 15.

energy requirements forecast to reflect the forecasted impact of distributed solar generation and electric vehicle load.[23]

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 the Companies' 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 48 calendar years and calendar variables from the forecast period. Consistency between the base energy forecasts and the weather-year forecast was ensured by adjusting the mean of the weather-year forecast to the mean of the monthly energy requirements forecast.[24]

Other key assumptions centered around economic data. Based on the data used by LG&E/KU, the economic outlook for Kentucky is a real economic growth rate of 6.5 percent for 2021, which is similar to the U.S. economy. Average annual growth rates of 1.9 percent and 1.8 percent were expected for the 2022-2026 period and 2027-2036 period, respectfully. The continued spread of COVID-19 and rising inflation were seen as the greatest near term risks.[25] Barring unexpected tax or policy changes, energy prices were anticipated to hold steady until later in the planning cycle when they were expected to track the inflation rate. Increased energy prices could accelerate adoption of distributed generation resources and hamper EV adoption due to increased cost of operation.[26]

Customer growth was expected to remain strong in the residential and manufacturing sectors, which has a positive effect on energy sales.[27] The large direct and indirect effects of the announced Ford battery plant are not included in the demand forecasts.[28] Increases in energy efficiency (EE) are expected to continue in appliances, heating and cooling equipment, and housing. EE gains are also expected to continue in the industrial and manufacturing sectors.[29]

Projections of the adoption of distributed energy resources, including both qualifying facilities and roof-top solar, assumed the retail rate would be paid for excess generation, instantaneous netting of usage and generation, and a continuation of the investment tax credit for 10 years. Based upon the 2020 National Renewable Energy

[23] 2021 IRP, Vol. II, Electric Sales and Demand Forecast Process at 15-16.

[24] 2021 IRP, Vol. II, Electric Sales and Demand Forecast Process at 13.

[25] 2021 IRP, Vol. I, Section 5 at 23-24.

[26] 2021 IRP, Vol. I, Section 5 at 24.

[27] 2021 IRP, Vol. I, Section 5 at 25.

[28] 2021 IRP, Vol. I, Section 5 at 21, FN25.

[29] 2021 IRP, Vol. I, Section 5 at 25-27.

Laboratory Annual Technology Baseline, both the capital and annual operation and maintenance (O&M) costs were expected to fall.[30] Distributed energy resources were expected to reach previously assumed 2050 levels by 2035 as costs continue to fall. The number of EVs were expected to grow from 3,737 to 38,000 over the 2020-2036 period.[31] Finally, a greater proportion of new homes were projected to add electric space heating versus gas. Following new customer growth, the positive effects on energy sales is offset by continued appliance and equipment gains and relatively smaller urban housing.[32]

CHANGES SINCE THE 2018 IRP

There have been several significant changes since the Companies' 2018 IRP. To begin with, without counting the direct and indirect effects of the new Ford battery plant, overall energy requirements have been slowly declining. Increased consumption from customer growth has been offset by declines in the mining sector and gains in industrial production efficiency and efficiencies from residential and commercial end uses. Both the increased adoption of electric heating versus natural gas and EVs will also be a positive factors for increasing energy requirements. These positive factors will be offset by increased appliance and equipment efficiencies, smaller more energy efficient homes, a greater penetration of distributed generation, and a continued decline in the mining sector.[33]

On net, the Companies' forecasted energy requirements in the 2021 IRP versus the 2018 IRP are slightly below 2018 levels (277 GWh lower) with the difference growing steadily through 2036 (1,229 GWh lower). In the 2021 IRP, energy requirements decline negative 0.2 percent annually from 32,229 GWh to 31,289 GWh over the 2021-2036 forecast period.[34] Similarly, forecast peak demand is lower than in the 2018 IRP. The forecast 2021 summer peak ranges from 182 MW to 303 MW lower than the 2018 IRP. The forecast winter peak ranges from 201 MW to 431 MW lower than the 2018 IRP. For the 2021 IRP, forecast summer peak declines at the annual rate of 0.16 percent from 6,168 MW to 6,026 MW over the forecast period. The winter peak declines slowly at the annual rate of 0.03 percent from 5,898 MW in 2022 to 5,737 MW.[35]

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[30] 2021 IRP, Vol. I, Section 5, at 27-29; *see also* 2021 IRP, Vol. I, Section 5, at 21 (indicating that generation cost forecasts are based on the "Moderate" case forecast in NREL's 2021 ATB); 2021 IRP, Vol. III, 2021 IRP Reserve Margin Analysis, at 21, Table 11 (in which the Companies note that SCCT costs are derived from the 2018 ATB); 2021 IRP, Vol. III, 2021 Long Term Resource Planning Analysis, at 11, FNs 6, 7, and 9 (referencing the NREL 2021 ATB as the data source for overnight capital costs); Response to Staff's First Request, Item 14.

[31] 2021 IRP, Vol. I, Section 5 at 30-31.

[32] 2021 IRP, Vol. I, Section 5 at 33-34.

[33] 2021 IRP, Vol. I, Section 6 at 1.

[34] 2021 IRP, Vol. I, Section 6 at 1, Table 6-1.

[35] 2021 IRP, Vol. I, Section 6 at 2, Table 6-2.

The Companies currently offer five Demand-Side Management Energy Efficiency (DSM-EE) programs to residential and nonresidential customers.[36] The current DSM portfolio was approved in Case No. 2017-00441,[37] and Companies received approval to continue the programs through December 31, 2025.[38] The Companies acknowledge that the successful deployment of DSM could reduce or defer the need for peaking resources, especially through the application of battery storage.[39] However, new DSM programs were not directly evaluated. Instead, the IRP identified opportunities for new DSM programs to be evaluated when the Companies' advanced metering infrastructure (AMI) has been implemented.[40] The ongoing effects of DSM-EE programs is inherent in the Companies' modeling, but the incremental effects of the programs was not included beyond 2025, despite the fact that the IRP is a long range planning document replete with assumptions regarding future customer behavior and regulatory actions.[41] On a combined basis, the DSM-EE program annual reductions in energy use grow from 633 GWh in 2021 to 756 GWh in 2025 and remain at that level through 2036. Summer demand reductions went from 374 MW in 2021 to 369 MW in 2025 and were assumed to remain at that level through 2036. Winter demand reductions were projected to grow from 200 MW in 2021 to 223 MW in 2025 and were assumed to remain at that level through 2036.[42]

COMBINED COMPANIES BASE CASE ENERGY FORECAST

The base case energy forecast for LG&E exhibited a relatively flat curve over the 2018–2033 forecast period. KU's total energy requirements, including company use and losses, exhibited a slow decline ranging from 19,976 GWh in 2021 to 19,212 GWh in 2036, LG&E's energy requirements exhibit similar pattern, ranging from 12,253 GWh in 2021 to 12,077 GWh by 2036.[43] On a combined company basis, energy requirements range from 32,231 GWh declining to 31,287 GWh over the forecast period.[44] As

[36] 2021 IRP, Vol. I, Section 8 at 19-20.

[37] *See* Case No. 2017-00441, *Electronic Joint application of Louisville Gas and Electric Company and Kentucky Utilities Company for Review, Modification, and Continuation of Certain Existing Demand-Side Management and Energy Efficiency Programs* (Ky. PSC Oct. 5, 2018), Order.

[38] *See* Case No. 2017-00441, Oct. 5, 2018, Order. This program plan was revised in Case No. 2022-00123, *Electronic Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company to Enhance the Budget of An Existing Demand-Side Management and Energy Efficiency Program* (Ky. PSC May 20, 2022), Order.

[39] 2021 IRP, Vol. I, Section 5 at 8.

[40] 2021 IRP, Vol. I, Section 5 at 11 and 41.

[41] 2021 IRP, Vol. I, Section 8 at 21, 22, and 24-26, Table 8-11, Table 8-12, and Table 8-13.

[42] 2021 IRP, Vol. I, Section 8 at 24-26, Table 8-13.

[43] 2021 IRP, Vol. I, Section 7 at 8-9, Table 7-19 and Table 7-20. Note that the KU requirements include the Virginia ODP requirements. ODP operates in five counties in southwestern Virginia. Separately over the forecast period, ODP sales are expected to decline slowly from 682 GWh to 585 GWh.

[44] 2021 IRP, Vol. I, Section 7 at 8-9 Table 7-19, Table 7-20. Note that due to the proximity of filing the IRP, the simulative effects of the new Ford Motor Company battery plant are not include in the forecasts.

discussed previously, gains in energy awareness and efficiency overshadow any gains from customer and economic growth. The table below shows the combined Companies' forecasted energy GWh sales by class after DSM program effects.

Class Energy Sales Forecast (GWh)[45]

	Residential	Commercial	Industrial	Public Authority	Lighting	Sales for Resale	ODP / Virginia	Total Co. Calendar	Utility Use and Losses	Total Company
2021	10,206	7,640	8,614	2,519	45	393	683	30,100	2,131	32,231
2022	10,055	7,685	8,716	2,538	44	394	675	30,107	2,128	32,235
2023	9,985	7,640	8,702	2,530	44	395	665	29,961	2,118	32,079
2024	9,994	7,618	8,697	2,520	44	396	660	29,929	2,115	32,044
2025	9,935	7,571	8,647	2,505	44	397	650	29,749	2,089	31,838
2026	9,893	7,520	8,587	2,491	44	398	643	29,576	2,071	31,647
2027	9,851	7,472	8,594	2,485	44	399	635	29,480	2,052	31,532
2028	9,863	7,451	8,600	2,483	44	400	629	29,470	2,049	31,519
2029	9,801	7,406	8,586	2,478	44	400	615	29,330	2,038	31,368
2030	9,785	7,366	8,571	2,471	44	401	608	29,246	2,031	31,277
2031	9,792	7,339	8,565	2,468	44	402	603	29,213	2,030	31,243
2032	9,847	7,330	8,570	2,467	44	403	600	29,261	2,021	31,282
2033	9,830	7,296	8,552	2,461	44	403	593	29,179	2,015	31,194
2034	9,858	7,279	8,548	2,459	44	403	589	29,180	1,991	31,171
2035	9,894	7,266	8,546	2,457	44	403	586	29,196	1,991	31,187
2036	9,974	7,268	8,557	2,459	44	403	585	29,290	1,997	31,287

PEAK LOAD FORECAST

On a combined basis in the base case, the Companies are a summer-peaking utility. The summer peak declines from 6,229 MW to 6,026 MW. The winter peak declines from 5,898 MW to 5,737 MW.[46]

HIGH AND LOW ENERGY AND DEMAND REQUIREMENT FORECASTS

In addition to the base-case scenario forecast, the Companies produced high and low scenario energy and demand requirement forecasts. Relative to the base-case scenario, the high energy scenario assumes electric heat pumps replace gas furnaces over time in new and existing homes, EVs grow faster than in the base case and account for 50 percent of all new vehicles sold by 2030, 180 MW of new high load factor industrial

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See 2021 IRP Vol. I, Section 5, at 21, 34, footnotes 25 and 34. Nonetheless, the Companies do not anticipate needing additional generation capacity prior to 2028.

[45] 2021 IRP, Vol. I, Section 7 at 8-9, Table 7-19, Table 7-20.

[46] 2021 IRP, Vol. I, Section 5 at 37, Table 5-14.

growth, and customer growth is 50 percent higher (0.6 percent vs. 0.4 percent).[47] The base-case energy requirements over the forecast period decline from 32,229 GWh to 31,289 GWh. Similarly, the peak demand forecast in the base-case scenario declines from 6,168 MW to 6,026 MW over the forecast period. However, under the high growth scenario, over the forecast period, energy requirements rise from 32,239 GWh to 38,001 GWh[48] and the peak demand rises from 6,168 MW to 7,648 MW.[49] In the high growth scenario, new industrial demand initially drives growth and then electric vehicles and the growth in and conversion to heat pumps in new and existing homes results in the Companies transitioning to a winter peaking utility by 2027.[50]

In contrast to the base-case scenario, the low-energy-requirements forecast assumed the loss of 180 MW of industrial load, customer growth is 50 percent slower (0.2 percent vs. 0.4 percent), and the elimination of the 1 percent cap on net metering.[51] Recall, the base-case energy requirements over the forecast period decline from 32,229 GWh to 31,289 GWh. Similarly, the peak demand forecast base case scenario declines from 6,168 MW to 6,026 MW over the forecast period. However, under the low growth scenario, energy requirements decline more rapidly from 32,229 GWh to 28,064 GWh and peak demand declines slowly from 6,168 MW to 5,364 MW over the forecast period.[52] Note that the loss of the 180 MW of industrial load accelerates the decline over the forecast period. Also note that there is only a 43 MW difference between the summer and winter load forecasts in 2036. The tables below show the energy and demand scenario forecast results.

Energy Requirements Forecast After DSM (GWh) [53]

Year	Low Energy Scenario	Base Energy Scenario	High Energy Scenario
2021	32,229	32,229	32,239
2022	31,939	32,238	32,271
2023	31,719	32,079	32,152
2024	30,951	32,045	32,980
2025	30,702	31,839	33,039

[47] 2021 IRP Vol. I, Section 5 at 34.

[48] 2021 IRP Vol. I, Section 5 at 32, Table 5-13.

[49] 2021 IRP Vol. I, Section 5 at 37, Table 5-14. Note that base case peak demands are forecast summer peaks.

[50] 2021 IRP Vol. I, Section 5 at 35.

[51] 2021 IRP Vol. I, Section 5 at 34.

[52] 2021 IRP Vol. I, Section 5 at 37, Table 5-14. Note that base case peak demands are forecast summer peaks.

[53] 2021 IRP Vol. I, Section 5 at 32, 37, Table 5-13, Table 5-14.

2026	29,788	31,648	33,816
2027	29,595	31,532	34,019
2028	29,427	31,519	34,387
2029	28,980	31,370	34,651
2030	28,549	31,279	35,036
2031	28,444	31,243	35,425
2032	28,353	31,283	35,968
2033	28,144	31,196	36,358
2034	28,043	31,172	36,866
2035	28,005	31,188	37,368
2036	28,064	31,289	38,001

Demand Scenario Forecast After DSM (MW)[54]

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

RESPONSES TO 2018 STAFF RECOMMENDATIONS

[54] 2021 IRP Vol. I, Section 5 at 37, Table 5-14.

LG&E/KU responded to the recommendations regarding load forecasting in the Commission Staff's Report addressing LG&E/KU's 2018 IRP as indicated below.

- The report recommended that the potential impact of existing and future environmental regulations affecting the price of electricity and other economic variables continue to be examined by LG&E/KU as a part of their load forecasts and sensitivity analyses. LG&E/KU stated that the impacts are evaluated in the companies low energy requirements forecast.

- The report recommended that LG&E/KU closely monitor, discuss, and model the potential impacts of cost trends of distributed solar generation and EVs in both base case and sensitivity analyses and continue to monitor and incorporate anticipated changes in EE impacts in their forecasts and sensitivity analyses. LG&E/KU noted that Section 5(3) of the IRP summarized the potential impacts of distributed generation and EVs and energy efficiency assumptions in the base load forecast.

- The report recommended that LG&E/KU include an expanded and more robust discussion (including the reasonableness of the High and Low assumptions) of each of the factors used to shock the base case forecast and a disaggregated sensitivity analysis. LG&E/KU indicated that the 2021 IRP contains a discussion of the high and low load forecasts, the major driving assumptions, and the degree to which the Companies varied the assumptions as well as the disaggregated impact of each of the high and low case assumptions on the base case forecast.

- The report noted that it was not clear how the reserve margin analysis results would be affected by altering the weather assumptions to better reflect similar assumptions driving the base case and High Low energy and peak demand forecasts and recommended that LG&E/KU provide more robust, complete, and consistent explanations assumptions driving energy, load, and resource planning forecasts. LG&E/KU noted that the 2021 IRP more clearly explained their weather assumptions. The Companies specifically noted that they developed their long-term base, high, and low energy requirements forecasts with the assumption that weather will be average or "normal" in every year—meaning weather does not explain any differences between the base, high, and low peak demand forecasts. For reliability planning, a completely separate planning analysis focused on their ability to reliably serve load over a range of weather and unit availability scenarios.

- The report recommended that LG&E/KU include discussion and analysis of the increase in DERs on load forecasts, including behind the meter generation at residential, commercial and industrial customer locations, and stated that these should be evaluated separately and cumulatively and include a discussion of drivers encouraging and discouraging such development. LG&E/KU noted that they included a summary of the factors that impact DER economics and the assumptions underlying the Companies' DER forecasts, but they did not separately discuss the customer classes.[55]

INTERVENOR COMMENTS

Attorney General

The Attorney General noted that since LG&E/KU completed it's the analysis for its 2021 IRP that the Ford Motor Company announced the construction of the twin battery plants in Hardin County, Kentucky for which the Companies will provide electric service. The Attorney General argued that the Companies' energy requirements would likely increase as a result of anticipated new load from the planned twin Ford Motor Company vehicle battery plants in Hardin County.[56]

The Attorney General also noted that another vehicle battery manufacturer announced plans to construct a plant in Bowling Green, Kentucky. Although the Companies will not serve that plant, the Attorney General argued that satellite industries from that plant and the Ford plants will likely be located within the Companies' service territories. Thus, the Attorney General asserted that those industries should increase the LG&E/KU's load.[57]

The Attorney General also noted that the IRP sets forth a potential scenario toward the end of the IRP planning period in which LG&E could become a winter-peaking utility under a high energy requirements scenario arising, in part, from increased adoption of electric space heating and electric vehicle penetration. The Attorney General stated that such a change could have significant ramifications for the combined Companies and their customers. The Attorney General encouraged the Companies to continue their analysis and reporting on any trends regarding this issue.[58]

Sierra Club

Sierra Club asserted that the IRP did not adequately discuss the implications of, and plans for, the growth of EVs.[59]

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[55] 2021 IRP, Vol. III, LG&E/KU's Response to Staff Recommendations at 1-4.

[56] Attorney General's Comments (filed April 22, 2022) at 2-3.

[57] Attorney General's Comments at 2-3.

[58] Attorney General's Comments at 2-3.

[59] Sierra Club's Initial Comments on the 2021 Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company (filed Apr. 22, 2022) (Sierra Club's Initial Comments) at 14.

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 based on their projected effects on load.[60] 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 2018 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 Section 5 of this Report.

