COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC RATES AND APPROVAL OF CERTAIN REGULATORY AND ACCOUNTING TREATMENTS	**))))))**	**CASE NO. 2025-00113**

In the Matter of:

ELECTRONIC APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES, AND APPROVAL OF CERTAIN REGULATORY AND ACCOUNTING TREATMENTS	**))))))**	**CASE NO. 2025-00114**

DIRECT TESTIMONY OF
CHARLES R. SCHRAM
VICE PRESIDENT, ENERGY SUPPLY AND ANALYSIS
ON BEHALF OF
KENTUCKY UTILITIES COMPANY AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Filed: May 30, 2025

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SECTION 1: INTRODUCTION AND OVERVIEW

Q. Please state your name, position, and business address.

A. My name is Charles R. Schram. I am Vice President, Energy Supply and Analysis for Kentucky Utilities Company ("KU") and Louisville Gas and Electric Company ("LG&E") (collectively, "Companies") and an employee of LG&E and KU Services Company, which provides services to KU and LG&E. My business address is 2701 Eastpoint Parkway, Louisville, Kentucky 40223. A complete statement of my education and work experience is attached to this testimony as Appendix A.

Q. Have you previously testified before this Commission?

A. Yes, I have testified before this Commission numerous times, including in the Companies' two most recent certificates of public convenience and necessity ("CPCN") application proceedings.[1]

Q. Please describe your job responsibilities.

A. I have four primary areas of responsibility: (i) fuel procurement (coal and natural gas) and coal combustion residual marketing for the Companies' generating stations, (ii) real-time dispatch optimization of the generating stations to meet the Companies' native load obligations, (iii) wholesale market activities, and (iv) sales and market analysis, and generation planning. As it pertains to these proceedings, the Sales Analysis and Forecasting group prepared the electric and gas load forecasts and the Generation Planning group prepared the generation forecast.

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[1] *Electronic Joint Application of Kentucky Utilities Company and Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity and Site Compatibility Certificates*, Case No. 2025-00045, Direct Testimony of Charles R. Schram (Feb. 28, 2025); *Electronic Joint Application of Kentucky Utilities Company and Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity and Site Compatibility Certificates and Approval of a Demand Side Management Plan and Approval of Fossil Fuel-Fired Generation Unit Retirements*, Case No. 2022-00402, Direct Testimony of Charles R. Schram (Dec. 15, 2022).

Q. What are the purposes of your direct testimony?

A. My testimony: (1) supports certain exhibits required by the Commission's regulations; (2) describes the Companies' gas and electric sales forecasts; (3) explains the process for developing class load profiles, which are an input to the Companies' cost of service study; (4) explains the Companies' forecast of generation and future resource mix; (5) explains changes from the base period to the forecasted test period for operating revenues, sales for resale, and purchased power; (6) discusses the Companies' Curtailable Service Riders and why the Companies are not proposing to expand them; (7) supports certain net metering service ("NMS") and qualifying facility ("QF") rate components; and (8) supports the Companies' request to move from filing an updated study of regional transmission organization ("RTO") membership annually to triennially with the Companies' integrated resource plan ("IRP") filings.

Q. Are you supporting any exhibits and schedules that are required by Commission regulation 807 KAR 5:001?

A. Yes, I am sponsoring (or co-sponsoring) the following exhibits and schedules for the corresponding filing requirements for both Companies:

• Factors Used in Forecast	Section 16(7)(c)	Tab 16
• Load Forecast Including Energy and Demand (electric)	Section 16(7)(h)5	Tab 26
• Mix of Generation (electric)	Section 16(7)(h)7	Tab 28
• Customer Forecast (gas)	Section 16(7)(h)14	Tab 35
• Sales Volume Forecast – cubic feet (gas)	Section 16(7)(h)15	Tab 36

Q. Please identify the documents you are sponsoring attached at Tab 16 of the Companies' Applications.

A. I am sponsoring the following documents that are among those attached at Tab 16 of the Companies' Applications and relate to the Companies' forecasts:

Item B – Electric Sales & Demand Forecast Process;

Item C – 2025 Electric Sales Forecast;

Item D – Annual Natural Gas Volume Forecast Process;

Item E – Class Load Profile Forecast Process;

Item F – 2025 Business Plan Gas Volume Forecast;

Item G – Annual Generation Forecast Process; and

Item H – 2025 Business Plan Generation and OSS Forecast.

Q. Are you sponsoring any exhibits to your testimony?

A. Yes. I am sponsoring the following exhibits to my direct testimony:

Exhibit CRS-1	Comparison of KU Electric Customers, Billing Demand, and Energy: Base Period vs. Forecasted Test Period
Exhibit CRS-2	Comparison of LG&E Electric Customers, Billing Demand, and Energy: Base Period vs. Forecasted Test Period
Exhibit CRS-3	Comparison of LG&E Gas Customers, Billing Demand, and Volume: Base Period vs. Forecasted Test Period
Exhibit CRS-4	Select Economic Inputs to Electric and Gas Forecasts
Exhibit CRS-5	Comparison of Generation Volume by Unit, Base Period vs. Forecasted Test Period

Exhibit CRS-6 2026-2027 Qualifying Facilities Rates & Net Metering Service-2 Bill Credit

Exhibit CRS-7 Collection of Schram Workpapers

Note that Exhibit CRS-7 consists of electronic workpapers being provided separately.

SECTION 2: OVERVIEW OF ELECTRIC LOAD FORECAST

Q. Please describe the Companies' electric load forecast process.

A. Each year, the Companies prepare a 30-year demand and energy forecast with the first six years used in the Companies' business plan. The electric load forecast process is essentially the same for both KU and LG&E and is described in the document at Tab 16 to the Companies' Applications entitled "Electric Sales & Demand Forecast Process." Essentially, the forecast process involves:

- Using historical data to develop models that relate the Companies' electricity usage, demand, sales, and number of customers by rate classes to exogenous factors such as economic activity, appliance efficiencies and adaptation, demographic trends, and weather conditions;
- Using the models in combination with forecasts of the exogenous factors to forecast the Companies' electricity usage, demand, sales, and number of customers for the various rate classes; and
- Using historical load shapes for each of KU and LG&E to convert the monthly sales forecasts into a 30-year hourly forecast that can be used for generation planning purposes, including forecasting peak demands.

Q. How do the Companies ensure their electric load forecast is reasonable?

A. The Companies employ three practices to produce methodologically sound and reasonable forecasts:

1. Building and rigorously testing statistically and econometrically sound mathematical models of the load forecast variables;
2. Using high-quality forecasts of future macroeconomic events that influence the load forecast variables, both nationally and in the service territory; and
3. Thoroughly reviewing and analyzing model outputs to ensure the results are reasonable based on historical trends and the Companies' own experience and understanding of long-term trends in electricity and natural gas usage.

Q. Have the Companies materially changed their approach to electric load forecasting since their 2020 rate cases?

A. No. Although we work continually to refine and improve our methods and models, these changes are typically incremental and do not depart from methods the Companies have successfully used for decades to provide safe and reliable service at the lowest reasonable cost. The electric load forecast the Companies are filing in these proceedings reflects information that has become available since the 2020 rate cases, such as updated actual load and customer data, updated national and regional economic forecasts, and updated model parameters, but it does not reflect fundamental methodological changes.

Q. How does the electric load forecast the Companies are filing in these proceedings relate to other load forecasts the Companies have recently filed with the Commission?

A. The Companies created an electric load forecast for their 2025 Business Plan in mid-2024 ("2025 BP Load Forecast"). That load forecast is identical to the Mid case load forecast the Companies created for their 2024 IRP filing made in late October 2024 ("2024 IRP Load Forecast"). The Companies then revised their load forecast for their late February 2025 application for certificates of public convenience and necessity ("CPCNs") for new supply-side resources ("2025 CPCN Load Forecast") to account for increased amounts of expected data center load growth.[2] Importantly, the differences among the Companies' forecasts all occur *after* 2026, i.e., after the forecasted test year in these rate cases, and all of the forecasts project data center load will begin taking service from the Companies beginning in 2027.[3] Thus, although the 2025 CPCN Load Forecast differs from the electric load forecast the Companies used to create their 2025 Business Plan in the years following 2026, it is identical for 2026, which supports the reasonableness of the forecast for that year and the Companies' applications in these proceedings.

Q. What else supports the reasonableness of the Companies' load forecasting approach?

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[2] *See Electronic 2024 Joint Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company*, Case No. 2024-00326, IRP Vol. I (Oct. 18, 2024); *Electronic Joint Application of Kentucky Utilities Company and Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity and Site Compatibility Certificates*, Case No. 2025-00045, Testimony of Tim A. Jones (Feb. 28, 2025).

[3] The Companies are aware that the developers of the Camp Ground Road data center intend to have the first 134 MW of service available for one or more end users in October 2026. The Companies will propose any necessary adjustments if there are developments during the pendency of these proceedings that would materially affect the Companies' load forecast for 2026.

A. The Commission Staff Report in the Companies' 2021 IRP case stated, "LG&E/KU's assumptions and methodologies for load forecasting are generally reasonable,"[4] though the report did make a number of load forecasting recommendations.

The Companies sought to address those recommendations in their 2022 CPCN-DSM load forecast.[5] The Commission explicitly found the Companies' 2022 CPCN-DSM load forecast to be reasonable in several respects when addressing intervenor criticisms,[6] and it did not find the Companies' 2022 CPCN-DSM load forecast to be unreasonable in any respect.

The Companies used the same processes and methodologies used in the 2022 CPCN-DSM Case to create the 2024 IRP load forecasts, and the Companies have used the same load forecasting processes and methodologies in this load forecast. Therefore, the Commission can have confidence in the reasonableness of the 2025 Load Forecast for ratemaking purposes in these proceedings.

Q. Does the Companies' load forecast capture the extent economic activity may vary across the state?

A. Yes. The Companies use economic inputs to specifically capture economic conditions appropriate to the parts of the state being served. Factors such as household formation and population growth, which have a strong correlation with the number of customers the Companies serve, can vary within the service territory. Recent trends show

[4] *Electronic 2021 Joint Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company*, Case No. 2021-00393, Order Appx. "Commission Staff's Report on the 2021 Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company" at 51 (Ky. PSC Sept. 16, 2022).
[5] Case No. 2022-00402, Direct Testimony of Tim A. Jones at 5 (December 15, 2022).
[6] Case No. 2022-00402, Order at 61-66 (Ky. PSC Nov. 6, 2023).

continued steady growth in the urban centers of Louisville and Lexington, while the rural areas are either experiencing limited growth or declining sales and customers.

Note that the 2025 Load Forecast also addresses how data center load may vary across the Companies' service territories, but again that does not affect the forecasted test year in these proceedings.

Q. Does the Companies' load forecast reflect the impact of the Companies' demand side management and energy efficiency ("DSM-EE") programs?

A. Yes. The load forecast reflects the demand and energy impacts of the Companies' past and future demand side management programs, including the Companies' recently approved 2024-2030 DSM-EE Program Plan.

Q. In addition to the Companies' DSM-EE programs, does the electric load forecast reflect other changes in end-use energy efficiency?

A. Yes. For example, the Companies incorporate specific end-use assumptions covering base load, heating, and cooling components into residential and small commercial forecasts. These end-use assumptions incorporate forecasts of both consumer adaptation and technology efficiency that are impacted by legislation and regulations of the energy efficiency of specific technologies. The 2025 Load Forecast also accounts for savings created by advanced metering infrastructure ("AMI"), including AMI-related conservation voltage reduction ("CVR") and ePortal savings.

Absent the savings created by customer-initiated energy efficiency improvements, AMI-related CVR and ePortal savings, and the energy efficiency effects of the Companies' 2024-2030 DSM-EE Program Plan, sales would be 1.6 percent (approximately 491 GWh) greater in 2026 than currently projected in the 2025 Load Forecast.

Q. Does the electric forecast reflect the impact of distributed generation and electric vehicles?

A. Yes. The Companies project distributed generation capacity (net metering and qualifying facilities ("QFs")) will grow from the year-end 2024 level of 59 MW (32 MW for KU; 27 MW for LG&E) to 85 MW (49 MW for KU; 36 MW for LG&E) by year-end 2025 and to 93 MW (53 MW for KU; 40 MW for LG&E) by year-end 2026. Nearly all of this capacity (99.8%) is solar. Thus, assuming an annual capacity factor of 16.3% results in a reduction of energy sales in the forecasted test period of 41 GWh and 34 GWh for KU and LG&E, respectively. These volumes represent roughly 0.25 percent of forecasted test year sales for each Company.

Importantly, the 2025 Load Forecast projects each of LG&E's and KU's cumulative generating capacity of net metering systems will reach 1% of its single-hour peak load during calendar year 2025 and 2026, respectively.[7] As Michael E. Hornung discusses, this has implications for a utility's net metering service obligations, i.e., after a utility's cumulative generating capacity of net metering systems reaches 1% of its single-hour peak load during a calendar year, it is no longer obligated to offer net metering service to customers not already taking such service after the Commission approves any necessary tariff change. Therefore, the 2025 Load Forecast shows a slower growth rate for distributed generation beginning in 2026 as the assumed

[7] Due to slower than forecasted recent net metering growth in the KU service territory and an updated understanding of the timing of the Solar for All program in Kentucky, the Companies no longer anticipate KU will reach the 1% level in 2026. The Companies continue to anticipate reaching the 1% level in the LG&E service territory this calendar year.

payment for excess generation drops to the appropriate SQF compensation rate.[8] The Companies' modeling assumes this change will impact capacity to a greater degree than the number of customers choosing to install solar because customers who do install solar will install relatively smaller systems. However, for the forecasted test period, the reduced distributed generation capacity addition rate resulting from assuming the Companies will cease offering Rider NMS-2 service to new net metering customers after reaching the 1% level does not materially impact forecasted sales.

