

Kentucky Public Service Commission

**Staff Report on the
2018 Integrated Resource Plan
of Louisville Gas and Electric Company
and Kentucky Utilities Company**

Case No. 2018-00348

July 2020

SECTION 1

INTRODUCTION

807 KAR 5:058, promulgated in 1990 and amended in 1995 by the Kentucky Public Service Commission (Commission), established an integrated resource planning (IRP) process that provides for regular review by the Commission Staff (Staff) of the long-range resource plans of the Commonwealth's six major jurisdictional electric utilities. The Commission's goal in establishing the IRP process was to ensure that all reasonable options for the future supply of electricity were being examined in order to provide ratepayers a reliable supply of electricity that was cost-effective.

Louisville Gas and Electric Company (LG&E) and Kentucky Utilities Company (KU) (collectively LG&E/KU or Companies) submitted their Joint 2018 IRP to the Commission on October 19, 2018. The Joint 2018 IRP reflects LG&E/KU's long term plan for meeting their customers' electricity requirements for the period 2018-2033.

On October 30, 2018, an Order was issued establishing a procedural schedule for this proceeding. The procedural schedule established a deadline for requesting intervention, two rounds of data requests to LG&E/KU, an opportunity for intervenors to file written comments, and an opportunity for LG&E/KU to file a response to any intervenor comments.

The following parties filed for, and were granted, intervention in this matter: 1) the Attorney General of the Commonwealth of Kentucky, by and through the Office of Rate Intervention (Attorney General) and 2) Sierra Club, Joe F. Childers, Alice Howell, Carl Vogel, Amy Waters, and Joe Dutkiewicz (collectively Sierra Club).

Southern Renewable Energy Association (SREA) did not request intervention; however, they did file written comments as allowed pursuant to 807 KAR 5:001, Section 11(2)(e).

LG&E and KU are investor-owned utilities that generate, purchase, transmit, and distribute electricity to customers located primarily in Kentucky. LG&E serves approximately 411,000 electric customers in nine Kentucky counties.¹ KU serves approximately 553,000 customers in 77 Kentucky counties.² KU also provides wholesale power to ten municipal electric systems in Kentucky.³ The Companies are wholly-owned

¹ Joint 2018 IRP at 5-1. LG&E also serves approximately 326,000 natural gas customers in 17 Kentucky counties. *Id.*

² *Id.* KU also serves customers in five counties in Virginia under the name Old Dominion Power Company as well as three customers in Tennessee. *Id.*

³ *Id.* Eight of the municipalities terminated their wholesale power purchase agreements and exited the KU system from April 30, 2017 through April 30, 2019.

subsidiaries of LG&E and KU Energy LLC (LKE), which is a subsidiary of PPL Corporation (PPL).

The Companies are owners and operators of interconnected electric generation, transmission, and distribution facilities. They operate the interconnected and centrally dispatched system through coordinated planning, construction, operation, and maintenance of their facilities.

With respect to supply-side resources, the Companies' net summer generation capacity in 2018 was 8,181 megawatts (MW).⁴ This consisted of 5,156 MW of coal-fired capacity, 662 MW of natural gas combined cycle (NGCC), 2,172 MW of large-frame simple-cycle combustion turbines (SCCT),⁵ 87 MW of small-frame SCCTs, 8 MW of solar capacity, and 96 MW of hydroelectric (hydro) power.⁶

The Companies' highest combined system peak demand of 7,175 MW occurred on August 4, 2010, and since that date the Companies have had two annual peak demands in excess of 7,000 MW with 7,114 MW in January 2014 and 7,079 MW in February 2015.⁷ The highest annual energy requirements for LG&E was 13.185 GWh in 2010; the highest annual energy requirements for KU was 23.452 GWh in 2010; the highest annual energy requirements for the combined LG&E/KU system was 36.637 GWh in 2010.⁸ Significant changes have occurred in their territories which make it unlikely they will ever reach such peak demands in the near and intermediate future.

The purpose of this report is to review and evaluate the Companies' Joint 2018 IRP in accordance with 807 KAR 5:058, Section 11(3), which requires Staff to issue a report summarizing its review of each IRP filing made with the Commission and make suggestions and recommendations to be considered by a utility in its next IRP filing. Staff recognizes that resource planning is a dynamic ongoing process. Specifically, Staff's goals are to ensure, among other things, the following.

- All resource options are robust and are fully and fairly evaluated;
- Critical data, assumptions, and methodologies for all aspects of the resource plan are well documented, fully supported, and reasonable; and
- The report also includes an incremental component noting any significant

⁴ *Id.* at 5-5.

⁵ The large-frame SCCT includes LG&E's 165 MW capacity purchase and tolling agreement with Bluegrass Generation.

⁶ Joint 2018 IRP at 5-5.

⁷ *Id.* at 5-2.

⁸ LG&E/KU's response to Commission Staff's First Request for Information (Staff's First Request), Item 3.

changes from the Companies' prior IRP, filed in 2014.

LG&E and KU state that the mandate for their Joint 2018 IRP is to meet future energy requirements within their service territories at the lowest possible cost consistent with reliable service. The Companies assert that they have an ongoing resource planning process and their Joint 2018 IRP represents only one snapshot in time of that process, which is fundamental to all corporate planning. The various sections of the LG&E/KU Joint 2018 IRP define ongoing and planned activities that collectively make up that process. LG&E and KU state that certain assumptions are made in their planning decisions and, as such, are subject to various degrees of risk and uncertainty. The Companies examined the economics and practicality of supply-side and demand-side options in order to forecast the least-cost options available to meet forecasted customer needs.

The LG&E/KU resource planning process contains the following:

- Establishment of reserve margin criteria;
- Assessment of the adequacy of existing generation units and purchased power agreements;
- Screening of demand-side resource options;
- Screening of supply-side resource options;
- Development of the optimal economic plan from the available resource options.

While their Joint 2018 IRP represents the Companies' analysis of the best options to meet customer needs at a given point in time, the resource plan options are reviewed and re-evaluated prior to implementation. If new generation is needed or demand-side options are to be expanded, the Companies must receive Commission approval prior to implementation and the information and data contained in the Companies' Joint 2018 IRP should serve, at a minimum, as a basis for determining the reasonableness of the needed new generation or expansion of demand-side management programs.

The Companies' base forecast for the combined summer peak is expected to decrease from 6,655 MW, their weather-normalized 2018 peak, to 6,339 MW in 2033.⁹ The Companies' winter peak load is expected to decrease from 6,322 MW to 6,129 MW over the same period, a decrease of 3.05 percent.¹⁰ Energy requirements for the combined Companies are projected to decrease 4.97 percent from 34,185 GWh in 2018 to 32,487 GWh in 2033.¹¹

⁹ *Id.* at 5-26.

¹⁰ *Id.*

¹¹ *Id.* at 5-25.

This report is organized as follows:

- Section 2, Load Forecasting – reviews LG&E’s and KU’s projected load growth and load forecasting methodology;
- Section 3, Demand-Side Management (DSM) – summarizes LG&E’s and KU’s evaluation of DSM opportunities;
- Section 4, Supply-Side Resource Assessment – focuses on supply resources available to meet the Companies’ load requirements and environmental compliance planning; and
- Section 5, Integration and Plan Optimization – discusses the Companies’ overall assessment of supply-side and demand-side options and their integration into an overall resource plan.

The report contains a number of recommendations for the Companies’ next IRP. The majority of Staff’s recommendations are contained in Sections 2, 3, and 4.

It must be noted that departures from the filing schedule in 807 KAR 5:058 have caused overlaps of past IRP filings. Staff recommends the Commission require LG&E/KU to file their next IRP on or before October 19, 2021.

SECTION 2

LOAD FORECASTING

BACKGROUND

This section reviews LG&E/KU's projected load changes and forecasting methodology. LG&E/KU conduct forecasting and resource planning on a combined company basis. The Companies' forecasting approach is based on econometric modeling of energy sales by customer class and incorporates specific information on the prospective energy requirements of its largest customers.

For the modeling, LG&E and KU applied historical internally generated data as well as various forecasting model data from the following: IHS Markit, the Kentucky Data Center, National Oceanic and Atmospheric Administration, Energy Information Administration (EIA), Management Applications consulting, Inc., National Renewable Energy Laboratory (NREL), Bloomberg New Energy Finance, and the Electric Power Research Institute.¹²

LOAD FORECAST METHODOLOGY

Generally, the Companies forecast electricity sales using a mix of macroeconomic data, historic energy use and customer specific data, weather data, and end use data. Energy requirements are obtained when transmission and distribution losses are combined with sales. Forecasts are made for LG&E and KU separately. While LG&E is a Kentucky only retail forecast, the KU forecast is comprised of Kentucky retail, Virginia retail (Old Dominion Power or ODP), and the Federal Energy Regulatory Commission's (FERC) wholesale forecast. Econometric and statistically adjusted end use (SAE) models for customer revenue and rate classes are developed. Broadly speaking, these models utilize macroeconomic data, historical and customer specific data, weather data (20 year normal degree days), and end use data to obtain sales forecasts.¹³

Certain large customer forecasts are made individually based upon specific information supplied by that customer. For the residential and commercial customer classes, SAE models are employed. Most of the forecasts are made on a billed energy basis, which is then converted to a monthly energy requirement basis for the Financial Planning department. In addition, the monthly energy requirements are converted into an hourly forecast using normalized load duration curves for the Generation Planning

¹² IRP, Vol. II, Table 1, at 5.

¹³ *Id.* Figure 1, at 3-4.

department.¹⁴ Additionally, the impact of increasing distributed solar generation and electric vehicle use is layered into the forecast.¹⁵

Key assumptions driving the forecasts include a reasonably strong national economy with an average growth rate of 2.0 percent through 2028. The Kentucky economy is projected to grow at about 1.5 percent through 2033. Recently, LGE/KU has observed consumers more active in efforts to use energy more efficiently and that trend is expected to continue through the use of more efficient appliances, including lighting, heating and cooling equipment, motors, and other equipment. Over the forecast period, residential and commercial energy efficiency improvements are forecasted to reduce energy requirements by almost 8 percent from current levels.¹⁶ Industrial sales are expected to remain flat over the forecast period. Growth in distributed generation is predicted to occur primarily through increased customer net metering with net metering solar capacity forecasted to grow to from 3 MW to 170 MW by 2033 driven primarily by declining solar prices and favorable net metering policy.¹⁷ In addition, the number of electric vehicles is expected to increase from 1,409 in 2017 to about 44,000 by 2033.¹⁸ Finally, the effect of the loss of load from eight municipal wholesale customers is reflected in both the 2018 – 2020 Base Energy Requirement and the peaks.¹⁹

CHANGES IN METHODOLOGY SINCE THE 2014 IRP

There have been several significant changes since the Companies' 2014 IRP. To begin with, the mining sector continues to decline due primarily to competitive natural gas prices and the continued retirement of coal fired generating units. Between 2014 and 2017, the Kentucky coal mining sector output declined by 35 million tons.²⁰ For the Companies, this translates into a 228 GWh load loss.²¹ Going forward, the Companies

¹⁴ *Id.* at 4 and 13-15.

¹⁵ IRP, Vol. I, at 5-7 – 5-8 and Vol. II at 1-13.

¹⁶ IRP, Vol. I, at 5-9 – 5-12.

¹⁷ *Id.* at 5-13. The Companies note, however, that the projected increase in net metering solar capacity is particularly uncertain.

¹⁸ *Id.* at 5-14. Like distributed solar generation, the Companies note that the projected increase in electric vehicles in their service territories is a key forecast uncertainty.

¹⁹ *Id.* at 5-25 – 5-26 and Tables 5-7 and 5-9.

²⁰ *Id.* at 6-1.