2019-2025 DSM/EE PROGRAM PLAN

LG&E/KU's current DSM/EE Program Plan for 2019 was approved in Case No. 2017-00441[61] and was subsequently modified in Case Nos. 2019-00105[62] and 2022-00123.[63] The 2019-2025 DSM/EE Program Plan currently includes the following approved programs:[64]

1. Residential and Small Nonresidential Demand Conservation Program – This program reduces peak demand with load-control devices that cycle central air conditioning systems, heat pumps, electric water heater, and pool pumps. This program is currently in maintenance mode status, and LG&E/KU is not currently investing in or deploying new load-control devices. Participants receive an end of cooling season credit if a qualifying Load Control Event is called during the season and if the customer was enrolled during at least one qualifying Load Control Event in that season.[65]

2. Large Nonresidential Demand Conservation Program – Designed to reduce peak load, this program employs switches or interfaces to customer equipment in large commercial and industrial businesses. The program communicates with the switches or interfaces to cycle the equipment. The Commission approved the addition of industrial

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

[61] *See* Case No. 2017-00441, Oct. 5, 2018 Order.

[62] Case No. 2019-00105*, Electronic Demand Side Management Filings of Louisville Gas and Electric Company and Kentucky Utilities Company* (Ky. PSC Aug. 19, 2019), Order.

[63] Case No. 2022-00123, *Electronic Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company to Enhance the Budget of an Existing Demand-Side Management and Energy Efficiency Program* (Ky. PSC May 20, 2022), Order.

[64] Case No. 2017-00441, Oct. 5, 2018 Order at 4.

[65] Case No. 2017-00441, Oct. 5, 2018 Order at 5–6.

customers to this program however, industrial customers may opt out of the program and associated charges if the customer has installed individual meters and implemented cost-effective energy-efficiency measures not subsidized by other rate classes for the loads served by such meters.[66]

3. Low Income Weatherization Program (WeCare) – The WeCare program is an education and weatherization program designed to reduce energy consumption of low-income customers. The program provides energy audits, energy education, and installation of weatherization and energy conservation measures to single family homes. The program also allows master-metered multifamily dwellings to qualify for program services.

4. Nonresidential Rebates Program – This program is designed to increase the implementation of EE measures by providing financial incentives to assist with the replacement of aging and less efficient equipment and for new construction built beyond code requirement for commercial and industrial customers. LG&E/KU provide prescriptive incentives that are available for energy audits and high efficiency equipment such as lighting, motors, pumps, variable frequency drives, and air conditioning retrofits installed in existing buildings. Custom incentives are available when customers implement energy-efficient technologies not currently covered in the prescriptive component of the program. Custom projects are offered for retrofit applications in existing buildings and are subject to preapproval. New construction rebates are available on savings over code plus bonus rebates for Leadership in Energy & Environmental Design (LEED) certification.[67] This program's budget was increased in Case No. 2022-00123.[68]

5. Advanced Metering Systems (AMS) Customer Service Offering – This program was first approved in Case No. 2014-00003[69] for 5,000 LG&E and 5,000 KU residential and general service customers on a first-come-first-served basis. In Case No. 2018-00005,[70] the Commission ordered the Companies to increase the number of meter offerings to 10,000 for LG&E and 10,000 for KU for those residential or small commercial

[66] Case No. 2017-00441, Oct. 5, 2018 Order at 6.

[67] Case No. 2017-00441, Oct. 5, 2018 Order at 6; Case No. 2022-00123, *Electronic Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company to Enhance the Budget of an Existing Demand-side Management and Energy Efficiency Program* (Ky. PSC May 20, 2022), Order at 3.

[68] Case No. 2022-00123, May. 20, 2022 Order at 6.

[69] Case No. 2014-00003, *Louisville Gas and Electric Company and Kentucky Utilities* (Ky. PSC Nov. 14, 2014), Order.

[70] Case No. 2018-00005, *Electronic Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for a Certificate of Public Convenience and Necessity for Full Deployment of Advanced Metering Systems* (Ky. PSC Aug. 30, 2018), Order.

customers who elected to participate. In Case Nos 2020-00350[71] and 2020-00349,[72] LG&E/KU were granted a CPCN for the full deployment of AMS metering. Through AMS, participants' consumption is captured, communicated, and stored, allowing participants to monitor their hourly usage through an online portal (MyMeter) within two business days.

In addition to demand side resources implemented as part of LG&E/KU's 2019-2025 DSM/EE Program Plan, LG&E/KU has a Curtailable Service Rider, which allows it to curtail the load of certain large customers who voluntarily sign up for the program in exchange certain consideration provided by the utility to the customer.

<u>DSM/EE PROGRAM ENERGY AND DEMAND IMPACTS</u>

The load changes for the 2019-2025 DSM/EE Program Plan are embedded in the load forecast for energy and demand. The following table summarizes the incremental energy impact and the summer and winter peak demand impact of LG&E/KU's current DSM/EE programs:[73]

DSM Energy Reduction (GWh)	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
AMS Customer Service Offering	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Residential and Small Nonresidential Demand Conservation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
WeCare	5.1	5.1	5.1	5.1	5.1	0.0	0.0	0.0	0.0	0.0
Large Nonresidential Demand Conservation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DSM Summer Peak Demand Reduction (MW)	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
AMS Customer Service Offering	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Residential and Small Nonresidential Demand Conservation	(7.7)	(7.4)	(7.0)	(6.8)	(6.4)	0.0	0.0	0.0	0.0	0.0
WeCare	0.4	0.4	0.4	0.4	0.4	0.0	0.0	0.0	0.0	0.0
Large Nonresidential Demand Conservation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

[71] Case No. 2020-00350, *Electronic Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Rates, A Certificate of Public Convenience and Necessity to Deploy Advanced Metering Infrastructure, Approval of Certain Regulatory and Accounting Treatments, and Establishment of a One-Year Surcredit* (Ky. PSC Dec. 12, 2021), Order.

[72] Case No. 2020-00349, *Electronic Application of Kentucky Utilities Company for an Adjustment of Its Electric Rates, a Certificate of Public Convenience and Necessity to Deploy Advanced Metering Infrastructure, Approval of Certain Regulatory and Accounting Treatments, and Establishment of a One-Year Surcredit* (Ky. PSC Dec. 6, 2021), Order.

[73] 2021 IPR, Vol. I, Section 8, at 24, Table 8-12.

DSM Winter Peak Demand Reduction (MW)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
AMS Customer Service Offering	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Residential and Small Nonresidential Demand Conservation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
WeCare	0.4	0.4	0.4	0.4	0.4	0.0	0.0	0.0	0.0	0.0
Large Nonresidential Demand Conservation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

When LG&E/KU showed the results of their resource assessment modeling, discussed in more detail below, they reflected the effects of all DSM/EE programs, except portions of the demand-conservation programs, based on the extent to which they reduced peak winter and summer demand.[74] Conversely, portions of demand-conservation programs (61 MW summer, 0 MW winter) were included in the IRP plan as resources to meet load along with LG&E/KU's Curtailable Service Rider (127 MW summer and winter).[75] However, as discussed below, the IRP did not fully explain the manner in which those resources were assessed.

For the 2021 IRP, LG&E/KU did not directly evaluate new DSM/EE programs or other demand side resources as potentially resources to the reduce and thereby meet its load. Rather, LG&E/KU indicated that they sought to identify potential DSM/EE opportunities that support and are associated with the implementation of AMI, but they had not done so when the IRP was filed.[76]

RESPONSES TO 2018 STAFF RECOMMENDATIONS

The 2018 IRP Commission Staff Report made the following recommendations regarding LG&E/KU's DSM/EE programs.

- The report recommended that LG&E/KU continue the stakeholder process through the DSM Advisory Group and strive to include recommendations and inputs from the stakeholders, recommended that the meetings be more than informational, and recommended that any changes to the DSM-EE program must be discussed in full including a transparent analysis of the cost and benefits inputs.

- The report recommended that LG&E/KU continue to identify cost-effective EE 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.

- The report recommended that LG&E/KU consider making AMI usage data available to customers that is closer aligned to real-time data and to consider

[74] *See* 2021 IRP, Vol. I, Section 8 at 28-29, Table 8-15, Table 8-16.

[75] *See* 2021 IRP, Vol. I, Section 8 at 28-29, Table 8-15, Table 8-16.

[76] 2021 IRP, Vol. I, Section 5 at 3.

prepay metering and real-time pricing options to enhance the customer experience for those customers participating in the AMI Pilot Program. The report also recommended that LG&E/KU examine the feasibility of peak time rebate programs and time-of-use rates.

- The report recommended that LG&E/KU 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.

- The report recommended that LG&E/KU continue exploring cost-effective DSM-EE as a method to avoid costly capital investments should energy margins diminish over time. In response to that recommendation, LG&E/KU referred to the response summarized above regarding the first DSM/EE recommendation.

Regarding the stakeholder process, LG&E/KU held a DSM Advisory Group meeting in September 2021 to begin processing the upcoming DSM filing, planning, and development process.[77] Further, LG&E/KU have hired Cadmus, Inc. (Cadmus) to assist in the development of the upcoming DSM/EE filing. Cadmus will identify cost-effective EE opportunities that will enhance the current offerings.[78] LG&E/KU stated that they plan to continue evaluating and improving through their Process and Impact Evaluation, Measurement, & Verification of programs as the addition of AMI interval data becomes available.[79]

INTERVENOR COMMENTS

Louisville/Jefferson County Metro Government

Louisville Metro stated that households that spend more than 6 percent on home energy are considered energy burdened and those that spend more than 10 percent are considered severely energy burdened. Louisville Metro noted that 67 percent of households with income below 200 percent of the federal poverty level face an energy burden and of those 60 percent face a severe energy burden. Louisville Metro stated that half of low-income households in Louisville have an energy burden greater than 7.6 percent and a quarter of them have an energy burden over 12.7 percent. Louisville Metro argued that home efficiency retrofits will play a significant role in both reducing greenhouse gas emissions and lowering energy burden for low-income families in Louisville.[80]

[77] 2021 IRP, Vol. III, LG&E/KU's Response to Staff Recommendations at 4.

[78] 2021 IRP, Vol. III, LG&E/KU's Response to Staff Recommendations at 4.

[79] 2021 IRP, Vol. III, LG&E/KU's Response to Staff Recommendations at 4.

[80] Louisville/Jefferson County Metro Government's Comments to the Louisville Gas and Electric Company and Kentucky Utilities Company 2021 Joint Integrated Resource Plan (Louisville Metro's Comments on LG&E/KU's 2021 IRP) (filed Apr. 22, 2022) at 2-3.

Louisville Metro stated that in 2008 LG&E/KU set a goal to save enough energy to prevent the need for a new power plant, and due to extensive DSM program offerings during that time, LG&E saved over 1.15 million MWhs. However, Louisville Metro noted that only a few of those programs are still in place because they were determined to no longer be cost-effective, despite the cost of DSM programs being projected to drop from $45 million to $14 million per year. Louisville Metro noted that current DSM offerings for residential customers now only include WeCare and Residential Demand Conservation, and that only the WeCare program provides direct savings to low-income families. Louisville Metro stated that this IRP defers the evaluation of any new DSM programs until implementation of advanced meters.[81]

Louisville Metro argued that the best practices for programs to support low-income customers include:

1. Offering a range of eligible measures;
2. Coordinating with Weatherization Assistance Program and other organizations on program delivery;
3. Providing a portfolio of programs;
4. Addressing health and safety;
5. Developing duel fuel and fuel-blind programs; and
6. Coordinating with bill payment assistance programs.

Louisville Metro recommended that the Commission encourage LG&E/KU to maximize the utilization of EE programs particularly for low-income customers in this IRP and all subsequent resource planning activities, which it argued would lower energy burdens for residents and address concerns around meeting peak demand, particularly during extreme cold and heat events.[82]

Sierra Club

Sierra Club criticized LG&E/KU's heavy reliance on fossil fuels through the mid-2030s. Sierra Club generally argued that this reliance was unnecessary due to availability of reliable, economical alternatives, including renewables, battery storage, and DSM/efficiency options.[83] Sierra Club criticized LG&E/KU's failure to evaluate new DSM/EE programs and argued that the IRP regulation requires it to evaluate new DSM/EE programs.[84]

Joint Intervenors

[81] Louisville Metro's Comments on LG&E/KU's 2021 IRP at 3-4.

[82] Louisville Metro's Comments on LG&E/KU's 2021 IRP at 4-5.

[83] Sierra Club's Initial Comments at 13-14.

[84] Sierra Club's Post-Hearing Comments on the 2021 Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company (filed Aug. 16, 2022) (Sierra Club's Post-Hearing Comments) at 6-7.

Joint Intervenors asserted that LG&E/KU's limited examination of demand side resources undermined the IRP. They noted that the regulation required DSM and EE programs to be considered as part of the IRP. Thus, they argued LG&E/KU's failure to consider such programs was unreasonable on its face.[85]

Joint Intervenors also asserted that EE programs offer the least-cost resource available to LG&E/KU. They stated that the industry-wide LCOE savings from EE programs "has been calculated as roughly $0.0240 to $0.0280 per kilowatt hour saved (or $24 to $28 per megawatt hour saved)" and that the LCOE compares favorably to the gas peakers in the Companies' resource planning.[86] Joint Intervenors also argued that EE programs "return value to customers by reducing their energy waste, thereby lessening overall usage and overall bills."[87]

Joint Intervenors indicated that LG&E/KU's current DSM/EE programs "have produced cumulative energy savings of approximately 1,410 GWh and reduced gross demand by over 486 MW."[88] They asserted that the past savings are likely just a fraction of the cost-effective efficiency savings available in the Companies' service territories. They stated that some utilities have been able to reduce energy usage by as much as 1 percent, which they indicated would be 171,760 MWh based on LG&E/KU's load.[89] They also noted that DSM/EE programs have additional benefits by reducing emissions associated with supply-side resources and asserted that the EPA estimated the value of health benefits associated with those reduced emissions to be 2.70 to 6.10 cents per kilowatt hour saved.[90]

Joint Intervenors recommended that LG&E/KU apply principles from the National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources (NSPM-DER). They asserted that the NSPM-DER offers a comprehensive, objective, policy- and technology-neutral, and economically sound guidance for developing jurisdiction-specific approaches to benefit-cost analyses of distributed energy resources.[91] They also argued that investments in DSM-EE programs can be scaled up by employing pay-as-you-save programs.[92]

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[85] Joint Intervenors' Initial Comments on Louisville Gas and Electric Company and Kentucky Utilities Company's Joint 2021 Integrated Resource Plan (Joint Intervenors' Initial Comments) (filed Apr. 22, 2022) at 22.

[86] Joint Intervenors' Initial Comments at 23.

[87] Joint Intervenors' Initial Comments at 24.

[88] Joint Intervenors' Initial Comments at 25.

[89] Joint Intervenors' Initial Comments at 25-26.

[90] Joint Intervenors' Initial Comments at 27-28.

[91] Joint Intervenors' Initial Comments at 29.

[92] Joint Intervenors' Initial Comments at 30-31; *see also* Joint Intervenors' Supplemental Comments on Louisville Gas and Electric Company and Kentucky Utilities Company's Joint Integrated Resource Plan (filed Aug. 22, 2022) (Joint Intervenors' Supplemental Comments) at 20-25; Joint Intervenors' Response to Supplement Post-Hearing Comments on Louisville Gas and Electric Company and Kentucky Utilities

Joint Intervenors argued that the LG&E/KU's assumption that there would be 6 percent savings as a result of end-use efficiency gains by the end of the planning period did not make up for the Companies' failure to evaluate DSM/EE programs in the IRP. They noted that all load forecasts include efficiency gains that organically reduce customer usage and that the 6 percent savings assumed by LG&E/KU is insufficient to account for that organic savings and what could be achieved with utility driven DSM/EE programs.[93]

LG&E/KU RESPONSES TO INTERVENOR COMMENTS

LG&E/KU argued that contrary to certain questioning at the hearing that they complied with the IRP regulation regarding DSM-EE modeling and discussion in the 2021 IRP. The Companies asserted that the IRP regulation does not require utilities to develop or even consider specific new DSM-EE programs as part of the IRP process, but rather, only requires utilities to describe and report on DSM-EE efforts that might be planned or underway and are included in utilities' IRPs. LG&E/KU stated that their IRP fully accounts for existing DSM-EE programs and projections for the currently approved 2018-2025 DSM-EE Program Plan, and it includes an assumed continuation of DSM-EE programs that would achieve the same levels of demand and energy savings as those projected to be achieved by 2025 for the remainder of the IRP planning period.[94]

LG&E/KU disagreed with claims that they have given short shrift to DSM and EE in their IRP. The Companies stated that their load forecast implicitly assumed that DSM and other customer-initiated energy efficiency improvements will continue throughout the IRP analysis period. Moreover, the Companies claimed that "DSM and customer-initiated energy efficiency improvements are assumed to achieve savings of over 6% of residential and small commercial sales—more than 800 GWh—by the end of the IRP planning period." The Companies claimed that it would be inaccurate to model different levels of DSM in the abstract, because DSM programs must target specifical end-uses that contribute to reducing the Companies' load when there are benefits associated with reducing load. The Companies stated that "[o]nly then can [they] compare the cost of achieving those load savings to other alternatives."[95] The Companies also argued that their approach to DSM/EE programs in the 2021 IRP was consistent with prior IRPs and Commission Staff's reports.[96]

Company's Joint Integrated Resource Plan (filed Sept. 6, 2022) (Joint Intervenors' Response to Supplemental Comments) at 5-12.

[93] Joint Intervenors' Supplemental Comments at 21-25.

[94] Supplement Post-Hearing Comments of Louisville Gas and Electric Company and Kentucky Utilities Company (filed Aug. 22, 2022) (LG&E/KU's Supplemental Comments) at 11-12.

[95] Response Comments of Louisville Gas and Electric Company and Kentucky Utilities Company (filed May 20, 2022) (LG&E/KU's Responsive Comments) at 45-47; *see also* LG&E/KU's Supplemental Comments at 11-15.

[96] Supplement Post-Hearing Responsive Comments of Louisville Gas and Electric Company and Kentucky Utilities Company (LG&E/KU's Response to Supplement Comments) at 6.

SECTION 4

SUPPLY-SIDE ASSESSMENT AND INTEGRATION

This section reviews LG&E/KU's supply-side assessment and its integration of supply and demand-side assessments and load to produce a resource acquisition plan. This section also reviews the parties' comments regarding LG&E/KU's supply-side assessment and integration. Commission Staff's discussion of and recommendations regarding those issues are discussed in Section 5 of this Report.

EXISTING CAPACITY

Since the Companies' 2018 IRP, the following units have been retired: Brown units 1 and 2 (272 MW), Cane Run 11 (14 MW) and Paddy's Run 11 (12 MW). In addition, the capacity purchase and tolling agreement with Bluegrass Generation (165 MW) has expired. The Companies utilize multiple existing generation resources. The Companies' baseload capacity includes 11 coal units with a total summer net capacity of 4,867 MW (4,910 MW winter capacity) and one Natural Gas Combined Cycle (NGCC) unit with a net summer capacity of 662 MW (683 MW winter). The Companies operate 18 load following Simple Cycle Combustion Turbine (SCCT) peaking units with a total net summer capacity of 2,068 MW (2,324 MW winter). Renewable generation resources supply a total net summer capacity of 105 MW (72 MW winter).[97] On a combined basis, the Companies' current generation resources have a net summer capacity of 7,702 MW (7,989 MW winter).