There is currently no reason to separately forecast distributed energy storage or other forms of distributed generation. Of the Companies' more than 5,400 distributed generation customers, only 11 have non-solar, non-battery distributed generation installations (one hydro and ten wind generators), the most recent being a wind installation in 2018. Similarly, based on the data available to the Companies, batteries have not proven to be particularly attractive to the Companies' customers to date: The Companies' net metering customers had only 2,481 kW of distributed battery storage capacity across 323 installations at the end of 2024, which is only about 6% of the Companies' net metering customer base and less than 0.03% of all customers. There is currently no reason to expect a surge in non-solar distributed generation or distributed energy storage in the Companies' service territories in the near term, making it reasonable to *explicitly* forecast only solar distributed energy resources, though it is important to note the 2025 Load Forecast *implicitly* captures customers' actual deployment and use of all types of distributed energy storage, including distributed

[8] Again, due to slower than forecasted recent net metering growth in the KU service territory and an updated understanding of the timing of the Solar for All program in Kentucky, the Companies no longer anticipate KU will reach the 1% level in 2026. The Companies continue to anticipate reaching the 1% level in the LG&E service territory this calendar year.

battery storage, and assumes the level of such resources increases with customer growth.

Finally, although the number of electric vehicles in the Companies' service territories has roughly quintupled since the Companies' 2020 rate cases (from about 3,100 in early 2020 to about 16,000 in 2024), their impact remains negligible in the near term. Assuming the average EV is driven 10,000 miles a year and requires 30 kWh per 100 miles of charge, this amounts to 32 GWh and 35 GWh of sales in the forecasted test period for KU and LG&E, respectively, or roughly 0.22 percent of each Company's sales.

Q. Please explain how weather is reflected in the electric load forecast.

A. Outside air temperature impacts customers' demand for heating and air conditioning to maintain a comfortable indoor living environment. Therefore, the forecasting process includes information that reflects historical monthly temperatures and projected normal temperatures. As discussed in Electric Sales & Demand Forecast Process at Tab 16, the Companies assume future weather will be the average of the weather experienced over the last 20 years. The Companies have used this approach for many years in IRP and CPCN filings. It is also consistent with a standard electric utility industry practice of using the average of historical weather as the basis for determining the "normal" weather when preparing a load forecast. This helps ensure there is an approximately equal chance actual weather will be warmer or cooler than the "normal" period, thereby avoiding weather bias in the forecast.

Q. How was the 2025 Load Forecast used to develop class load shapes for the cost of service study?

A. The Companies use historical hourly load data by customer class to develop forecasted energy sales by class on an hourly basis. This process is essentially the same for both KU and LG&E and is described in detail in the document at Tab 16 to the Companies' Applications entitled "Class Load Profile Forecast Process." Part of this process includes various quality control and data integrity checks to ensure that the resulting forecasts of class profiles are reasonable.

SECTION 3: KU ELECTRIC LOAD FORECAST

Q. How are KU's customer count and electricity sales expected to change in the forecasted test period as compared to the base period?

A. As shown in Exhibit CRS-1, from the base period (September 2024 through August 2025) to the forecasted test period (calendar year 2026), total retail KU calendar-adjusted electric sales increase by 596 GWh (3.3 percent) and total customers increase by 4,699 (0.9 percent). The customer growth is consistent with what one would expect given historical growth trends, as well as economic and other assumptions underlying the forecast.[9] Economic growth in Lexington and the areas around Louisville served by KU is partially offset by the impact of slower growth in the rural areas that KU serves. The growth in sales from the base period to the forecasted test period is primarily a result of BlueOval SK Battery Park ("BOSK") and two other notable economic development projects.

Q. Please discuss the effects on KU's sales of the startup of BOSK and the two other notable economic development projects you mentioned.

[9] See Exhibit CRS-4 for detailed assumptions for the forecasted test period.

A. BOSK is located in KU's service territory and consists of two phases. It is my understanding that BOSK expects to begin battery production at Phase 1 in 2025 (about 140 MW peak demand), though it has not done so to date, and Phase 2 is indefinitely paused. The 2025 Load Forecast reflects this, with full Phase 1 production assumed throughout 2026, no energy for Phase 2, and only contract minimum demands for Phase 2. BOSK accounts for a total difference in base period versus forecasted test year sales difference of 488 GWh.

The 2025 Load Forecast also reflects two new economic development loads, one an expansion of an existing industrial customer's load and the other a new industrial customer load, each of which is approximately 20 MW and both of which the Companies expect to come fully online in 2026 and take service under Rate RTS. These loads account for a total difference in base period versus forecasted test year sales difference of 228 GWh.

Q. Please discuss other differences in sales and customers between the base period and the forecasted test period.

A. As mentioned above, the two new RTS customers' loads and BOSK's special contract account for most of the increase in sales between the base period and forecasted test period. As can be seen in Exhibit CRS-1, sales for almost all rates other than RTS are forecasted to slightly decrease from the base period to the forecasted test period, which is consistent with the recent historical trend.

The majority of KU's customer growth comes from the residential class, which is also consistent with historical trends.

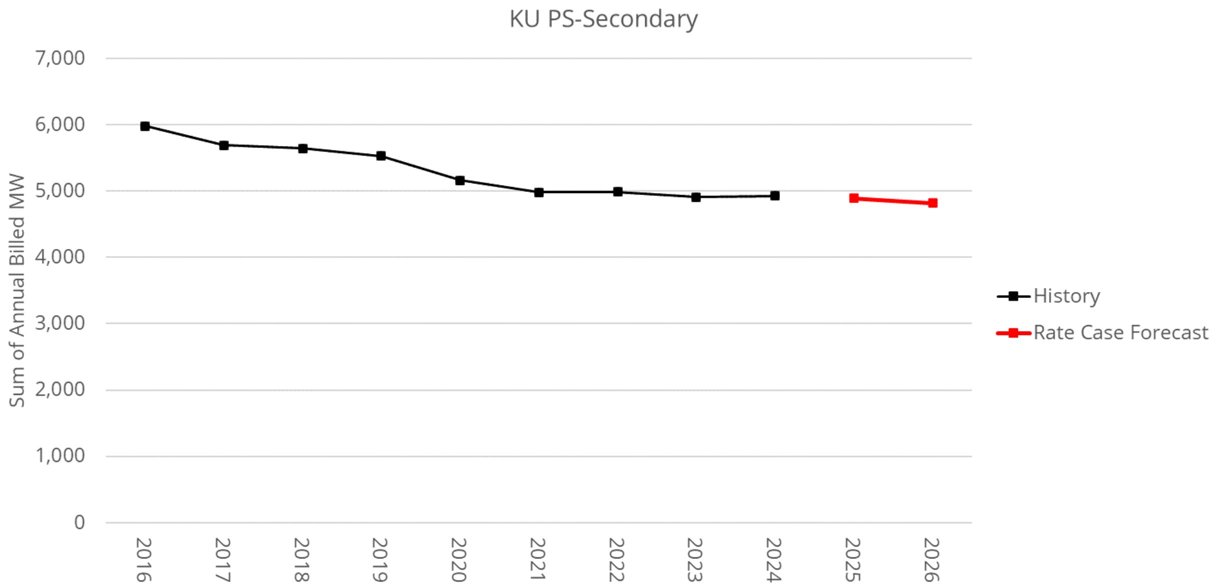
Q. In Exhibit CRS-1, why are RS and GS sales forecasted to decrease in the forecasted test period while the average number of RS and GS customers are forecasted to increase?

A. RS and GS sales have historically been slightly declining while RS and GS customers have historically been increasing. This is the result of use-per-customer declines related to end-use energy efficiency improvements over time. The Companies' forecast continues this trend, resulting in a lower forecasted test period than base period.

Q. In Exhibit CRS-1, why are PS-Secondary sales forecasted to decrease by 87 GWh, customers to decrease by 72, and demands to decrease by 95 MW in the forecasted test period?

A. PS-Secondary sales, customers, and demands have historically been declining. The Companies' forecast continues this trend, resulting in a lower forecasted test period than base period. Figure 1 below shows KU's PS-Secondary billed demands history and forecast; note that the values shown are annual sums of monthly billed demands.

Figure 1: KU PS Secondary Sum of Annual Billed Demands (MW)



Q. Is there a difference in the weather between the base period and the forecasted test period, and does that affect projected sales in each period?

A. Yes, but there is only a slight difference in total and the difference varies month-to-month. The six actual months in the base period are generally milder than the normal forecasted test period except January. However, there is more load associated with January HDDs than shoulder month HDDs, so a cold January can materially impact sales. The base period consists of actual billed data for the first six months and therefore reflects the actual weather during that time. On the other hand, sales in the last six months of the base period and the entire forecasted test period are based on 20-year normal weather for the KU service area as described in Annual Electric Sales & Demand Forecast Process at Tab 16. Table 1 compares the actual monthly heating degree days ("HDDs") and cooling degree days ("CDDs") to their 20-year normal values.

Table 1: Comparison of 2024-2025 Calendar Month Actual and 20-Year Average Weather (KLEX)

Month	Actual Degree Days	Average Degree Days	Difference
September (CDD)	234	183	-51
October (HDD)	177	245	68
November (HDD)	394	562	168
December (HDD)	728	802	74
January (HDD)	1118	956	-162
February (HDD)	713	783	70

Q. Please describe the primary differences in billing demands between the base period and the forecasted test period.

A. BOSK is the main driver for the differences in demands from the base period to the forecasted test year. BOSK was assumed to be on the RTS rate through the end of 2024, which includes the first four months of the base period (September 2024 – December 2024). BOSK was then assumed to switch to its special contract rate in January 2025, which causes a portion of the base period for RTS to be different from the forecasted test period. This is the main driver of the large positive variances on the special contract rate.

Additionally, BOSK has a minimum base contract demand on the RTS rate that is causing the increase in base MVA for the first four months of the base period. However, due to BOSK not being at full usage, both intermediate and peak demand differences across periods are not as significant. This is the main driver of base RTS demands being higher in the base period.

Importantly, both of the new economic development loads of approximately 20 MW each discussed above are assumed to take service on the RTS rate. These two new economic development projects are the main driver of the increase in RTS intermediate and peak demands while also offsetting some of the decrease in RTS base demands being caused by BOSK.

Q. Do you believe the forecasted billing determinants for the forecasted test period are a reasonable basis for developing revenue forecasts?

A. Yes. The forecast process is one that has been employed for many years and has been reviewed by the Commission in the context of IRPs, CPCN proceedings, environmental cost recovery ("ECR") filings, and the Companies' base-rate cases. It reflects the best data available at the time it was prepared, and the output is reasonable both in a historical context and given the underlying input assumptions.

SECTION 4: LG&E ELECTRIC LOAD FORECAST

Q. How are LG&E's customer count and electricity sales forecasted to change in the forecasted test period as compared to the base period?

A. As can be seen in Exhibit CRS-2, from the base period (September 2024 through August 2025) to the forecasted test period (calendar year 2026), total LG&E calendar-adjusted electric sales decrease by 45 GWh (-0.4 percent) and total customers increase by an average of 4,242 (1.0 percent). Lower sales in the forecasted test period primarily due to RS and GS customers are partially offset by higher sales from RTS customers. The customer growth forecast is consistent with recent historical trends.

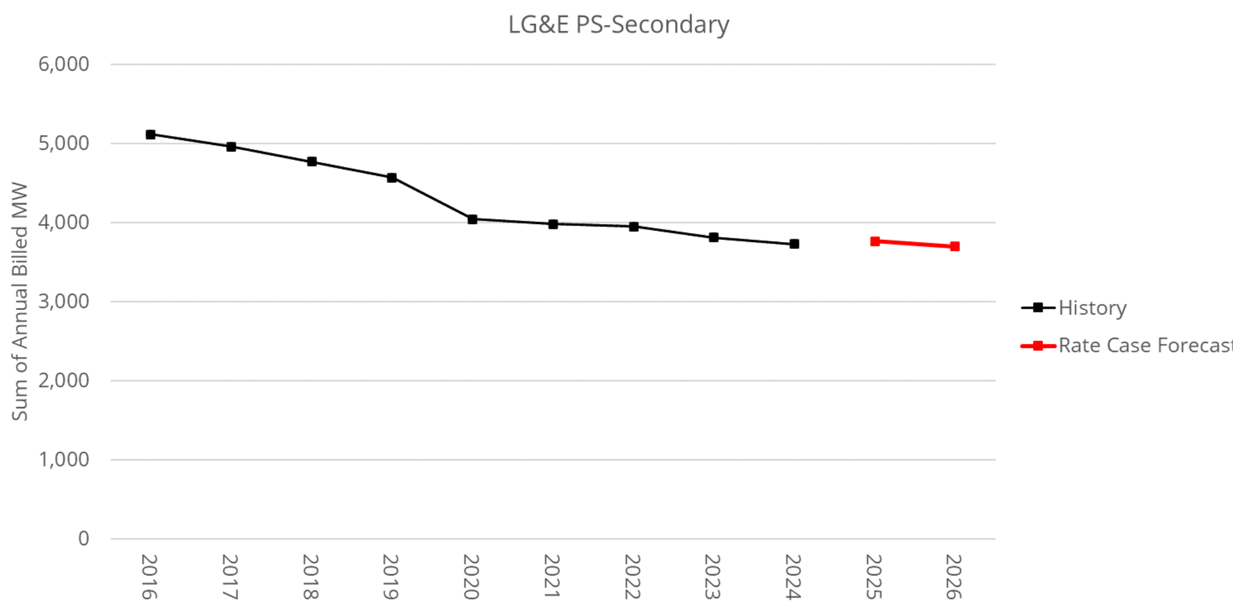
Q. In Exhibit CRS-2, why are RS and GS sales forecasted to decrease in the forecasted test period while the average number of RS and GS customers are forecasted to increase?