²¹ *Id.* at 6-1 – 6-2.

believe that this sector has stabilized.²² Another difference is there have been a number of large customers that have left the system, resulting in a load loss of 555 GWh.²³ Also, the residential, commercial, and industrial class customers have exhibited marked efficiency gains at a pace faster than anticipated in 2014. In the 2014 IRP, the Companies were forecasting increases in electric end use intensities, 7 percent for KU and 11 percent for LG&E; however, in the current IRP, both KU and LG&E are forecasting a 9 percent decline.²⁴ LG&E/KU also note increased rural to urban customer growth, primarily residential, and increased electric heating customer penetration, even though most urban customers have access to gas heating.²⁵

Relative to the 2014 IRP, the combined effect of the significant change factors have produced both lower peak forecasts and sales forecast. Over the forecast period, the Companies' combined summer peak demand is 6,655 MW in 2018 declining to 6,339 MW in 2033. That is 528 MW less in 2018 and 1,357 MW less by 2033 relative to the 2014 forecast.²⁶ Similarly, the current IRP energy sales forecast is less than the 2014 projections. For the combined Companies, energy sales are projected to decline from 31,602 GWh in 2018 to 29,930 GWh in 2033. That is 2,207 GWh less in 2018 and 5,654 GWh less by 2033 as compared to the 2014 forecast.²⁷

There have been changes to both the Companies' supply and demand-side resources since the previous IRP filing. In order to comply with environmental regulations, the Companies retired the Green River and Cane Run coal units for a total of 726 MW. Cane Run 7, a 662 MW natural gas combined cycle unit, was brought on line in 2015.²⁸ Also, additional emission controls have been added to make the Companies' remaining coal units compliant with Environmental Protection Agency (EPA) regulations. A 10 MW solar installation has been added to the E. W. Brown station and the maximum output from each of the eight Zorn hydro units has been expanded from 10 MW to 12.6 MW. In addition, the Companies retired two coal units in February 2019 at the E. W. Brown station (272 MW) and plan to retire the Zorn 1 hydro unit (14 MW) in 2021.²⁹

²² *Id.* at 6-3.

²³ *Id.*

²⁴ *Id.* Table 6-1 at 6-6.

²⁵ *Id.* at 6-7 – 6-9.

²⁶ *Id.* Table 6-5 at 6-12.

²⁷ *Id.* Table 6-6 at 6-13.

²⁸ *Id.* at 6-16.

²⁹ *Id.*

Finally, the Companies' 165 MW capacity purchase and tolling agreement with Bluegrass Generation ended on April 30, 2019.³⁰

To gauge the cost effectiveness of potential demand-side resource programs, the Companies applied an avoided cost of capacity of zero. This zero capacity cost level has rendered many DSM programs to be no longer cost-effective. When combined with low load growth, no capacity constraints, and low natural gas prices, the Companies' recently approved suite of DSM and energy efficiency (DSM-EE) programs is smaller than in previous IRP filings because of the tighter cost-benefit constraints. Going forward, the Companies are also making non-residential DSM-EE programs available to industrial customers and unless these customers opt out, they will participate in the DSM rate recovery mechanism.³¹

RESIDENTIAL LOAD FORECAST

SAE models when combined with econometric models allow the forecaster to incorporate the end uses for electricity that, in part, drive energy requirements. Energy use is a function of Space Heating, Space Cooling, and Other equipment variables. The heating variable is a function of the number of heating degree days, equipment saturation levels and operating efficiencies, monthly average days per billing cycle, thermal integrity and square footage of homes, average household size and income, and real energy prices.³² The cooling variable is a function of much the same data, except that cooling degree days, cooling equipment saturation and operating efficiencies are used.³³ The Other equipment variable captures all other non-weather sensitive end uses.³⁴ It is a function of appliance and equipment saturation levels, appliance efficiency levels, average household size and income, real energy prices, and monthly average billing cycle days.³⁵

The number of residential customers is a function of the number of forecasted households or population in each company's service territory.³⁶ Residential sales are the

³⁰ *Id.*

³¹ *Id.* at 6-17.

³² *Id.* Vol. II, Appendix A at 17.

³³ *Id.* at 21.

³⁴ *Id.* at 24.

³⁵ *Id.* Note that the KU forecast includes ODP residential customers.

³⁶ *Id.* at 9.

product of the forecasted number of customers and energy use-per-customer.³⁷ Over the 2018-2033 forecast period, KU residential energy requirements are forecast to remain relatively stable, fluctuating between 5,908 GWh to 6,021 GWh. Similarly over the forecast period, LG&E energy requirements are expected to grow slowly from 4,096 GWh to 4,168 GWh. On a combined basis, residential energy requirements over the same period grow from 10,117 GWh to 10,137 GWh.³⁸

COMMERCIAL AND INDUSTRIAL FORECAST

The Commercial and Industrial (C&I) forecasts are made up of several separate forecasts with customers grouped by rate schedule. Large C&I customers are forecast separately based largely upon data obtained from the customer.³⁹ The General Service energy use forecasts use SAE models similar to that used for the residential forecasts and are a function of heating and cooling equipment and other non-weather sensitive equipment and binary variables. The KU Secondary forecast is a function of weather, cooling efficiencies, number of customers, and binary variables. The LG&E Secondary forecast is a function of weather, economic variables, the number of customers, and binary variables. The ODP Secondary forecast is a function of weather, number of customers, and binary variables. The KU All Electric Schools forecast is a function of weather, KU households, and binary variables. The ODP Municipal Pumping forecast is a trend analysis of recent sales. The KU and LG&E Primary forecasts are functions of an industry weighted industrial production index and weather. Where appropriate, certain large customers may be forecast separately. The LG&E Special Contract forecast, the KU Fluctuating Load Service forecast and the KU and LG&E Retail Transmission Service forecasts are primarily based upon individual customer forecasts. The ODP Industrial forecast is a function of weather and mining production indices.⁴⁰

Over the forecast period, the KU C&I energy requirements are expected to grow from 10,279 GWh to 10,403 GWh and then decline slowly to 10,301 GWh. Similarly, LG&E's C&I energy requirements are expected to grow from 6,466 GWh to 6,529 GWh. On a combined basis, the Companies' C&I energy requirements is forecast to grow from 16,745 GWh to 16,830 GWh.⁴¹

PUBLIC AUTHORITY AND LIGHTING

³⁷ *Id.* at 8.

³⁸ IRP, Vol. I, Tables 7-19 – 7-20 at 7-8 – 7-9. Forecasts include DSM program effects.

³⁹ IRP, Vol. II, at 9.

⁴⁰ *Id.* at 10-12.

⁴¹ IRP, Vol. I, Tables 7-19 and 7-20 at 7-8 – 7-9.

Separate forecasts are also made for Public Authorities (PA) and Lighting using recent sales trends.⁴² Over the forecast period, KU PA energy requirements are expected to decline from 1,559 GWh to 1,429 GWh. Similarly, KU Lighting requirements decline from 42 GWh to 33 GWh. Over the forecast period, LG&E PA requirements are forecast to decline from 1,069 GWh to 1,028 GWh. Similarly, LG&E Lighting requirements are expected to decline from 19 GWh to 16 GWh.⁴³

SALES FOR RESALE FORECAST

The KU Municipal forecast represents a compilation of individual municipal customer forecasts. Each municipal customer generates its own forecast, which is then reviewed by KU and compared to the customer's historical trend.⁴⁴ Over the forecast period, KU Sales for Resale is expected to decline from 1,844 GWh to 457 GWh.⁴⁵ The decline is primarily the result of the exit of eight municipals discussed in Section 1.

COMBINED COMPANIES BASE CASE ENERGY FORECAST

The Base Case energy forecast for LG&E exhibits a relatively flat curve over the 2018 – 2033 forecast period. LG&E's energy requirements range from 12,370 GWh in 2018 to 12,435 GWh by 2033. KU's energy requirements exhibit a similar pattern after accounting for the loss of the eight municipal utilities' load. KU's 2018 energy requirement is 21,815 GWh falling to 20,237 GWh in 2020, reflecting the lost municipal load. From 2020 onward, KU's energy requirement is forecast to slowly decline, ranging from 20,237 GWh in 2020 to 20,053 GWh in 2033.⁴⁶ On a combined company basis, energy requirements range from 34,185 GWh declining to 32,487 GWh over the forecast period.⁴⁷ As discussed previously, gains in energy awareness and efficiency overshadow any gains from customer and economic growth.

PEAK LOAD FORECAST

On a combined basis, the Companies are a summer peaking utility. The summer peak declines 294 MW from 6,655 MW to 6,361 MW. The winter peak declines 350 MW

⁴² IRP, Vol. II, at 12.

⁴³ IRP, Vol. I, Tables 7-19 and 7-20 at 7-8 – 7-9.

⁴⁴ IRP, Vol. II, at 12.

⁴⁵ IRP, Vol. I, Table 7-19 at 7-8.

⁴⁶ 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 723 GWh to 645 GWh.

⁴⁷ IRP, Vol. I, Table 5-7 at 5-25 and Tables 7-19 and 7-20 at 7-8 – 7-9.

from 6,322 MW to 5,972 MW. Accounting for the lost municipal load, the summer peak demand ranges from 6,361 MW in 2020 falling to 6,339 MW by 2033. By contrast, the winter peak grows slowly from 5,972 MW in 2020 to 6,129 MW in 2033. The overall growth in winter peak reflects the increasing penetration of electricity over natural gas in the winter heating season.⁴⁸

HIGH AND LOW ENERGY REQUIREMENT FORECASTS

In addition to the base case scenario forecast, the Companies produced a high energy requirements forecast and low energy requirements forecast. Relative to the base case scenario, the high energy scenario assumes a more robust economic growth, a lower cost of service, a higher electric vehicle adoption rate and lower distributed generation driven by net metering reform. The base case energy requirements over the forecast period decline from 34,185 GWh to 32,486 GWh. Similarly, the peak demand forecast base case scenario declines from 6,655 MW to 6,339 MW over the forecast period. However, under the high growth scenario, over the forecast period, energy requirements rise from 34,409 GWh to 35,869 GWh⁴⁹ and the peak demand rises from 6,697 MW to 6,845 MW.⁵⁰

In contrast to the base case scenario, the low energy requirements forecast assumed weaker economic growth, a higher than expected cost of service, lower electric vehicle adoption rates and higher rate of distributed generation adoption. As part of the low energy scenario, the Companies' six largest industrials shut down, all of the remaining municipal customers leave the system, and residential and commercial sales decline by 5 percent. Again, the base case energy requirements over the forecast period decline from 34,185 GWh to 32,486 GWh. Similarly, the peak demand forecast base case scenario declines from 6,655 MW to 6,339 MW over the forecast period. However, under the low energy requirements scenario, energy requirements decline slowly from 33,885 GWh to 28,136 GWh and peak demand declines slowly from 6,598 MW to 5,437 MW over the forecast period.⁵¹

INTERVENOR COMMENTS

Neither the Attorney General nor the Sierra Club offered comments regarding either the load forecast methodology or the load forecast results.

RESPONSES TO 2014 STAFF RECOMMENDATIONS

⁴⁸ *Id.* Table 5-9 at 5-26.

⁴⁹ *Id.* at 5-32 and Table 5-10 at 5-33.

⁵⁰ *Id.* at 5-32 and Tables 5-10 - 5-11 at 5-33. Note that the combined Companies are a summer peaking utility. Peak demands are forecast summer peaks.

⁵¹ *Id.*

The Staff Report addressing LG&E/KU's 2014 IRP contained the following recommendations regarding the Companies' load forecasting.