Given the current and pending changes in environmental regulations and possible new laws and regulations to reduce CO_2 emissions, the Companies' analyses assumed that all remaining CO_2 emitting units are retired at the end of their book lives. Also, the Companies' small frame SCCTs will be retired due to age and inefficiency. Addition, the analysis assumes that in 2025 a major maintenance event will force the SCCT units to retire.[98]

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 based on the projected loads discussed above.[99] The Companies used the PLEXOS resource expansion model to

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[97] 2021 IRP, Vol. I, Section 5, at 6, Table 5-1; 2021 IRP, Vol. III, Long Term Planning Analysis, at 9, Table 6. Note Table 5-1 includes the Companies' share of the Ohio Valley Electric Corporation (OVEC) generation capacity under coal generation. Per Table 6, the Companies' agreement with OVEC supplies 152 MW summer capacity and 158 winter capacity. Also, note that there are slight differences in the generation capacities listed between Table 5-1 and Table 6.

[98] *See* 2021 IRP, Vol. I Section 5 at 16, Table 5-4.

[99] 2021 IRP, Vol. III, Long Term Planning Analysis at 6.

simulate and optimize resources decisions under various scenarios, but it first considered and identified resources to be assessed.

LG&E/KU considered nuclear, SCCT with Carbon Capture and Storage (CCS), NGCC without CCS, and pump hydro energy storage facilities, among a few other resources, but ultimately did not include those resources as options in the resource expansion model.[100] LG&E/KU's resource expansion model only included large frame SCCTs without CCS, NGCC with CCS, four and eight hour batteries, and utility scale solar and wind located in Kentucky.[101]

LG&E/KU's resource expansion model used the following key criteria to evaluate the resources assessed. For dispatchable resources, criteria include capacity, heat rate, overnight capital cost, fixed Operation & Maintenance (O&M), firm gas cost, variable O&M, and fuel cost. For non-dispatchable resources, criteria include capacity, contribution to peak, net capacity factor, overnight capital cost, fixed O&M cost, investment tax credits and production tax credits.[102]

The table below shows the generation resources made available to the Plexos model.

Dispatchable and Non-Dispatchable Generation Resources[103]

Dispatchable Resources (2022 Installation; 2022 Dollars)

	SCCT	NGCC w/CCS	NGCC w/o CCS	Battery Storage 4-hour	Battery Storage 8-hour
Summer Capacity (MW) [1]	220	513	513	1+	1+
Winter Capacity (MW) [1]	248	539	539	1+	1+
Heat Rate (MMBtu/MWh)[2]	9.7	7.2	6.4	N/A	N/A
Capital Cost ($/kW) [2]	885	2,304	1,008	1,274	2,300
Fixed O&M ($/kW-yr) [2]	22	69	29	32	58
Firm Gas Cost ($/kW-yr)[3]	22	22	19	N/A	N/A
Variable O&M ($/MWh) [2]	5.24	6.08	1.85	N/A	N/A
Fuel Cost ($/MWh)	27.45	20.23	17.98	N/A	N/A

Non-Dispatchable Resources (2022 Installation; 2022 Dollars)

[100] 2021 IRP, Vol. I, Section 5 at 40-41.

[101] 2021 IRP, Vol. III, Long Term Planning Analysis at 10.

[102] 2021 IRP, Vol. I, Section 5, Table 5-15 and Table 5-16 at 40.

[103] 2021 IRP, Vol. III, Long Term Planning Analysis at 11, Table 8 and Table 9; Response to Staff's First Request, Item 26h. Note that NGCC w/o CCS was included in the table for comparison purposes only and was not included in the Companies' IRP analyses.

	KY Solar	KY Wind
Summer Capacity (MW)[4]	100+	100+
Winter Capacity (MW) [4]	100+	100+
Contribution to Summer Peak	79%	24%
Contribution to Winter Peak	0%	32%
Net Capacity Factor[2]	25.1%	27.4%
Capital Cost ($/kW) [2]	1,305	1,325
Fixed O&M ($/kW-yr) [2]	23	44
Investment Tax Credit	26%	N/A
Production Tax Credit ($/MWh)[5]	N/A	15

1. NREL 2021 ATB did not specify capacity values. Capacities are typical of installation capacity values.
2. NREL's 2021 ATB cost forecasts in real 2019 dollars inflated to nominal dollars at 2 percent annually.
3. Firm gas transportation costs based on cost of firm gas transportation at Cane Run 7.
4. NREL 2021 ATB did not specify capacity values. Capacities shown are typical installation capacity values. Solar and wind capacity values are modeled in 100 MW increments.
5. A production tax credit of $15 per MWh is included for the first 10 years.

RESERVE MARGIN ANALYSIS

Similar to the 2018 IRP, the Companies utilized two different but related models to develop an optimal reserve margin. Both the Equivalent Load Duration Curve (ELDC) Model and the Strategic Energy Risk Valuation Model (SERVM) are used to estimate the number of loss of load events (LOLE) in 10 years over a range of reserve margins, as well as reliability and generation production costs based on equivalent load duration curves. Key inputs to the models include the study year (2025), which is the year of Mill Creek 1's planned retirement and the assumed retirement of the small frame SCCTs.[104] Additional inputs include neighboring regions (MISO, PJM, and TVA) each modeled as a single market, generation unit availability (equivalent forced outage rates (EFOR)), fuel prices, interruptible contracts, available transmission capacity, load (amounts and timing), marginal resource costs, the value of lost load (interrupted manufacturing processes, lost productivity and product, damage to electrical services and discomfort), spinning reserves, and scarcity pricing (market prices exceed marginal cost of supply).[105] Various scenarios were run adding and retiring generation resources in both summer and winter.[106] The results of both the ELDC and SERVM model analyses were consistent. The high end of the Companies' high end reserve margin range is the reserve margin required to meet the 1-in-10 LOLE physical reliability guideline.[107] Based on the analyses results, the Companies conclude that guideline requires a 24 percent summer and 35 percent winter reserve margin. The low end of the reserve margin range is estimated

[104] 2021 IRP, Vol. III, 2021 IRP Reserve Margin Analysis at 11-12.

[105] 2021 IRP, Vol. III, 2021 IRP Reserve Margin Analysis at 12-22.

[106] 2021 IRP, Vol. III, 2021 IRP Reserve Margin Analysis at 22-29.

[107] 2021 IRP, Vol. III, 2021 IRP Reserve Margin Analysis at 27.

based on the increase in load that would require the addition of an SCCT.[108] Based on the ELDC model, the addition of approximately 300 MW load (all else being equal) decreases the reserve margin to 17 percent summer and 26 percent winter and the reliability and production cost benefits of adding new SCCT capacity would outweigh the cost of capacity.[109] The Companies' conclude that its going forward 2021 target reserve margin range is 17-24 percent summer and 26-35 percent winter.[110]

The table below presents the Companies' Base Case summer and winter peak demand and resource summary highlighting dates where resources are either added or retired.[111] Over the 2022-2036 forecast period, the Companies assume that unit retirements will include Mill Creek 1 (300 MW summer, 300 MW winter) in 2024, Haefling 1-2 and Paddy's Run 1-2 (47 MW summer, 55 MW winter) in 2025, Mill Creek 2 and Brown 3 (709 MW summer, 713 MW winter) in 2028, Ghent 1-2 and Brown 9 (1,081 MW summer, 1,103 MW winter) in 2034, Brown 8 and 10 (242 MW summer, 266 MW winter) in 2035, and Brown 11 (121 MW summer, 128 MW winter) in 2036. In addition, the Companies will add 100 MW of solar power from Rhudes Creek Solar in 2023 and 160 MW power purchase agreement through the Companies' Green Tariff Option in 2025. Solar capacity values reflect 78.6 percent contribution to summer peak based on the LG&E/KU's experience with its existing units and zero percent contribution to winter peak because winter peak occurs at night.[112] The optimal plan also calls for the addition of 2 SCCTs (220 MW summer and 248 MW winter) and 500 MW solar in 2028,[113] 4 SCCTs and 1,600 MW solar in 2034, 100 MW batteries in 2035 and in 2036.[114]

Summer Peak Demand and Resource Summary (MW)

	2021	2022	2023	2024	2025	2028	2034	2035	2036
Gross Peak Load	6,456	6,522	6,500	6,485	6,461	6,378	6,331	6,334	6,337
DSM	-288	-294	-300	-305	-311	-311	-311	-311	-311
Net Peak Load	6,168	6,229	6,201	6,179	6,150	6,067	6,020	6,023	6,026
Existing Capability(1)	7,702	7,702	7,702	7,702	7,702	7,702	7,702	7,702	7,702
CSR	127	127	127	127	127	127	127	127	127

[108] 2021 IRP, Vol. III, 2021 IRP Reserve Margin Analysis at 27.

[109] 2021 IRP, Vol. III, 2021 IRP Reserve Margin Analysis at 27; *see also* 2021 IRP, Vol. I, Section 5 at 41-42.

[110] 2021 IRP, Vol. III, 2021 IRP Reserve Margin Analysis at 29-30.

[111] 2021 IRP, Vol. I, Section 8 at 12, 28, and 29, Table 8-3, Table 8-15 and Table 8-16; *see also* 2021 IRP, Vol. III, 2021 IRP Long-Term Resource Planning Analysis at 20 and 24, Table 17 and Table 22.

[112] 2021 IRP, Vol. I, Section 6 at 7, footnotes 52, 53, 54, and 55, Table 6-5; 2021 IRP, Vol. III, 2021 IRP Long-Term Resource Planning Analysis at 10, Table 7; *see also* 2021 IRP, Vol. I, Section 5 at 42.

[113] 2021 IRP, Vol. III, 2021 IRP Long-Term Resource Planning Analysis at 20 and 24, Table 17, FN19.

[114] 2021 IRP, Vol. III, 2021 IRP Long-Term Resource Planning Analysis at 20, Table 17.

DCP	63	61	60	58	56	52	45	44	43
Retirements / Additions									
Coal	-300	-300	-300	-300	-300	-1,009	-1,969	-1,969	-1,969
Large-Frame SCCTs	0	0	0	0	0	0	-121	-363	-484
Small-Frame SCCTs	0	-14	-14	-14	-61	-61	-61	-61	-61
New SCCTs	0	0	0	0	0	440	1,320	1,320	1,320
New Solar	0	0	79	79	204	597	1,855	1,855	1,855
New Battery Storage	0	0	0	0	0	0	0	100	200
Total Supply	7,592	7,576	7,653	7,651	7,728	7,848	8,897	8,754	8,732
Reserve Margin	1,424	1,348	1,452	1,472	1,578	1,780	2,877	2,732	2,706
Reserve Margin %	23.1%	21.6%	23.4%	23.8%	25.7%	29.3%	47.8%	45.4%	44.9%

Winter Peak Demand and Resource Summary (MW)

	2021	2022	2023	2024	2025	2028	2034	2035	2036
Gross Peak Load	6,053	6,192	6,173	6,165	6,142	6,088	6,026	6,030	6,048
DSM	-288	-294	-300	-305	-311	-311	-311	-311	-311
Net Peak Load	5,765	5,898	5,874	5,859	5,831	5,777	5,715	5,719	5,737
Existing Capability(1)	7,973	7,973	7,973	7,973	7,973	7,973	7,973	7,973	7,973
CSR	127	127	127	127	127	127	127	127	127
DCP	0	0	0	0	0	0	0	0	0
Retirements / Additions									
Coal	0	0	0	0	-300	-1,013	-1,978	-1,978	-1,978
Large-Frame SCCTs	0	0	0	0	0	0	-138	-404	-532
Small-Frame SCCTs	0	0	0	0	-55	-55	-55	-55	-55
New SCCTs	0	0	0	0	0	496	1,488	1,488	1,488
New Solar	0	0	0	0	0	0	0	0	0
New Battery Storage	0	0	0	0	0	0	0	100	200
Total Supply	8,100	8,100	8,100	8,100	7,744	7,527	7,416	7,250	7,222
Reserve Margin	2,335	2,201	2,226	2,240	1,913	1,750	1,701	1,531	1,485
Reserve Margin %	40.5%	37.3%	37.9%	38.2%	32.8%	30.3%	29.8%	26.8%	25.9%

(1) Existing Capacity includes 152 MW OVEC capacity at the time of summer peak and not the 172 MW contracted amount.

The Companies note two events that have an impact on the IRP results that are not reflected in the Tables above. First, on September 27, 2021, Ford announced plans to add twin electric vehicle battery plants with production to begin in 2025.[115] Each plant will require approximately 160 MW for a total of 320 MW.[116] Even with the addition of the anticipated load, the companies anticipated having sufficient generation capacity until 2028.[117] Second on October 19, 2022, the Companies announced plans to enter into a 125 MW solar PPA to exclusively serve five customers participating in the Companies' Green Tariff Option 3.[118] Staff notes that the tables above present a more complete picture of the Companies' base case optimal plan scenario. Tables 6-5 and 6-6 in Volume I of the IRP present an incomplete picture of supply resources and reserve margins over the forecast period by omitting select additional generation resources.[119]

Sensitivity Scenario Analyses

The Companies ran multiple sensitivity analyses with base, high and low fuel (coal and natural gas) prices and base, high and low economic scenarios as reflected in the load forecasts. Several factors had led to increased natural gas prices including increased demand for Mexican pipeline and liquefied natural gas exports, potential regulations regarding methane emissions from gas wells, bans on fracking and the growth of baseload generation.[120] The base, high and low natural gas price forecasts are based on forecasts of the Henry Hub natural gas prices on the NYMEX and in combination with the Energy Information Administration (EIA) 2021 Annual Energy Outlook (AEO) High Oil and Gas Supply Case.[121] Base, high and low coal price forecasts are Illinois Basin (ILB) coal prices based on a combination of coal bids received and the annual growth rate reflected in the EIA 2021 AEO High Oil and Gas Supply case for "All Coals, Minemouth." Both the high and low coal price forecasts reflect the relationship of changes in natural gas and ILB coal prices.[122]

The table below presents a summary of the Companies' least cost resource plan.

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[115] *See* Office of the Governor Press Release, *Ford and Partner SK Innovation Will Build Two Electric Battery Plants, Creating 5,000 Kentucky Jobs, Investing $5.8 Billion* (Sept. 27, 2022).

[116] *See* Case No. 2022-00066 *Application of Kentucky Utilities Company for a Certificate of Public Convenience and Necessity for the Construction of Transmission Facilities in Hardin County, Kentucky* (filed Mar. 31, 2022), Application, Direct Testimony of Beth McFarland at 2.

[117] 2021 IRP, Vol. I, Section 5 at 44 footnote 47.

[118] 2021 IRP, Vol. I, 2021 IRP Reserve Margin Analysis at 24, footnote 25.

[119] 2021 IRP, Vol. I, Section 6 at 7-8, Table 6-5, Table 6-6; *see also* 2021 IRP, Vol. III, 2021 IRP Long-Term Resource Planning Analysis, at 16-18, Table 14 and Table 15.

[120] 2021 IRP, Vol. III, 2021 IRP Long-Term Resource Planning Analysis at 12.

[121] 2021 IRP, Vol. III, 2021 IRP Long-Term Resource Planning Analysis at 12.

[122] 2021 IRP, Vol. III, 2021 IRP Long-Term Resource Planning Analysis at 13.

New Generation in Least Cost Plan Summary Results[123]

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

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

The Companies draw two broad conclusions from the analysis. NGCC with CCS is not cost-effective in any of the scenarios when compared to renewables paired with SCCTs and batteries. As the Companies retire generation assets, renewable resources (for energy) and SCCTs (for capacity) are the cost-effective replacement resources. Batteries are introduced in 2034 when the Ghent units retire. As with the base case scenario, the sensitivity analysis results are not entirely surprising since the Companies

[123] 2021 IRP, Vol. I, Section 5 at 43, Table 5-19; 2021 IRP, Vol. III, 2021 IRP Long Term Resource Plan Analysis at 5, Table 3.

only modeled SCCTs and NGCC with CCS to supply capacity as a backstop for renewable resource intermittency. In addition, in the presence of high gas prices, batteries play a larger role in supplying capacity wholly or in part the SCCTs. The Companies indicate that as a result of the addition of the future 320 MW Ford load, there is a lesser likelihood of the Low Load scenario being realized.[124] The Companies allow that the successful deployment of DSM programs could reduce or defer the need for peaking resources.[125] Given that sentiment and the fact that the IRP is a long range planning study, it is somewhat surprising that the Companies did not model additional DSM programs.

IMPROVEMENTS IN GENERATION, TRANSMISSION AND DISTRIBUTION

Generation

The Companies are working to make efficiency improvements to the generation fleet. The generation fleet is in the process of implementing an Operational Technology Cyber Security Governance Program. The program is a road map of risk reducing mitigation strategies including governance, asset and change management, network segmentation, access control, antivirus, patch, and vulnerability management, disaster recovery and business continuity, network monitoring, and system hardening.[126] Participation and coordination with the Electric Power Research Institute (EPRI) is ongoing. New distributed control technologies continue to be researched and installed, which includes both hardware and software upgrades. Additionally, instruments are being installed on all generation step-up transformers to remotely monitor and detect failures.[127] Upgrades and enhancements to freeze-protection systems are planned and implemented as needed.[128] Steps have been taken to mitigate feedwater heaters using extraction steam that have common failure mechanisms and continue to repair and replace units as needed.[129] Efforts are underway to comply with new Effluent Limit Guidelines.[130] Four cooling towers have been rebuilt and additional rebuilds are being evaluated.[131] Dix Dam is undergoing improvements to maintain reliability.[132]

Transmission

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[124] 2021 IRP, Vol. I, Section 5, at 34-35, footnote 34.

[125] 2021 IRP, Vol. III, 2021 IRP Long-Term Resource Planning Analysis at 5.

[126] 2021 IRP, Vol. I, Section 8 at 3.

[127] 2021 IRP, Vol. I, Section 8 at 4.

[128] 2021 IRP, Vol. I, Section 8 at 5.

[129] 2021 IRP, Vol. I, Section 8 at 6.

[130] 2021 IRP, Vol. I, Section 8 at 6.

[131] 2021 IRP, Vol. I, Section 8 at 7.

[132] 2021 IRP, Vol. I, Section 8 at 7.