A. RS and GS sales have historically been slightly declining while RS and GS customers have historically been increasing. This is the result of use-per-customer declines related to end-use energy efficiency improvements over time. The Companies' forecast continues this trend, resulting in a lower forecasted test period than base period.

Q. In Exhibit CRS-2, why are PS-Secondary sales forecasted to decrease by 85 GWh, customers by 20, and demands by 57 MW in the forecasted test period?

A. PS-Secondary sales, customers, and demands have historically been declining. The Companies' forecast continues this trend, resulting in a lower forecasted test period than base period. Figure 2 below shows LG&E's PS-Secondary billed demands history and forecast; note that the values shown are annual sums of monthly billed demands.

Figure 2: LG&E PS Secondary Sum of Annual Billed Demands (MW)



Q. In Exhibit CRS-2, why is TOD-Secondary base demand expected to increase by 44 MVA, intermediate demand by 54 MVA, and peak demand by 52 MVA?

A. TOD-Secondary base, intermediate, and peak demands have historically been increasing. As Table 2 below shows, the Companies' forecast continues this trend, resulting in higher values for the forecasted test period than the base period for all demands; note that the values shown are annual sums of monthly billed demands.

Table 2: LG&E TOD-Secondary MVA Demands

Year	Base	Intermediate	Peak
2024 (Actual)	4,747	3,533	3,439
2025 (Forecast)	4,761	3,575	3,481
2026 (Forecast)	4,806	3,629	3,534

Q. Is there a difference in the weather between the base period and the forecasted test period?

A. Yes, but only a slight difference in total and the difference varies month-to-month. Similar to KU, the actual months in the base period are generally milder than the normal forecasted test period except for January. The base period consists of actual billed data for the first six months and, therefore, reflects the actual weather during that time. Table 3 compares the actual monthly HDDs and CDDs to their 20-year normal values used in the forecast period.

Table 3: Comparison of 2024-2025 Calendar Month Actual and 20-Year Average Weather (KSDF)

Month	Actual Degree Days	Average Degree Days	Difference
September (CDD)	313	255	-58
October (HDD)	110	190	80
November (HDD)	357	492	135
December (HDD)	683	748	65
January (HDD)	1059	897	-162
February (HDD)	701	726	25

Q. Do you believe the forecasted billing determinants for the forecasted test period are a reasonable basis for developing revenue forecasts?

A. Yes. As I said before, the forecast process is one that has been employed for many years and has been reviewed by the Commission in the context of IRPs, CPCN cases, ECR filings, and the Companies' base-rate cases. It reflects the best data available at the time it was prepared, and the output is reasonable both in a historical context and given the underlying input assumptions.

SECTION 5: LG&E NATURAL GAS FORECAST

Q. Please provide an overview of the 2025 Load Forecast of natural gas volumes for LG&E.

A. As discussed in document entitled "Annual Natural Gas Volume Forecast Process" at Tab 16 of LG&E's Application, the natural gas volume forecast consists of two broad types of customers: (1) sales to consumers and (2) transportation for customers who procure their own natural gas. As shown in Exhibit CRS-3, from the base period (September 2024 through August 2025) to the forecasted test period (calendar year 2026), natural gas sales are forecasted to increase by 158,451 Mcf (0.5 percent) and total customers on sales rates are forecasted to increase by 1,988 (0.6 percent). Comparing the same time periods, volumes for transportation customers are forecasted to increase by 1,418,648 Mcf (8.6 percent).

Q. In Exhibit CRS-3, how do the unbilled adjustments impact the comparison of the base period and forecasted test period?

A. The unbilled adjustments mostly impact the residential and commercial rate classes. The residential unbilled adjustment shown in Exhibit CRS-3 impacts residential rate class sales, and the other unbilled adjustment mostly impacts commercial rate class sales. Both of these unbilled adjustments should be added into the variances shown in their respective rate classes to get the most accurate comparison of the two periods.

Q. In Exhibit CRS-3, what are the major reasons for changes in Firm Transport (FT) volumes from the base period to the forecasted test period?

A. As discussed in Section 3: KU Electric Load Forecast, BOSK Phase 1 was forecasted to be at operating at full usage starting January 2025. BOSK accounts for a total difference in base period versus forecasted test year sales difference of 762,447 Mcf as well as a demand difference of 24,750 Mcf. This is about half of the total increase in sales and demand from the base period to the forecasted test period. The remaining increase is tied to increases from other major account expansions that total 628,648 Mcf.

Q. In Exhibit CRS-3, what is the major reason for the changes in RGS and CGS volumes from the base period to the forecasted test period?

A. The unbilled component discussed above is the main driving factor in the difference in volumes from the base period to the forecasted test period.

Q. Do you believe the forecasted billing determinants for the forecasted test period are a reasonable basis for developing revenue forecasts?

A. Yes. The forecast process is one that has been employed for many years, reflects the best data available, and the output is reasonable both in a historical context and given the underlying input assumptions. The natural gas forecast process uses many of the same methodologies and forecasting techniques as the electric forecast the Commission has reviewed in the context of IRPs, CPCN cases, ECR filings, and in LG&E's gas base-rate cases.

SECTION 6: GENERATION FORECAST

Q. Please describe how the generation forecast is prepared.

A. A software program called PROSYM is used to simulate the dispatch of the Companies' generation fleet. The model uses a forecast of hourly energy requirements for the combined KU and LG&E system (including load in Virginia and wholesale requirements contracts) along with information on the Companies' generation fleet (unit capacity, heat rate, fuel cost, variable operations and maintenance, emissions, maintenance schedules, forced outage rate, etc.) and market conditions (spot wholesale electricity prices, transmission availability) to first optimize the cost of serving native load via self-generation and market energy purchases and then to sell any economic generation into the market. This process is described in detail in the document entitled "Generation Forecast Process" attached at Tab 16 of the Companies' Applications.

Q. Why do the Companies jointly plan and dispatch their generation system?

A. KU and LG&E jointly dispatch their generation units to achieve operational efficiencies associated with serving their combined loads. Pursuant to the Companies' Power Supply System Agreement approved by the Federal Energy Regulatory Commission, the Companies' joint planning objectives are to maximize the economy, efficiency, and reliability of their combined systems as a whole. Dispatch of generation, whether from the Companies' own generating resources or from purchased power, is determined by lowest variable operating cost, regardless of ownership, required to maintain system reliability. Therefore, it is reasonable to view the Companies' generation systems from the perspective of the combined KU and LG&E system.

Q. What are the primary reasons for differences in the generation volumes in the forecasted test period compared to the base period?

A. Exhibit CRS-5 shows generation volumes in the forecasted test period compared to the base period. The difference between the two periods is relatively minor at a system-wide level, though it may vary significantly for individual units primarily due to unit retirements, maintenance schedules, other outages, load, weather, and fuel costs. Mill Creek 1 retired four months into the base period, resulting in minimal generation in the base period and none in the forecasted test period. Generation volumes at Ghent 3, Mill Creek 4, and Trimble County 2 all show differences due to their planned outages. Simple-cycle combustion turbine ("SCCT") variance reflects shifting between units due to the difference in modeled starting order and real-time operations. Other unit-by-unit differences are primarily attributable to the timing and duration of planned and forced outages.

Q. Have there been or will there be other changes to the Companies' generation fleet since the Companies' 2020 rate cases?

A. Yes. LG&E retired the 300 MW Unit 1 at the Mill Creek Generating Station at the end of 2024. LG&E has received Commission approval to retire Mill Creek 2 (297 MW) in 2027 when the 645 MW Mill Creek 5 natural gas combined cycle unit becomes operational, but it is considering delaying Mill Creek 2's retirement due to battery energy storage system ("BESS") cost risks regarding the associated investment tax credit and tariffs. The Companies' Solar Share Facilities have grown to 2.1 MW. The Companies currently anticipate 120 MW Mercer County Solar Facility and the 120 MW Marion County Solar Facility will achieve commercial operation in 2027. The Companies also currently anticipate their BESS to be located at the E.W. Brown Generating Station ("Brown BESS") will achieve commercial operation in 2027 pending final determination of critical equipment availability and appropriate contracting.

In addition to the resources discussed above that the Commission approved in the Companies' 2022 CPCN-DSM proceeding, the Companies have entered into a total of six solar power purchase agreements ("PPAs"), four of which the Commission approved in the 2022 CPCN-DSM proceeding.[10] Three of the six PPAs have terminated, and the other three have not proceeded materially. It is currently highly unlikely they will proceed sufficiently to result in any energy purchases by the Companies in the forecasted test year.

Regarding the Companies' small-frame combustion turbines ("CTs"), LG&E retired the 14 MW Zorn 1 and the 35 MW Paddy's Run 11 in 2021. The Companies continue to assume their remaining small-frame CTs (Paddy's Run 12 and Haefling Units 1 and 2) will retire in 2025, but they will continue to operate the units until they are uneconomical to repair.

Finally, although the Companies anticipated in their 2020 rate cases that KU's 412 MW Brown 3 would retire in 2028, they currently anticipate it will retire in 2034.

Q. In your professional opinion, is the 2025 generation forecast reasonable and reliable for the purposes of these proceedings?

A. Yes. The Companies developed the forecast using the best data available and with processes and software the Companies have used for many years and have been the basis for information provided to the Commission in numerous IRP, CPCN, and ECR cases. In short, using sound models and assumptions produces reasonable forecasts, and the Companies' 2025 generation forecast is reasonable and reliable for the purposes of these proceedings.

[10] Case No. 2022-00402, Order at 179 (Ky. PSC Nov. 6, 2023).

SECTION 7: CURTAILABLE SERVICE RIDERS

Q. Please describe the Companies' Curtailable Service Riders.

A. The Companies currently have two Curtailable Service Rider ("CSR") rate schedules, CSR-1 and CSR-2, both of which have been closed to new customers since July 1, 2017. Both allow the Companies to request up to 100 hours per year of physical curtailments and an additional 275 hours per year of buy-through curtailments, but each has its own restrictions concerning the conditions under which the Companies may request physical curtailments, when buy-through is available, the number of curtailment events, and the duration of curtailment events. They also have different credits for curtailable billing demand, though they both have the same non-compliance charge of $16.00/kVA. Existing CSR customers may terminate their CSR contracts at any time upon six months' notice.

Q. Have the Companies called upon their CSR customers to curtail?

A. Yes. The Companies have used economic (buy-though) and physical curtailments under their CSR riders to provide value to all customers, whose rates pay the credits CSR customers receive. Most notably, the Companies called upon their CSR customers for physical curtailments during Winter Storm Elliott. Although not perfect, CSR customers' compliance was very good, with only a few customers slightly delayed in their compliance.[11] These customers' curtailments helped avoid additional possible load shedding during Winter Storm Elliott.

Q. How do the CSR tariff constraints you mentioned above affect the value of CSR compared to a resource owned by the Companies?

[11] *See Electronic Investigation of Louisville Gas and Electric Company and Kentucky Utilities Company Service Related to Winter Storm Elliott,* Case No. 2023-00422, Order at 41-44 (Ky. PSC Jan. 7, 2025).

A. The restrictions on CSR-1 and CSR-2 significantly reduce their value as compared to a comparable amount of a resource such as a battery energy storage system ("BESS"). BESS can be available all 8,760 hours of the year, typically can provide peak output four hours at a time (or longer at lower output), can fully charge and discharge up to twice a day, can be instantly dispatchable (no advance notice is required to use an owned BESS resource), and can be available for dispatch irrespective of which other units the Companies have committed or dispatched. In contradistinction, CSR-1 and CSR-2 have the following constraints:

- CSR-1
  - Maximum curtailment hours per year: 375
  - Curtailment duration constraints: minimum 30 minutes; maximum 14 hours
  - Maximum curtailment events per day: two
  - Advance notice of beginning or ending curtailment: at least 60 minutes
  - Hours with buy-through option per year: 275
  - Hours Companies can request physical curtailment per year: 100
  - Constraints on when Companies may request physical curtailment:
    - All available units have been dispatched or are being dispatched; and
    - All off-system sales have been or are being curtailed
- CSR-2
  - Maximum curtailment hours per year: 375
  - Curtailment duration constraints: minimum 30 minutes; maximum 14 hours
  - Maximum curtailment events per day: two

- Advance notice of beginning or ending curtailment with buy-through option: at least 60 minutes
- Hours with buy-through option per year: 275
- Physical curtailment request constraints and conditions
    - Hours Companies can request physical curtailment per year: 100
    - Maximum physical curtailment requests per year: 20
    - When more than ten of the Companies' primary combustion turbines (those with a capacity greater than 100 MW) are being dispatched, Companies may request, but customers may buy through, physical curtailment request
        - Any buy-through of a physical curtailment request will not count toward the 100-hour limit or 20-curtailment-request limit, but will count toward the 275 buy-through hours
        - Customer has ten minutes after receiving a physical curtailment request with buy-through option to inform the Companies whether it will physically curtail (default if customer provides no response is buy-through); customer electing physical curtailment then has 30 minutes to physically curtail (i.e., a total of 40 minutes from first notification from the Companies)
    - Constraints on Companies' physical curtailment requests without a buy-through option:

- All available units have been dispatched or are being dispatched
- Customers have 40 minutes to comply with curtailment request

As a practical matter, there is no material difference between CSR-1 and CSR-2 from a dispatcher's perspective when physical curtailments are involved—when it matters most. Using either CSR requires picking up the phone to call customers to request curtailments, which is a time-consuming and distracting process under challenging system conditions. It is important to reiterate that point: There is no "CSR button" that causes curtailments to occur. The Companies must call customers and count on them to respond timely, i.e., within 40 or 60 minutes for CSR-2 and CSR-1, respectively. This significantly reduces the value of CSR relative to BESS, and it places a practical constraint on how much CSR load can be added and be reasonably expected to add any dependable reliability value to the system.