- The potential impact of existing and future environmental regulations on the price of electricity and other economic variables that affect the price of electricity remains a topic of significant interest within the electric utility industry and the utility regulatory community. Therefore, the effects of such regulations should continue to be examined by LG&E and KU as a part of their load forecasts and sensitivity analyses. Even though the Companies do not model changes in environmental regulations explicitly, Staff is satisfied that the Companies' use of economic and price data adequately reflect the potential impacts of future environmental regulations in load forecasts and sensitivity analyses.
- The potential continues to exist for future increases in electricity prices due to stricter environmental requirements that are large enough to affect consumer behavior and energy consumption. An updated analysis and discussion of how such price increases may impact the elasticity of consumer demand should be included in the Companies' next IRP. Staff is satisfied that with the Companies efforts thus far to incorporate variables such as distributed generation and electric vehicle adoption that influence the long run demand for electricity. In addition, Staff notes that economic and environmental effects are taken into account and are reflected in price elasticities through the Companies' use of SAE models.
- As required by the IRP regulation (807 KAR 5:058, Section 7(4)(d)), LG&E and KU should reflect anticipated changes in EE impacts in their forecasts for the full planning period included in the IRP. Staff is satisfied that the Companies are incorporating changes in end use EE in their load forecasts

Overall, the Joint 2018 IRP addressed these recommendations and Staff is satisfied with and accepts the manner and method in which the Companies' load forecasting in their Joint 2018 IRP incorporated the recommendations set forth in the Staff Report to the Companies' 2014 IRP.

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

- The potential impact of existing and future environmental regulations affecting the price of electricity and other economic variables continues to be a topic of significant interest. Therefore, the effects of such regulations should continue to be examined by LG&E/KU as a part of their load forecasts and sensitivity analyses in the next IRP filing.

- As discussed in the Joint 2018 IRP, the economics of current cost trends of distributed solar generation and electric vehicle penetration can have important effects on the demand for electricity. An increase in adoption rates of the former will tend to decrease electricity demand while increasing demand for the latter. In addition, LG&E's 2020-00016⁵² and Siting Board cases 2020-00040⁵³ and 2020-00043⁵⁴ highlight the improving economics and demand for large scale solar projects, which could have an impact on demand growth. For the next IRP, the Companies should closely monitor, discuss, and model the potential impacts of these trends in both base case and sensitivity analyses.
- LG&E and KU should continue to monitor and incorporate anticipated changes in EE impacts in their forecasts and sensitivity analyses.
- There were four major driving assumptions comprising the Companies' High and Low scenarios and the results were reported on a combined basis. In addition, the discussion did not include the degree to which the Companies varied each of the factors from the base case. Reporting results on a combined basis provides the extreme case scenarios which, in part, is the point of the analyses. However, such reporting masks the effects of varying individual factors, which could provide useful information. For the next IRP, 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. For example, in the Low sensitivity analysis, what circumstances would cause the cost of service decline by 5 percent and how would the lower cost be passed on to which customers and how would that affect demand? In the next IRP, in addition to the

⁵² Case No. 2020-00016, *Electronic Application of Louisville Gas and Electric Company and Kentucky Utilities Company for Approval of a Solar Power Contract and Two Renewable Power Agreements to Satisfy Customer Requests for a Renewable Energy Source Under Green Tariff Option #3* (Ky. PSC May 8, 2020).

⁵³ Case No. 2020-00040, *Application of Turkey Creek Solar, LLC for an Application for a Certificate of Public Convenience and Necessity to Construct an Approximately 50 Megawatt Merchant Electric Solar Generating Facility in Garrard County, Kentucky Pursuant to KRS 278.700* (Application filed March 27, 2020).

⁵⁴ Case No. 2020-00043, *Application of Glover Creek Solar, LLC for a Certificate of Public Necessity to Construct an Approximately 55 Megawatt Merchant Electric Solar Generating Facility in Metcalf County, Kentucky Pursuant to KRS 278.700 and 807 KAR 5:110* (Application filed March 27, 2020).

cumulative shock to the base case, there should be a disaggregated sensitivity analysis.

- The Base Case energy and peak demand forecasts are based on a 20-year historical period and the peak winter high demand forecast ranges from 6,355 MW to 6,764 MW by 2033. However, the maximum winter demand in the reserve margin analysis is based on an actual peak of 7,336 MW from 45 years ago. This represents a 981 MW – 572 MW difference. It is somewhat counter intuitive that the reserve margin (which seems unreasonably excessive) could be driven, in part, by an extreme outlier weather event, the effects of which are not even closely matched by the Companies' High peak load forecast. The High winter peak forecast in 2021 (the target year of the 2018 Reserve Margin Analysis) is 6,082 MW; a 1,254 MW difference. It is 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. Such disparities in the assumptions' reasonableness can erode the confidence that may be placed in the forecast results and reserve margin analyses. For the next IRP, the Companies should provide more robust and complete explanations as well as a more consistent use of assumptions driving energy, load, and resource planning forecasts.
- LG&E and KU should include discussion and analysis of the increase in distributed energy resources on load forecasts. This should include behind the meter generation at residential, commercial and industrial customer locations. These should be evaluated separately and cumulatively and include a discussion of drivers encouraging and discouraging such development.

SECTION 3

DEMAND-SIDE MANAGEMENT/ENERGY EFFICIENCY

INTRODUCTION

This section discusses the DSM-EE aspects of the LG&E/KU IRP. At the time of the Joint 2018 IRP filing, the Companies' most recent DSM application, Case No. 2017-00441,⁵⁵ was also filed and proposed to continue, modify, or terminate certain DSM-EE programs. The Commission issued a Final Order in Case No. 2017-00441 on October 5, 2018, approximately two weeks prior to the filing date of LG&E/KU's IRP, accepting the revised DSM-EE programs. This Joint 2018 IRP included the DSM-EE proposals from Case No. 2017-00441.

DSM-EE PROGRAMS THAT EXPIRED AT THE END OF 2018

The following programs, which were approved in Case No. 2014-00003⁵⁶ expired at the end of 2018 due to the programs reaching the end of their approval cycle and useful life.

1. Residential Conservation Program/Home Energy Performance – This program helped customers reduce home energy costs using on-line or onsite energy audits. Residential customers were provided help in identifying specific energy efficient measures to reduce energy costs in their home, such as water-saving faucet or shower fixtures, LED lightbulbs, and air-sealing measures. The program was allowed to expire as the majority of the measures are no longer cost-effective.

2. Residential Refrigerator Removal Program – This program provided removal and recycling of secondary refrigerators and freezers from customer households. This program became cost prohibitive due to the lack of vendors to remove and recycle the non-energy efficient appliances.

3. Customer Education and Public Information Program (CEPI) – Designed to help customers make sound energy-use decisions, increase control over energy bills, and empower them to actively manage their energy usage, the CEPI campaign will be discontinued as part of LG&E/KU's DSM-EE portfolio to reflect the scaled down program

⁵⁵ Case No. 2017-00441, *Electronic Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for the Review, Modification, and Continuation of Certain Existing Demand-Side Management and Energy Efficiency Programs* (Ky. PSC Oct. 5, 2018).

⁵⁶ See Case No. 2014-00003, *Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for the Review, Modification, and Continuation of Existing, and Addition of New, Demand-Side Management and Energy Efficiency Programs* (Ky. PSC Nov. 14, 2014).

offerings. LG&E/KU will continue to provide energy-efficiency messages to customers, just not as part of a DSM-EE program. Also, the Companies propose to retain program advertising in the budgets for the specific individual programs remaining in the 2019-2025 DSM-EE Program Plan.

4. School Energy Management Program (SEMP) - This program facilitates the hiring and retaining of qualified energy specialists by public, private, and independent school districts. The Commission ordered the termination of SEMP in Case No. 2017-00441⁵⁷ finding that the costs as a utility resource exceeded the benefits.⁵⁸

DSM-EE PROGRAMS REVISED OR UNCHANGED

The following programs were revised or kept unchanged per Case No. 2017-00441:

1. RESIDENTIAL AND SMALL NON-RESIDENTIAL DEMAND CONSERVATION PROGRAM – This program employs switches in homes to help reduce the demand for electricity during peak times. The program is designed so the Companies can communicate with switches to cycle central air conditioning units, heat pumps, electric water heaters, and pool pumps off and on through a predetermined sequence. LG&E/KU decided to change the program to a maintenance mode status, and cease to invest in or deploy new load-control devices. New participants will be allowed to enroll if existing devices are available from customers who chose to no longer participate, with the program gradually phased out as devices eventually fail. The monthly bill credit paid to participants from June through September was replaced with an end of cooling season credit which will be received only 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. Bill credits from multifamily participants previously split between the property owner and the tenant will only be paid to the tenant. LG&E/KU also discontinued all quality assurance and quality control checks on installed devices.

2. LARGE NON-RESIDENTIAL DEMAND CONSERVATION PROGRAM – Previously called Commercial Load Management/Demand Conservation Program, this program employs switches or interfaces to customer equipment in large commercial and industrial businesses to help reduce the demand for electricity during peak times. The program communicates with the switches or interfaces to cycle equipment. This program is designed to reduce peak load and thereby delay the need to invest in the construction of new generation assets. The Commission approved the addition of industrial customers

⁵⁷ Case No. 2017-00441, Direct Testimony of Gregory S. Lawson at 26 (filed Dec. 6, 2017).

⁵⁸ *Id.* Final Order at 30-31 (Ky. PSC Oct. 5, 2018).

to this program in Case No. 2017-00441.⁵⁹ An industrial customer 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.⁶⁰

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. Previously, incentives were based on a tier structure which was dictated by energy consumption. The tier structure was eliminated in favor of an incentive structure based upon the average amount of funds per home. The maximum income requirement was increased to match that of the Weatherization Assistance Program, which is 200 percent of the poverty level. LG&E/KU modified the program to allow master-metered multifamily dwellings to qualify for program services.

4. NON-RESIDENTIAL REBATES PROGRAM –This program is designed to increase the implementation of DSM-EE measures by providing financial incentives to assist with the replacement of aging and less efficient equipment and for new construction built beyond code requirements. 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 certification.⁶¹

Modifications include expanding this program to include industrial customers, subject to the statutory opt-out,⁶² and changes in the rebate amount calculation so that rebates are based on the first year annual energy savings rather than on an incentive. Other modifications include removal of prescriptive measures that are no longer cost-

⁵⁹ *Id.* at 31.

⁶⁰ *Id.* Direct Testimony of David E. Huff at 26-27 (filed Dec. 6, 2017). KRS 278.285(3) authorizes industrial customers with energy-intensive processes to opt out of utility offered DSM programs.

⁶¹ This program was previously called Commercial Conservation/Commercial Incentives Program.

⁶² KRS 278.285(3).

effective, lowering of the efficiency tier lighting and HVAC options, and the addition of new cost-effective prescriptive measures. The Non-Residential Rebates Program has been experiencing an increase in the number of customers adopting energy-related technologies and participating in the program.⁶³

5. ADVANCED METERING SYSTEMS (AMS) CUSTOMER SERVICE OFFERING – This program was first approved in Case No. 2014-00003⁶⁴ for 5,000 LG&E and 5,000 KU residential and general service customers on a first-come-first-served basis. In Case No. 2018-00005,⁶⁵ 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 customers who elected to participate. As of December 31, 2018, there were 8,543 active customer enrollments (LG&E 4,716 and KU 3,827) and 8,333 meters installed for 8,235 customers (LG&E 4,510 and KU 3,725) in the AMS Opt-In service.⁶⁶ Participants' consumption is captured, communicated, and stored, allowing participants to monitor their hourly usage through an online portal, called MyMeter, within two business days. The deployment of AMS is a component of the joint ten-year plan only to the extent that AMS data is used as part of distribution system planning only for load allocation in models for the LG&E downtown networks.⁶⁷

DSM-EE PROGRAM COST-EFFECTIVENESS AND ENERGY SAVINGS

The 2019-2025 DSM-EE Program Plan uses zero avoided capacity costs,⁶⁸ which has a significant impact on program and portfolio cost-effectiveness and the DSM Incentive component is currently zero based on budget and savings projections. This component may change if the DSM-EE programs produce net resource savings in the future.