The transmission system is assessed to identify needed construction projects and upgrades required to maintain system reliability and to meet projected customer demands.[133] Transmission system construction projects and upgrades are identified and prioritized through various existing processes. The annual transmission expansion process (TEP) identifies potential transmission constraints and results in construction projects and system upgrades to maintain reliability. The TEP complies with NERC Reliability Standard TPL-001 and along with, the Companies' Transmission Planning Guidelines, is approved by the Companies' Independent Transmission Organization (ITO).[134] The ITO oversees and approves interconnection projects through the generator interconnection (GI) process. The GI process requires generator owners to submit their projects to a queue by providing information that includes the exact location, capacity, and commercial operation start date. Transmission studies are conducted in queue order. The studies identify any applicable transmission projects that are required to prevent reliability issues as a result of power flow changes on the grid from the generator addition.[135] A transmission service request (TSR) must be submitted for new load delivery points or for load increases at existing delivery points. Like GIs, transmission studies are conducted in queue to identify needed projects to accommodate the incremental load at the delivery point to maintain reliability.[136] A list of planned projects was provided separately in the IRP, Volume III 2021 IRP Long-Term Resource Planning Analysis.[137]

<u>Distribution</u>

The Companies report that the greatest contribution to improved reliability has been the continued advancement of distribution automation since 2017. The installation of Supervisory Control and Data Acquisition (SCADA) connected reclosers and deployment of advanced distributing management system has enabled the automated detection of fault conditions, isolation of faults and expedited service restoration has helped minimize the impact of faults on the distribution system.[138] The Companies continue to invest in new substations. Advanced data analytics tools and resources are allowing for more targeted investment in areas of concern based on outage history, geo-spatial characteristics and environmental factors.[139] Finally, the Companies are moving forward with deployment of AMI, and enhanced distribution line-device voltage controls and supporting information systems.[140] The increasing number of customer owned

[133] 2021 IRP, Vol. I, Section 8 at 10.

[134] 2021 IRP, Vol. III, IRP 2021—Transmission Portion at 1.

[135] 2021 IRP, Vol. III, IRP 2021—Transmission Portion at 1.

[136] 2021 IRP, Vol. III, IRP 2021—Transmission Portion at 1.

[137] 2021 IRP, Vol. III, IRP 2021—Transmission Portion, Transmission Expansion Plan Projects.

[138] 2021 IRP, Vol. I, Section 8 at 8.

[139] 2021 IRP, Vol. I, Section 8 at 8.

[140] 2021 IRP, Vol. I, Section 8 at 9.

distributed generators presents additional Companies' gird enhancements and will support greater situational awareness as greater numbers of DERs are implemented throughout the system. In order to accommodate the increasing number of interconnection requests, the Companies plan to implement an online DER interconnection application portal to manage the administrative processes.[141]

RESPONSES TO 2018 STAFF RECOMMENDATIONS

LG&E/KU responded to the recommendations regarding its supply-side assessment and integration in the Commission Staff's Report addressing LG&E/KU's 2018 IRP as indicated below.

- The report recommended that LG&E/KU continue their consideration of the comments of any intervenor groups and detail how those comments were considered in their system planning and preparation of the next IRP. LG&E/KU noted that the least-cost generation portfolios in the long-term resource planning analysis were developed with the goal of minimizing energy costs as well as the cost of new capacity, as requested by SREA. The Companies also noted that all renewable cost assumptions are based on the "Moderate" case forecast from NREL's 2021 Annual Technology Baseline and were evaluated with applicable tax incentives.

- The report recommended that the 2021 IRP's reserve margin analysis and long-term resource plan analysis model the effects of increased interest and participation of the Companies' large commercial and industrial customers in purchasing increased amounts of renewable energy, which may be generated by third party suppliers as opposed to the Companies' own generation sources. LG&E/KU stated that there long-term resource planning analysis reflects the planned additions of Rhudes Creek Solar in 2023 (100 MW nameplate) and an additional 160 MW of Green Tariff Option 3 solar in 2025. The Companies further stated, as noted above, that utility-scale solar is selected beyond 2025 as a least-cost resource in almost all cases evaluated in the Companies' Long-Term Resource Planning analysis. The Companies noted that the IRP does not specify whether the additional solar is associated with the Green Tariff Option 3 program, but portions of it could be.

- The report noted that the 2018 IRP made no mention of any reliability concerns within the neighboring regions, availability of or additions to generation capacity in those regions, reduced demand within the markets, or whether the neighboring regions' stated reserve margins are considered inadequate for planning purposes. In addition, to whether or not neighboring utilities would have excess energy to sell during LG&E/KU's winter peak demand, there is no support for assumptions regarding available transmission capacity. Without further study, evidence, and discussion, it is difficult to ascertain the risk of not being able to rely on neighboring regions to serve and LG&E/KU being able to import energy that would justify such

[141] 2021 IRP, Vol. I, Section 8 at 10.

high reserve margins. The circumstances that allow for neighboring regional reserve margins to be relatively lower than the Companies' may also be advantageous to the Companies if it were a member of an RTO. It is possible that under some RTO analysis scenarios, the Companies and their customers may benefit from lower costs, lower reserve margins without sacrificing reliability, and, depending on load profiles, higher revenues overall. Staff also notes that LG&E/KU have upgraded select generation units for blackstart capability and that PJM provides compensation for that capability.

LG&E/KU noted in the 2021 IRP that the basis for their assumptions regarding available transmission capacity is provided in Section 4.4 of the 2021 IRP Reserve Margin Analysis in Volume III of the 2021 IRP. Furthermore, the Companies note that this analysis includes a sensitivity analysis in Section 5.1 where the maximum available transmission capacity is doubled from 500 MW to 1,000 MW. Finally, the Companies noted, as discussed in their 2021 RTO Membership Analysis, that they do not recommend RTO membership at this time.

- The report recommended that LG&E/KU provide updated comprehensive and detailed cost/benefit studies comparing the full costs of joining MISO or PJM and all potential benefits such as increased revenues, lower reserve margin requirements, and improved reliability versus operating under its existing operating construct. LG&E/KU indicated that they provided this analysis in their 2021 RTO Membership Analysis.

- The report recommended that LG&E/KU provide greater discussion of and support for the use of various assumptions used in the reserve margin analysis and noted that the input assumptions used in the reserve margin analysis should be consistent with those used in energy, load, and resource planning. LG&E/KU referred to their discussion of weather used to project load and the reserve margin, as discussed in Section 2 of this Report. The Companies' noted that they have attempted to do a better job demonstrating that load assumptions in both analyses are completely consistent.

- The report recommended that LG&E/KU provide the effects of varying the input parameters separately so as to gauge the individual effects on the reserve margin and that LG&E/KU provide a detailed discussion of the implications of varying the modeling input assumptions and greater support for (reasonableness) of how the modeling inputs are varied in the analyses. LG&E/KU noted that Section 5.1 of the 2021 IRP Reserve Margin Analysis contained the sensitivity analysis. The Companies stated that impacts from varying key inputs are presented separately, and discussion of the sensitivity analysis is expanded to further assess the reasonableness of the results and provide more information regarding the range of inputs evaluated.

- The report recommended that LG&E/KU incorporate SREA's modeling recommendations regarding capacity only planning, allowing renewable energy to compete directly against existing generation units, and including energy storage resources into the modeling and forecast methodology. LG&E/KU stated that least-cost generation portfolios were developed with the goal of minimizing energy costs as well as the cost of new capacity in the 2021 IRP Long-Term Resource Planning Analysis, though as noted above, the model was not permitted to economically select new generation over existing units.

- The report recommended that LG&E/KU provide a more robust and complete discussion of all the actions being taken to enhance the efficiency and reliability of the transmission and distribution systems. LG&E/KU stated that key distribution reliability and resiliency programs are addressed in Section 8.(2).(a) of the IRP and include Advanced Distribution Management System, substation transformer replacements, aging infrastructure replacements, pole inspection and treatment, volt/VAR optimization and AMI. LGE/KU further stated that it has efficient transmission processes to add new generation (including renewables) and incremental load described in Volume III of the IRP as well as programs to improve the reliability of the transmission system, including replacement of critical line and substation assets, upgrades to the protection and control systems, improved line sectionalization and automatic restoration through the installation of in-line breakers and switches, enhanced vegetation management, pole inspection, and switch maintenance.

- The report recommended that LG&E/KU address any order related to SB 100 in the next IRP. LG&E/KU noted that the Commission's ruling on their net metering tariff was released on September 24, 2021. Given the proximity of the announcement to the October 19, 2021 IRP filing date, the forecast could not be updated to reflect the new net metering rates but rather were based on the old rates.

- The report recommended that LG&E/KU evaluate energy and capacity, including renewable resources, that is supplied from resources that are outside LG&E/KU's service territory in their resource assessment and reserve margin analyses. However, the report noted that in that evaluation all costs, including those associated with transmission and distribution losses, should be included as well the inclusion of any benefits such as government subsidization. The report also recommended that LG&E/KU incorporate the effects of increased numbers of large renewable facilities within its service territory as a viable resource that is allowed to compete with existing generation. LG&E/KU claimed that their resource screening analysis considered in-state and out-of-state wind and that the costs of solar and wind in the Companies' long-term resource planning analysis are consistent with recent responses to request for proposals. The Companies also stated that the least-cost generation portfolios in the long-term resource planning analysis were developed with the goal of minimizing energy costs as well as the cost of new capacity.

- The report recommended that LG&E/KU address any possible capacity ratings changes with renewables in their forecast, especially with solar. LG&E/KU stated that the availability of solar during peak events is a key source of uncertainty in the 2021 IRP and is discussed in the 2021 IRP Reserve Margin Analysis.[142]

INTERVENOR COMMENTS

Attorney General

The Attorney General stated that the growing national-level interest in electrifying both space heating and motor vehicles will require significantly more electric generation capacity. The Attorney General pointed out that the Companies' IRP analysis recognizes that renewable resources alone will be unlikely to meet additional load. The Attorney General also stated that greater penetration of renewable resources will create a need for utility-scale battery storage, which the Attorney General stated will increase costumer costs on an exponential basis. The Attorney General stated that Kentucky ratepayers cannot easily absorb the massive new costs that will be added onto their bills. Thus, the Attorney General encouraged the Companies to carefully consider affordability in the mix of options for their future supply side resource needs.[143]

The Attorney General stated that LG&E/KU spending to meet summer capacity needs is only the beginning, because additional forms of capacity will have to be added in order to meet winter capacity needs. The Attorney General recommended that the Companies' future IRP analysis include studies to determine whether its summer and winter capacity needs could be better served if the Companies used more dispatchable resources that are not limited by seasonable considerations. The Attorney General also recommended that the Companies consider whether a lower reserve margin of dispatchable supply-side resources, available year-round, could provide the least cost solution.[144]

The Attorney General observed that one of the benefits of using turbine-driven, synchronous generations is the production of natural inertia that forces the flow of electrons down the wires, which retards the decay of frequency and produces short circuit strength which provides ride-through capability for intermittent and sustained oscillations. The Attorney General noted that "[g]reater usage of renewable, non-thermal generation results in less natural inertia and a greater need for synchronous assets or grid-forming technologies (such as grid-forming inverters) to maintain system voltage and frequency support in order to keep the grid stable, reliable and safe." The Attorney General encouraged the Companies to conduct detailed studies into cost projections for grid forming technologies and to include such costs in its next IRP to provide a more transparent means of informing the Commission and the public regarding the true costs of converting to renewable resources.[145]

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[142] 2021 IRP, Vol. III, LG&E/KU's Response to Staff Recommendations at 4-9.

[143] Attorney General's Comments at 4-5.

[144] Attorney General's Comments at 5.

[145] Attorney General's Comments at 6.

The Attorney General also expressed concern regarding any large-scale, rapid adoption of renewable resources in the Commonwealth. Specifically, the Attorney General argued that:

1. Kentucky's climate does not provide adequate wind and solar capacity to make large-scale, rapid adoptions of renewable resources cost-effective for utility ratepayers;
2. The inherently intermittent nature of renewable supply-side resources carries reliability risks;
3. The cost of transmission should be considered when renewable resources are compared against other resource options;
4. The renewable energy transition will increase utility bills;
5. Renewables resources cannot support baseload generation and lack the ability to meet increased demand; and
6. Renewables present significant transmission and grid issues.[146]

The Attorney General argued that policies should be pursued "to ensure affordability and reliability are not compromised in the race to renewables," which the Attorney General asserted includes operating fossil fuel plants for as long as economically feasible.[147]

In response comments filed on September 6, 2022, the Attorney General, citing to Louisville Metro's supplemental comments, noted "LG&E/KU's potential resource planning decision to build a new [NGCC] generating unit."[148] The Attorney General disagreed with the suggestion of some commenters that the economics of resource selections and LG&E/KU's recent requests for proposal should be reevaluated based on the passage of the Inflation Reduction Act. The Attorney General argued that the "[t]he request to evaluate the Inflation Reduction Act's impact on 'the evaluation of responses to outstanding request for proposals,' relates specifically to LG&E/KU's potential NGCC generation investment," and is intended to favor renewables over fossil generation.[149]

The Attorney General also argued that even if renewable resources are the lowest cost in certain scenarios that they fail to provide necessary reliability.[150] The Attorney General acknowledged that renewable resources may be cost-effective as one element of a diverse portfolio. However, the Attorney General argued that the Commission should ensure that reliability is a critical element of the planning process. Thus, the Attorney General argued that LG&E/KU should be required in the next IRP to specify how they will

[146] Attorney General's Comments at 6-10.

[147] Attorney General's Comments at 10-11; *see also* Attorney General's Response to Supplement Post-Hearing Comments (filed Sept. 6, 2022) (Attorney General's Post-Hearing Comments) (arguing in favor of the importance of fossil fuels in providing reliable low cost energy and noting the importance of gas as a bridge fuel).

[148] Attorney General's Post-Hearing Comments at 5.

[149] Attorney General's Post-Hearing Comments at 6.

[150] Attorney General's Post-Hearing Comments at 7.

ensure reliability while employing renewable energy, particularly during peak-time demand.[151]

The Attorney Generally lastly noted that no law allows the Commission to consider private emissions goals in generation planning. Thus, the Attorney General lastly argued that PPL's net-zero carbon emissions plan is irrelevant to this generation planning process.[152]

Louisville/Jefferson County Metro Government

Louisville/Jefferson County Metro Government (Louisville Metro) stated that it is a large customer of LG&E and that it represents a broad customer class of over 750,000 residents. Louisville Metro noted that in September 2019, Mayor Greg Fisher declared a climate emergency calling for action to address the increasing climate effects of heat and flooding and in February 2020 that Metro Council passed Louisville Metro Resolution No. 0009, Series 2020, which resolved to support:

1. 100 percent clean, renewable electricity for Louisville Metro operations by 2030;
2. 100 percent clean energy for Louisville Metro operations by 2035; and
3. 100 percent clean energy community-wide by 2040.

In 2022, Louisville Metro joined the Department of Energy's Better Climate Challenge and committed to reducing municipal greenhouse gas emissions by 50 percent by 2032 from the 2016 baseline.[153]

Louisville Metro argued that its goals align with the goal of LG&E/KU's parent company to achieve a 70 percent reduction in carbon emissions from 2010 levels by 2035. Louisville Metro noted that it is making progress towards its carbon reduction goals but that its ability to achieve its goals relies on large part on the carbon intensity of LG&E/KU's grid mix. Louisville Metro suggested that LG&E/KU consider the publicly stated greenhouse gas reduction and renewable energy goals of Louisville Metro and other customers in the evaluation of IRP scenarios.[154]

LG&E/KU indicated that the EPA has recently indicated that in the coming year, new rules will be rolled out for mercury, ozone, water, and coal ash that will likely change the calculus of energy production costs for fossil fuels, particularly coal. Louisville Metro also noted that nearby states have found that shifting investments to solar and battery storage will save ratepayers money and significantly reduce carbon emissions even when retiring coal assets early. Louisville Metro encouraged LG&E/KU to model early closure

[151] Attorney General's Post-Hearing Comments at 7.

[152] Attorney General's Post-Hearing Comments at 8-9.

[153] Louisville Metro's Comments on LG&E/KU's 2021 IRP at 1-2.

[154] Louisville Metro's Comments on LG&E/KU's 2021 IRP at 5-8.

of all coal-fired power plants in the "Earliest Practicable" scenario as Duke Energy Carolinas, LLC and Duke Energy Progress, LLC did in their 2020 IRP.[155]

Louisville Metro applauded LG&E/KU's work on pilot-scale carbon capture at the E.W. Brown generating station. Louisville Metro asserted that coal replacement with clean energy portfolios—a combination of renewables, EE, DR, and storage—can or will be able to provide the same services as gas plants at lower costs and with better public health and environmental outcomes. It argued that legitimate concerns around reliably meeting peak demand with non-dispatchable resources can be addressed through the use of utility-scale battery storage. It noted that cost projections from the National Renewable Energy Lab's 2021 update show 4-hour battery storage cost relative to 2020 costs continuing to drop precipitously until 2030, with continuing declines under two of three scenarios. Citing an article from Energy News Network, it noted that analyst believe that by 2030, 5 gigawatts of large-scale battery storage will be cost-effective in similar markets such as North Carolina.[156]

Louisville Metro stated that the planning process should recognize the external cost of fossil fuel combustion. Louisville Metro acknowledged that the Commission has not historically included the external costs of burning fossil fuels in its IRP analysis, but it argued those costs are real and will continue without immediate action. Thus, Louisville Metro argued that such costs should be considered when evaluating the future of energy in Kentucky.[157]

Louisville Metro noted that in the hearing in this case that LG&E/KU acknowledged that they had published a request for proposal in June 2022 and that an affiliate is expected to submit a proposal to self-build a 660 MW NGCC unit without CCS to meet a capacity shortfall in 2028. Louisville Metro further noted that LG&E/KU indicated that it expected to request a Certificate of Public Convenience and Necessity (CPCN) around the end of 2022 based on that RFP as well as a simultaneous proposal to update its DSM/EE programs.[158]

Louisville Metro indicated that it is concerned based on the intended timing of the CPCN that LG&E/KU intends to propose the NGCC without CCS, and if so, argues that LG&E/KU should be required to explain its reasoning for proposing a CPCN for a resource that is not needed until 2028 and was not considered viable in the IRP. Louisville Metro also notes that the construction of two NGCCs without CCS would not be consistent with the Companies' commitment to PPLs carbon emissions plan.[159] Louisville Metro also

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[155] Louisville Metro's Comments on LG&E/KU's 2021 IRP at 6.

[156] Louisville Metro's Comments on LG&E/KU's 2021 IRP at 6-8.

[157] Louisville Metro's Comments on LG&E/KU's 2021 IRP at 7-10.

[158] Louisville/Jefferson County Metro Government's Supplement Comments to the Louisville Gas and Electric Company and Kentucky Utilities Company 2021 Joint Integrated Resource Plan (filed Aug. 22, 2022) (Louisville Metro's Supplemental Comments on LG&E/KU's 2021 IRP) at 3-4.