Q. Have the Companies studied expanding their CSR programs?

A. Yes. In its January 7, 2025 final order in its Winter Storm Elliott investigation case, the Commission "recommend[ed] that LG&E/KU continue to evaluate the expansion of their CSR programs and whether the current penalty for non-compliance is an effective deterrent."[12] Prior to that, the Companies evaluated expanding their CSR programs in their 2024 Integrated Resource Plan Resource Assessment.[13] The Companies did so again in their 2025 CPCN Resource Assessment, which they filed

[12] *Id.* at 43.
[13] *Electronic 2024 Joint Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company*, Case No. 2024-00326, IRP Vol. III, 2024 IRP Resource Assessment (Oct. 18, 2024).

after the Commission's order quoted above.[14] Both of those analyses modeled a 100 MW expansion of the Companies' CSR-2 program among other resource options. The CSR-2 expansion proved to be uneconomical in all scenarios the Companies studied. That result is unsurprising given the relatively high cost of CSR credits, the buy-through optionality, and the constraints on when the Companies are able to call for physical curtailments.

To better understand the value of expanded CSR that would add cost-effective reliability, the Companies prepared analyses under my direction to develop credits for a hypothetical CSR program with characteristics closer to those of the avoided capacity resource (BESS) while preserving some limitations of the Companies' existing CSR offerings. The hypothetical CSR offering the Companies studied had the following characteristics and constraints:

- 100 MW capacity
- No buy-through option
- No advance notice requirement (assumed instantaneous and immediate response when needed)
- No noncompliance provision (assumed full and instantaneous compliance)
- Maximum physical curtailment hours per year: 100
- Maximum physical curtailment events per year: 20
- Maximum physical curtailment events per day: two (no minimum or maximum curtailment duration per event)

[14] *Electronic Joint Application of Kentucky Utilities Company and Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity and Site Compatibility Certificates*, Case No. 2025-00045, Direct Testimony of Stuart A. Wilson, Exh. SAW-1 (Feb. 28, 2025).

- Companies may request physical curtailment only when all available units have been dispatched or are being dispatched

The credits for this hypothetical CSR program are shown in the table below.[15]

CSR Credits for Hypothetical CSR Program ($/kVA-mo)

	KU	LG&E
Transmission	3.38	3.32
Primary	3.44	3.38

For an expanded CSR to be supportive of system reliability, it would need to better reflect the characteristics of the avoided capacity resource, with no buy-through option, no advanced notice requirement, no noncompliance provision, and no limits on system conditions, which are unlikely to be attractive to potential CSR customers. Thus, the Companies are not proposing to expand their CSR programs at this time.

Finally, there does not appear to be a need to increase the current CSR noncompliance penalties. The Companies have not encountered any significant noncompliance, and it is not clear that increasing the noncompliance penalty would result in greater adherence. Therefore, the Companies are not proposing to increase the current CSR noncompliance penalties.

SECTION 8: SUPPORT FOR CERTAIN NMS-2, SQF, AND LQF RATE COMPONENTS

Q. What is your understanding of the Companies' LQF and SQF riders?

A. According to the Public Utility Regulatory Policies Act of 1978 ("PURPA") as implemented in Kentucky by Commission regulations, the Companies have an obligation to purchase the electrical output of certain types and sizes of renewable or

[15] The values provided are based on Cane Run BESS costs and assume the project is eligible for 50% Investment Tax Credit ("ITC"). Due to tariff changes, the project may not be able to meet the domestic content requirements for the 10% bonus credit, in which case the project would be eligible for 40% ITC instead of 50%.

cogeneration electric generating facilities at the utility's avoided cost; such facilities are qualifying facilities ("QFs").[16] For example, the Commission's QF regulation obligates a serving utility to purchase the output of a renewable generator of up to 80 MW under certain conditions.[17] In compliance with the Commission's QF regulation, the Companies have two QF standard rate riders:

- SQF – for small (100kW or less) QFs and
- LQF – for QFs greater than 100 kW.

Q. What is the primary basis for determining QF compensation?

A. The Commission's QF regulation is clear that compensation for QFs "shall be based on avoided costs."[18] The regulation defines avoided costs to be "incremental costs to an electric utility of electric energy or capacity or both which, if not for the purchase from the qualifying facility, the utility would generate itself or purchase from another source."[19]

Q. In layman's terms, what is "avoided cost?"

A. The basic idea underlying the concept of avoided cost is that customers should pay no more for energy or capacity from a QF than they would pay for energy or capacity from a non-QF resource. The avoided cost concept is important because, generally speaking, the Companies must purchase output and capacity from QFs for which the Companies' customers are going to pay. Logically, customers would not want the Companies to pay more for QF energy and capacity than they otherwise would pay for another resource. The purpose of PURPA's QF provisions as implemented in Kentucky is to allow non-

[16] *See* 807 KAR 5:054.
[17] *See, e.g.*, 807 KAR 5:054 Section 1(10).
[18] *See* 807 KAR 5:054 Section 7(2) and (4).
[19] *See* 807 KAR 5:054 Section 1(1).

utility renewable generation and co-generation to compete in the same terms as other utility resources while protecting customers (who ultimately have to pay the bill) from paying more than they otherwise would for power generation.

Q. What do you recommend using as the basis for calculating avoided energy cost in these cases?

A. Assumptions for computing hourly energy costs included the resource-constrained load forecast and approval of the resource portfolio the Companies proposed in Case No. 2025-00045 ("2025 CPCN Plan").[20] To focus the analysis on the cost of the Companies' resources serving native load, market electricity purchases and off-system sales were not permitted in PROSYM.

Q. How did you use the 2025 CPCN Plan to calculate avoided energy cost?

A. Section 2 of Exhibit CRS-6 describes in detail the methodology used to calculate the avoided energy cost for four generation technologies based on their unique generation capabilities:

1. single axis tracking solar (24.7 percent annual capacity factor)
2. fixed tilt solar (15.5 percent annual capacity factor)
3. wind (31.7 percent annual capacity factor), and
4. other technologies (e.g., cogeneration facilities with a steam host, hydro, biomass).

This methodology takes the hourly output from the Companies' PROSYM generation model for 2026 through 2033 (8 years) and computes the annual avoided energy cost

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[20] *See, e.g.*, *Electronic Application of Kentucky Utilities Company and Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity and Site Compatibility Certificates*, Case No. 2025-00045, Application (Feb. 28, 2025).

by backing down generation using an hourly generation profile for each of the generation technologies assuming an 80 MW nameplate rated unit.

Q. Why did you back down generation by 80 MW to calculate avoided energy cost?

A. The largest nameplate sized renewable QF allowed by 807 KAR 5:054 is 80 MW, so by comparing the cost of generation with and without the energy from an 80 MW QF of each technology type, one can determine the incremental energy cost that would be avoided with each type of generation technology. Also, the one percent cap on net metering generation capacity would equate to approximately 60 MW in total for the combined Companies (about 35 MW for KU and 25 MW for LG&E), increasing to approximately 80 MW in total as economic development load increases through 2031, so it is reasonable to use one set of 80 MW avoided energy cost data for LQF, SQF, and NMS-2.

Q. What types of costs are included in avoided energy costs?

A. Avoided energy costs can also be thought of as variable energy costs. These are costs that are associated with the generation of a MWh of energy. The largest category of avoided energy cost is fuel. Other avoided energy costs include SO_2 and NO_x emission allowances and emission system reagents (e.g., limestone, ammonia). See Section 2 of Exhibit CRS-6 for a listing of the components of avoided energy costs in PROSYM. Note that, except for fuel, virtually every other category of variable energy costs is related to environmental compliance (e.g., emission allowances and operation of emission control equipment).

Q. What avoided energy cost do you recommend should be used for the SQF and LQF rates?

A. Table 3 in Exhibit CRS-6 shows the annual values for 2026 through 2033 of the Companies' avoided energy cost for each of the generation technologies. To simplify tariff administration, I am recommending these annual values be converted to levelized values based on the choice of 2-year or 7-year PPA and the starting year of the 7-year PPA. The levelization process is described in Section 2 of Exhibit CRS-6. My recommended avoided energy prices by technology, contract term, and contract starting year are shown in Table 4 in Section 2 of Exhibit CRS-6, which is replicated as Table 12 in Section 5.

Q. What is your recommended methodology for calculating avoided capacity costs for the SQF and LQF riders?

A. As described in Section 3 of Exhibit CRS-6, I recommend using PLEXOS to evaluate each technology's contribution to the timing and size of the Companies' future need for capacity.

Q. What are the results of the PLEXOS analysis?

A. Results showed that 80 MW QF PPAs of single-axis tracking solar, fixed tilt solar, and wind do not result in any changes to the Companies' optimal resource plan. Therefore, I recommend the avoided capacity cost for these three technology types be zero. However, 80 MW of "other" technologies, which is assumed to be fully dispatchable, results in a decreased amount of Cane Run BESS in 2028. Therefore, I recommend an avoided capacity cost for "other" technologies based on Cane Run BESS costs.

Q. Are any adjustments necessary for using Cane Run BESS costs as the basis for avoided capacity costs for other technologies?

A. Yes. Because other technologies are assumed to be fully dispatchable, their capacity contribution is assumed to be 100 percent. However, the capacity contribution of BESS in the context of the Companies' proposed resource plan in Case No. 2025-00045, was determined to be 83 percent. Therefore, I recommend applying an availability factor of 120 percent (100 percent divided by 83 percent) to the capacity cost of the Cane Run BESS to reflect the higher reliability of fully dispatchable resources.

Q. When do the Companies have a capacity need?

A. Because the Companies are transitioning from lower economic minimum reserve margins to higher minimum reserve margins developed to reduce the loss of load expectation to one day in ten years, the capacity need is assumed to be immediate, in 2026.

Q. What avoided capacity cost do you recommend be used for the SQF and LQF rates?

A. Because 80 MW QFs for single-axis tracking solar, fixed tilt solar, and wind have no impact on the Companies' optimal resource plan, I recommend the avoided capacity cost of these technologies be zero. Also, because a 2-year PPA for any technology would not have a material impact on the Companies' optimal resource plan, I recommend the avoided capacity cost for all 2-year PPAs be zero. Table 9 in Exhibit CRS-6 shows the annual values for 2026 through 2033 of the Companies' avoided capacity cost for other technologies. To simplify tariff administration, I am recommending these annual values be converted to levelized values based on the starting year of the 7-year PPA. The levelization process is described in Section 3 of Exhibit CRS-6. My recommended avoided capacity prices by technology, contract term, and contract starting year are shown in Table 10 in Section 3 of Exhibit CRS-6, which is replicated as Table 13 in Section 5.

Q. Do the Companies include line losses in their recommended QF rates?

A. Yes. Table 15 in Section 5 of Exhibit CRS-6 shows line loss assumptions by company for energy and capacity. Tables 12-18 in Section 5 of Exhibit CRS-6 shows QF rates with and without line losses.

Q. Does your recommended approach to avoided energy and capacity costs differ for NMS-2 customers who supply excess energy to the grid compared to SQF and LQF customers?

A. Because the vast majority of net metered customers employ fixed tilt solar technology, I recommend using the average of the 2026 and 2027 starting year 7-year PPA SQF and LQF avoided energy rates for that technology as the avoided energy component of NMS-2 compensation for customers that supply excess energy to the grid. I further recommend that, consistent with the SQF and LQF rates for fixed tilt solar, the avoided capacity component of NMS-2 compensation be zero.

Q. What is the appropriate value for the avoided ancillary services cost component of the Rider NMS-2 compensation rate?

A. The appropriate value for the avoided ancillary services cost component of the Rider NMS-2 compensation rate is zero. As the Companies explained in their 2020 rate cases,[21] their Open Access Transmission Tariff ("OATT") includes seven ancillary

[21] *Electronic Application of Kentucky Utilities Company for an Adjustment of Its Electric Rates, a Certificate of Public Convenience and Necessity to Deploy Advanced Metering Infrastructure, Approval of Certain Regulatory and Accounting Treatments, and Establishment of a One-Year Surcredit*, Case No. 2020-00349, and *Electronic Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Rates, a Certificate of Public Convenience and Necessity to Deploy Advanced Metering Infrastructure, Approval of Certain*

services, each with its own tariffed rate.[22] *Schedule 1: Scheduling, System Control and Dispatch* relates to fixed dispatch center costs that cannot be avoided by increased or decreased generation on the system. *Schedule 4: Energy Imbalance Service* is an ancillary service charge that applies only to differences that occur between the scheduled and actual delivery of energy by a customer transmitting power across the Companies' transmission system. Therefore, costs recovered under Schedule 4 cannot possibly be avoided by energy supplied to the grid by customer-generators. Similarly, *Schedule 9: Generator Imbalance Service* applies only to differences that occur between the output of a generator located in the Transmission Owner's Balancing Authority and a delivery schedule provided by the generator. Therefore, costs recovered under Schedule 9 cannot possibly be avoided by energy supplied to the grid by customer-generators.

Schedule 2: Reactive Supply and Voltage Control recovers costs of specific components of a generator that can provide reactive power (VAR). Therefore, to the extent that the cost of a generator is avoided, whether it is a conventional generator or otherwise, the avoided cost of the components that could supply VARs would also be avoided. Therefore, an additional avoided cost for reactive power should not be added beyond what is recovered through an avoided generation capacity component. In other words, the avoided cost of reactive power is embedded in the avoided generation capacity cost.

Regulatory and Accounting Treatments, and Establishment of a One-Year Surcredit, Case No. 2020-00350, Supplemental Testimony of W. Steven Seelye at 13-22 (July 13, 2021); Case Nos. 2020-00349 and 2020-00350, Supplemental Rebuttal Testimony of W. Steven Seelye at 32-34 (Aug. 5, 2021).