ENERGY EFFICIENCY

⁶³ Response to Staff's Second Data Request at 6 (filed Dec. 17, 2019).

⁶⁴ Case No. 2014-00003, *Louisville Gas and Electric Company and Kentucky Utilities* (Ky. PSC Nov. 14, 2014).

⁶⁵ 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).

⁶⁶ Case No. 2014-00003, Post Case Referenced Correspondence (filed Jan. 30, 2019).

⁶⁷ Response to Staff's Second Data Request at 9b (filed Dec. 17, 2019).

⁶⁸ IRP Vol. 1 at 6-17 (filed Oct. 19, 2018).

Energy efficiencies in the residential and commercial sectors have continued to improve in recent years at a faster clip than expected because of a speedy acceptance of LED lighting among residential and commercial customers, big improvements in cooling efficiencies which decreased customer demand during the summer months, less miscellaneous energy usage in the LG&E sector, and larger efficiency estimations in commercial office spaces.⁶⁹ Residential energy concentration in the LG&E/KU service territories was projected to remain mostly flat through 2018 in the 2014 IRP, and then increase 6.6 percent by 2033. In the Joint 2018 IRP, this index declined 3.3 percent from 2014 to 2018 and is projected to decrease an additional 6.0 percent from 2018 to 2033.⁷⁰

Lighting volumes were projected to fall in the 2014 IRP due to the increased saturation of LEDs. This saturation came about because of new EIA lighting standards that began in 2012 and with a second phase beginning in 2020.⁷¹ Prices for LEDs dropped much lower than expected leading to widespread residential consumer adoption. In the Joint 2018 IRP, the volume of demand for residential lighting is lower than was projected in the 2014 IRP.

Cooling volume demand was projected to increase in the 2014 IRP due in part to EIA assumptions regarding the efficiency of residential building shells. In the Joint 2018 IRP, the decline in cooling volume is driven by expected efficiency improvements in cooling end-uses.⁷²

Miscellaneous end-uses include all other end-uses and is the largest end-use sector. Miscellaneous end-use examples include televisions, personal computers, security systems and gaming systems. Miscellaneous consumption is forecast to remain flat through 2033 in the Joint 2018 IRP.⁷³

LG&E/KU use the information from end-use efficiency indices as published by EIA's Annual Energy Outlook (AEO). EIA's projections for commercial end-uses is based on the Commercial Buildings Energy Consumption Survey (CBECS) that is conducted

⁶⁹ *Id.* at 6-5 and 6-6.

⁷⁰ *Id.* at 6-5.

⁷¹ *Id.* at 6-6.

⁷² *Id.*

⁷³ *Id.*

every 5 to 10 years.⁷⁴ Commercial energy sales since 2014 have been lower than forecasted due to greater than anticipated efficiency improvements. Lighting's contribution to commercial energy consumption in the 2012 CBECS has decreased significantly with LEDs and CFLs taking the place of incandescent bulbs. For the commercial sector nationally, lighting's share of total electricity consumption has decreased from 38 percent to 17 percent survey-to-survey. All projections are lower in the Joint 2018 IRP as compared to the 2014 projections.⁷⁵

RENEWABLE ENERGY

The Companies have customers who are interested in purchasing green energy produced by renewable energy sources. The Green Tariff and Solar Share Program were developed to attempt to meet these customers' interests. E.W. Brown Solar is being used to serve all customers and is not available for allocation to individual customers. The Solar Share Program is an opportunity for customers of LG&E/KU to share in local solar energy and receive solar energy credits on their monthly bill by subscribing to shares of solar in 250-watt increments. Additionally, Renewable Energy Certificates are sold to others with the proceeds being returned to all customers.⁷⁶

INTERVENORS' COMMENTS

The intervenors filed no written comments about LG&E/KU's DSM-EE analyses and potential.

RESPONSES TO 2014 STAFF RECOMMENDATIONS

The Staff Report addressing LG&E/KU's 2014 IRP contained the following recommendations regarding the Companies' DSM-EE analysis.

- Staff encouraged the Companies to continue to review new possible cost-effective DSM-EE programs and seek ways to expand the current approved DSM-EE plan. Staff notes that since the 2014 IRP Staff Report, the Commission began to more closely evaluate the cost-effectiveness of utility DSM programs.⁷⁷ In response, LG&E/KU filed Case No. 2017-00441 where

⁷⁴ *Id.*

⁷⁵ *Id.*

⁷⁶ Response to Staff's First Data Request at 5.e.

⁷⁷ See Case No. 2017-00427 *Electronic Annual Cost Recovery Filing For Demand Side Management By Duke Energy Kentucky, Inc.* and Case No. 2017-00097 *Electronic Investigation Of The*

the Companies reviewed their DSM portfolio and determined that no new programs needed to be proposed, but that some existing programs would benefit from modification and other programs should be terminated.

- Staff encouraged the Companies to review industrial DSM programs, and, after the Industrial Potential Study was completed, examine the DSM-EE needs of their industrial customers. The Industrial Potential Study⁷⁸ was filed with the Commission in May 2016, and as noted in Case No. 2017-000441, supported expansion of non-residential customers to include industrial customers.⁷⁹ Staff is satisfied that the Companies have used the information obtained in the Industrial Potential Study to make nonresidential programs available to industrial customers. Except for those that qualify to opt out, industrial customers are now included in the DSM rate recovery mechanism and are eligible for all nonresidential program offerings.⁸⁰
- Staff recommended that the Companies continue to educate customers and to promote the availability of and participation in DSM/EE programs. Due to the change in DSM programing, the customer education and public information program that was part of the Companies' DSM-EE portfolio was discontinued in Case No. 2017-00441.
- Staff recommended that the Companies continue to define and improve procedures to evaluate, measure, and verify (EM&V) both actual costs and benefits of energy savings based on the actual dollar savings and energy savings as required by 807 KAR 5:058, Section7(4)(d). Staff is satisfied the Companies pursued EM&V to a greater level in the latest DSM application by applying the California tests to their DSM-EE portfolio as a whole, and determining whether the DSM-EE portfolio was cost-effective.
- Staff recommended that the Companies model growth from new customers that participate in existing plans. Such modeling will include EE from new

Reasonableness Of The Demand Side Management Programs And Rates Of Kentucky Power Company (Jan. 18, 2018).

⁷⁸ Case No. 2014-00003, *Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company or Review, Modification, and Continuation of Existing, and Addition of New, Demand-Side Management and Energy-Efficiency Programs* (filed May 26, 2016).

⁷⁹ See Case No. 2017-00441, Application, paragraph 21.

⁸⁰ *Id.* Final Order at 31 (Ky. PSC Oct. 5, 2018).

DSM-EE programs and should consider the impact on low, mid and high case scenarios. Due to the scrutiny of DSM programs conserving cost-effectiveness, LG&E/KU did not offer new programs.

Case No. 2017-00441

The Commission issued a Final Order in Case No. 2017-00441 on October 5, 2018, approximately two weeks prior to the filing date of LG&E/KU's Joint 2018 IRP, which addressed the status of the current DSM programs. In the Application, the Companies requested and received approval for the 2019-2025 DSM-EE Program Plan. This DSM-EE Program Plan was supported by three separate studies, which demonstrated the technically and economically achievable DSM-EE potential across residential, commercial, and industrial rate classes. LG&E/KU performed the California tests for the proposed DSM program suite utilizing estimates of the benefits and costs that would directly impact customers' bills. These scores were based upon zero avoided cost due to excess capacity. In the Application, LG&E/KU noted that significant changes in market conditions, in particular the combination of increasing customer adoption of EE measures and declining avoided costs of energy and capacity, have occurred, making it more difficult for DSM-EE programs to be cost-effective.⁸¹ Thus, LG&E/KU began introducing reductions in their DSM-EE program as well as reduced incentive revisions. In the Final Order, the Commission evaluated the California test scores for the proposed DSM program suite and all but the Nonresidential Rebates Program proved not to be cost effective. However, despite this, the Commission recognized that the programs for which LG&E/KU proposed to continue, specifically the Demand Conservation Program which utilizes load-control devices, added value to system reliability by enabling load reduction and due to large investments in these programs, the cost of removing the load-control devices outweighed the costs of continuing the program in maintenance mode.⁸² In addition, the Commission found that expanding the availability of DSM programs to industrial customers to be reasonable finding that LG&E/KU adequately defined what an industrial customer is and the corresponding opt-out criteria was reasonable.

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

- The Companies should continue the stakeholder process through the DSM Advisory Group and strive to include recommendations and inputs from the stakeholders. These meeting should be more than informational, but entail fluid dialog between all vested parties. Any changes to the DSM-EE

⁸¹ See Case No. 2017-00441, Final Oder at 4 (Ky. PSC Oct. 5, 2018).

⁸² *Id.* at 29.

program must be discussed in full including a transparent analysis of the cost and benefits inputs.

- Staff recommends that LG&E/KU continue to identify cost effective 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.
- Staff strongly encourages LG&E/KU to consider making AMS usage data available to customers that is closer aligned to real-time data and to consider prepay metering and real-time pricing options to enhance the customer experience for those customers participating in the AMI Pilot Program. In addition, Staff suggests LG&E/KU examine the feasibility of peak time rebate programs and time-of-use rates.
- As required by the IRP regulation (807 KAR 5:058, Section 7(4)(d)), the Companies 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.
- Staff encourages LG&E/KU to continue exploring cost-effective DSM-EE as a method to avoid costly capital investments should energy margins diminish over time.

SECTION 4

SUPPLY-SIDE AND DEMAND-SIDE RESOURCE ASSESSMENT

In this Section, Staff reviews, summarizes, and comments on LG&E/KU's evaluation of existing and future supply and demand-side resources. In addition, there is a discussion on LG&E/KU's environmental compliance plan.

EXISTING CAPACITY

As of September 2018, the Companies utilize multiple existing generation resources. The Companies' baseload capacity includes 14 coal units with a total summer net capacity of 5,156 MW (5,200 MW winter capacity) and one NGCC unit with a net summer capacity of 662 MW (683 MW winter). The Companies operate 22 load following SCCT peaking units with a total net summer capacity of 2,259 MW (2,516 MW winter). Renewable resources include 12 renewable generation resources with a total net summer capacity of 104 MW (72 MW winter). On a combined basis, the Companies' generation resources have a net summer capacity of 8,181 MW (8,471 MW winter). In addition, the Companies' Curtailable Service Rider (CSR) (141 MW summer and winter) and the Demand Conservation Program (DCP) (127 MW summer, 0 MW winter) are two demand side resources that can be counted on to provide a net summer capacity of 268 MW (141 MW winter).⁸³

The Companies provided a detailed operational profile of the E.W. Brown solar generation facility.⁸⁴ The 10.2 MW alternating current (maximum output) facility is comprised of 44,500 panels with 10 inverters. In 2017, the facility produced 17,336 MWh which is equivalent to a 19.8 percent capacity factor. It operated above 9.9 MW for 137 hours during 2017, approximately 1.5 percent of the hours in 2017. Its contribution to monthly peak averaged 4.6 MW.⁸⁵

Company owned solar also includes a 4 MW shared solar facility in Shelby County, Kentucky. In Case No. 2020-00016,⁸⁶ the Commission approved, subject to modifications, the Companies proposed solar power contract and two renewable power

⁸³ *Id.* Table 5-1 at 5-5. However, in the reserve margin analysis, CSR is modeled as a generation resource even though it directly reduces demand. DCP (which includes both residential and non-residential programs) is dispatchable and modeled as a demand reduction program. See IRP, Vol. III, 2018 IRP Reserve Margin Analysis footnotes 16 and 17 at 15-16.