[159] Louisville Metro's Supplemental Comments on LG&E/KU's 2021 IRP at 3-4.

noted that the Inflation Reduction Act, which was passed after the hearing in this case, will likely have a significant impact on LG&E/KU's resource planning and should be taken into account before any decisions are made with respect to future resource requirements.[160]

Sierra Club

Sierra Club argued that LG&E/KU's continued participation in the Ohio Valley Electric Corporation (OVEC) from which the Companies purchase power pursuant to an Inter-Company Power Agreement (ICPA) is uneconomical. Sierra Club noted that the 2011 extension to the ICPA was approved based on the assumption that the cost per KWh of OVEC's generation compared favorably to LG&E/KU's generation costs; that OVEC's facilities were expected to be in compliance with existing and pending environmental requirements; and that the energy available from OVEC is cost-effective, among other things. Sierra Club asserted that those facts and assumptions are no longer accurate.[161]

Sierra Club, citing to testimony from Jeremy Fisher, PhD filed for the Sierra Club in previous cases, also argued that OVEC's practice of committing almost all of the OVEC units into PJM with a "must-run" status is imprudent and harmful to the Companies retail ratepayers. Sierra Club stated that by doing so OVEC was committing almost all of the OVEC units into PJM regardless of prevailing market prices and that has resulted in millions of dollars of operational loses for OVEC in recent years and has artificially inflated its capacity factor and thereby indicated that OVEC's facilities are more economical.[162]

Sierra Club argued that the Commission should revisit whether LG&E/KU should receive full recovery from their Kentucky retail customers of the Companies OVEC costs going forward. Sierra Club also encouraged LG&E/KU to request, through their position on the OVEC board, a fresh independent evaluation of OVEC's viability and sensibility through the remainder of the 2040 term, akin to what OVEC commissioned to inform the extension of the ICPA in 2011, and to urge other board members to vote to terminate the ICPA as soon as practical given the issues with OVEC's facilities. Sierra Club also encouraged the Companies to include a scenario in its next IRP that excludes OVEC's energy and capacity as well as the costs associated with the Companies' payments to OVEC under the ICPA.[163]

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[160] Louisville Metro's Supplemental Comments on LG&E/KU's 2021 IRP at 5-6.

[161] Sierra Club's Initial Comments at 4-5; *see also* Sierra Club's Post-Hearing Comments at 4 (asserting that Mr. Bellar acknowledged that the approval of the OVEC contract was based on assumptions that turned out not to be accurate).

[162] Sierra Club's Initial Comments at 8.

[163] Sierra Club's Initial Comments at 11-13; *see also* Sierra Club's Post-Hearing Comments at 2-5 (in which Sierra Club again raised concerns about the cost of OVEC; included confidential information comparing and contrasting the per MWh cost of OVEC as compared to other LG&E/KU resources and resource options; and noted, among other things, that LG&E/KU's own executives have raised concerns about the continued viability of OVEC, that the EPA has ordered the closure and cleanup of OVECs coal

Sierra Club criticized LG&E/KU's heavy reliance on fossil fuels through the mid-2030s. Sierra Club argued that this reliance was unnecessary due to availability of reliable, economical alternatives, including renewables, battery storage, and DSM/efficiency options.[164]

Sierra Club stated that LG&E/KU should plan on being proactive in fostering EV growth. Sierra Club argued that greater EV adoption offers benefits for grid resiliency, including the capability of reducing peak load, mitigating blackouts, and reducing customer bills. Sierra Club also questioned LG&E/KU's RTO analysis, because LG&E/KU did not explain in discovery how the process of determining their target reserve margin would change or what their target reserve margin would be if they if they joined PJM or MISO.[165]

Joint Intervenors

Joint Intervenors indicated that the IRP regulation was adopted in response to real world planning errors that were made by utilities, including LG&E/KU, that resulted in additional costs being passed on to customers.[166] Joint Intervenors argued that the IRP regulation and common-sense call for examination of all potentially cost-effective resources if the aim is the lowest-cost planning and that the IRP process should result in a plan that the utility provisionally expects to implement.[167] Joint Intervenors asserted that a robust analysis cannot and should not be deferred until the Companies are ready to imminently file a CPCN application. Rather, Joint Intervenors stated that a utility's IRP should reflect a robust analysis resulting in an actual plan and that those analyses should be reexamined and updated at times when the utility acts on their integrated resource plan with a CPCN application.[168]

Although Joint Intervenors did thank LG&E/KU for making their modelers available for questions by Joint Intervenors experts during their review of the IRP, Joint Intervenors argued that the LG&E/KU's process, methodologies, simplifying assumptions, and documentation result in an inadequate IRP. A report prepared by Anna Sommer and Chelsea Hotaling of Energy Futures Group (EFG) on behalf of Joint Intervenors identified the following key issues with LG&E/KU's IRP:

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ash impoundments, and that the Michigan Public Service Commission's contractual participation in OVEC was imprudent and unfair to its ratepayers).

[164] Sierra Club's Initial Comments at 13-14.

[165] Sierra Club's Initial Comments at 14.

[166] Joint Intervenors' Supplemental Comments at 3-6.

[167] Joint Intervenors' Supplemental Comments at 5-13.

[168] Joint Intervenors' Supplemental Comments at 5-16; *see also* Joint Intervenors' Response to Supplemental Comments at 1-3.

1. The Companies' IRP does not identify a least-cost plan or a preferred resource plan.

2. The Companies used different models for capacity expansion and production cost modeling, increasing the possibility of inconsistent assumptions and constraints, increasing opportunities for errors, and reducing transparency.

3. The Companies used capacity expansion modeling to optimize portfolios in only the final year of the planning period, rather than using the model to optimize decisions about when within the planning period resources should be added or retired.

4. The Companies developed individual expansion portfolios for each of nine different scenarios, but never tested how any among those portfolios might perform under a variety of future conditions or scenarios.

5. The Companies have not evaluated potentially economically-optimal unit retirements.

6. The Companies have not evaluated the cost-effectiveness of additional EE and DR investments, instead exclusively focusing on supply-side resources.

7. The Companies have not provided adequate documentation to confirm all the constraints and assumptions used in the modeling.

8. The Companies performed a single production cost modeling run of a single portfolio (Base Load and Base Fuel scenario portfolio). As a result, the Companies can provide the present value of revenue requirements for only that single portfolio, and no comparison to other portfolios is possible.

9. The Companies' IRP does nothing to consider the risks associated with carbon pricing, carbon regulation, or carbon reduction goals.

10. The Companies are using an outdated approach to reserve margin analysis, using load duration curves incapable of accurately capturing the reliability impacts of variable or time-dependent resources.

11. The Companies analysis evaluating a range of scenarios for achieving aggressive emission reduction goals is methodologically dubious and appears to misrepresent costs, resource options, resource performance, and efficiency savings.

12. The Companies' Solar Intermittency Study is out of sync with applicable balancing standards, current operating conditions, and the capabilities of modern renewable and storage systems.

Due to those alleged issues, Joint Intervenors argued the IRP does not examine all the potentially cost-effective resource options available to LG&E/KU; does not provide sufficient information to determine whether the Companies' acquisition plan is lowest cost;

does not test the robustness of any portfolio under a variety of future scenarios; and does not consider whether existing units may be economically retired.

To address those issues, the EFG report made the following recommendations:

1. Encourage the Companies to establish an ongoing IRP stakeholder process for the purpose of considering and inviting stakeholder input and review on certain potentially complex changes to the Companies' IRP methodology, inputs, and assumptions.

2. Encourage the Companies to negotiate a discounted, project-based licensing fee that permits interested intervenors the ability to perform their own 7 modeling runs in the same software package(s), and encourage the Companies to absorb the cost of these licensing fees.

3. Clarify that upon filing of an IRP, LG&E/KU should make available, on request and ideally simultaneously with filing of the IRP, the modeling inputs (including settings) and outputs, assumptions, any post-processing spreadsheets (e.g. to create the revenue requirements) in electronic spreadsheet format, and the model manual(s).

4. Recommend that the Companies adopt the typical practice of using a single model for capacity expansion and production cost modeling.

5. Direct the Companies to model a full planning period and not just a single year.

6. Recommend that the Companies document their analytical work so that it clearly conveys the steps taken and information relied upon.

7. Encourage the Companies to limit out-of-model adjustment and include as many system costs in the model as is feasible.

8. Direct the Companies to economically evaluate all potentially cost-effective resource options available to it, specifically including a wide range of levels of new and expanded DSM and other DERs such as distributed solar and storage. The DSM levels should be developed through the meaningful and participatory collaboration of the DSM Advisory Group as previously recommended by Staff.

9. Direct the Companies to consider key issues or uncertainties potentially impacting their resource plan, particularly including analysis of the impacts of a carbon price and meeting a significant emission reduction goal, such as PPL's corporate goal, on the Companies' resource plans.

10. Encourage the Companies to cease use of the Equivalent Load Duration Curve Model (ELDCM) for reliability modeling.

Joint Intervenors also criticized LG&E/KU for failing to specifically consider the needs of low and fixed income customers. They noted that Companies' indicated that there aim was to "'provide all customers, irrespective of income or other demographic criteria, with safe and reliable service at the lowest reasonable cost,' but the Companies have not considered or performed any analysis of the impacts of the proposed Integrated Resource Plan on residential customers with low- or fixed- incomes."[169] Joint Intervenors indicated that the Companies position was that they were not required and did not have the authority to differentiate between low- and fixed-income customers and all other customers in an IRP. Joint Intervenors argue that position is not supported by law or logic.

Joint Intervenors asserted that LG&E/KU unreasonably failed to consider the potential impacts of future carbon regulation. They noted that LG&E/KU's current and planned resources depend heavily on fossil fuels, which they asserted presents a significant cost risk in the event carbon prices are imposed. However, Joint Intervenors argued that LG&E/KU failed to transparently assess the risk of carbon prices. They stated that the failure to incorporate carbon price risk into the IRP was a significant mistake that undermined that validity of the process. Joint Intervenors argued that the risk of a carbon price should have been better incorporated into the long-term planning analysis.[170]

Joint Intervenors noted that since this IRP was filed that there have been a number of changes that further affect the viability of the base case plan in the IRP. Specifically, Joint Intervenors stated that actual fuel costs are higher than projected by LG&E/KU, that the methane charge in the Inflation Reduction Act will increase the cost of fossil fuel generation, and that the Inflation Reduction Act will decrease the cost of renewable resources.[171] Joint Intervenors also argued that LG&E/KU's next IRP should evaluate a more robust set of potentially cost-effective resources[172] and that present value revenue requirements should be presented for all portfolios.[173] Joint Intervenors asserted that LG&E/KU's 2021 IRP did not support investment in NGCC generation or any other resource.[174]

<u>Southern Renewable Energy Association</u>

SREA submitted two reports as its comments on LG&E/KU's IRP. The reports were prepared separately by Miriam Makhyoun, the CEO of EQ Research, a national energy consulting firm, and Dr. Jennifer Chen, the President of ReGrid, as research and policy analysis consultancy.

Ms. Makhyoun made the following primary findings and recommendations:

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[169] Joint Intervenor's Initial Comments at 8.

[170] Joint Intervenor's Initial Comments at 31-35; *see also* Joint Intervenors' Supplemental Comments at 25-29*; see also* Joint Intervenors' Response to Supplemental Comments at 3-5.

[171] Joint Intervenors' Supplemental Comments at 16-19.

[172] Joint Intervenors' Supplemental Comments at 29-31.

[173] Joint Intervenors' Supplemental Comments at 40-41.

[174] Joint Intervenors' Response to Supplemental Comments at 12-13.

1. LG&E/KU's IRP does not provide a reasonable basis for determining that it should build new natural gas peaker plants. The Companies should conduct additional modeling and analysis on renewable resources paired with energy storage, among other solutions, to examine opportunities to avoid the construction of additional natural gas generation, including 2-hour and 4-hour solar plus storage and stand-alone storage as alternatives to the additional planned natural gas-fired capacity.

2. LG&E/KU should provide a robust stakeholder engagement process, including holding public meetings and technical conferences as it develops its IRP, responding to stakeholder requests for information, sharing modeling files, and not opposing interested stakeholders from intervening in their IRP proceeding to provide comments.

3. LG&E/KU should conduct an analysis to identify which, if any, legacy generating plants could be retired early to save ratepayers money, given the high cost of generation identified by the Companies at a number of their existing coal and natural gas generation facilities.

4. LG&E/KU should conduct substantially more robust reliability modeling suitable for analyzing scenarios featuring high deployment of renewable energy and battery storage.

5. LG&E/KU should model solar paired with battery storage as a distinct, separate resource, and batteries utilizing durations other than 4 hours, including shorter durations, should also be considered (both paired and standalone), and the Companies should not preclude these resources from participating in resource solicitations.

6. LG&E/KU should conduct another RFP in 2022 to pursue additional renewable energy over the next three years, or use its 2021 RFP results to select additional renewable energy and battery storage projects in the near term to take advantage of federal tax credits that will be phased out in future years.

Dr. Chen's report also criticized LG&E/KU's RTO analysis and argued that it failed to adequately assess the potential benefits of RTO membership. Dr. Chen argued that the Companies should be working cooperatively with the RTOs to develop a fully informed, accurate, comprehensive, and forward-looking study of RTO benefits and costs using data and modeling tools from the RTOs as well as data from the Companies. She stated that the Commission and stakeholders could help develop an evaluation framework and provide input and feedback on the study.

Dr. Chen stated that the Commission could invite the RTOs to consider assisting in evaluating the benefits and costs of an Energy Imbalance Market or Energy Imbalance Service, which are extensions of RTO energy markets for voluntary participation by non-RTO member utilities. She stated that the Commission could request that the RTO provide its modelling assistance free of charge or in the alternative could potentially obtain funding from the Department of Energy's state energy office for the RTO study.

KIUC

KIUC stated that LG&E/KU have a hundred-year track record of providing low-cost, reliable power to their customers and argued that on issues of resource planning that they should be given the benefit of the doubt, especially compared to parties that have a predetermined agenda. KUIC notes that the Companies are sponsoring a least-cost plan to serve customers after the retirement of certain coal assets that relies less on capital intensive renewables that would be more profitable for them.[175]

KIUC noted that LG&E/KU's least cost plan, as filed, was 440 MW SCCT and 500 MW of solar in 2028, 880 MW of SCCT, and 1,600 MW of solar in 2034, 100 MW of battery storage in 2035 and 100 MW of battery storage in 2036. However, KIUC asserted that as the case progressed that a different least cost plan emerged that included 513 MW of NGCC generation without CCS in 2028, 1,026 MW of NGCC generation without CCS in 2034 and 100 MW of battery storage in 2036.[176]

KIUC stated that the new plan results in 8.6 million fewer tons of CO2 primarily because NGCC generation displaces coal generation. KIUC noted that it is not surprising that NGCC without CCS is more economical than SCCT, because the incremental capital cost of adding a heat recovery steam generator is relatively small but the energy costs are at least 30 percent less. KIUC also argued that the assumption that NGCC would not be required to be retrofit on an existing NGCC plant is reasonable. KIUC noted that CCS is not commercially viable and is still in the research stage.[177] However, KIUC stated that the future rate-making treatment of an NGCC unit may be important, especially the assumed depreciable life of the plant.[178]

KIUC noted that Kentucky has no renewable portfolio standard and is not likely to adopt one anytime soon and is unlikely to join the Regional Greenhouse Gas Initiative; that federal agency regulation of CO2 was made less likely by *West Virginia v. Environmental Protection Agency*,[179] and that Congress is unlikely to tax energy. Thus, KIUC argued that LG&E/KU's assumption that there will not be a price or tax on CO2 emissions over the next fifteen years is reasonable.[180]

LG&E/KU RESPONSES TO INTERVENOR COMMENTS

LG&E/KU provided responses to the comments filed by several of the intervenors. LG&E/KU emphasized that IRP proceedings are informal, constructive, non-adversarial,

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[175] Post-Hearing Comments of Kentucky Industrial Utility Customers, Inc. (KIUC's Post-Hearing Comments) (filed Aug. 22, 2022) at 1.

[176] KIUC's Post-Hearing Comments at 1-2.

[177] KIUC's Post-Hearing Comments at 2-3.

[178] KIUC's Post-Hearing Comments at 4.

[179] *West Virginia v. Environmental Protection Agency,* 42 S.Ct. 2587 (2022).

[180] KIUC's Post-Hearing Comments at 3.

and nonbinding. Further, LG&E/KU maintained that "IRP proceedings are an ongoing stakeholder process that extends across decades."[181] LG&E/KU disagreed with commenters who asserted that IRPs should require a pre-filing IRP Stakeholder Process and argued that the history of IRPs demonstrates that the process itself is a stakeholder process.[182]

LG&E/KU disagreed with claims that it is dragging its feet or failing to move quickly enough into renewable and solar generation. The Companies stated that they have proposed to develop such generation at a rate that balances the need to meet its projected load in a least-cost, reliable manner while accounting for Kentucky's unique environment for producing energy using renewable resources. The Companies further noted that the Attorney General, who is responsible for representing the interest of Kentucky customers, has expressed concerns that they may be proposing too many renewable resources, and that other intervenors do not share the same goals and interest as LG&E/KU in reliability, reasonable costs, and meeting demand.[183]

LG&E/KU challenged criticisms indicating that solar and other renewables are the least-cost options based on levelized cost of energy (LCOE). LG&E/KU stated that using only LCOE as a measure is over simplified and does not take into consideration generation profiles of the resources. There is further discussion regarding types of generation and its capabilities, qualities, and limitations in regard to actual implementation and modeling exercises. LG&E/KU stated that the IRP plays on the strengths of the available technology including renewables and batteries to best achieve the goals of reliable service at the lowest cost.[184]

LG&E/KU emphasized that the CO2 emission constraints presented in the IRP are reasonable and consistent with PPL's carbon emission plan. They stated that none of the recent legal developments suggest that there will be a CO2 pricing regime in the foreseeable future, and that PPL was consulted regarding the development of the IRP, and that even though PPL's corporate goals are not considered within the IRP process, the IRP is in line with PPL's corporate goals. [185]

LG&E/KU also asserted that their IRP reasonably and consistently accounts for carbon regulation "by assuming that CCS technology would be required for new NGCC units by the end of the IRP period."[186] First, the Companies argued that it was reasonable to assume that CCS would be required for NGCC units but not SCCT units, because it would be prohibitively uneconomical to require CCS for an SCCT unit due to the nature

[181] LG&E/KU's Responsive Comments at 1-2.

[182] LG&E/KU's Responsive Comments at 13-14

[183] LG&E/KU's Responsive Comments at 15-18; *see also* LG&E/KU's Supplemental Comments at 1-2.