[22] The nine tariffed OATT ancillary services are: (1) Schedule 1: Scheduling, System Control and Dispatch; (2) Schedule 2: Reactive Supply and Voltage Control; (3) Schedule 3: Regulation and Frequency Response; (4) Schedule 4: Energy Imbalance Service; (5) Schedule 5: Spinning Reserve Service; (6) Schedule 6: Operating Reserve Service; and (7) Schedule 9: Generator Imbalance Service.

An argument can be made that the costs related to *Schedule 3: Regulation and Frequency Response*, *Schedule 5: Spinning Reserve Service*, and *Schedule 6: Operating Reserve Service* could be avoided if generation capacity costs are deemed to be avoidable. In the Companies' Open Access Transmission Tariff ("OATT") approved by FERC, these three ancillary service rates are calculated as a specified percentage of the Companies' fixed generation capacity costs. Because it is the Companies' conclusion that customer-generators providing excess energy under NMS-2 do not avoid any generation capacity cost, it is also the Companies conclusion that the avoided cost related to these three ancillary services is also zero.

Q. What is the appropriate value for the avoided carbon cost component of the Rider NMS-2 compensation rate?

A. The appropriate value for the avoided carbon cost component of the Rider NMS-2 compensation rate is zero. Because there is currently no carbon price for the Companies' carbon emissions—and the recently finalized federal greenhouse gas regulations applicable to the Companies' operations would not create a carbon price—Rider NMS-2 customers' energy exports avoid *zero* carbon cost. If this changes in the future, the Companies can update this Rider NMS-2 component. But the appropriate Rider NMS-2 avoided carbon cost component for the foreseeable future, and certainly for the forecasted test year in these proceedings, is zero.

Q. What is the appropriate value for the avoided environmental compliance cost component of the Rider NMS-2 compensation rate?

A. The appropriate value for the avoided environmental compliance cost component of the Rider NMS-2 compensation rate is zero. Based on how the Companies are recommending calculating avoided energy and capacity costs, there is no need for a separate avoided environmental compliance cost component of NMS-2 compensation. This is true for several reasons. First, variable environmental compliance costs, i.e., those that vary with energy production, are already accounted for in the avoided energy cost calculations. Second, any avoided costs driven by environmental regulatory changes that affect generation capacity decisions are already reflected in the avoided generation capacity cost component. Third, environmental compliance costs reflected in capital improvements at a unit (e.g., installing a selective catalytic reduction system) would be unaffected by energy exported to the grid by a customer-generator. Thus, any non-zero Rider NMS-2 avoided environmental compliance cost component would double-count any such avoided costs and would harm other customers.

SECTION 9: SCHEDULE D-1 SUPPORT

Q. Does your testimony support the Jurisdictional Adjustments to the base period for Operating Revenues from Sales of Electricity in Schedule D-1?

A. Yes. For the reasons I have stated, the volumetric differences in both KU's and LG&E's electric and gas load forecasts are the major reason for the differences in Operating Revenues from Sales of Electricity (Account Nos. 440, 442.2, 442.3, 444, and 445) between the base period and the forecasted test period.

Q. In Schedule D-1, what revenues and expenses are included in Sales for Resale (Account No. 447) and Purchased Power (Account No. 555)?

A. Sales for Resale contains intercompany sales revenue. Purchased Power contains intercompany purchased power expense, market economy purchased power expense, and Ohio Valley Electric Corporation ("OVEC") purchase power expense. Intercompany sales revenue for one company in Account No. 447 equals the intercompany purchased power expense for the other company in Account No. 555. Off-System Sales ("OSS") revenues recorded to Account No. 447 and OSS-related purchased power expenses recorded to Account No. 555 have been removed with a pro forma adjustment.

Q. What are the differences in Sales for Resale and Purchased Power between the base period and the forecasted test period?

A. Compared to the base period, KU's Sales for Resale in the forecasted test period are expected to increase slightly by $1.2 million, from $10 million to $11.2 million; LG&E's Sales for Resale in the forecasted test period are expected to increase by $3.8 million, from $26.0 million to $29.8 million. These variances fluctuate by month and can be caused by differences in fuel prices, weather, and planned outages.

Compared to the base period, KU's Purchased Power is expected to be slightly higher by $0.9 million; LG&E's Purchased Power in the forecasted test period is expected to be lower by $4.7 million. The decrease in LG&E's Purchased Power is primarily explained by a decrease in OVEC purchased power.

SECTION 10: REQUEST FOR RELIEF FROM ANNUAL RTO MEMBERSHIP STUDY FILING REQUIREMENT

Q. Briefly, what is the history of the current requirement for the Companies to file a study of RTO membership every year?

A. The Commission's final orders in the Companies' 2018 base rate cases directed the Companies to file an updated RTO membership study annually by March 31 each year.[23] The Commission later issued orders in the same case dockets authorizing the

[23] *Electronic Application of Kentucky Utilities Company for an Adjustment of Its Electric Rates*, Case No. 2018-00294, Order (Ky. PSC Apr. 30, 2019); *Electronic Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Rates*, Case No. 2018-00295, Order (Ky. PSC Apr. 30, 2019).

Companies to file their annual RTO study by October 31 each year but denying the Companies' request to file RTO membership studies triennially with their IRP filings rather than annually.[24]

Q. Why would it be reasonable for the Commission to relieve the Companies of the annual RTO study filing requirement in favor of filing such a study triennially with the Companies' IRP filing?

A. Like the Companies' triennial IRP, conducting the RTO membership study is a significant undertaking, and it is best conducted in the context of the global planning effort of an IRP. Moreover, because RTO markets and rules are still in a considerable amount of flux, there is little value in refreshing the analysis annually; rather, allowing more time between analyses for markets and rules, particularly those for RTO capacity markets, to develop, settle, and mature should result in more robust and reliable analyses. Therefore, the Companies' request to move from annual RTO membership filings to triennial filings with each IRP is reasonable.

Q. Does this conclude your testimony?

A. Yes, it does.

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[24] Case Nos. 2018-00294 and 2018-00295, Order (Ky. PSC Feb. 18, 2021); Case Nos. 2018-00294 and 2018-00295, Order (Ky. PSC Mar. 22, 2021).

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

The undersigned, **Charles R. Schram**, being duly sworn, deposes and says that he is Vice President – Energy Supply and Analysis for Kentucky Utilities Company and Louisville Gas and Electric Company and an employee of LG&E and KU Services Company, that he has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of his information, knowledge, and belief.

Charles R. Schram

Charles R. Schram

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 27th day of May 2025.

Caroline J. Davison

Notary Public

Notary Public ID No. KYNP63286

My Commission Expires:

January 22, 2027

CAROLINE J. DAVISON
COMM EXPIRES 01/22/2027
NOTARY PUBLIC
ID # KYNP63286
STATE AT LARGE, KENTUCKY

APPENDIX A

Charles R. Schram

Vice President, Energy Supply and Analysis
LG&E and KU Services Company
2701 Eastpoint Parkway
Louisville, Kentucky 40223

Professional Experience

LG&E and KU

Vice President, Energy Supply and Analysis	2025 – Present
Director, Power Supply	2016 – 2025
Director, Energy Planning, Analysis & Forecasting	2008 – 2016
Manager, Transmission Protection & Substations	2006 – 2008
Manager, Business Development	2005 – 2006
Manager, Strategic Planning	2001 – 2005
Manager, Distribution System Planning & Eng.	2000 – 2001
Manager, Electric Metering	1997 – 2000
Information Technology Analyst	1995 – 1997

U.S. Department of Defense – Naval Ordnance Station

Manager, Software Integration	1993 – 1995
Electronics Engineer	1984 – 1993

Education

Master of Business Administration
University of Louisville, 1995

Bachelor of Science – Electrical Engineering
University of Louisville, 1984

E.ON Academy General Management Program: 2002-2003

Center for Creative Leadership, Leadership Development Program: 1998

Civic Activities

The Housing Partnership – Board of Directors, 2017 – Present

Leadership Louisville – Bingham Fellows class of 2020

Comparison of KU Electric Customers, Billing Demand, and Energy by Rate Classes: Base Period vs Test Period

					Base Period					
					Billed Actual	Calendar Forecasted	Total	Forecasted Test Period		
Rate	Category	Values		Period	(Sep '24 - Feb '25)*	(Mar '25 - Aug '25)	(Sep '24 - Aug '25)	(Jan '26 - Dec '26)	Difference	% Difference
KU RETAIL										
AES	Customers	Avg Number of Customers			396	390	393	385	(8)	-2.2%
	Energy	Sum of Volume	GWh		66	56	121	118	(3)	-2.3%
EV_Charge	Customers	Avg Number of Customers			10	14	12	14	2	16.7%
	Energy	Sum of Volume	GWh		0	0	-	0	0	0.0%
FLS	Customers	Avg Number of Customers			1	1	1	1	-	0.0%
	Demand	Sum of Volume	MVA	Base	1,250	1,249	2,499	2,505	6	0.2%
	Demand	Sum of Volume	MVA	Intermediate	1,204	1,234	2,437	2,454	17	0.7%
	Demand	Sum of Volume	MVA	Peak	849	855	1,704	1,701	(3)	-0.2%
	Energy	Sum of Volume			259	277	537	531	(6)	-1.2%
GS	Customers	Avg Number of Customers			85,768	86,202	85,985	86,536	551	0.6%
	Energy	Sum of Volume	GWh		899	866	1,765	1,720	(45)	-2.5%
GTOD	Customers	Avg Number of Customers			41	1	21	1	(20)	-95.2%
	Demand	Sum of Volume	MW	Base	1	0	2	0	(2)	-76.0%
	Demand	Sum of Volume	MW	Peak	1	0	1	0	(1)	-53.2%
	Energy	Sum of Volume	GWh		1	0	1	0	(1)	-76.4%
OSL	Customers	Avg Number of Customers			6	6	6	6	-	0.0%
	Demand	Sum of Volume	MW	Base	5	5	10	9	(1)	-9.4%
	Demand	Sum of Volume	MW	Peak	2	1	3	3	(0)	-16.6%
	Energy	Sum of Volume	GWh		0	0	-	0	0	0.0%
PS-Pri	Customers	Avg Number of Customers			202	199	200	198	(2)	-1.0%
	Demand	Sum of Volume	MW	Base	130	132	262	258	(4)	-1.5%
	Energy	Sum of Volume	GWh		42	44	85	83	(2)	-2.1%
PS-Sec	Customers	Avg Number of Customers			4,107	4,051	4,079	4,007	(72)	-1.8%
	Demand	Sum of Volume	MW	Base	2,489	2,422	4,911	4,816	(95)	-1.9%
	Energy	Sum of Volume	GWh		782	768	1,550	1,463	(87)	-5.6%
RS	Customers	Avg Number of Customers			454,264	455,893	455,078	459,320	4,242	0.9%
	Energy	Sum of Volume	GWh		3,252	2,755	6,007	5,980	(27)	-0.4%
RTOD	Customers	Avg Number of Customers			111	106	109	107	(2)	-1.6%
	Demand	Sum of Volume	MW	Base	0	0	-	0	0	0.0%
	Demand	Sum of Volume	MW	Peak	0	0	-	0	0	0.0%
	Energy	Sum of Volume	GWh		1	1	2	2	(0)	-19.9%
RTS	Customers	Avg Number of Customers			20	20	20	21	1	5.0%
	Demand	Sum of Volume	MVA	Base	2,061	1,774	3,835	3,725	(110)	-2.9%
	Demand	Sum of Volume	MVA	Intermediate	1,701	1,649	3,350	3,514	164	4.9%
	Demand	Sum of Volume	MVA	Peak	1,658	1,631	3,289	3,467	178	5.4%
	Energy	Sum of Volume	GWh		835	816	1,651	1,862	211	12.8%
Special Contract	Customers	Avg Number of Customers			-	1	1	1	-	0.0%
	Demand	Sum of Volume	MVA	Base	-	840	840	3,120	2,280	271.4%
	Demand	Sum of Volume	MVA	Intermediate	-	832	832	1,663	831	99.9%
	Demand	Sum of Volume	MVA	Peak	-	823	823	1,646	823	100.0%
	Energy	Sum of Volume	GWh		-	560	560	1,104	544	97.1%
TOD-Pri	Customers	Avg Number of Customers			263	267	265	266	1	0.3%
	Demand	Sum of Volume	MVA	Base	5,371	5,414	10,784	10,815	31	0.3%
	Demand	Sum of Volume	MVA	Intermediate	4,223	4,461	8,685	8,716	31	0.4%
	Demand	Sum of Volume	MVA	Peak	4,164	4,390	8,554	8,580	26	0.3%
	Energy	Sum of Volume			1,920	2,066	3,986	3,963	(23)	-0.6%
TOD-Sec	Customers	Avg Number of Customers			810	795	803	809	6	0.8%
	Demand	Sum of Volume	MVA	Base	3,212	3,172	6,384	6,373	(11)	-0.2%
	Demand	Sum of Volume	MVA	Intermediate	2,438	2,457	4,895	4,836	(59)	-1.2%
	Demand	Sum of Volume	MVA	Peak	2,377	2,402	4,778	4,720	(58)	-1.2%
	Energy	Sum of Volume	GWh		897	959	1,856	1,840	(16)	-0.8%
Lighting	Customers	Avg Number of Customers			1,311	1,312	1,312	1,312	-	0.0%
	Energy	Sum of Volume	GWh		64	53	116	118	2	1.5%
KU Unbilled Adjustment**										
Residential	Energy	Sum of Volume	GWh		14		14	-	(14)	-100.0%
Other	Energy	Sum of Volume	GWh		(62)		(62)	-	62	-100.0%
Total KU Unbilled	Energy	Sum of Volume	GWh		(47)		(48)	-	48	-100.0%
KU WHOLESALE										
Municipal - Remaining	Customers	Avg Number of Customers			2	2	2	2	23	0.0%
	Demand	Sum of Volume	MW	Base	359	390	748	771	7	3.1%
	Energy	Sum of Volume	GWh		181	194	375	382	7	2.0%

Total KU KY Retail Energy - Calendar Adjusted	Energy	Sum of Volume	GWh		8,970	9,220	18,189	18,785	596	3.3%
Total KU KY Energy - Calendar Adjusted	Energy	Sum of Volume	GWh		9,151	9,414	18,565	19,167	602	3.2%
Total KU Customers	Customers	Avg Number of Customers			547,310	549,257	548,285	552,984	4,699	0.9%

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**Billed sales in September include a portion of the energy consumed in September and a portion of the energy consumed in August. Likewise, billed sales for February include a portion of the energy consumed in February and a portion of the energy consumed in January. The portion of the energy consumed in February but not included in February billed sales is the "unbilled" portion of calendar-month ("calendar") sales for February. To properly compare the Base Period to the Forecasted Test Period (which includes twelve months of calendar sales), unbilled sales for February must be added to the Base Period and unbilled sales for August (which are included in September billed sales) must be subtracted from the Base Period. Because August unbilled sales are greater than February unbilled sales, the total unbilled sales adjustment is negative.