⁸⁴ See IRP, Vol. III, E.W. Brown Solar Profile, 2017.

⁸⁵ *Id.* at 2-10.

⁸⁶ Case No. 2020-00016, *Electronic Application of Louisville Gas and Electric Company and Kentucky Utilities Company for Approval of a Solar Power Contract and Two Renewable Power Agreements to Satisfy Customer Requests for a Renewable Energy Source under Green Tariff Option #3* (Ky. PSC May 8, 2020).

agreements to satisfy two customer requests for a renewable energy source. The resulting order was for 75 MW for two customers and 25 MW for LGE/KU.⁸⁷

Known changes to the existing fleet include near term unit retirements and the exit of eight municipal wholesale customers. Brown Units 1 and 2 representing 272 MW of coal generating capacity retired in February 2019. The expiration of the Bluegrass Power Purchase Agreement representing 165 MW peaking capacity coincided with the exiting of the eight municipal wholesale customers in April 2019. In addition, Zorn 1 representing 14 MW peaking capacity will retire in 2021. The decision to retire the Brown and Zorn units was made in lieu of expending significant resources to comply with environmental and gas pipeline regulations.⁸⁸

RESOURCE ASSESSMENT AND ACQUISITION PLAN

In order to develop an optimal long term resource plan, the Companies undertook an analysis of potential new demand and supply side resources, reassessed its reserve margin criteria, and then developed its optimal plan.⁸⁹ A key element of an optimal long term plan is accounting for uncertainty. Uncertainty is introduced into the load forecast through factors that influence how customers use energy. There is uncertainty surrounding the introduction of and implementation of various federal and state environmental regulations, which will directly influence the Companies' compliance strategies and costs going forward.⁹⁰ Finally, the useful lives of the Companies' generating assets is uncertain. Two scenarios are considered (55 and 65 years) in the analyses.⁹¹

GENERATION TECHNOLOGY OPTIONS

The following key criteria were used to evaluate possible cost competitive generation technologies: capacity, contribution to peak, net capacity factor, heat rate,

⁸⁷ On May 29, 2020, LG&E/KU filed for reconsideration and clarification.

⁸⁸ *Id.*

⁸⁹ *Id.* at 5-15.

⁹⁰ See Response to Staff's Second Data Request Item 4 dated November 5, 2019. PPL has a corporate goal of reducing CO₂ emissions by 70 percent from 2010 levels by 2050. The reductions will be accomplished by replacing coal generation with a combination of natural gas generation and renewables. Additional actions include increased energy efficiency, reduced greenhouse gas emissions from substations and vehicle emissions. Both PPL's climate goals and LG&E/KU's IRP Scenarios, which are parsimonious with PPL climate goals, are consistent with least cost planning principles. LG&E/KU's Scenario 1 is reflective of the current environmental regulatory regime. Under the current regime, unless LG&E/KU make modifications to it plants that increase other emissions, further CO₂ reductions will be driven by economics rather than regulation.

⁹¹ *Id.* at 5-19-5-20.

overnight capital cost, fixed O&M cost, firm gas transportation cost, variable O&M, fuel cost, and transmission cost.⁹² Peaking, baseload and intermediate generation resources as well as renewable and DSM resources were evaluated. The evaluation of peaking generation resources included natural gas SCCT and battery storage technologies. SCCTs are inexpensive on a \$/kW basis and can be easily fitted with environmental controls. Batteries offer fast response times and scalability and the costs, while still relatively expensive, have been declining and that trend is expected to continue.⁹³

Baseload and intermediate generation resources included NGCC, super critical coal, integrated gasification combined cycle (IGCC), coal with 30 percent and 90 percent carbon capture, and nuclear. NGCC capital and fixed operating costs are 3-4 times lower than new coal capacity. These units offer faster ramp times and cycling flexibility. Super critical coal units are the most efficient with the lowest emission rates among coal technologies. Carbon capture technology has been demonstrated in the field, but not at sufficient utility scale levels. The potential for carbon capture regulation represents a potentially significant cost and risk factor for existing and potentially new coal generation resources. As the technology continues to develop, it will become less of a factor. IGCC is more proven for utility scale generation than CC technology, but there are a limited number of IGCC plants in operation and in various stages of commercialization. Nuclear technology was also evaluated in the analysis.⁹⁴ The analysis included renewable resources including wind, solar and hydro. Wind technology is a proven scalable renewable option and both in-state and out-of-state⁹⁵ wind options were evaluated. Solar technology is a proven scalable technology as well. During summer peak, about 80 percent of solar capacity resource is assumed to be available.⁹⁶ The Companies have completed the upgrades to the Dix Dam and Ohio Falls stations. There are no other viable hydro resource alternatives near the service territory. Biopower was evaluated both as a co-fired resource and on a stand-alone basis, of which both have high capital and operating costs.⁹⁷

The Companies evaluated the demand-side resource options based upon the most recent approved DSM program. The DCP is the only dispatchable program and is currently being run in “maintenance” mode, i.e., the annual incentive has been reduced,

⁹² IRP, Vol. III, 2018 IRP Resource Screening Analysis, Section 2 at 6.

⁹³ *Id.* at 8.

⁹⁴ *Id.* Table 2, at 7 and at 8-9.

⁹⁵ *Id.* at 6.

⁹⁶ *Id.* at 9.

⁹⁷ *Id.* at 9-10.

payable in load control event years, and the number of new customers is limited by the number of conservation devices available.⁹⁸

Other technologies considered, but not included for evaluation, include fuel cells, reciprocating engines, microturbines, circulating fluidized bed boilers, waste to energy generation, and concentrated solar power. These technologies were not considered due to scalability, potential NSPS impact, and high capital, operating or maintenance cost. The results of the preliminary generation screening analysis is presented in Table 1 below.

Table 1: Generation and Demand-Side Resource Options⁹⁹

Type	Category	Technology Option	Summer Capacity ¹⁰ MW	Contribution To Peak ¹¹		Net CF %	Heat Rate ¹² MMBtu/MWh	Cost ¹² \$/kW	O&M ¹² \$/kW-yr	Firm Gas Cost ¹³ \$/kW-yr	Variable O&M ¹² \$/MWh	Fuel Cost \$/MWh	Trans. Cost \$/MWh
				Summer	Winter								
Generation Resources (2018 Dollars)	Peaking	SCCT	201	100%	100%	5-90	9.8	911	13	22	7.31	27.90	N/A
		Battery Storage	1-500	100%	100%	5-40	N/A	2,073	9	N/A	2.72	N/A	N/A
	Baseload / Intermediate	NGCC	368	100%	100%	10-90	6.4	1,070	11	19	2.83	18.36	N/A
		Supercritical Coal	500	100%	100%	50-90	8.8	3,757	34	N/A	4.86	17.51	N/A
		IGCC	500	100%	100%	50-90	8.6	4,028	56	N/A	7.84	17.13	N/A
		Coal w/30% CO ₂ Capture	500	100%	100%	50-90	9.7	5,202	72	N/A	7.31	19.33	N/A
		Coal w/90% CO ₂ Capture	500	100%	100%	50-90	11.5	5,752	84	N/A	9.88	22.82	N/A
		Nuclear	1,000	100%	100%	70-90	10.5	5,884	103	N/A	2.36	6.92	N/A
		Biopower (Dedicated)	50	100%	100%	50-90	13.5	3,948	114	N/A	5.69	41.02	N/A
	Biopower (Co-fire)	500	100%	100%	50-90	9.7	4,068	34	N/A	4.86	54.79	N/A	
	Renewables	KY Wind	50-500	15%	33%	30-40	N/A	1,637	53	N/A	N/A	N/A	N/A
		Non-KY Wind	50-500	15%	33%	40-50	N/A	1,515	53	N/A	N/A	N/A	12
		PV Solar	1-500	80%	0%	18-22	N/A	1,093	10	N/A	N/A	N/A	N/A
Hydro		10-100	60%	40%	20-40	N/A	5,826	32	N/A	N/A	N/A	N/A	
DSM	Demand-Side	DCP ¹⁴	127	100%	0%	N/A	N/A	N/A	18	N/A	\$5/customer	N/A	N/A

¹⁰ NREL's 2018 ATB did not specify capacity. The capacities shown are representative of typical installations.

¹¹ The summer contribution to peak for wind options is based on MISO's capacity credit for wind resources. Contributions to peak for solar and hydro options are based on the Companies' experience with Brown Solar and the Ohio Falls hydro units.

¹² Source: NREL's 2018 ATB (<https://atb.nrel.gov>). The Companies inflated NREL's forecast, which was provided in real 2016 dollars, to nominal dollars at 2% annually.

¹³ Firm gas transportation costs are based on the cost of firm gas transportation for Cane Run 7 and the Trimble County SCCTs.

¹⁴ Inputs for the DCP reflect program modifications approved in the Companies' most recent DSM filing. The summer capacity of this program is forecast to decrease from 127 MW in 2018 to 87 MW in 2021 due to customer attrition, but any actual decline is uncertain. Fixed O&M is the annual cost that could be saved if the DCP was discontinued.

As a result of the analysis summarized in the table above, the DCP, SCCT and battery storage, NGCC, non-KY wind and solar PV were selected as potential new resources to be evaluated further in the detailed resource planning analysis.¹⁰⁰

RESERVE MARGIN ANALYSIS

⁹⁸ *Id.* at 10.

⁹⁹ *Id.* Table 2 at 7.

¹⁰⁰ *Id.* Table 3 at 13.

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) 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 (2021),¹⁰¹ 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).¹⁰²

The results of the analysis are provided in Table 2 below.

Table 2: Peak Demand and Resource Summary (Base Energy Requirements Forecast MW)¹⁰³

	2018	2019	2020	2021	2022	2023	2024	2027	2030	2033
Summer Peak Demand	7,028	6,703	6,688	6,674	6,657	6,653	6,638	6,655	6,650	6,627
DCP	-127	-96	-91	-87	-84	-80	-77	-67	-59	-52
DSM	-247	-247	-236	-236	-236	-236	-236	-236	-236	-236
Net Peak Demand	6,655	6,360	6,361	6,350	6,338	6,338	6,325	6,352	6,355	6,339
Existing Capability ⁴	7,754	7,476	7,476	7,476	7,477	7,477	7,478	7,478	7,478	7,478
Small-Frame SCCTs	87	87	87	73	73	73	73	73	73	73
CSR	141	141	141	141	141	141	141	141	141	141
Bluegrass	165	0	0	0	0	0	0	0	0	0
OVEC ⁵	152	152	152	152	152	152	152	152	152	152
Total Supply	8,299	7,856	7,856	7,842	7,843	7,843	7,844	7,844	7,844	7,844
Reserve Margin	1,644	1,495	1,495	1,491	1,505	1,505	1,518	1,492	1,489	1,505
Reserve Margin %	24.7%	23.5%	23.5%	23.5%	23.7%	23.7%	24.0%	23.5%	23.4%	23.7%

¹⁰¹ *Id.* at 9. Note that the year 2021 is the first year after the eight municipal customers (representing 285 MW coincident peak demand) left the system and the expiration of the Bluegrass Contract (165 MW), and the retirements of Brown Units 1 and 2 (272 MW) and Zorn (14 MW).

¹⁰² *Id.* at 9-20.

¹⁰³ IRP, Vol. III, 2018 IRP Reserve Margin Analysis, Table 1 at 6.