[184] LG&E/KU's Responsive Comments at 19-29.

[185] LG&E/KU's Responsive Comments at 29-31.

[186] LG&E/KU's Supplemental Comments at 2.

of SCCTs as peaking units.[187] The Companies also noted that the models they ran in response to Commission Staff's requests demonstrated that carbon pricing is not a reliable proxy for all forms of future carbon regulation, because the model would not select NGCC without CCS for a carbon price below $150 per ton.[188] Finally, the Companies argued that their 2021 IRP was consistent with their commitment to PPL's carbon emission plan, because the resource choices are the same through the planning period and there is no statute, regulation, or market circumstance that would currently require them to follow the plan, and therefore, there is nothing to model.[189]

Responding to concerns about LG&E/KU's modeling processes, LG&E/KU stated that their approach and process has proven itself reliable over several years. The Companies referenced the 2014 Polar Vortex and pointed out that during that event that LG&E/KU actually exported power instead of having to shed load to maintain reliability. The Companies indicated that they are not opposed to using a single program or process, but rather, are concerned that the most reliable method is chosen. LG&E/KU similarly argued that their modeling techniques with respect to retirements have been historically accurate and stated that they are most familiar with what assets are likely to be retired early such that there modeling and assumptions regarding retirements are reasonable.[190]

In response to Joint Intervenors assertion that the Equivalent Load Duration Curve Model (ELDMCM) should not be used, LG&E/KU stated that their approach to reliability modeling was appropriate. The Companies asserted that the ELDMCM is effective in modeling variable resources such as solar and that it demonstrates that solar improves reliability during summer and winter. LG&E/KU acknowledged that ELDMCM is not an appropriate tool for time-dependent resources such as battery storage and that LG&E/KU did not use it for that purpose. [191]

Responding to criticisms that LG&E/KU's assumptions regarding battery storage were unfavorable, the Companies stated that their assumptions were indeed favorable. Specifically, LG&E/KU noted that they assumed tax incentives for battery storage regardless of the generation source used to charge the batteries and used a lower cost projection from the end of the IRP planning period that was more favorable toward battery storage.[192]

LG&E/KU disagreed with Joint Intervenors and SREA's argument that the assumption that the Companies' thermal units would not have outages that correlated to extreme weather events is flawed. The Companies stated that the forced outage data for

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[187] LG&E/KU's Supplemental Comments at 3-4.

[188] LG&E/KU's Supplemental Comments at 4-6.

[189] LG&E/KU's Supplemental Comments at 8-9.

[190] LG&E/KU' Responsive Comments at 31-39.

[191] LG&E/KU's Responsive Comments at 39-41.

[192] LG&E/KU's Responsive Comments at 41.

their generating units does not support a claim that the Companies' generator outages are correlated to seasonal weather. The Companies noted that the weather correlated events cited by SREA in California, Texas, and PJM were caused by a lack of dispatchable resources or the failure to contract for fuel or fuel transport for otherwise available dispatchable resources, which they attribute to planning designed to RTO requirements as opposed to actually serving load. The Companies stated that their units have been properly weatherized and are operated to ensure they are available when needed, and that they maintain adequate coal inventory and have firm transportation.[193]

LG&E/KU argued that they appropriately included OVEC in their IRP modeling. The Companies noted that they assumed that OVEC would continue to operate and the Companies would continue to be subject to the ICPA, which they argue is appropriate. The Companies noted that Sierra Club did not present any modeling that showed that remaining in OVEC was uneconomical, did not present a realistic scenario under which LG&E/KU could exit the ICPA or analyze the cost or legal basis for exiting the ICPA. Thus, they assert that Sierra Club has not indicated that they should do anything different with respect to OVEC.[194]

LG&E/KU also disagreed that they did not include sufficient amounts of different types of DERs in their IRP analysis. The Companies argued that they adequately accounted for reasonably foreseeable DER scenarios with their low energy requirement forecast scenario, which assumed high DER penetration, and that there was no reason to model or include additional DERs as a utility resource.[195]

LG&E/KU disagreed with the criticisms of their Solar Intermittency Study, which was produced in response to request for information. The Companies noted that the study found that imbalances in the system increased by all measures when more than 1,000 MW of solar capacity are interconnected and that significant changes to the Companies' generation and transmission systems would be required to interconnect more than 1,000 MW of solar. The Companies disagreed with Joint Intervenors criticism that they did not consider automatic generation control, and noted that the point of the study was to show at what point interconnections would require renewable curtailments, energy storage, or other system improvements.[196]

Responding to allegations that LG&E/KU did not adequately review RTO membership, LG&E/KU disagreed and outlined several reasons why RTO membership is not likely favorable to LG&E/KU customers at this time. LG&E/KU stated that large energy and capacity market benefits of RTO's were not overlooked and that not modeling day-ahead markets or CO2 pricing in the RTO analysis did not materially affect LG&E/KU's

[193] LG&E/KU's Responsive Comments at 41-43.

[194] LG&E/KU's Responsive Comments at 43-45; LG&E/KU's Supplemental Comments at 18-19.

[195] LG&E/KU's Responsive Comments at 47-48.

[196] LG&E/KU's Responsive Comments at 51-52.

analysis. On the contrary, LG&E/KU alleged that RTO cost sharing could harm customers.[197]

LG&E/KU stated that they have fully complied with the Commission's modeling transparency requirements. They noted that the final orders in their 2020 rates cases, which were issued on September 24, 2021, required them to submit details regarding how they would increase modeling transparency within 90 days and that the Commission indicated that the plan should at minimum allow for one model re-run per intervening party and the Commission, upon a party's request, per proceeding and for provision of inputs and assumptions to the models in native formats within the initial filing. LG&E/KU argued that due to the timing of that order there was no modeling transparency requirement in effect when the Companies filed their IRP on October 19, 2021. However, the Companies also noted that they ran additional models for Commission Staff, which was the only party to request a modeling run, and that they provided an unprecedented amount of data in this case.[198]

LG&E/KU stated that it would be possible to model transmission costs if Commission Staff desire it but noted that it is important to note that the primary effect would be to add costs to the values the Companies' model for such resources and that the accuracy of such costs would be dubious at best. The Companies noted that they do not require RFP respondents to provide transmission costs for their proposals because the Companies have good information about such costs from a known location to the Companies' transmission system. However, the Companies pointed out that the problem with attempting to model transmission costs for resources with unknown locations is that they will necessarily be inaccurate.[199]

LG&E/KU stated that contrary to the claims of commenters they did explicitly considered Indiana wind resources and demonstrated that, though Indiana has better wind conditions than Kentucky, transmission costs make Kentucky wind power more cost-effective. The Companies also indicated that they did not consider out of state solar, because it would have had the same characteristics as Kentucky solar but would have had additional transmission costs.[200] The Companies did also agree to a number of recommendations made by commenters or suggested at the hearing.[201]

[197] LG&E/KU's Responsive Comments at 53-59.

[198] LG&E/KU's Supplemental Comments at 9-11.

[199] LG&E/KU's Response to Supplement Comments at 11-12.

[200] LG&E/KU's Response to Supplement Comments at 11.

[201] *See* LG&E/KU's Response to Supplement Comments.

SECTION 5

REASONABLENESS AND RECOMMENDATIONS

INTRODUCTION

Many aspects of LG&E/KU's 2021 IRP, including many of the methodologies and assumptions used to produce the IRP, were 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 2021 IRP. This section discusses the reasonableness of LG&E/KU's 2021 IRP and the issues and areas for improvement, and makes recommendations for LG&E/KU's next IRP.

REASONABLENESS OF LOAD FORECASTING

LG&E/KU's assumptions and methodologies for load forecasting are generally reasonable. Further, the Companies also incorporated most of Commission Staff's recommendations from the 2018 IRP for increasing the level of specificity and explanation of the various models and modeling results. However, there are areas the load forecasting portion of LG&E/KU's IRP could be improved.

In response to LG&E/KU's 2018 IRP, Commission Staff recommended that LG&E/KU include a discussion and analysis of the increase in DERs, including a separate and cumulative discussion for residential, commercial, and industrial customers.[202] LG&E/KU did include a detailed discussion of distributed solar, which was helpful and informative, and occasionally distinguished between facilities connected pursuant to their net metering tariffs and those connected pursuant to their qualifying facilities tariffs.[203] However, there was no separate, detailed discussion of the economics, incentives, and uncertainties of distributed solar for different customer classes or for service taken under the net metering tariffs and the qualifying facilities tariffs. There was also no significant discussion of DERs other than distributed solar.

Commission Staff believes that the economics, incentives, and uncertainties of distributed solar and other DERs could be different for residential, commercial, and industrial customers. For instance, it would seem relatively easy for a commercial customer that has a portion of its load that is constant from significant refrigeration or some other appliance to size solar facilities such that it uses all energy generated. Further, certain commercial and industrial customers have other incentives to invest in DERs such as a commitment to action on climate change. Thus, Commission Staff

[202] Case No. 2018-00348, *Electronic 2018 Joint Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company* (Ky. PSC Jul. 30, 2020), Commission Staff's Report at 13.

[203] *See* 2021 IRP, Vol. I, Section 5 at 27-30 (discussing the effect of distributed solar cumulatively but noting that the slight increase in distributed solar for the base case after 2027 was due to qualifying facilities); 2021 IRP, Vol. I, Section 8 at 18 (showing the growth in all qualifying facilities).

believes the IRP should discuss the adoption of DERs, and particularly distributed solar, for such customers separately, so the reasonableness of the assumptions, methodologies, and projections can be better analyzed.

Similarly, there are different requirements and limitations for taking service under LG&E/KU's net metering tariffs as compared to their qualifying facilities tariffs,[204] including most importantly that the one percent cap that LG&E/KU is permitted to adopt pursuant to KRS 278.466 is not applicable to qualifying facilities.[205] LG&E/KU assumed a one percent cap on service under the net metering tariffs in the base case but showed the significant impact distributed solar would have on load by 2036 if net metering service was not subject to the one percent limitation.[206] Due the significant effect of the one percent cap, Commission Staff believe that DERs, including distributed solar, at qualifying facilities should be assessed and discussed separately, so the specific assumptions and methodologies used to project the effect of those facilities on load and peak demand can be analyzed.

Further, with the continued declining cost of distributed solar and the effect of the one percent cap,[207] it would have been useful to see a discussion regarding whether and the extent to which customers that would have taken service under the Net Metering Service-2 tariff would continue to interconnect DERs even if they received no credit for energy sent back into the system because the one percent cap had been reached when they sought to connect. For instance, customers that could size their facilities such that it was not necessary to sell into the system or could otherwise offset enough of their own usage to cover the cost of the facilities without a credit. In such cases, as with residential and small commercial DSM programs, the payback may be longer and the customer may only be offsetting its utility bill. However, in the face of increasing utility bills, it is not unreasonable to explore such growth in DERs over the forecast period.

Similarly, it would have been useful to explore the effects of having residential households being able to apply solar facility energy offsets to EV charging stations in addition to the household usage. A step further would be to apply net metering to EV

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[204] *See generally* LG&E P.S.C. Electric No. 13, First Revision of Original Sheet No. 57 (the first page of LG&E's "Net Metering Service-1" tariff); LG&E P.S.C. Electric No. 13, First Revision of Original Sheet No. 58 (the first page of LG&E's "Net Metering Service-2" tariff); LG&E P.S.C. Electric No. 13, First Revision of Original Sheet No. 55 (the first page of LG&E's "Small Capacity Cogeneration and Small Power Production Qualifying Facilities" tariff); LG&E P.S.C. Electric No. 13, First Revision of Original Sheet No. 56 (the first page of LG&E's "Large Capacity Cogeneration and Small Power Production Qualifying Facilities" tariff).

[205] *See* 16 U.S.C. § 824a-3 (requiring a utility to sell electricity to purchase electric energy from qualifying facilities); 807 KAR 5:054 (implementing the federal requirement that utilities sell to and purchase from qualifying facilities); *see also* 2021 IRP, Vol. I, Section 5 at 28 (indicating that the Companies did not apply the 1 percent limit to qualifying facilities).

[206] *See* 2021 IRP, Vol. I, Section 5 at 29-30, Figure 5-15 (showing that peak demand would be reduced by several hundred MWs without the 1 percent cap permitted by HB100).

[207] *See* 2021 IRP, Section 5 at 29-30 (discussing the declining cost of solar and the effect of imposing a 1 percent limit on distributed solar other than qualifying facilities).

charging as well as household usage could spur both the growth in EV charging and in residential distributed solar. Even if the one percent cap were to be reached, using residential solar to offset EV charging could spur additional growth.

REASONABLINESS OF DEMAND AND SUPPLY SIDE RESOURCE ASSESSMENTS

Limitations on Resource Options in Model

Commission Staff believes that the primary issue with the LG&E/KU's resource assessment was its exclusion of numerous resource options from the model. As noted by Joint Intervenors, 807 KAR 5:058, Section 8(1) states that the "[t]he plan . . . shall include assessment of potentially cost-effective resource options available to the utility." Section 8(2) then requires utilities to "describe and discuss all options considered for inclusion in the plan including:"

> (a) Improvements to and more efficient utilization of existing utility generation, transmission, and distribution facilities;
> (b) Conservation and load management or other demand-side programs not already in place;
> (c) Expansion of generating facilities, including assessment of economic opportunities for coordination with other utilities in constructing and operating new units; and
> (d) Assessment of nonutility generation, including generating capacity provided by cogeneration, technologies relying on renewable resource, and other nonutility sources.[208]

The only reasonable interpretation of those subsections is that a utility's plan must assess all potentially cost-effective resource options, including those listed in Section 8(2). LG&E/KU's plan unreasonably excluded or failed to consider a number of potentially cost-effective resource options without adequate justification.

Mostly notably, LG&E/KU did not model new DSM/EE programs beyond their current approved plan including an inherent progression in appliance efficiencies and only showed the incremental effect of the current program on load through 2025. LG&E/KU only identified opportunities for new DSM/EE programs that will be evaluated in the future based on data and DSM pilot programs associated with the implementation of AMI.[209] LG&E/KU made no assessment of whether those resource options were potentially cost-effective.[210] LG&E/KU's failure to assess any new DSM/EE opportunities against other resources prevented potentially lower cost options from being evaluated.

Commission Staff also believes LG&E/KU's assessment of potential supply side resources was also too narrow. Specifically, the Companies' model was only permitted

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[208] 807 KAR 5:058, Section 8(2).

[209] 2021 IRP, Vol. I, Section 5 at 11.

[210] *See* 2021 IRP, Vol. I, Section 5 at 11.

to select large frame SCCT without CCS, NGCC with CCS, solar, wind, and battery storage, all sited in the Companies' balancing area.[211] Further, the model was not permitted to select the economic retirement of any of LG&E/KU's existing supply-side resources.[212] Given those constraints and the cost difference between NGCC with CSS and SCCT without CCS, the model had very few options regarding the type and timing of supply-side resource additions it could select.

Excluding or limiting the model's ability to select certain resources for qualitative reasons may be appropriate in certain circumstances,[213] but such limitations should be fully explained and justified. Commission Staff believes that LG&E/KU did not adequately justify the basis for some limitations it placed on the selection of supply-side resources in its IRP.

First, in the IRP, LG&E/KU provided only a vague explanation that it modeled NGCC with CCS only based on the Biden administration's policies and the national focus on clean energy.[214] Then, when asked in requests for information why they modeled SCCT without CCS only, LG&E/KU stated:

> The Companies assumed the [New Source Performance Standard] NSPS would pertain only to NGCC units. This assumption is consistent with the lack of costs for a SCCT with CCS in NREL's 2021 ATB.[215]

While they did provide additional explanation in their comments,[216] the Companies assumption that CCS would be required for NGCC but not SCCT was not adequately justified in the IRP, especially given the significant effect those assumptions had on the

[211] 2021 IRP, Vol. III, 2021 Long Term Planning Analysis at 10.

[212] July 12, 2022 HVT at 18:04:30–18:05:30.

[213] For instance, a utility would not want to model a resource that could not legally be built because it could render the results of the model useless if that resource were selected. Similarly, it would not be logical to allow the model to select a new NGCC plant in the first year of the planning period when it could not possibly be built in time.

[214] *See* 2021 IRP, Vol. III, 2021 Resource Screening Analysis at 11-12 (stating only that "[b]ased on the Biden administration's energy policy and the national focus on moving to clean energy, the current environment does not support the installation of NGCC without CCS due to its CO2 emissions" and "SCCT was evaluated to support reliability as the industry transitions to resources with increasing intermittency"); *see also* 2021 IRP, Vol. III, 2021 Resource Screening Analysis at 6. The Companies did provide costs and ran a scenario with NGCC without CCS at Staff's request and they indicated that NGCC without CCS had significantly lower costs. *See* Response to Staff's First Request, Item 26h; LG&E/KU's Response to Staff Second Request for Information (Response to Staff's Second Request), Items 1 and 2.

[215] Response to Staff's Second Request, Item 2; *see also* July 12, 2022 HVT at 15:49:48 (noting that the assumption that CCS would be required for NGCC but not SCCT was driven by rumors and other things going on in the industry relating to the federal government looking to reduce natural gas infrastructure).

[216] *See* LG&E/KU's Supplemental Comments at 3-4.

supply-side resources selected by the model.[217] In addition, given that CCS technology is still being market proven,[218] there was not adequate discussion of finding acceptable CO_2 storage and use options or reasonable cost estimates for those applications.

LG&E/KU also excluded resource options outside of its balancing area, including out-of-state wind, from the resource assessment model based on the assumption that transmission costs would make those resources uneconomical.[219] Commission Staff agree that transmission costs, including transmission rates, if any, and to the extent possible, interconnection and network upgrade costs, should be considered when evaluating resources outside of LG&E/KU's balancing area, as well as resources in its balancing area. However, it is not clear that the Companies performed any updated analysis of expected transmissions costs for resources outside of its balancing area.[220]

Given the constant changes in the transmission system and differences that may arise based on the location of the resource, Commission Staff believes that it would be unreasonable to summarily exclude resources outside of LG&E/KU's balancing area based on past assessments if placement of a resource outside of their balancing area would provide some advantage, such as a higher capacity value or access to a new resource. Thus, while it appears they may have done so for Indiana wind in this IRP, the Companies should reasonably consider current transmission costs for such out of balancing area resources before excluding them from the model, and if possible to do so accurately, given the number of variables involved, the Companies should model such resources with transmission costs to determine if they would be selected in any of the various scenarios.[221]

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[217] When the model was permitted to select NGCC without CCS in a base fuel and load scenario, it selected 1,539 MW of NGCC without CCS and 100 MW of Battery Storage instead of 1,320 MW of SCCT, 2,100 MW of Solar, and 200 MW of Battery Storage. Response to Staff's Second Request, Item 1.