Comparison of LG&E Electric Customers, Billing Demand, and Energy by Rate Classes: Base Period vs Test Period

					Base Period			Forecasted Test		
Rate	**Category**	**Values**		**Period**	**Billed Actual (Sep '24 - Feb '25)***	**Calendar Forecasted (Mar '25 - Aug '25)**	**Total (Sep '24 - Aug '25)**	**Period (Jan '26 - Dec '26)**	**Difference**	**% Difference**
PS-Pri	Customers	Avg Number of Customers			60	60	60	60	(0)	-0.6%
	Demand	Sum of Volume	MW	Base	84	92	176	177	1	0.4%
	Energy	Sum of Volume	GWh		29	30	59	59	(0)	-0.3%
PS-Sec	Customers	Avg Number of Customers			2,606	2,584	2,595	2,575	(20)	-0.8%
	Demand	Sum of Volume	MW	Base	1,857	1,905	3,762	3,705	(57)	-1.5%
	Energy	Sum of Volume	GWh		627	679	1,306	1,254	(52)	-3.9%
TOD-Pri	Customers	Avg Number of Customers			138	136	137	136	(1)	-1.0%
	Demand	Sum of Volume	MVA	Base	2,587	2,585	5,172	5,169	(3)	-0.1%
	Demand	Sum of Volume	MVA	Intermediate	2,065	2,178	4,242	4,266	24	0.6%
	Demand	Sum of Volume	MVA	Peak	2,021	2,142	4,163	4,190	27	0.6%
	Energy	Sum of Volume	GWh		937	1,024	1,960	1,961	1	0.1%
TOD-Sec	Customers	Avg Number of Customers			591	582	587	584	(3)	-0.6%
	Demand	Sum of Volume	MVA	Base	2,384	2,378	4,762	4,806	44	0.9%
	Demand	Sum of Volume	MVA	Intermediate	1,750	1,826	3,575	3,629	54	1.5%
	Demand	Sum of Volume	MVA	Peak	1,704	1,779	3,482	3,534	52	1.5%
	Energy	Sum of Volume	GWh		681	697	1,379	1,347	(32)	-2.3%
Special Contract	Customers	Avg Number of Customers			2	2	2	2	-	0.0%
	Demand	Sum of Volume	MW	Base	56	58	114	115	1	1.0%
	Energy	Sum of Volume	GWh		33	32	65	64	(1)	-0.8%
GS	Customers	Avg Number of Customers			47,965	48,143	48,054	48,371	317	0.7%
	Energy	Sum of Volume	GWh		583	633	1,216	1,176	(40)	-3.3%
GTOD	Customers	Avg Number of Customers			55	4	30	4	(26)	-86.5%
	Demand	Sum of Volume	MW	Base	3	0	3	1	(2)	-68.0%
	Demand	Sum of Volume	MW	Peak	2	0	3	1	(2)	-70.0%
	Energy	Sum of Volume	GWh		1	0	1	0	(1)	-51.0%
EV Charge	Customers	Avg Number of Customers			11	14	13	14	1	7.7%
	Energy	Sum of Volume	GWh		0	0	-	0	0	0.0%
OSL	Customers	Avg Number of Customers			1	1	1	1	-	0.0%
	Demand	Sum of Volume	MW	Base	1	1	2	2	0	20.8%
	Demand	Sum of Volume	MW	Peak	0	0	-	0	0	0.0%
	Energy	Sum of Volume	GWh		0	0	-	0	0	0.0%
RS	Customers	Avg Number of Customers			390,718	392,935	391,827	395,712	3,885	1.0%
	Energy	Sum of Volume	GWh		2,069	2,191	4,261	4,112	(149)	-3.5%
RTOD	Customers	Avg Number of Customers			142	140	141	141	0	0.3%
	Demand	Sum of Volume	MW	Base	0	1	1	1	0	2.8%
	Demand	Sum of Volume	MW	Peak	0	0	1	1	(0)	-10.3%
	Energy	Sum of Volume	GWh		1	1	2	2	0	11.4%
RTS	Customers	Avg Number of Customers			13	13	13	13	-	0.0%
	Demand	Sum of Volume	MVA	Base	1,113	1,115	2,228	2,229	1	0.0%
	Demand	Sum of Volume	MVA	Intermediate	978	975	1,953	1,928	(25)	-1.3%
	Demand	Sum of Volume	MVA	Peak	869	898	1,767	1,774	7	0.4%
	Energy	Sum of Volume	GWh		476	543	1,019	1,052	33	3.3%
Lighting	Customers	Avg Number of Customers			1,595	1,723	1,659	1,723	64	3.9%
	Energy	Sum of Volume	GWh		51	43	94	95	1	1.3%
LG&E Unbilled Adjustment**										
Residential	Energy	Sum of Volume	GWh		(89)		(89)		89	-100.0%
Other	Energy	Sum of Volume	GWh		(102)		(102)		102	-100.0%
Total LG&E Unbilled	Energy	Sum of Volume	GWh		(191)		(191)		191	-100.0%
Total LG&E Energy - Calendar Adjusted	Energy	Sum of Volume	GWh		5,300	5,873	11,171	11,126	(45)	-0.4%
Total LGE Customers	Customers	Avg Number of Customers			443,841	446,333	445,089	449,331	4,242	1.0%

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Comparison of LG&E Gas Customers, and Volumes by Rate Classes: Base Period vs Test Period

				Base Period					
				Billed Actual	Calendar Forecasted	Total	Forecasted Test Period		
Rate	Category	Volume Type	Values	(Sep '24 - Feb '25)*	(Mar '25 - Aug '25)	(Sep '24 - Aug '25)	(Jan '26 - Dec '26)	Difference	% Difference
As-Available Gas Service, Commercial	Customers	Sales	Average Number of Customers	1	1	1	1	-	0.0%
	Gas Volumes	Sales	Volume (Mcf)	12,124	8,911	21,035	20,960	(75)	-0.4%
As-Available Gas Service, Industrial	Customers	Sales	Average Number of Customers	1	1	1	1	-	0.0%
	Gas Volumes	Sales	Volume (Mcf)	11,120	18,097	29,217	31,040	1,823	6.2%
Distributed Generation Gas Service	Customers	Sales	Average Number of Customers	8	7	8	7	(1)	-12.5%
	Demand	Sales	Billed Demand (Mcf)	3,489	2,344	5,832	4,687	(1,145)	-19.6%
	Gas Volumes	Sales	Volume (Mcf)	43	32	76	59	(17)	-22.8%
Commercial Gas Service	Customers	Sales	Average Number of Customers	25,334	25,987	25,661	26,053	392	1.5%
	Gas Volumes	Sales	Volume (Mcf)	6,544,063	3,148,764	9,692,827	10,503,398	810,571	8.4%
Industrial Gas Service	Customers	Sales	Average Number of Customers	215	215	215	216	1	0.2%
	Gas Volumes	Sales	Volume (Mcf)	724,079	511,479	1,235,558	1,273,082	37,524	3.0%
Gas Special Contracts - LG&E Generation	Customers	Generation	Average Number of Customers	1	1	1	1	-	0.0%
	Gas Volumes	Generation	Volume (Mcf)	138,308	114,491	252,799	239,089	(13,711)	-5.4%
Gas Transport Service, FT	Customers	Transport	Average Number of Customers	79	79	79	79	-	0.0%
	Demand	Transport	Billed Demand (Mcf)	563,706	576,559	1,140,265	1,199,292	59,027	5.2%
	Gas Volumes	Transport	Volume (Mcf)	8,184,648	7,998,382	16,183,030	17,602,553	1,419,523	8.8%
Residential Gas Service	Customers	Sales	Average Number of Customers	305,025	306,280	305,652	307,249	1,597	0.5%
	Gas Volumes	Sales	Volume (Mcf)	11,825,744	5,360,085	17,185,830	19,075,214	1,889,384	11.0%
Substitute Gas Sales Service	Customers	Sales	Average Number of Customers	1	1	1	1	-	0.0%
	Demand	Sales	Billed Demand (Mcf)	6,036	7,774	13,810	15,547	1,737	12.6%
	Gas Volumes	Sales	Volume (Mcf)	7,627	381	8,007	4,750	(3,257)	-40.7%
TS-2: Gas Transport/Firm Balancing (IGS)	Customers	Transport	Average Number of Customers	9	9	9	9	-	0.0%
	Gas Volumes	Transport	Volume (Mcf)	169,236	231,639	400,875	400,000	(875)	-0.2%
LG&E Gas Unbilled Adjustment**						-			
Residential	Gas Volumes	Sales	Volume (Mcf)	1,592,558		1,592,558		(1,592,558)	-100.0%
Other	Gas Volumes	Sales	Volume (Mcf)	984,943		984,943		(984,943)	-100.0%
Total LGE Gas Unbilled	Gas Volumes	Sales	Volume (Mcf)	2,577,501		2,577,501		(2,577,501)	-100.0%

Total Volumes - Calendar Adjusted	Gas Volumes	Total	Volume (Mcf)	30,194,494	17,392,261	47,586,755	49,150,144	1,563,389	3.3%
Total Customers	Customers	Total	Average Number of Customers	330,674	332,581	331,628	333,616	1,988	0.6%
Total Sales Volumes - Calendar Adjusted	Gas Volumes	Sales	Volume (Mcf)	21,702,301	9,047,749	30,750,051	30,908,502	158,451	0.5%
Total Customers	Customers	Sales	Average Number of Customers	330,585	332,492	331,539	333,527	1,988	0.6%
Total Transport Volumes	Gas Volumes	Transport	Volume (Mcf)	8,353,884	8,230,021	16,583,905	18,002,553	1,418,648	8.6%
Total Customers	Customers	Transport	Average Number of Customers	88	88	88	88	-	0.0%
Total Generation Volumes	Gas Volumes	Generation	Volume (Mcf)	138,308	114,491	252,799	239,089	(13,711)	-5.4%
Total Customers	Customers	Generation	Average Number of Customers	1	1	1	1	-	0.0%