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

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

As can be seen from Table 2, the Companies' planning reserve margin is approximately 24 percent. This is significantly higher as compared to the planning reserve margins of MISO (17 percent), PJM (16 percent), and TVA (15 percent) that were used in the study.¹⁰⁴ The Companies reference uncertainty regarding its ability to rely on neighboring regions' markets to serve load, specifically mentioning the 20 GW retired in PJM over the last five years and another 3 GW in planned retirements over the coming five years.¹⁰⁵ However, in reply comments to the SREA, the Companies provided more recent examples of neighboring region reserve margins: MISO at 18 percent, TVA 17 percent summer and 25 percent winter and Duke Energy Carolinas 17 percent minimum reserve.¹⁰⁶

According to the Companies' 2014 IRP Reserve Margin Study, a target range of 16-21 percent was set. In order to meet a 1 (load loss event) in 10 years probable LOLE guideline, a 21 percent reserve margin was required. In the current IRP using the same 1 in 10 LOLE guideline, an approximate 24 percent reserve margin is required to meet the same threshold. Table 3 illustrates the various generation portfolios analyzed and the estimated total cost of each. Though the Companies utilized two models, only the ELDC modeling results are presented. Note that the portfolios highlighted in gray have LOLEs more than five times the existing portfolio and are not considered viable. The results from the SERVIM model are essentially the same.¹⁰⁷

¹⁰⁴ *Id.* at 10.

¹⁰⁵ *Id.*

¹⁰⁶ *Joint Response of Louisville Gas and Electric Company and Kentucky Utilities Company to the Comments of Sierra Club and Southern Renewable Energy Association, (filed February 17, 2020) at 6-7.* Statistics have been updated based upon more recent data.

¹⁰⁷ *Id.* Tables 13 and 14 at 22.

Table 3: Reserve Margin Analysis Results (ELDC Model, 2021 Dollars)¹⁰⁸

Generation Portfolio	2021 Reserve Margin	LOLE	[A] Capacity Cost (\$M/year)	Reliability and Generation Production Costs (\$M/year)			Total Cost: Capacity Costs + Reliability and Generation Production Costs (\$M/year)		
				[B] Avg	[C] 85th %ile	[D] 90th %ile	[A]+[B] Avg	[A]+[C] 85th %ile	[A]+[D] 90th %ile
Add 140 MW of SCCT capacity to Existing portfolio	25.7%	0.9	55.7	765	781	790	821	837	846
Add 70 MW of SCCT to Existing portfolio	24.6%	1.2	47.1	766	782	791	813	829	838
Existing portfolio**	23.5%	1.6	38.5	767	783	793	805	821	831
Retire DCP	21.7%	1.7	36.1	767	783	793	803	819	829
Retire DCP and small frame SCCTs	20.6%	2.0	35.9	768	783	794	803	819	830
Retire DCP, small frame SCCTs, Brown 8	18.7%	2.9	34.4	770	789	799	805	824	833
Retire DCP, small frame SCCTs, Brown 8-9	16.9%	4.3	33.0	775	799	806	808	832	839
Retire DCP, small frame SCCTs, Brown 8-10	15.0%	6.3	31.6	781	812	822	813	844	854
Retire DCP, small frame SCCTs, Brown 8-11	13.1%	9.0	30.2	790	829	843	820	859	873
Retire DCP, small frame SCCTs, Brown 3	14.2%	7.4	0.0	784	817	832	784	817	832

** Includes retirements of Brown 1 and 2 and Zorn 1

The Companies maintain that the reserve margin target increase is primarily due to increased variability in winter peak demand.¹⁰⁹ The winter peak exceeded 7,000 MW in both 2014 and 2015 and the maximum winter peak (from 1985) modeled was 7,336 MW. The Companies attribute the higher reserve margins (peak loads) to an increasing penetration of electric heating load.¹¹⁰ Based upon the results of the ELDC Model and SERVM, the Companies state that the Existing and Retire DCP portfolios are represented as the least cost generation portfolios. However, the total cost of the Retire DCP and small frame SCCTs is also essentially the same with only a slight increase in LOLE.

Given the existing portfolio reserve margin, a minimum target was established by estimating the effect of increasing load to the existing portfolio to the point where the Companies would have to add 70 MW of SCCT capacity as the least costly solution

¹⁰⁸ *Id.* Tables 12 and 13 at 21-22.

¹⁰⁹ *Id.* Footnote 2 at 3.

¹¹⁰ *Id.* at 24 and Tables 12-14 at 22 and Vol. I, Key Forecast Uncertainties, Weather, at 5-26.

versus maintaining the existing generation portfolio. The reserve margin at that point is approximately 16 percent.¹¹¹

The Companies performed a sensitivity analysis using the ELDC Model to evaluate reserve margin changes when the cost of unserved energy, scarcity prices, EFOR, and available transmission capacity (ATC) were varied. The Companies varied the cost of unserved energy up and down by 25 percent from the base case of \$18,300/MWh. The scarcity prices were also varied up and down by 25 percent. EFOR rates were increased by 1.5 points and decreased by 1.0 points. ATC was modeled as no access to neighboring transmission (no import or export power) and as high cost for 1,000 MW during peak hours. The results show that the total cost of generation portfolio minus the DCP program is only slightly less than the Companies' existing generation portfolio.¹¹²

Based upon the analyses, the Companies' target reserve margin will range from 17-25 percent.

ASSESSMENT OF NON-UTILITY GENERATION - COGENERATION, RENEWABLES, AND OTHER SOURCES

The Companies consider short-term market purchases from other utilities on a non-firm basis as a non-utility generation option.¹¹³ In addition, as was discussed in the Staff Report on the Companies' 2014 IRP and in the Companies' current IRP, successful cogeneration facilities are very site specific and require an industrial host with the appropriate technical and economic factors which allow the project to be cost-effective and provide a return on the investment. The Companies offer tariffs for large capacity cogeneration and small power production qualifying facilities. As of the filing of this IRP, there are 11 cogeneration customers and one hydro generation customer.¹¹⁴

With respect to net metering customers and qualifying facilities, load growth through 2033 is expected to occur through solar generation net metering,¹¹⁵ From 2014 through 2017, the number of net metering customers increased 100 percent from 243 to 486.¹¹⁶ In addition, there are four customers with wind generation and one with hydro generation. Increased solar generation is forecasted to grow from 3 MW to 170 MW.

¹¹¹ *Id.* Tables 15 and 16, at 25.

¹¹² *Id.* Tables 13, 14, and 17, at 22 and 26.

¹¹³ IRP, Vol. I, at 8-6.

¹¹⁴ *Id.* at 5-13, 8-6, and Vol. III, at 4. These options are not explicitly included as resources in the resource plan.

¹¹⁵ *Id.* at 5-13.

¹¹⁶ *Id.*

The main drivers for this projected increase are declining solar prices and favorable net metering policies; however, the Companies cautioned that this forecast is uncertain.¹¹⁷

ENVIRONMENTAL REGULATION AND COMPLIANCE PLANNING

Since 2009, the Companies have made significant investments on environmental control projects to comply with applicable state and federal regulations. Going forward, compliance with current environmental regulations and uncertainty about the final form of pending environmental regulations will impose additional implementation compliance costs. The Companies' compliance efforts include reducing SO₂ and NO_x emissions under the Acid Rain Deposition Program and the updated Cross State Air Pollution Rules.¹¹⁸ Generation units have been updated to comply with the Mercury and Air Toxics Standard and monitors have been installed to ensure compliance with National Ambient Air Quality Standards (NAAQS) regarding SO₂ and NO_x emissions and ozone formation.¹¹⁹ Subsequent to the retirement of Brown units 1 and 2 in February of 2019, all of the Companies coal units will be equipped with fabric filter baghouses and flue gas desulfurization equipment, and all but three coal units will be equipped with selective catalytic reduction (SCR).¹²⁰ In addition, the closing of the coal-fired units at the Cane Run generation station has aided compliance with fine particulate matter NAAQS requirements.¹²¹

Regulations requiring reductions in greenhouse gasses has been a moving target. The current rule, Affordable Clean Energy (ACE) Rule, was published on July 8, 2019.¹²² The ACE Rule establishes new guidelines for states to regulate greenhouse gas (CO₂) emissions from existing fossil fuel-based electric generation units. It replaced the Clean Power Plan which was stayed by the United States Supreme Court on February 9, 2016.¹²³ The New Source Review revisions were not finalized with the final ACE Rule and allows for heat rate efficiency improvements to existing power plants to satisfy best system of emissions reductions of greenhouse gasses requirements.¹²⁴ The Companies are evaluating the heat rate improvement projects identified in the final ACE Rule for their

¹¹⁷ *Id.*

¹¹⁸ IRP Vol. I at 8-29-8-30.

¹¹⁹ *Id.* at 8-30-8-31.

¹²⁰ *Id.* at 5-20.

¹²¹ *Id.* at 8-32.

¹²² LG&E/KU's response to Staff's First Request, Item 31.

¹²³ IRP Vol. I at 8-34.

¹²⁴ *Id.*

technical and economic feasibility as they apply to each of the Companies ACE-affected generation units.¹²⁵ However, until the state implementation plan (SIP) for the ACE Rule is finalized and approved, the Companies will continue to evaluate its timeline and compliance options.¹²⁶

There are multiple regulations pertaining to water intake and effluent. The Clean Water Act Section 316(b) serves to mitigate harmful effects of cooling water intake from water sources. The Companies are studying the best way to bring the Mill Creek station into compliance with the 125 MGD standard.¹²⁷ In addition, the Companies are working to ensure compliance with Clean Water Act Steam Electric Power Generating Effluent Limitation Guidelines (ELG). Revised rules will require further treatment of flue-gas desulfurization (FGD) scrubbers and impose a prohibition of discharge of ash transport waters by 2023.¹²⁸

Finally, the Companies currently monitor the groundwater around its coal combustion residual impoundments. The EPA is reviewing parts of the regulation and future revisions may necessitate the eventual closure of the Companies impoundments.¹²⁹ When the Companies complete the projects necessary to comply with the Coal Combustion Residual Rule, all of the generating units will be in compliance with all known state and federal regulations.¹³⁰ However, due to the three coal units not being retrofitted with SCR, with future changes to NAAQS, one or more of the following actions will be required in the next 3 to 7 years: investment to control emissions of nitrogen oxides, changes in plant operation during ozone season, unit retirements, or acquisition of new generation.¹³¹

EFFICIENCY IMPROVEMENTS-GENERATION

The Companies are undertaking planning for a number of activities in the business plan to improve generation efficiencies. Included in the plans, among other things, are updating controls to the latest technologies, turbine overhauls and repair work, boiler tube

¹²⁵ LG&E/KU's response to the Attorney General's First Request for Information (Attorney General's First Request), Item 8 and IRP, Vol. I, at 5-20.

¹²⁶ *Id.* and IRP Vol. 1, at 5-20. The deadline for the Commonwealth of Kentucky to submit its SIP is July 8, 2022. Thereafter, the EPA will have one year to rule upon Kentucky's SIP.

¹²⁷ IRP Vol. I at 8-35.

¹²⁸ *Id.*

¹²⁹ *Id.* at 8-35-8-36.

¹³⁰ LG&E/KU's response to Staff's First Request, Item 31.

¹³¹ *Id.*

replacements, pulverizer rebuilds, air quality control replacements, cooling system repairs, and generator rewinds and repair work.¹³² In addition, a number of other projects are directed at efforts to reduce environmental impact, maintain the efficient utilization of generation facilities, and meet regulatory compliance.