[218] *See* July 13, 2022 HVT at 12:36:10 – 12:38:41 (in which LG&E/KU's witness notes that CCS would currently be difficult to implement technically in Kentucky and elsewhere and notes that it would be economically challenging because the infrastructure to deal with the CO2 does not currently exist); July 12, 2022 HVT at 11:46:30 – 11:49:11 (in which LG&E/KU's witness noted that they are looking at how to implement CCS, including potential storage sites or economic uses of CO2 but indicated that he was unable to give a timeframe for when they might find something that is feasible).

[219] *See* July 12, 2022 HVT at 13:28:57 – 13:31:09.

[220] *See* July 12, 2022 HVT at 13:28:57 – 13:31:09; *see also* July 12, 2022 HVT at 13:31:12 – 13:32:50 (noting that LG&E/KU had evaluated out of state wind in response to previous requests for proposals that included out of state wind and that transmissions costs had always hurt those projects and made them non-viable economically); *but see* LG&E/KU's Response to Supplement Comments at 11 (indicating that Indiana wind was explicitly considered); 2021 IRP Vol. III, 2021 IRP Resource Screening Analysis at 10.

[221] Commission Staff understand LG&E/KU's point that the estimated transmissions cost might not be reasonably accurate if the location of the resource is unknown, and if it is not possible to model resources with reasonable accuracy with transmissions costs, then it should not be done. However, the transmission costs should at minimum be considered and discussed.

LG&E/KU excluded nuclear generation from the model's resource assessment due its expected costs and operating characteristics as well as the Companies' inexperience with the resource and potential issues with public acceptance.[222] However, given the effect of fuel prices on NGCC and SCCT units, the cost of nuclear was not so high that it should have been removed from the model.[223] Further, since the model will not select a resource that is not the least cost option to meet the projected load, utilities should be cautious about excluding a resource from the model based on cost. Additionally, given the cost of NGCC with CCS, it seems likely that an NGCC unit with CCS would be operated much like a nuclear unit would be operated.[224] Finally, while the Companies' inexperience with nuclear and issues with public acceptance of nuclear are valid concerns, they also do not support excluding nuclear generation from the model as a resource option at the end of the planning period, because whether nuclear generation was selected by the model or not, including it would be informative about the direction the Companies need to move in the next 15 years and beyond to develop necessary expertise and experience or to obtain access to nuclear generation through a third party or partnership.

In fact, in their response comments, LG&E/KU note the importance of thermal resources for reliability and explained the cost of attempting to serve their load with only intermittent resources and energy storage. Further, while it was not modeled, the Companies indicated their expectation that they would not burn unabated coal or natural gas beyond 2050.[225] However, the only resource the Companies' assessed in the model that would logically provide base load thermal generation was NGCC with CCS, which arguably has issues with costs and feasibility that are even more uncertain than nuclear generation.[226] Thus, while it may not have changed the IRP's results given the fuel prices and other assumptions in the model, Commission Staff believes LG&E/KU should have

[222] *See* IRP, Vol. III, 2021 Resource Screening Analysis at 11 (discussing the high cost of nuclear and its operating characteristics as a basis for excluding it); July 12, 2022 H.V.T. at 16:02:20 – 16:04:35 (discussing the Companies inexperience and public acceptance as issues with nuclear generation).

[223] LG&E/KU projected that in 2031 the LCOE of NGCC with CCS, an 85% capacity factor, and high natural gas prices, as projected in the IRP, would be $93.03 per MWh whereas it projected the LCOE for nuclear generation would be $115.38 per MWh in 2031. *See* LG&E/KU's Response to Commission Staff's Post-Hearing Request for Information, Item 3 (discussing the LCOE for NGCC with CCS); Response to Staff First Request, Item 51 (discussing the LCOE for nuclear). While there are some unknowns about the nuclear projections provided, such as the capacity factor and type of nuclear generation used to project the LCOE, those numbers are not so different that they justify excluding nuclear from the model entirely. Further, given the significant increases in natural gas prices since LG&E/KU made their high fuel cost assessment in the IRP, the cost of nuclear now likely compares very favorably to NGCC with CCS.

[224] *See also* Jul. 12, 2022 H.V.T. at 16:00:50 – 16:01:52 (in which LG&E/KU's witness noted differences in how nuclear and NGCC with CCS could be operated but acknowledged that an NGCC unit running at an 85% capacity factor would have a similar load profile to a nuclear unit).

[225] *See* Jul. 12, 2022 H.V.T. at 11:43:27 – 11:46:36; 11:53:00 – 11:54:25.

[226] *See* Jul. 12, 2022 H.V.T. at 11:46:30 – 11:49:11 (in which LG&E/KU's witness noted that they are looking at how to implement CCS, including potential storage sites or economic uses of CO2, but indicated that he was unable to give a timeframe for when they might find something that is feasible); Jul. 13, 2022 H.V.T. at 12:36:10 – 12:38:41 (in which LG&E/KU's witnesses notes that CCS would currently be difficult to implement in Kentucky and elsewhere).

included nuclear generation as a resource option assessed by the model or at minimum should have included a more detailed explanation of why it was being excluded.

Finally, LG&E/KU excluded pumped hydroelectric energy storage facilities from the model's resource assessment because it stated land-use requirements for such resources make them unsuitable in the Companies' service territories.[227] However, as with other potential resources, there is no evidence that LG&E/KU investigated the siting of pumped hydroelectric facilities. Further, LG&E/KU included NGCC with CCS despite acknowledging that it had not investigated and was unsure whether CCS, which can be dependent on geography, is viable in Kentucky.[228] Thus, while LG&E/KU's judgement may be correct, the Companies did not justify the exclusion of pumped-hydro facilities as an energy storage resource based on land use concerns, especially since siting was not assessed and was not used to exclude other resources that are likely site dependent.

Consideration of OVEC in the IRP

Sierra Club asserted that the facts and assumptions regarding OVEC's costs that were used to justify entering into the ICPA are no longer accurate and encouraged the Commission to revisit whether LG&E/KU should receive full recovery from their Kentucky retail customers of the Companies' OVEC costs; encouraged the Companies, through their seat on the board, to request a fresh independent evaluation of OVEC's viability, and encouraged the Companies to include a scenario in the next IRP that excludes OVEC's energy and capacity as well as the costs associated with the Companies' payments to OVEC under the ICPA. LG&E/KU argued that Sierra Club's proposals are beyond the scope of the IRP and that they have not established that exiting OVEC is economical.

Commission Staff agrees that LG&E/KU's ability to recover sunk costs arising from OVEC is beyond the scope of this IRP, and Commission Staff have not seen an analysis indicating that the marginal costs of energy from OVEC is uneconomical. However, Commission Staff does note that the IRP regulation anticipates that a utility will consider improving efficiencies in existing resources and that OVEC was barely discussed in the IRP or resource assessment beyond the capacity it would provide. Further, there are some questions regarding the cost-effectiveness of OVEC to the extent significant upgrades or improvements are necessary to keep it operational. Thus, to ensure that potential efficiencies at OVEC are being properly considered, Commission Staff believe that the next IRP should discuss recent developments regarding OVEC, including any material upgrades or changes in O&M that have or will be required, whether LG&E/KU believe OVEC will be economical with those upgrades or changes, and any actions LG&E/KU has taken or plans to take, considering any limits imposed by the contract, to avoid such costs if they would make OVEC uneconomical for LG&E/KU.

[227] 2021 IRP, Vol. III, 2021 IRP Resource Screening Analysis at 6.

[228] *See* Jul. 13, 2022 H.V.T. at 12:36:10 – 12:38:41 (noting the importance of geography for CO2 storage and the potential difficulties with implementing CCS in Kentucky); Jul. 12, 2022 H.V.T. at 11:47:55 – 11:52:06 (discussing the need for storage based on geography for CCS).

Transmission Constraints

The IRP regulation contemplates that potentially cost-effective transmission upgrades would be considered along with "coordination" or partnerships with other utilities as a resource option for meeting load.[229] In that regard, an IRP "shall discuss any known, significant conditions which restrict transfer capabilities with other utilities."[230]

LG&E/KU's 2021 IRP included a map of its current transmission system that showed interconnections with neighboring systems and identified and briefly described planned transmission projects.[231] The Companies also briefly discussed available transmission capacity, stated that "[t]he Companies' import capability is assumed to be negatively correlated with load," and generally estimated the transmission capacity available to import energy.[232]

However, LG&E/KU's discussion of available transmission capacity was in its reserve margin analysis and seemed to assume that their projected load was being served with resources in LG&E/KU's service territory, so those resources were using available capacity and thereby limiting amounts that could be imported to meet demand that was higher than expected. It would be useful to understand the LG&E/KU's transfer capabilities and limits on those abilities if the energy being imported was being used to serve LG&E/KU's projected load. Thus, Commission Staff believes that additional discussion of transfer capabilities should be included in the next IRP, including a discussion of any known, significant conditions that restrict LG&E/KU's ability to import energy to serve projected load.

Partnerships Opportunities

Many of LG&E/KU's neighboring utilities will need new generation in the near or midterm. However, at least some of those utilities have indicated that it would be most economical for them to obtain a portion of a generation resource that is larger than they currently require and are seeking partnerships.[233] Depending on the timing of LG&E/KU's need, a partnership could also potentially assist it in reducing the cost of a resource, especially if a potential partner had access to lower cost financing or was willing to sell power at a slight discount to achieve other savings from economies of scale that it could

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[229] *See* 807 KAR 5:056, Section 8(1) (stating that potentially cost-effective resource options should be considered); 807 KAR 5:056, Section 8(2) (identifying such resource options as including "improvements to and more efficient utilization of existing . . . transmission . . . facilities" and "assessment of economic opportunities for coordination with other utilities in constructing and operating new units").

[230] 807 KAR 5:058, Section 8(3)(a).

[231] *See* 2021 IRP, Vol. III, Transmission Expansion Plan Projects; IRP, 2021 IRP, Vol. III, Transmission System Map.

[232] *See* 2021 IRP, Vol. III, 2021 IRP Reserve Margin Analysis at 16.

[233] *See* Case No. 2020-00299, *Electronic 2020 Integrated Resource Plan of Big Rivers Electric Corporation* (Ky. PSC Nov. 22, 2021), Commission Staff's Report on the 2020 Integrated Resource Plan of Big Rivers Electric Corporation at 43.

not without such a partnership. Thus, if generation scaling is likely to have an impact on cost, the possibility of a partnership should also be considered and discussed when determining what resources to model.

Accounting for Carbon Costs

In addition to justifications provided regarding specific resources, Commission Staff has broader concerns regarding the manner in which LG&E/KU account for potential carbon regulation. Specifically, while LG&E/KU accounted for the prospect of carbon regulation by excluding new coal units and modeling NGCCs with a requirement that they include CCS (as well as including certain incentives for other resources),[234] the model was permitted to select large frame SCCTs without CCS, based on the assumption that new SCCT units would not require CCS in 2035.[235] Further, LG&E/KU assumed that an existing coal unit would continue to operate beyond 2060 without CCS.[236] However, pursuant PPL's carbon emission plan, LG&E/KU also indicated that it does not intend to burn unabated coal or natural gas beyond 2050.[237]

Despite those apparent contradictions, LG&E/KU asserted that its IRP is consistent with PPL's carbon emission plan through 2035, because both the IRP and the carbon emission plan reflect the same coal unit retirements through 2035 and any projections beyond that date are outside the scope of the 2021 IRP and irrelevant. The Companies also argued that there is no particular statute, regulation, or market circumstance that requires them to stop burning unabated coal or natural gas beyond 2050, so there is nothing related to PPL's carbon emission plan to reflect in the 2021 IRP.[238]

Commission Staff disagrees that projections beyond 2035 are beyond the scope of or irrelevant to the 2021 IRP, because projected useful lives of new generating units can affect the value of those units and projected useful lives of existing units can affect the value of upgrades necessary to keep those units operational. For instance, in the base case, the 2021 IRP projected the addition of 440 MW of new SCCTs without CCS in 2028 and 880 MW of new SCCTs without CCS in 2034. If those SCCTs were taken

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[234] LG&E/KU also excluded coal-fired generation from the model due to environmental risks, which include the risk of carbon regulation.

[235] July 13, 2022 HVT at 12:44:11–12:47:10.

[236] LG&E/KU assumed that most existing coal units would operate for their remaining book lives, which for Trimble County Unit 2 would be 2066. See 2021 IRP, Vol. I, Section 5 at 17-18 (stating that all "CO2-emitting units," other than a few specifically mentioned as retiring early, "are assumed to retire at the end of their book depreciation lives"); Jul. 12, 2022 H.V.T. at 11:42:20 – 11:42:50 (indicating that the book life for Trimble County Unit 2 currently extends to 2066). LG&E/KU also acknowledged that it would not be practical to install CCS on existing coal units. See Jul. 12, 2022 H.V.T. at 11:49:14 – 11:49:55 (noting that they stopped looking at CCS for existing coal units because it was unlikely to ever be economical to retrofit such units).

[237] *See* July 12, 2022 HVT at 11:43:27–11:46:36; 11:53:00–11:54:25.

[238] LG&E/KU's Supplemental Comments at 8-9.

out of service in 2050 to meet PPL's carbon emission plan, then their useful lives would be reduced by about 50 percent,[239] which would affect the economics of those units during the planning period. Further, while LG&E/KU indicated that it required CCS on NGCC units due to projections regarding the New Source Performance Standard (NSPS), its witness also indicated that it required CCS for any new NGCC units due to the expectation that natural gas units without CCS would be taken out of service in 2050 to meet the carbon emission plan.[240] Thus, LG&E/KU's projections regarding carbon regulation beyond the IRP planning period are relevant to the 2021 IRP.

Given the relevance of carbon regulation beyond 2035, Commission Staff is concerned about inconsistencies between assumptions in the 2021 IRP and the Companies' commitment to the PPL carbon emission plan. There may not be a particular projected statute, regulation, or market circumstance that would require compliance with PPL's carbon emission plan by 2050. However, the Companies indicated that their commitment to the carbon emission plan through 2050 was based on an analysis of potential environmental regulations, potential technology developments, and potential issues obtaining coal.[241] While such an analysis would understandably be subject to uncertainty, as LG&E/KU's witness noted,[242] if the Companies felt their analysis justified their commitment to the carbon emission plan, they should have incorporated their commitment into the IRP and explained the basis for their analysis and the uncertainties associated with it.

In fact, while it may change as circumstances change and assumptions become more or less likely, an IRP is supposed to reflect a utility's actual plan for meeting projected load.[243] If an IRP does not reflect a utility's actual plan at the time it is produced or is based on assumptions that are different than those used to develop a utility's actual plan, the IRP has limited use for assessing a utility's proposed actions for meeting future load. Thus, Commission Staff believes that it was unreasonable to develop the 2021 IRP without incorporating and explaining assumptions LG&E/KU used to develop their actual plan, which includes their commitment to the PPL carbon emission plan.

Commission Staff agrees with the Attorney General's comments that resource planning should not be driven by a corporate policy because that would essentially hand resource planning over to the utility itself without oversight. However, Commission Staff's concern is that LG&E/KU's commitment to PPL's carbon emission plan is based on underlying assumptions regarding the risk of future carbon regulation, available

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[239] LG&E/KU's witness indicated that SCCTs would have a useful life of up to 40 years. July 12, 2022 HVT at 15:48:00. If LG&E/KU placed SCCTs on online in 2028 and 2035 and took them out of service in 2050, then it could potentially reduce their useful life by as much as 25 years. *See* July 12, 2022 HVT at 15:48:30.

[240] July 12, 2022 HVT at 11:53:00-11:54:20.

[241] July 13, 2022 HVT at 16:54:30-16:57:10.

[242] July 13, 2022 HVT at 16:57:10-16:59:30.

[243] 807 KAR 5:058, Section 5(5).

technologies, and the cost of resources that are not reflected in the IRP such that customers could be stuck with stranded costs if those assumptions prove accurate. Further, given that IRP is intended to justify a resource acquisition plan and allow scrutiny of that plan, Commission Staff is concerned that LG&E/KU proposed a plan that is inconsistent with its publically stated plan not to burn unabated coal or natural gas beyond 2050 without any explanation of the inconsistencies.

Setting aside differences between the 2021 IRP and the PPL carbon emission plan, Commission Staff also believes that LG&E/KU's assessment of the potential impacts of carbon regulation should have been more robust. As noted above, LG&E/KU excluded NGCC without CCS from the resource assessment due to limits it projected would be imposed through the NSPS but provided little explanation for that assumption in the IRP. Further, LG&E/KU briefly explained that they did not model a carbon price due to recent unspecified discussions regarding carbon regulation focused on regulation through the Clean Energy Standard and because no law or regulation setting a carbon price was being seriously discussed.[244] However, while it was somewhat unclear due to the brevity of the explanation, LG&E/KU's assessment of a potential carbon price appears to be in the very short term. Given the significant effects carbon regulation could have on the useful lives and cost of resources assessed,[245] Commission Staff believes the IRP's assessment and discussion of potential carbon regulation was too limited and should have been more thorough and assessed the regulatory risk and its effect on costs over a longer period of time, including any effect on the economics of resources that could be selected in the planning period.[246]

Commission Staff also disagrees, in part, with statements in LG&E/KU's post-hearing comments indicating that recent developments support its assumption that carbon regulation is likely to be achieved through application of the NSPS alone. Commission Staff agrees that limitations imposed on the EPA in *West Virginia v. EPA* make it more likely that it would attempt to regulate carbon emissions through the direct regulation of generating facilities and statements from the current administration and incentives in the Inflation Reduction Act support that prospect.[247] However, given

[244] 2021 IRP, Vol. I, Section 5, at 20; *see also* Response to Staff's First Request, Item 8 (indicating that the paragraph on page 20 Vol. I, Section 5 of the 2021 IRP included each basis for its decision not to include a carbon price).

[245] Notably, the capital cost of NGCC with CCS is nearly twice that of NGCC without CCS. Further, as noted above, LG&E/KU has indicated that they do not intend to burn unabated natural gas beyond 2050, which would reduce the useful life of SCCTs installed in 2035 by half.

[246] For instance, given the long lives of the resources at issue, it would have been reasonable to assess the risk of carbon pricing over a longer period instead focusing only on recent comments of the current administration to justify modeling only the NSPS. The IRP also could have included a more detailed description of when and how LG&E/KU expected the NSPS to apply, and as discussed below, the model could have been permitted to select resources based on when LG&E/KU expected changes in that standard. Additionally, if potential regulation could mandate the closure of specific types of units by a certain date, then the risk of such regulation should have been assessed and reflected in the model to the extent possible—perhaps through the use of shorter useful lives that correspond to the risk of mandated closure.