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	KY Real Gross State Product (GSP) Millions of 2017 US$, SAAR	KY Employment, Manufacturing Thousand	KY Employment, Non-Manufacturing Thousand	KY Industrial Production Index, Mining (2017=100)	Real Median Household Income Thousands of 2017 US$, SAAR
1/1/2010	185,687.67	207.56	1,541.76	171.00	49.99
2/1/2010	185,429.29	206.94	1,540.21	170.78	49.62
3/1/2010	185,170.91	206.33	1,538.67	170.56	49.26
4/1/2010	186,772.48	207.28	1,543.56	170.54	49.26
5/1/2010	188,374.05	208.22	1,548.44	170.52	49.27
6/1/2010	189,975.62	209.17	1,553.33	170.50	49.27
7/1/2010	191,056.88	209.33	1,552.44	170.90	49.25
8/1/2010	192,138.14	209.50	1,551.56	171.29	49.24
9/1/2010	193,219.40	209.67	1,550.67	171.69	49.22
10/1/2010	193,266.00	210.24	1,553.96	171.37	49.06
11/1/2010	193,312.59	210.82	1,557.24	171.06	48.90
12/1/2010	193,359.19	211.40	1,560.53	170.74	48.74
1/1/2011	192,408.89	211.31	1,561.30	169.98	48.95
2/1/2011	191,458.60	211.22	1,562.07	169.22	49.17
3/1/2011	190,508.31	211.13	1,562.83	168.46	49.38
4/1/2011	190,842.15	211.43	1,564.14	168.67	49.27
5/1/2011	191,175.98	211.73	1,565.46	168.88	49.15
6/1/2011	191,509.82	212.03	1,566.77	169.09	49.04
7/1/2011	191,697.07	212.16	1,569.60	168.74	48.94
8/1/2011	191,884.32	212.28	1,572.43	168.40	48.84
9/1/2011	192,071.57	212.40	1,575.27	168.05	48.74
10/1/2011	193,394.69	213.46	1,576.37	168.57	48.66
11/1/2011	194,717.81	214.51	1,577.47	169.08	48.57
12/1/2011	196,040.93	215.57	1,578.57	169.59	48.49
1/1/2012	195,900.40	216.44	1,581.62	168.70	48.50
2/1/2012	195,759.87	217.32	1,584.68	167.81	48.50
3/1/2012	195,619.35	218.20	1,587.73	166.92	48.51
4/1/2012	195,856.73	219.56	1,588.14	162.73	48.47
5/1/2012	196,094.11	220.91	1,588.56	158.55	48.43
6/1/2012	196,331.50	222.27	1,588.97	154.37	48.38
7/1/2012	196,040.37	223.33	1,587.79	151.36	48.33
8/1/2012	195,749.25	224.40	1,586.61	148.34	48.28
9/1/2012	195,458.12	225.47	1,585.43	145.33	48.24
10/1/2012	194,856.09	226.13	1,586.56	143.40	48.49
11/1/2012	194,254.05	226.80	1,587.68	141.46	48.74
12/1/2012	193,652.02	227.47	1,588.80	139.53	48.99
1/1/2013	195,799.00	227.80	1,590.68	137.67	49.28
2/1/2013	197,945.98	228.13	1,592.56	135.81	49.58
3/1/2013	200,092.97	228.47	1,594.43	133.95	49.88
4/1/2013	199,514.28	228.60	1,595.01	134.28	50.00
5/1/2013	198,935.59	228.73	1,595.59	134.61	50.11
6/1/2013	198,356.90	228.87	1,596.17	134.94	50.23
7/1/2013	198,571.21	228.60	1,598.92	135.25	50.13
8/1/2013	198,785.52	228.33	1,601.68	135.56	50.03
9/1/2013	198,999.84	228.07	1,604.43	135.87	49.93
10/1/2013	198,807.73	229.03	1,605.99	134.52	49.63
11/1/2013	198,615.63	230.00	1,607.54	133.17	49.32
12/1/2013	198,423.52	230.97	1,609.10	131.82	49.01
1/1/2014	198,124.91	231.39	1,609.38	131.91	48.93
2/1/2014	197,826.31	231.81	1,609.66	132.01	48.85
3/1/2014	197,527.70	232.23	1,609.93	132.10	48.76
4/1/2014	198,200.82	232.92	1,613.24	133.79	48.59
5/1/2014	198,873.94	233.61	1,616.56	135.49	48.42
6/1/2014	199,547.06	234.30	1,619.87	137.19	48.25
7/1/2014	199,583.58	234.94	1,622.46	137.48	48.18
8/1/2014	199,620.09	235.59	1,625.04	137.77	48.12
9/1/2014	199,656.61	236.23	1,627.63	138.06	48.06
10/1/2014	199,429.40	236.72	1,629.33	138.31	48.30
11/1/2014	199,202.19	237.21	1,631.03	138.56	48.54
12/1/2014	198,974.97	237.70	1,632.73	138.80	48.78
1/1/2015	199,050.70	238.28	1,633.30	135.29	49.25
2/1/2015	199,126.42	238.86	1,633.87	131.79	49.71
3/1/2015	199,202.14	239.43	1,634.43	128.28	50.17
4/1/2015	199,823.85	239.63	1,636.38	125.66	50.46
5/1/2015	200,445.57	239.83	1,638.32	123.05	50.75
6/1/2015	201,067.29	240.03	1,640.27	120.43	51.04
7/1/2015	200,998.17	240.60	1,642.33	119.60	51.22
8/1/2015	200,929.05	241.17	1,644.40	118.76	51.39
9/1/2015	200,859.93	241.73	1,646.47	117.93	51.56
10/1/2015	201,006.24	242.62	1,649.69	115.38	51.79
11/1/2015	201,152.55	243.51	1,652.91	112.83	52.02

12/1/2015	201,298.86	244.40	1,656.13	110.28	52.25
1/1/2016	200,498.81	244.97	1,656.19	107.07	52.21
2/1/2016	199,698.76	245.53	1,656.24	103.85	52.18
3/1/2016	198,898.71	246.10	1,656.30	100.63	52.15
4/1/2016	199,847.31	246.74	1,656.53	98.14	52.18
5/1/2016	200,795.91	247.39	1,656.77	95.65	52.22
6/1/2016	201,744.50	248.03	1,657.00	93.16	52.26
7/1/2016	202,431.13	248.64	1,659.33	92.83	52.42
8/1/2016	203,117.76	249.26	1,661.67	92.50	52.59
9/1/2016	203,804.39	249.87	1,664.00	92.17	52.76
10/1/2016	203,732.34	249.81	1,663.63	93.08	52.76
11/1/2016	203,660.29	249.76	1,663.27	93.99	52.77
12/1/2016	203,588.24	249.70	1,662.90	94.91	52.78
1/1/2017	203,202.43	249.84	1,664.50	97.09	52.95
2/1/2017	202,816.63	249.99	1,666.10	99.27	53.13
3/1/2017	202,430.82	250.13	1,667.70	101.46	53.30
4/1/2017	202,792.31	250.33	1,667.86	101.59	53.40
5/1/2017	203,153.79	250.53	1,668.01	101.73	53.49
6/1/2017	203,515.28	250.73	1,668.17	101.87	53.59
7/1/2017	203,757.60	250.60	1,668.04	100.86	53.73
8/1/2017	203,999.92	250.47	1,667.92	99.85	53.87
9/1/2017	204,242.24	250.33	1,667.80	98.85	54.01
10/1/2017	204,745.67	250.43	1,670.13	98.46	54.19
11/1/2017	205,249.10	250.53	1,672.47	98.08	54.36
12/1/2017	205,752.52	250.63	1,674.80	97.69	54.53
1/1/2018	205,379.25	250.76	1,674.31	97.06	54.65
2/1/2018	205,005.97	250.88	1,673.82	96.42	54.76
3/1/2018	204,632.70	251.00	1,673.33	95.78	54.88
4/1/2018	205,159.03	251.19	1,675.94	98.17	55.05
5/1/2018	205,685.37	251.38	1,678.56	100.56	55.21
6/1/2018	206,211.70	251.57	1,681.17	102.95	55.38
7/1/2018	206,141.30	251.53	1,680.56	104.46	55.44
8/1/2018	206,070.90	251.50	1,679.94	105.97	55.49
9/1/2018	206,000.50	251.47	1,679.33	107.49	55.54
10/1/2018	206,305.50	251.83	1,680.00	108.47	55.64
11/1/2018	206,610.50	252.20	1,680.67	109.46	55.73
12/1/2018	206,915.50	252.57	1,681.33	110.45	55.82
1/1/2019	207,482.87	252.56	1,682.73	111.71	56.19
2/1/2019	208,050.23	252.54	1,684.13	112.97	56.55
3/1/2019	208,617.60	252.53	1,685.53	114.23	56.92
4/1/2019	209,374.23	252.44	1,687.22	114.13	56.84
5/1/2019	210,130.87	252.36	1,688.91	114.04	56.76
6/1/2019	210,887.50	252.27	1,690.60	113.95	56.68
7/1/2019	211,502.70	252.50	1,692.70	112.06	56.57
8/1/2019	212,117.90	252.73	1,694.80	110.17	56.46
9/1/2019	212,733.10	252.97	1,696.90	108.28	56.36
10/1/2019	213,395.57	252.36	1,697.40	109.24	56.22
11/1/2019	214,058.03	251.74	1,697.90	110.21	56.07
12/1/2019	214,720.50	251.13	1,698.40	111.17	55.93
1/1/2020	213,599.40	250.74	1,698.54	107.41	56.00
2/1/2020	212,478.30	250.36	1,698.69	103.65	56.07
3/1/2020	211,357.20	249.97	1,698.83	99.90	56.14
4/1/2020	204,823.77	238.54	1,632.17	90.77	58.13
5/1/2020	198,290.33	227.12	1,565.50	81.64	60.12
6/1/2020	191,756.90	215.70	1,498.83	72.51	62.11
7/1/2020	198,170.60	222.58	1,531.54	75.65	60.43
8/1/2020	204,584.30	229.46	1,564.26	78.79	58.75
9/1/2020	210,998.00	236.33	1,596.97	81.93	57.07
10/1/2020	211,013.03	237.48	1,603.40	83.07	56.42
11/1/2020	211,028.07	238.62	1,609.83	84.21	55.76
12/1/2020	211,043.10	239.77	1,616.27	85.34	55.10
1/1/2021	211,797.27	240.62	1,622.78	87.66	57.39
2/1/2021	212,551.43	241.48	1,629.29	89.97	59.67
3/1/2021	213,305.60	242.33	1,635.80	92.29	61.95
4/1/2021	213,434.33	242.06	1,641.34	93.40	59.83
5/1/2021	213,563.07	241.78	1,646.89	94.52	57.71
6/1/2021	213,691.80	241.50	1,652.43	95.63	55.59
7/1/2021	213,882.00	242.09	1,656.91	95.36	55.47
8/1/2021	214,072.20	242.68	1,661.39	95.10	55.35
9/1/2021	214,262.40	243.27	1,665.87	94.83	55.23
10/1/2021	215,175.10	243.91	1,673.36	95.51	55.23
11/1/2021	216,087.80	244.56	1,680.84	96.18	55.23
12/1/2021	217,000.50	245.20	1,688.33	96.86	55.23
1/1/2022	216,781.43	245.88	1,691.38	97.15	55.64
2/1/2022	216,562.37	246.56	1,694.42	97.44	56.05
3/1/2022	216,343.30	247.23	1,697.47	97.73	56.45
4/1/2022	216,518.23	248.88	1,701.24	98.80	56.51

5/1/2022	216,693.17	250.52	1,705.02	99.87	56.57
6/1/2022	216,868.10	252.17	1,708.80	100.95	56.63
7/1/2022	217,313.97	252.94	1,713.66	102.08	56.63
8/1/2022	217,759.83	253.72	1,718.51	103.21	56.62
9/1/2022	218,205.70	254.50	1,723.37	104.34	56.62
10/1/2022	218,422.17	254.52	1,727.57	104.12	56.37
11/1/2022	218,638.63	254.54	1,731.77	103.90	56.12
12/1/2022	218,855.10	254.57	1,735.97	103.68	55.86
1/1/2023	220,024.63	254.43	1,742.10	105.02	55.74
2/1/2023	221,194.17	254.30	1,748.23	106.37	55.62
3/1/2023	222,363.70	254.17	1,754.37	107.72	55.49
4/1/2023	222,849.90	255.12	1,755.73	107.19	55.17
5/1/2023	223,336.10	256.08	1,757.10	106.67	54.85
6/1/2023	223,822.30	257.03	1,758.47	106.14	54.53
7/1/2023	224,720.50	257.19	1,760.20	105.89	54.46
8/1/2023	225,618.70	257.34	1,761.93	105.63	54.40
9/1/2023	226,516.90	257.50	1,763.67	105.38	54.33
10/1/2023	227,089.70	257.06	1,764.84	105.79	54.30
11/1/2023	227,662.50	256.61	1,766.02	106.20	54.28
12/1/2023	228,235.30	256.17	1,767.20	106.61	54.25
1/1/2024	228,437.33	256.09	1,769.13	106.67	54.42
2/1/2024	228,639.35	256.01	1,771.07	106.72	54.60
3/1/2024	228,841.38	255.93	1,773.00	106.78	54.77
4/1/2024	229,292.39	255.96	1,777.14	107.10	54.83
5/1/2024	229,743.40	255.99	1,781.29	107.41	54.90
6/1/2024	230,194.41	256.02	1,785.43	107.73	54.97
7/1/2024	230,432.55	255.90	1,787.45	107.66	55.04
8/1/2024	230,670.68	255.78	1,789.48	107.60	55.10
9/1/2024	230,908.82	255.66	1,791.50	107.53	55.17
10/1/2024	231,107.97	255.12	1,792.97	108.22	55.19
11/1/2024	231,307.13	254.59	1,794.45	108.90	55.21
12/1/2024	231,506.28	254.06	1,795.93	109.59	55.23
1/1/2025	231,661.20	252.64	1,797.49	110.34	55.30
2/1/2025	231,816.13	251.22	1,799.04	111.10	55.37
3/1/2025	231,971.05	249.81	1,800.60	111.86	55.44
4/1/2025	232,183.44	248.95	1,801.54	112.43	55.45
5/1/2025	232,395.83	248.09	1,802.48	113.00	55.46
6/1/2025	232,608.22	247.24	1,803.43	113.57	55.48
7/1/2025	232,826.61	246.24	1,804.18	113.84	55.48
8/1/2025	233,045.01	245.23	1,804.93	114.12	55.48
9/1/2025	233,263.40	244.23	1,805.68	114.40	55.49
10/1/2025	233,481.02	243.34	1,806.15	114.81	55.50
11/1/2025	233,698.63	242.45	1,806.61	115.23	55.51
12/1/2025	233,916.25	241.55	1,807.08	115.65	55.51
1/1/2026	234,129.97	241.03	1,807.18	115.93	55.57
2/1/2026	234,343.69	240.50	1,807.29	116.21	55.62
3/1/2026	234,557.41	239.98	1,807.39	116.50	55.68
4/1/2026	234,795.28	239.42	1,807.73	116.60	55.70
5/1/2026	235,033.15	238.87	1,808.07	116.69	55.73
6/1/2026	235,271.02	238.31	1,808.40	116.79	55.75
7/1/2026	235,499.25	237.76	1,808.87	116.83	55.76
8/1/2026	235,727.48	237.20	1,809.33	116.87	55.77
9/1/2026	235,955.71	236.64	1,809.79	116.91	55.78
10/1/2026	236,147.38	236.15	1,810.19	116.67	55.78
11/1/2026	236,339.05	235.66	1,810.58	116.43	55.79
12/1/2026	236,530.73	235.17	1,810.98	116.19	55.80
1/1/2027	236,771.83	234.72	1,811.34	115.96	55.84
2/1/2027	237,012.94	234.26	1,811.71	115.74	55.89
3/1/2027	237,254.05	233.81	1,812.08	115.51	55.93
4/1/2027	237,478.04	233.35	1,812.51	115.48	55.94
5/1/2027	237,702.02	232.88	1,812.94	115.45	55.95
6/1/2027	237,926.00	232.42	1,813.36	115.42	55.97
7/1/2027	238,199.99	232.00	1,813.87	115.18	55.99
8/1/2027	238,473.99	231.58	1,814.37	114.95	56.01
9/1/2027	238,747.98	231.16	1,814.88	114.71	56.03
10/1/2027	238,988.95	230.84	1,815.51	114.38	56.05
11/1/2027	239,229.92	230.51	1,816.15	114.06	56.06
12/1/2027	239,470.89	230.19	1,816.79	113.73	56.08
1/1/2028	239,769.08	229.93	1,817.36	113.44	56.13
2/1/2028	240,067.28	229.67	1,817.93	113.15	56.18
3/1/2028	240,365.48	229.41	1,818.50	112.85	56.22
4/1/2028	240,609.59	229.10	1,819.12	112.67	56.25
5/1/2028	240,853.70	228.78	1,819.73	112.50	56.27
6/1/2028	241,097.81	228.47	1,820.35	112.32	56.29
7/1/2028	241,377.55	228.17	1,820.98	112.16	56.32
8/1/2028	241,657.28	227.86	1,821.62	112.01	56.34
9/1/2028	241,937.01	227.56	1,822.25	111.85	56.37