The Companies have made significant efforts to maintain their combustion turbine fleet with the goal of both maintaining reliability and maintaining efficiency.¹³³ With respect to the Companies hydroelectric units, the multi-year rehabilitation at the Ohio Falls Station brought many improvements in reliability and output with the installation of new trash racks and distribution control system upgrades.¹³⁴ At the Dix Dam hydro site, structural improvements of the dam parapet wall are scheduled as well as upgrades to the station auxiliary power system and the crest gate walkway.¹³⁵

The Companies completed the blackstart project,¹³⁶ which has improved the resiliency of the system restoration plan. The project was implemented by the installation of new diesel engine powered generator packages at the Trimble County and Cane Run Stations. The Companies aver that the identified primary combustion turbines utilized in the blackstart process are a critical portion of the system restoration path and the utilization of diesel generators for blackstart conversion simplifies the electrical connections and complexity of startup while improving the overall reliability of the system restoration path.¹³⁷ In addition, the diesel generation systems adds to the ability to more easily test the blackstart capability of the primary combustion turbines, without configuration changes to the transmission and distribution systems, which improves reliability and flexibility of the overall system.¹³⁸

EFFICIENCY IMPROVEMENTS-TRANSMISSION

The transmission system is assessed to identify needed construction projects and upgrades required to maintain system reliability and to meet projected customer

¹³² IRP Vol. I at 8-2.

¹³³ *Id.* at 8-4.

¹³⁴ *Id.*

¹³⁵ *Id.*

¹³⁶ *Id.*

¹³⁷ *Id.*

¹³⁸ *Id.*

demands.¹³⁹ A list of transmission projects was included in the 2018 IRP Long-Term Resource Planning Analysis.¹⁴⁰

EFFICIENCY IMPROVEMENTS-DISTRIBUTION

Using common practices, guidelines, and standards, the Companies' distribution systems have been enhanced over the years through the construction of substations and distribution lines, as well as the integration of modern technology to meet growing customer loads and to improve service reliability and quality.¹⁴¹

The Companies monitor peak substation transformer loads on an annual basis and develop load forecasts over a ten-year planning period. This information is utilized in developing the need for capacity enhancements necessary to address load growth and improve system performance as well as accommodating the impacts of distributed generation. Advances in energy efficiency technology have slowed load growth such that the Companies have shifted its focus to enhancing reliability (projects improving the worst performing circuits and mitigating the effects of major equipment failures) and aging infrastructure replacement projects.¹⁴²

The Companies state that they design, build, and operate their distribution system in a cost-effective, efficient manner. Efficient substation and distribution transformers are purchased and are DOE complaint. Capacitors are installed when reasonable to enhance the efficiency of substation, distribution and transmission system facilities. Substation bus power factors are designed to be near unity.¹⁴³

INTERVENOR COMMENTS

Sierra Club

The Sierra Club recommends that the Companies' contract with the Ohio Valley Electric Corporation (OVEC), the extension of which was approved by the Commission in 2011,¹⁴⁴ should be revisited due to its cost and that the current IRP did not consider a scenario in which OVEC's energy and capacity as well as the other costs associated with the Companies' payments to OVEC under the Inter-Company Power Agreement were

¹³⁹ *Id.* at 8-5.

¹⁴⁰ IRP Vol. III.

¹⁴¹ IRP Vol. I, at 8-5.

¹⁴² *Id.*

¹⁴³ *Id.*

¹⁴⁴ Sierra Club Comments at 5.

considered in the analysis.¹⁴⁵ The Sierra Club asserts that the operating circumstances and assumptions upon which the Commission approved the extension of the OVEC contract have materially changed and which will render the OVEC power uneconomic.¹⁴⁶

The Sierra Club contends that the Companies' target reserve margin is unnecessarily high and uneconomical relative to neighboring regions.¹⁴⁷ Finally, the Sierra Club asserts that the Companies inaccurately described the relative costs of renewable generation resources and that a breakeven analysis should be provided in the next IRP to show under what circumstances the fossil replacement by renewables is cost-effective.¹⁴⁸

Southern Renewable Energy Association

The SREA was not a party to the case, but submitted comments. The SREA recommends that the Companies should review its renewable costs and use the NREL Annual Technology Baseline (ATB) data as a benchmark to its levelized cost of energy (LCOE) calculations and ensure that appropriate tax credits are included in modeled renewable costs. The SREA contends that it is possible that the IRP methodology software artificially includes and inflates renewable costs. Further, the SREA states that it is unclear how market based energy purchases are treated in the models.¹⁴⁹

The SREA argues that production and investment tax credits for renewables have not been evaluated and included in the analyses appropriately. Hybrid renewable and energy storage systems should also be evaluated further. Renewable energy resources in conjunction with storage devices can have significantly higher capacity values and can perform multiple ancillary services. The SREA argues that this has not been properly evaluated in the IRP analyses.¹⁵⁰

The SREA argues that the Companies models may be overly dependent on capacity-only additions. Asserting that this type of planning tends to under value or not select lower cost energy based resources, the SREA maintains the IRP tends to favor building new gas fired generation or legacy generation retention when a mix of lower cost renewable energy may lead to reduced ratepayer costs overall.¹⁵¹

¹⁴⁵ *Id.*

¹⁴⁶ *Id.* at 1-5.

¹⁴⁷ *Id.* at 6-7.

¹⁴⁸ *Id.* at 7-9.

¹⁴⁹ Southern Renewable Energy Association comments filed January 17, 2020 at 2-4 of 14.

¹⁵⁰ *Id.* at 7-9 of 14.

¹⁵¹ *Id.* at 9-10 of 14.

Finally, the SREA took issue with the Companies' retention of the high cost Brown Unit 3 (\$84/MWh) in the generation portfolio on the basis that the portfolio is more reliable with the unit in the mix and with significantly less production cost volatility. The SREA argued that reliability could also be provided with new generation technologies and price volatility of a low cost resource is not inherently worse than a stable higher cost resource.¹⁵² SREA argued that renewable resources are available to the Companies at lower cost (\$30-\$35/MWh).

The SREA included the following recommendations for the Companies' next IRP:¹⁵³

- LG&E&KU should move away from the capacity only or capacity focused resource planning;
- LG&E&KU should allow renewable energy to directly compete against existing generation units;
- The NREL ATB should be used for all renewable energy resource cost and performance assumptions;
- Energy storage resources should be allowed to access multiple revenue streams including but not limited to frequency control, voltage regulation, energy arbitrage, peaking and other value stacks;
- Cost projections for renewable energy and energy storage should continually decline over time, while performance projections should continually increase;
- Federal tax credits, including the PTC and ITC, should be incorporated for renewable energy and energy storage projects in relevant years;
- Levelized cost of energy benchmarks (in \$/MWh values) should be provided for all energy resources. LCOE values should be like Lazard Associates and NREL ATB values.
- Significant procurement of renewable energy and energy storage should occur across all portfolios; and
- Large customers should be allowed to directly procure renewable energy resources.

LG&E/KU RESPONSES TO INTERVENOR AND PUBLIC COMMENTS

¹⁵² *Id.* at 10 and 12 of 14.

¹⁵³ *Id.* at 13 of 14.

In response to both the Sierra Club and SREA, the Companies stated that the Sierra Club's and SREA's criticisms are unfounded and policy-driven and that their stated purpose is to replace fossil with renewable generation and assume that such changes will not impose any additional risk to service reliability.¹⁵⁴ The Companies argue that the current IRP regulation and process works fine, and that its recent filing for a solar power purchase contract¹⁵⁵ is further evidence of evaluating alternative energy resources. In addition, the Companies argue that they have properly used appropriate cost of capital and financing as inputs into the analyses and that the analyses have been conducted appropriately.¹⁵⁶

Regarding the Sierra Club's comments, the Companies argue that comments regarding OVEC have been repeated from prior testimony submitted in its last rate case, and that unless the OVEC sponsors can be persuaded and the contract can be terminated, any analysis estimating the resource requirements without OVEC will not be productive.¹⁵⁷ The Companies further argued that the reserve margin is not out of line when compared to neighboring utilities.¹⁵⁸ The Companies argued that the most recent NREL ATB tended to support its overnight cost of capital estimates¹⁵⁹ The Companies were amenable to conducting further study regarding replacement of NGCC with renewables as the appropriate generation technology.¹⁶⁰

Regarding comments by SREA pertaining to LCOE for solar and wind, the Companies argue that it used the 2018 edition of the NREL ATB versus the 2019 edition used by SREA. The remaining disparity between SREA's and the Companies' LCOE is attributable to the different ROE, cost of debt, and capital structure assumptions used in the calculations. The Companies used its own versus what was inherent in the 2018 NREL ATB.¹⁶¹ SREA's citation of other utilities with greater concentrations of renewables

¹⁵⁴ See *Joint Response of Louisville Gas and Electric Company and Kentucky Utilities Company to the Comments of Sierra Club and Southern Renewable Energy Association*, filed February 17, 2020.

¹⁵⁵ See Case No. 2020-00016, *Electronic Application of Louisville Gas and Electric Company and Kentucky Utilities Company for Approval of a Solar Power Contract and Two Renewable Power Agreements to Satisfy Customer Requests for a Renewable Energy Source Under Green Tariff Option #3* (Ky. PSC May 8, 2020).

¹⁵⁶ Companies Response at 1-3.

¹⁵⁷ *Id.* at 5. Staff notes that the Sierra Club was informed that filing the testimony in LG&E/KU's next IRP case would provide a better venue to consider OVEC purchases.

¹⁵⁸ *Id.* at 6-7.

¹⁵⁹ *Id.* at 7-8.

¹⁶⁰ *Id.* at 8.

¹⁶¹ *Id.* at 8-9.

and lower LCOE values is without merit. Regarding federal tax credits, the Companies argue that they did include both appropriate level and expiration of federal tax credits in both their IRP Resource Screening Analysis and the Long-Term Planning analysis. Regarding the issue of hybrid renewable energy storage systems, the Companies argue that it did consider varying levels as shown in its IRP Table 5-15 on page 5-39. The economics of battery storage and hybrid renewable and energy storage systems would be different if the Companies were members of an RTO, where battery storage systems receive a capacity value and ancillary service payments.¹⁶²

2014 STAFF RECOMMENDATIONS

In addressing its review of LG&E/KU's 2014 IRP, Staff noted that LG&E/KU should provide and discuss relevant information regarding various aspects of its system and how governmental agencies, customers, and non-company actions affect its system. Staff further stated that given the continued and accelerated changes in environmental and other policies and interests, the consideration of each of the following areas of concern must be discussed in future resource plans.

- LG&E/KU should continue to discuss the existence and promotion of any cogeneration within their service territory and any consideration given to it. The Companies responded that its tariffs provide for non-utility generation options and that there are 11 cogeneration customers currently. In addition, these types of generation resources are better suited for producing energy and are uncontrollable and uncertain for satisfying system energy requirements.
- LG&E/KU should continue to provide a discussion of any distributed generation and the impact of such generation on its system. The Companies responded that distributed generation is discussed in Sections 5.2 IRP Methodology and Key Assumptions, 5.(3) Load Forecast, and 8.(2).(a) Improvements to and More Efficient Utilization of Existing Facilities.
- LG&E/KU should continue to list and describe the net metering equipment and system types installed in its service territory and the impact of the system. The Companies responded that net metering is discussed in Sections 5.(2) IRP Methodology and Key Assumptions and 5.(3) Load Forecast Summary, Key Forecast Uncertainties.
- LG&E/KU should continue to provide a complete discussion of compliance actions and plans relating to current and pending environmental regulations in their future resource planning. The Companies responded that Sections 5.(2), 5.(5) and 5.(6) discuss resource planning uncertainties, Section 6

¹⁶² *Id.* at 10-11.

discusses significant changes to environmental regulations, and Section 8.(5).(f) discusses environmental compliance planning.