[247] *See* LG&E/KU's Supplemental Comments at 6-7.

questions about the feasibility of CCS,[248] it is unclear whether the EPA could regulate carbon through constraints on specific generating units and such regulation could be held up for some time in litigation even if they did. Given the urgency with which many view the need to address carbon emissions, Commission Staff believes such issues and potential delays in other forms of regulation raise the prospect, particularly over a timeline of 15 years or more, that a federal price or tax on CO2 emissions could be implemented through the reconciliation process in the same way the tax on methane emissions was imposed in the Inflation Reduction Act.[249] Thus, Commission Staff believes that the regulatory risk or prospect of a tax on CO2 emissions should be seriously considered and discussed in detail in LG&E/KU's next IRP and any assumption regarding a CO2 price or tax, including that a CO2 price is unlikely, should be fully supported such that the reasonableness of the assumption can be assessed.

REASONABLENESS OF INTEGRATION ASSESSMENT

Optimizing Resource Decisions throughout Planning Period

Commission Staff agrees with certain intervenors that the PLEXOS resource expansion model should have been used to simulate and optimize resources decisions, including the economic retirement of existing units, throughout the 15-year planning period. First, optimizing resource decisions throughout the planning period has the potential to reduce costs and ensures that the appropriate resources are selected when they are needed.[250] In fact, assuming the validity of LG&E/KU assumptions, there is evidence that LG&E/KU's decision not to allow the model to optimize resource decisions throughout the planning period had a significant effect on the resources selected by the model.

For example, LG&E/KU only modeled NGCC with CCS based on the assumption that the NSPS would require CCS for NGCC units in 2035.[251] However, application of a specific NSPS is contingent on the EPA establishing that technology exists to satisfy the

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[248] *See* July 12, 2022 HVT at 11:46:30–11:49:11 (in which LG&E/KU's witness noted that they are looking at how to implement CCS, including potential storage sites or economic uses of CO2, but indicated that he was unable to give a timeframe for when they might find something that is feasible); Jul. 13, 2022 H.V.T. at 12:36:10 – 12:38:41 (in which LG&E/KU's witnesses notes that CCS would currently be difficult to implement in Kentucky and elsewhere).

[249] LG&E/KU's witness acknowledged at the hearing that they had not considered the risk of potential methane regulation in the IRP, though they indicated it was likely to become a bigger issue before the next IRP. July 13, 2022 HVT at 13:11:30–13:12:00. However, in August 2022, Congress passed the Inflation Reduction Act through the reconciliation process, and among other things, it amended the Clean Air Act to add a charge of $1,500 by 2026 for methane emissions at certain facilities. Public Law No: 117-169, Sec. 60113, (c) and (e).

[250] *See, e.g.* Case No. 2020-00299, Commission Staff's Report on the 2020 Integrated Resource Plan of Big Rivers Electric Corporation at 41-42 (discussing how the utility had excluded certain wholesale customers from the projected load used to assess resources for the IRP plan, because the contracts ended before the end of the planning period, which resulted in a plan that did not have capacity in the short term to serve their projected load).

[251] July 13, 2022 HVT at 12:44:11–12:47:10.

standard when the new resource is constructed,[252] and LG&E/KU seems to contend that the standard will not require CCS for NGCC units placed in service in 2028.[253] If LG&E/KU had allowed the model to optimize resources throughout the planning period and included its assumptions regarding the application of the NSPS, it likely would have selected NGCC without CCS to fill a capacity shortfall in 2028, given other assumptions reflected in the model, whereas the model could not select that resource in 2035.

There are also numerous less obvious optimizing decisions that the model may have selected throughout the planning period if it had been configured to optimize resource decisions throughout the planning period. Optimizing resource decisions throughout the planning period would also require little additional work, so LG&E/KU could produce a more accurate result with little additional costs.[254] Thus, Commission Staff believes LG&E/KU should have used the model to optimize resource decisions throughout the planning period.

Treatment of Existing Demand Side Options

LG&E/KU's treatment of existing demand side resources in the model is unclear. For instance, Table 8-13 of the IRP showed total demand reduction at summer peak of 369.2 MW in 2025, including 118.7 MW and 27.5 MW for residential/small nonresidential and large nonresidential demand conservation, respectively.[255] However, when showing the results of the model at summer peak in 2025 in Table 8-15, LG&E/KU reflected "DSM" of 311 MW reducing load and 56 MW of demand conservation as a resource to meet load.[256] Further, while Table 8-12 reflected no incremental change in demand conservation programs during the planning period,[257] Table 8-15 showed the demand conservation resource decreasing in each year of the planning period.[258] Similarly, Table 8-15 listed the Curtailable Service Rider and the Demand Conservation Program as generation resources but noted they are not considered "Existing capability" with other

[252] *See* July 13, 2022 HVT at 12:35:10–12:36:35 (noting that the NSPS allows the EPA to impose limits on emissions by new generation units but requires that the limits be imposed on the unit and based on existing technology).

[253] *See* July 13, 2022 HVT at 12:33:13–12:36:35 (noting that the Clean Air Act requires the EPA to review the NSPS on an 8 year basis and that the next review is due in 2023 but indicating that a NSPS that required CCS due to limits imposed on NGCC's would currently be very difficult to meet).

[254] *See* July 13, 2022 HVT at 08:38:34-08:39:30 (noting that allowing the model to select when resources would be economically retired during the planning period would mostly require additional computer run time without significant changes in the inputs); *see also* July 12, 2022 HVT at 17:57:20-17:59:30 (discussing generally how the modeling inputs are developed); Joint Intervenors' Supplemental Comments at 41-42 (discussing how optimizing for each year of the planning period does not require additional inputs but is a matter of telling the model to optimize for those periods).

[255] 2021 IRP, Vol. I, Section 8 at 25, Table 8-13.

[256] 2021 IRP, Vol. I, Section 8 at 28. Table 8-15.

[257] 2021 IRP, Vol. I, Section 8 at 22, Table 8-12.

[258] 2021 IRP, Vol. I, Section 8 at 28 Table 8-15.

generation resources and there was limited explanation in the IRP for how they were treated by the model.[259] Commission Staff believes that the IRP should have contained a more thorough discussion of how existing demand side resources were considered by the model, so those reviewing the model could understand the key assumptions and analyze the bases for those assumptions.

Projected Reserve Margin

Despite the Companies' intent to maintain reserve margin targets of 17-24 percent in the summer and 26-35 percent in the winter, the base case plan reserve margin climbs to 45 percent in the summer by 2036; double the summer target. This is driven by the planned retirement of coal-fired baseload units, the addition of 1,600 MW of solar capacity, and the need to account for the intermittency of solar generation. Nonetheless, although the winter reserve margin is at the lower end of the winter target, a 45 percent summer reserve margin appears to be excessive and could present an excessive burden on ratepayers.

Presentation of IRP Plan

As discussed briefly above, the IRP regulation contemplates that a utility's IRP will include an actual plan for meeting projected load during the planning period.[260] In that regard, the IRP is required to include the "[s]teps to be taken during the next three years to implement the plan."[261] The plan is also supposed to identify and provide specific, detailed information regarding "all existing and planned electric generating facilities which the utility plans to have in service . . . during any of the fifteen (15) years of the forecast period" as well as demand-side resources that the utility included in the plan.[262] The regulation then anticipates that the plan will evolve through subsequent IRP filings based on new information and changes in circumstances.[263]

Although LG&E/KU provided a significant amount of useful information that will help in assessing future proposed generation acquisitions, the 2021 IRP, like the IRPs of

[259] *See* 2021 IRP, Vol. I, Section 8 at 28, Table 8-15.

[260] *See* 807 KAR 5:058, Section 8(1) ("The plan shall include the utility's resource assessment *and acquisition plan* for providing an adequate and reliable supply of electricity to meet forecasted electricity requirements at the lowest possible cost."); *see also* 807 KAR 5:058, Section 7(6) ("A utility shall file all updates of load forecasts with the commission when they are adopted by the utility."); 807 KAR 5:058, Section 6 (indicating that all IRPs shall summarize significant changes since the last IRP, including changes to resource plans).

[261] 807 KAR 5:058, Section 5(6).

[262] 807 KAR 5:058, Section 8(3)(b), (e).

[263] *See* 807 KAR 5:058, Section 8(1) ("The plan shall include the utility's resource assessment *and acquisition plan* for providing an adequate and reliable supply of electricity to meet forecasted electricity requirements at the lowest possible cost."); *see also* 807 KAR 5:058, Section 7(6)(" A utility shall file all updates of load forecasts with the commission when they are adopted by the utility."); 807 KAR 5:058, Section 6 (indicating that all IRPs shall summarize significant changes since the last IRP, including changes to resource plans).

some other utilities, was conducted more as a planning exercise with the understanding that the plan proposed will not likely be implemented. Commission Staff believes that this resulted in an IRP plan that is not consistent with LG&E/KU's actual expectations and is less rigorous than required by the IRP regulation.

For instance, the "Steps to be Taken During Next Three Years to Implement Plan" only mentioned adding generation that has already been approved, a plan to implement pilot DSM/EE projects associated with AMI, and plans to monitor various issues that might affect future resource acquisitions.[264] However, given the timelines associated with constructing most units, LG&E/KU would need to start specific planning now to meet its projected capacity shortfall in 2028.[265] In fact, LG&E/KU acknowledged at the hearing in this case that they requested proposals for new generation to meet their 2028 demand on June 22, 2022[266] and that they will likely file a CPCN for new generation in early 2023.[267] These are things that should have been, but were not included and discussed in the 2021 IRP.

Perhaps more importantly, as discussed above with respect to PPL carbon emission plan, if there is some assumption that will drive LG&E/KU's actual plan, it should be reflected in the IRP. In the example above, if LG&E/KU knows that there will be unmet demand in 2028, then it should model meeting that demand in 2028 as opposed to 2036. Such discrepancies affect the validity of the plan produced by the IRP.

Commission Staff acknowledges that previous Commission Staff reports have not found that utilities' IRPs were unreasonable despite being treated more as a planning exercise than a means to develop an actual plan. However, given the energy transition that is expected in the coming decades, Commission Staff believes that the need to holistically review utilities' actual long-term resource acquisition plans is more important than ever. Further, Commission Staff believes that if a utility's actual plan is reviewed in piecemeal fashion as requests for CPCNs are made or modifications to DSM/EE programs are requested that mistakes are more likely to be made and proposed short term actions will be unavoidable as the only means to meet demand in time. Thus, Commission Staff believes that resource acquisition plans in future IRPs should be developed as if they would actually be implemented to meet the utility's projected load

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[264] 2021 IRP, Vol. I, Section 5 at 44.

[265] *See* July 13, 2022 HVT at 13:45:28–13:46:21 (noting that you have to start well ahead of your potential need because it takes potentially multiple years for a resource to be developed); July 12, 2022 HVT at 14:10:22 – 14:11:30 (noting that given the development time and construction time for assets that the "time is upon us" to deal with the projected retirements of units in 2028); *see also* July 12, 2022 HVT at 16:51:35–16:53:28 (indicating that it would take 4 to 5 years to build an NGCC from the date they decided to move forward if they were building at an existing site; that it would take a year or less to build an SCCT at an existing site; and that it would take at least 10 to 15 years to build a nuclear unit).

[266] July 12, 2022 HVT at 14:10:22–14:11:30.

[267] July 13, 2022 HVT at 14:37:30–14:40:00 (discussing LG&E/KU's expectation that they would file a CPCN for new generation associated with the June 2022 request for proposal and indicating that the timeframe would be in or about early 2023).

with the idea that this actual plan will be updated and evolve as facts and circumstances change or become more clear.

2022 Request for Proposals

While it was not mentioned in the IRP, as noted above, LG&E/KU indicated at the hearing in this case that they published a Request for Proposal (RFP) on June 22, 2022, for supply-side resources to meet their projected capacity shortfall in 2028. The Companies indicated that the RFP was resource neutral, that they will base any request for a CPCN on the results of the RFP, and that they will file a request to modify their DSM/EE programs in conjunction with any request for a CPCN. However, while LG&E/KU indicates that no decision has been made regarding the resource they will select, there is some indication that they are likely to propose an NGCC unit without CCS.

Although LG&E/KU evaluated NGCC without CCS in response to a request by Commission Staff, the Companies' IRP did not evaluate NGCC without CCS as a potential resource option. This illustrates the issues with the IRP in that it did not consider a resource that LG&E/KU may propose to construct shortly after the IRP concludes. It also raises the prospect that an NGCC unit without CCS will not receive the holistic review anticipated by the IRP.

Commission Staff is encouraged by LG&E/KU's statements indicating that they will evaluate new DSM/EE programs along with any requests for a CPCN. However, since all resources were not included in the IRP, Commission Staff believe that it would be useful for LG&E/KU to provide a more holistic review in any CPCN and DSM/EE program cases. Further, since the Inflation Reduction Act likely affected the cost of proposals received, Commission Staff do believe that LG&E/KU should obtain updated proposals reflecting those cost changes, so that customers are not overcharged for generation capacity.

Commission Staff note that the Attorney General opposed any recommendation to reevaluate resources based on changes arising from the Inflation Reduction Act, and indicated that it was intended to favor renewable generation, which the Attorney General argued is less reliable. Commission Staff understand the Attorney General's concerns about reliability and agree that thermal generation plays an important role in maintaining reliability. However, even without updated RFP responses, an NGCC unit without CCS may not be the least cost resource, so if the RFP responses were not updated, customers could simply end up paying more for the same resource. Further, LG&E/KU should not and has not indicated an intention to select resources that will not provide adequate reliability even if they are least cost. Thus, while some may have that motive, Commission Staff's intention in suggesting that the RFP responses should be updated in light of the Inflation Reduction Act is to ensure the least-cost, most reasonable resource is selected.

REASONABLENESS OF 2021 IRP OVERALL

Commission Staff believes that many of the issues discussed above affected the reasonableness of the optimal, base case plan produced by the IRP. In fact, there does not appear to be a single party to this review–LG&E/KU included–who is likely to support implementing the optimal, base case plan at this point.[268] Thus, LG&E/KU did not establish that the 2021 IRP produced a least cost plan to reliably serve its projected load.

STAFF RECOMMENDATIONS FOR LG&E/KU'S NEXT IRP

Load Forecasting Recommendations

- LG&E/KU should expand their discussion of the reasonableness of underlying assumptions including supporting documentation listing known facts.

- LG&E/KU should continue to monitor and incorporate anticipated changes in EE impacts in their forecasts and sensitivity analyses. In addition, the Companies should not assume that current DSM-EE programs will not be renewed. Further, in the context of a long-range planning study, it would be reasonable for the Companies to model increased participation in current programs up to their current limits.

- LG&E/KU should expand its discussion of DERs 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 should 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, if any, that are adopted after this report.

- LG&E/KU should analyze and discuss whether and the extent to which customers that would have taken service under the Net Metering Service-2 tariff would continue to interconnect DERs even if they received no credit for energy sent back into the system because the one percent cap had been reached when they sought to connect.

Demand-Side Resource Recommendations

- LG&E/KU should identify and assess all potentially cost-effective demand-side resource options.

- Any changes to demand-side resources should be discussed in full including a transparent analysis of the cost and benefits inputs.

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[268] As discussed in the Comments above, the Attorney General and KIUC seem to tentatively support the construction of an NGCC unit without CSS to meet 2028 demand, and LG&E/KU appear to be moving in that direction as well, despite excluding that resource from the IRP's resource expansion model. Conversely, other parties support additional renewable and DSM/EE resources or at minimum believe that the plan did not fairly evaluate those resources.

- 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 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 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 should consider and model more aggressive options to increase use of the curtailable service rider and demand conservation program.

- LG&E/KU should consider DSM/EE programs specifically designed to shift EV charging from peak periods.

- Commission Staff notes the increased nonresidential participation in DSM-EE programs[269] and the impact it has in reducing energy requirements and peak demand and recommends 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 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 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.

Supply-side Resource Recommendations

- LG&E/KU should provide a more robust discussion of supply-side resources and should assess all potentially cost-effective resources using the resource expansion model, including nuclear generation at the end of the planning period.

- LG&E/KU should describe and discuss all supply-side resources that were considered, including variations of the same resource (e.g., NGCC with and without CCS or traditional and small-cell nuclear), and if a resource was considered but ultimately not included in the resource expansion model. LG&E/KU should explain each basis for excluding the resource, including the specific information used to support each basis such as cost estimates that resulted in a resource being excluded as too expensive or

[269] Case No. 2022-00123, final Order at 3.

engineering concerns that resulted in a resource being excluded based on a determination that it is not feasible.

- LG&E/KU should consider resources outside of its service territory with transmission costs based on specific updated analyses of transmission costs.

- LG&E/KU should consider interconnection costs and the cost of necessary network upgrades to the extent possible when assessing resources both in and outside its service territory and should describe and discuss how such costs were considered, whether and how such costs were included in the resource expansion model, uncertainties associated with how such costs were considered, and if applicable, why such costs could not be included in the resource expansion model.

- LG&E/KU should include a more detailed and broader explanation of potential and expected carbon regulation, given the significant effects such regulation could have on future resources, including a description of potential carbon regulation that would affect the useful life or cost of any resource, an explanation of the risk or likelihood and potential timing of such regulation, an explanation of how LG&E/KU accounted for the risk of each such regulation in its assessment of resources, e.g. modeling the cost of a resource using a shorter useful life or modeling a carbon cost, and an explanation of why LG&E/KU accounted for the risk in that manner. The potential regulations discussed should include at minimum the NSPS and carbon pricing or a carbon tax.

- LG&E/KU should include additional discussion of transfer capabilities in the next IRP, including a discussion of any known, significant conditions that restrict LG&E/KU's ability to import energy to serve projected load.

- LG&E/KU should consider and discuss savings, if any, that could be achieved by obtaining resources owned and operated by third parties or through partnerships.

- LG&E/KU should consider and discuss opportunities, if any, to partner with nearby utilities to gain experience with new generation resources, including nuclear generation.

- LG&E/KU should discuss recent developments regarding OVEC, including any material upgrades or changes in O&M that have or will be required, whether LG&E/KU believe OVEC will be economical with those upgrades or changes, and any actions LG&E/KU has taken or plans to take, though potentially limited by the contract, to avoid such costs if they would make OVEC uneconomical for LG&E/KU.

<u>Integration Recommendations</u>

- LG&E/KU should use the model to optimize resource decisions throughout the planning period.

- Resource acquisition plans in future IRPs should be developed as if they would actually be implemented to meet LG&E/KU's projected load.

- For the IRP, the Companies should include additional scenarios that compare and contrast assumptions, especially those that turn out to be primary drivers of modeling results and, hence, potential directions of future capital budgets and customer bill impacts.

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