- LG&E/KU should continue their consideration of the comments of any intervenor groups and detail how those comments were considered in its system planning and preparation of the next IRP.
- At the time, the EPA issued a proposed rule to regulate carbon dioxide emissions from electric generating units under Section 111(d) of the Clean Air Act. It was anticipated that the Brown Solar Facility will help Kentucky meet its requirements under the proposed rule. Staff recommended that LG&E/KU provide a complete discussion of activities and developments related to the Brown Solar Facility and its impact. The Companies filed the E.W. Brown Solar Profile, 2017 in response to the recommendation. It notes that the ACE rule eliminates solar energy production as a GHG emission reduction technology. However, in 2017 the facility generated 17,336 MWh and eliminated approximately 16,200 tons of CO₂.¹⁶³
- The Companies' 2014 Reserve Margin Study indicated that a 16 percent reserve margin will be inadequate under future generation and transmission capacity conditions, and physical reliability guidelines. Staff recommended that LG&E/KU should provide in its next IRP a current and appropriate reserve margin study, along with sufficient study and analysis of expected and changing future uncertainties of adequacy and reliably meeting customers' needs. The Companies provided the 2018 IRP Reserve Margin Analysis in the IRP Volume III.

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

- LG&E/KU should continue their consideration of the comments of any intervenor groups and detail how those comments were considered in its system planning and preparation of the next IRP.
- Given the recent filing of Case No. 2020-00016, the next IRP's reserve margin analysis and long-term resource plan analysis should model the effects of increased interest and participation of the Companies' large commercial and industrial customers in purchasing increased amount of renewable energy, which may be generated by third party suppliers as opposed to the Companies' own generation sources.

¹⁶³ The Companies filed a report in conjunction with the IRP in Vol. III, at 6-7 and E.W. Brown Solar Profile, 2017.

- The 2018 Reserve Margin Analysis is well thought out. The starting premise appears to be that the Companies continue to operate as a standalone entity as opposed to being a member of an RTO. That assumption appears to drive several key input modeling constraints, which in turn may drive a higher reserve margin than would otherwise be the case. The Companies mention anecdotally the retirement of generation capacity within PJM and the reserve margins of neighboring utility systems, which may limit its ability to import power when needed as further support for the maintenance of its high reserve margin. The reduction in installed capacity would seem to support the Companies' planned maintenance of a high reserve margin. However, the Companies make no mention of any reliability concerns within the neighboring regions, availability of or additions to generation capacity, 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 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.¹⁶⁴
- In the next IRP, the Companies should 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.
- The Companies should provide greater discussion of and support for (reasonableness) the use of various assumptions used in the reserve

¹⁶⁴ Staff notes that the Companies have recently completed one RTO study. However, over time, circumstances change and key assumptions that were valid previously may have changed too. See LG&E/KU's response to the Attorney General's First Request for Information, Item 76 (Filed Nov. 1, 2019).

margin analysis. If not addressed in Section 2, where appropriate, the input assumptions used in the reserve margin analysis should be consistent with those used in energy, load, and resource planning.

- In addition to the current sensitivity analyses methodology, the Companies should provide the effects of varying the input parameters separately so as to gauge the individual effects on the reserve margin. The Companies should also provide more 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.
- For the next IRP, the Companies should incorporate SREA's modeling recommendations regarding capacity only planning, allowing renewable energy to compete directly against existing generation units, and energy storage resources into the modeling and forecast methodology. Other recommendations should be incorporated appropriately.
- Staff notes that in addition to the ongoing transmission projects, the Companies have taken steps in conjunction with other Kentucky based utilities to ensure the reliability of their respective transmission systems. For example, in Case No. 2017-00410,¹⁶⁵ the Commission approved the joint application for pre-approval of the sale or purchase of utility-owned transformers with an original book value in excess of \$1 million and ancillary equipment pursuant to the agreement for Regional Equipment Sharing for Transmission Outage Storage Restoration (RESTORE Agreement). In the next IRP, in addition to a listing of transmission related projects, (including information contained in its annual Transmission System Improvement Plan, the Companies should 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.
- Changes in federal and state law and policy could impact the growth of distributed generation, particularly as it relates to net metering. In Kentucky, in Case No. 2019-00256,¹⁶⁶ the Commission initiated an administrative proceeding to consider the implementation of legislation enacted by the

¹⁶⁵ Case No. 2017-00410, *Electronic Joint Application of Duke Energy Kentucky, Inc., East Kentucky Power Cooperative, Inc., Kentucky Utilities Company, and Louisville Gas and Electric Company for Approval of Transactions Related to the RESTORE Agreement* (Ky. PSC Feb. 22, 2018).

¹⁶⁶ Case No. 2019-00256, *Electronic Consideration of the Implementation of the Net Metering Act* (Ky. PSC Dec. 18, 2019).

2019 General Assembly. Senate Bill 100, entitled An Act Related to Net Metering (Net Metering Act), which became effective on January 1, 2020. The Companies should address any ruling pertaining to the Net Metering Act in the any future IRPs.

- If not addressed above, the Companies should 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, 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. In addition, Staff notes that there are a number of merchant solar generation facilities in the process of regulatory approval that may be in response to large industrial customer sustainability goals. The Companies should also 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 should address any possible capacity ratings changes with renewables in their forecast, especially with solar.

SECTION 5

INTEGRATION AND PLAN OPTIMIZATION

The final step in the IRP process is to integrate supply-side and demand-side options to achieve the optimal resource plan. This section will discuss the integration process and the resulting LG&E/KU plan.

THE INTEGRATION PROCESS

As was discussed in the Load Forecast and Supply Side Sections, the Companies developed base case estimates of load and optimal resource portfolios and performed sensitivity analyses to gauge the effects of different varying risk factors on the base case scenarios. The long term optimal resource plan takes all of these elements into account in an effort to effectively manage the risks inherent in the forecasting process.

SUMMARY OF KEY INPUTS AND UNCERTAINTIES

In the development of the energy and peak demand forecasts, variations in weather and economic conditions were used to project high and low forecasts around the Base Case forecast. Tables 2 and 3 in the long term planning analysis provide summaries of these analyses.¹⁶⁷

The Companies peak demand forecast reflects the departure of eight municipal customers and the impact of changes to its DSM programs.¹⁶⁸ The generation capacity decreased by 437 MW in 2019 due to identified retirements and the expiration of its 165 MW Bluegrass Station contract. Prospectively, the Companies state that no additional capacity retirements are expected beyond 2021, and absent any such retirements, the Companies do not have a need for capacity in their Base Case energy requirements forecast through the 15-year planning period.¹⁶⁹

With respect to supply-side resources, the Companies utilized the PROSYM production cost model from ABB to model generation production costs.¹⁷⁰ The current and pending environmental regulation compliance costs play an important role in the choice of generation technology and capacity. In addition, the operating life of generation units is a key consideration. By 2030, about 2,500 MW of the Companies' generation

¹⁶⁷ IRP, Vol. III, 2018 IRP Long Term Resource Planning Analysis at 7-8.

¹⁶⁸ *Id.* at 3.

capacity will be 50 years old. For the purposes of the Joint 2018 IRP, whether the units retire then or are extended another 10 years has a significant impact on the choice of optimal plans. Therefore, the Companies modeled both a 55-year and a 65-year unit operating life scenario. In the long Term Resource Planning Analysis, Table 4 summarizes the differences in summer rated capacity retirements in each of the two scenarios. In the 55-year operating life scenario, 2,428 MW is retired and only 49 MW is retired in the 65-year operating life scenario.¹⁷¹ Unit performance attributes are also important. Ramping rates and availability are key factors in the choice of generation technology mix. Coal units ramp more slowly, but are available to run most of the time. NGCC ramp faster than coal but may not run as often. CT's ramp very quickly but are designed more for peaking purposes and run even less than NGCCs. Renewables can provide relatively low cost energy, but are not as reliable for supplying capacity to satisfy demand.¹⁷² The expected price of coal, natural gas, CO₂, SO₂, and NO_x all play important roles in the selection of the optimal generation portfolio.¹⁷³ Finally, the Companies' reserve margin and specific financial characteristics (ROE, cost of debt, tax rate, etc.) are important considerations that play into the formulation of the long run generation portfolio.¹⁷⁴

OVERALL PLAN INTEGRATION

In the Long Term Resource Planning Analysis, Table 15 provides the optimal expansion plans for both the 55-year and 65-year generating life scenarios.¹⁷⁵ Under the 55-year unit life scenario, key results include up to 500 MW of solar generation, as excess winter capacity, could be added to the generation mix. Also, NGCC is the optimal least cost replacement generation technology, even in the face of high CO₂ prices. This is not unreasonable when coal fired generation is being retired. Under the 65-year generation life scenario combined with the high load growth and zero CO₂ price scenarios, NGCC and battery storage are least cost options. With high CO₂ prices, both solar and wind generation are introduced into the optimal generation mix. In addition, under the 65-year, low load growth scenarios (regardless of natural gas and CO₂ prices) the small frame CT, Brown unit 3, the DCP and Brown SCCTs are retired in order to keep the reserve margin below 25 percent.¹⁷⁶

¹⁷¹ *Id.* at 10.

¹⁷² *Id.* at 12.

¹⁷³ *Id.* at 13-17.

¹⁷⁴ *Id.* at 19.

¹⁷⁵ *Id.* at 24.

¹⁷⁶ *Id.*

In summary, in the 55-year operating life optimal plan, the economics of meeting loads with renewables (solar and wind) coupled with SCCT's and batteries for peaking needs, is not cost-effective. In the absence of significantly lower than forecasted costs of renewables and battery storage or significantly higher natural gas prices, NGCC is forecasted to be the primary source of replacement capacity as coal resources are retired.¹⁷⁷

DISCUSSION OF REASONABLENESS

Staff commends the Companies' effort in developing its Joint 2018 IRP. It recognizes the significant changes the Companies have had to manage since the revised filing of the 2014 IRP's Resource Assessment Addendum.¹⁷⁸ It addressed supply-side resource changes due to planned retirements of coal-fired generation and the expiration of the Bluegrass Station contract as well as the reduction in load due to the exodus of the municipal customers. The Companies continued its analysis in the current IRP with respect to its load forecasting and reserve margin analysis. Multiple supply-side options were developed and risks were identified in its current plan.

Staff is generally satisfied with the Companies' analysis of the many uncertainties and risks LG&E/KU will be facing over the planning period. The improvements in its load forecasting analysis, reserve margin analysis, and its supply-side screening and optimization plan have produced an optimal plan that is cost-effective.

¹⁷⁷ *Id.*

¹⁷⁸ 2014 IRP, Resource Assessment Addendum (filed Oct. 17, 2014).

*Honorable Allyson K Sturgeon
Senior Corporate Attorney
LG&E and KU Energy LLC
220 West Main Street
Louisville, KENTUCKY 40202

*Kentucky Utilities Company
220 W. Main Street
P. O. Box 32010
Louisville, KY 40232-2010

*Joe F Childers
Joe F. Childers & Associates
300 Lexington Building
201 West Short Street
Lexington, KENTUCKY 40507

*Louisville Gas and Electric Company
220 W. Main Street
P. O. Box 32010
Louisville, KY 40232-2010

*Honorable Kendrick R Riggs
Attorney at Law
Stoll Keenon Ogden, PLLC
2000 PNC Plaza
500 W Jefferson Street
Louisville, KENTUCKY 40202-2828

*Larry Cook
Assistant Attorney General
Office of the Attorney General Office of Rate
700 Capitol Avenue
Suite 20
Frankfort, KENTUCKY 40601-8204

*Matthew Miller
Sierra Club
50 F Street, NW, Eighth Floor
Washington, DISTRICT OF COLUMBIA 20001

*J. Michael West
Office of the Attorney General Office of Rate
700 Capitol Avenue
Suite 20
Frankfort, KENTUCKY 40601-8204

*Robert Conroy
LG&E and KU Energy LLC
220 West Main Street
Louisville, KENTUCKY 40202