10/1/2028	242,191.03	227.28	1,822.91	111.64	56.40
11/1/2028	242,445.05	227.00	1,823.56	111.42	56.43
12/1/2028	242,699.06	226.73	1,824.22	111.21	56.46
1/1/2029	243,004.28	226.70	1,824.69	111.13	56.53
2/1/2029	243,309.50	226.67	1,825.15	111.05	56.59
3/1/2029	243,614.72	226.64	1,825.61	110.97	56.66
4/1/2029	243,925.43	226.63	1,826.08	110.78	56.70
5/1/2029	244,236.14	226.63	1,826.56	110.59	56.74
6/1/2029	244,546.85	226.63	1,827.03	110.40	56.78
7/1/2029	244,843.93	226.70	1,827.53	110.15	56.82
8/1/2029	245,141.01	226.77	1,828.04	109.91	56.87
9/1/2029	245,438.10	226.84	1,828.55	109.67	56.91
10/1/2029	245,755.37	226.88	1,829.04	109.44	56.96
11/1/2029	246,072.64	226.92	1,829.54	109.21	57.00
12/1/2029	246,389.91	226.96	1,830.04	108.98	57.05
1/1/2030	246,681.57	227.05	1,830.44	108.72	57.12
2/1/2030	246,973.24	227.14	1,830.85	108.46	57.20
3/1/2030	247,264.90	227.22	1,831.25	108.19	57.27
4/1/2030	247,623.45	227.18	1,832.10	107.94	57.31
5/1/2030	247,982.00	227.15	1,832.96	107.69	57.36
6/1/2030	248,340.54	227.11	1,833.81	107.44	57.40
7/1/2030	248,620.24	227.06	1,834.23	107.12	57.44
8/1/2030	248,899.94	227.00	1,834.64	106.80	57.48
9/1/2030	249,179.64	226.95	1,835.06	106.48	57.52
10/1/2030	249,437.07	226.88	1,835.21	106.08	57.54
11/1/2030	249,694.51	226.82	1,835.36	105.68	57.57
12/1/2030	249,951.94	226.75	1,835.51	105.27	57.59
1/1/2031	250,255.48	226.69	1,835.78	105.03	57.65
2/1/2031	250,559.03	226.62	1,836.06	104.78	57.70
3/1/2031	250,862.57	226.55	1,836.34	104.53	57.76
4/1/2031	251,207.63	226.46	1,836.70	104.41	57.79
5/1/2031	251,552.68	226.36	1,837.05	104.28	57.81
6/1/2031	251,897.74	226.27	1,837.41	104.16	57.84
7/1/2031	252,251.48	226.19	1,837.85	104.04	57.87
8/1/2031	252,605.22	226.11	1,838.28	103.93	57.90
9/1/2031	252,958.96	226.02	1,838.71	103.81	57.93
10/1/2031	253,316.88	225.97	1,839.16	103.67	57.96
11/1/2031	253,674.79	225.92	1,839.61	103.54	57.99
12/1/2031	254,032.71	225.86	1,840.06	103.41	58.02
1/1/2032	254,354.23	225.79	1,840.30	103.26	58.08
2/1/2032	254,675.75	225.72	1,840.54	103.11	58.15
3/1/2032	254,997.27	225.65	1,840.78	102.97	58.21
4/1/2032	255,347.34	225.56	1,841.11	102.83	58.24
5/1/2032	255,697.42	225.47	1,841.45	102.69	58.28
6/1/2032	256,047.49	225.37	1,841.78	102.55	58.31
7/1/2032	256,388.94	225.26	1,842.24	102.40	58.35
8/1/2032	256,730.39	225.14	1,842.71	102.26	58.38
9/1/2032	257,071.84	225.02	1,843.17	102.11	58.42
10/1/2032	257,408.58	224.89	1,843.66	101.97	58.45
11/1/2032	257,745.31	224.76	1,844.15	101.84	58.49
12/1/2032	258,082.04	224.63	1,844.64	101.70	58.53
1/1/2033	258,408.16	224.46	1,845.06	101.55	58.59
2/1/2033	258,734.28	224.28	1,845.47	101.39	58.65
3/1/2033	259,060.40	224.11	1,845.88	101.24	58.71
4/1/2033	259,419.40	223.90	1,846.40	101.11	58.75
5/1/2033	259,778.40	223.70	1,846.92	100.98	58.78
6/1/2033	260,137.39	223.49	1,847.44	100.85	58.82
7/1/2033	260,493.28	223.31	1,847.96	100.71	58.85
8/1/2033	260,849.16	223.13	1,848.48	100.58	58.89
9/1/2033	261,205.04	222.95	1,849.00	100.45	58.92
10/1/2033	261,566.20	222.78	1,849.48	100.31	58.96
11/1/2033	261,927.35	222.60	1,849.97	100.18	58.99
12/1/2033	262,288.50	222.43	1,850.45	100.05	59.02
1/1/2034	262,632.18	222.24	1,850.77	99.86	59.08
2/1/2034	262,975.86	222.05	1,851.09	99.68	59.14
3/1/2034	263,319.54	221.85	1,851.41	99.50	59.21
4/1/2034	263,693.98	221.62	1,851.85	99.33	59.24
5/1/2034	264,068.41	221.39	1,852.29	99.16	59.28
6/1/2034	264,442.85	221.15	1,852.72	99.00	59.32
7/1/2034	264,803.92	220.93	1,853.16	98.84	59.36
8/1/2034	265,165.00	220.72	1,853.60	98.68	59.40
9/1/2034	265,526.07	220.50	1,854.04	98.52	59.45
10/1/2034	265,877.69	220.27	1,854.47	98.35	59.49
11/1/2034	266,229.31	220.04	1,854.90	98.18	59.54
12/1/2034	266,580.94	219.81	1,855.32	98.01	59.58
1/1/2035	266,941.06	219.91	1,855.49	97.91	59.64
2/1/2035	267,301.19	220.01	1,855.65	97.81	59.69

3/1/2035	267,661.32	220.10	1,855.81	97.70	59.75
4/1/2035	267,981.37	220.19	1,856.10	97.52	59.79
5/1/2035	268,301.42	220.28	1,856.39	97.34	59.82
6/1/2035	268,621.47	220.36	1,856.67	97.15	59.86
7/1/2035	268,961.69	220.43	1,856.95	96.93	59.89
8/1/2035	269,301.90	220.50	1,857.23	96.72	59.93
9/1/2035	269,642.12	220.57	1,857.50	96.50	59.97
10/1/2035	269,995.54	220.65	1,857.80	96.30	60.01
11/1/2035	270,348.97	220.72	1,858.09	96.11	60.05
12/1/2035	270,702.39	220.80	1,858.38	95.91	60.10
1/1/2036	271,007.31	220.92	1,858.64	95.72	60.17
2/1/2036	271,312.24	221.04	1,858.91	95.53	60.25
3/1/2036	271,617.17	221.16	1,859.17	95.33	60.32
4/1/2036	271,920.71	221.22	1,859.53	95.10	60.36
5/1/2036	272,224.25	221.28	1,859.88	94.87	60.41
6/1/2036	272,527.79	221.35	1,860.24	94.63	60.45
7/1/2036	272,849.10	221.45	1,860.71	94.38	60.50
8/1/2036	273,170.41	221.54	1,861.17	94.13	60.55
9/1/2036	273,491.73	221.64	1,861.63	93.88	60.61
10/1/2036	273,816.12	221.80	1,862.15	93.61	60.66
11/1/2036	274,140.51	221.96	1,862.67	93.35	60.71
12/1/2036	274,464.90	222.12	1,863.19	93.09	60.76
1/1/2037	274,752.38	222.26	1,863.72	92.91	60.84
2/1/2037	275,039.86	222.40	1,864.26	92.73	60.92
3/1/2037	275,327.34	222.54	1,864.79	92.55	61.00
4/1/2037	275,659.97	222.55	1,865.34	92.27	61.05
5/1/2037	275,992.60	222.56	1,865.88	91.99	61.10
6/1/2037	276,325.22	222.56	1,866.43	91.72	61.15
7/1/2037	276,673.74	222.54	1,867.14	91.43	61.21
8/1/2037	277,022.27	222.52	1,867.84	91.15	61.26
9/1/2037	277,370.79	222.50	1,868.55	90.86	61.32
10/1/2037	277,714.76	222.56	1,869.26	90.57	61.37
11/1/2037	278,058.73	222.63	1,869.98	90.27	61.42
12/1/2037	278,402.70	222.69	1,870.69	89.98	61.47
1/1/2038	278,722.95	222.79	1,871.44	89.62	61.55
2/1/2038	279,043.20	222.89	1,872.18	89.27	61.62
3/1/2038	279,363.45	222.99	1,872.93	88.92	61.70
4/1/2038	279,708.63	222.99	1,873.56	88.61	61.75
5/1/2038	280,053.80	222.99	1,874.19	88.30	61.80
6/1/2038	280,398.98	222.99	1,874.82	88.00	61.86
7/1/2038	280,750.15	223.00	1,875.44	87.68	61.91
8/1/2038	281,101.33	223.02	1,876.05	87.37	61.97
9/1/2038	281,452.50	223.03	1,876.67	87.05	62.02
10/1/2038	281,792.33	223.16	1,877.20	86.74	62.08
11/1/2038	282,132.17	223.28	1,877.72	86.43	62.13
12/1/2038	282,472.00	223.40	1,878.25	86.12	62.18
1/1/2039	282,768.42	223.53	1,878.62	85.70	62.26
2/1/2039	283,064.84	223.66	1,879.00	85.27	62.34
3/1/2039	283,361.26	223.79	1,879.38	84.85	62.43
4/1/2039	283,692.24	223.84	1,879.70	84.54	62.48
5/1/2039	284,023.23	223.90	1,880.02	84.23	62.53
6/1/2039	284,354.21	223.96	1,880.33	83.92	62.59
7/1/2039	284,703.63	224.05	1,880.85	83.63	62.65
8/1/2039	285,053.04	224.14	1,881.36	83.34	62.71
9/1/2039	285,402.45	224.23	1,881.87	83.05	62.77
10/1/2039	285,743.04	224.37	1,882.33	82.79	62.82
11/1/2039	286,083.63	224.52	1,882.78	82.53	62.87
12/1/2039	286,424.21	224.66	1,883.24	82.27	62.92
1/1/2040	286,754.20	224.71	1,884.03	82.08	63.00
2/1/2040	287,084.20	224.76	1,884.82	81.88	63.08
3/1/2040	287,414.19	224.81	1,885.62	81.69	63.16
4/1/2040	287,853.35	224.65	1,886.65	81.46	63.23
5/1/2040	288,292.51	224.49	1,887.68	81.23	63.29
6/1/2040	288,731.67	224.33	1,888.72	80.99	63.35
7/1/2040	289,036.53	224.54	1,889.42	80.79	63.41
8/1/2040	289,341.39	224.75	1,890.11	80.58	63.47
9/1/2040	289,646.25	224.97	1,890.81	80.38	63.53
10/1/2040	289,955.14	224.91	1,890.84	80.18	63.58
11/1/2040	290,264.03	224.85	1,890.87	79.98	63.63
12/1/2040	290,572.92	224.80	1,890.90	79.79	63.68
1/1/2041	290,896.36	224.79	1,891.43	79.61	63.77
2/1/2041	291,219.80	224.78	1,891.96	79.43	63.86
3/1/2041	291,543.24	224.77	1,892.49	79.25	63.95
4/1/2041	291,892.74	224.73	1,893.05	79.06	64.01
5/1/2041	292,242.24	224.68	1,893.60	78.87	64.08
6/1/2041	292,591.74	224.64	1,894.15	78.67	64.14
7/1/2041	292,965.85	224.60	1,894.76	78.46	64.20

8/1/2041	293,339.97	224.56	1,895.37	78.24	64.26
9/1/2041	293,714.08	224.52	1,895.97	78.03	64.33
10/1/2041	294,084.47	224.55	1,896.49	77.83	64.38
11/1/2041	294,454.85	224.58	1,897.00	77.63	64.44
12/1/2041	294,825.24	224.62	1,897.51	77.43	64.49
1/1/2042	295,156.89	224.65	1,898.13	77.26	64.58
2/1/2042	295,488.55	224.68	1,898.75	77.09	64.68
3/1/2042	295,820.20	224.71	1,899.37	76.92	64.77
4/1/2042	296,177.59	224.62	1,899.68	76.72	64.83
5/1/2042	296,534.98	224.53	1,899.99	76.53	64.89
6/1/2042	296,892.37	224.44	1,900.30	76.34	64.94
7/1/2042	297,273.81	224.39	1,900.86	76.14	65.00
8/1/2042	297,655.25	224.34	1,901.41	75.94	65.06
9/1/2042	298,036.69	224.29	1,901.96	75.74	65.12
10/1/2042	298,408.71	224.30	1,902.32	75.53	65.18
11/1/2042	298,780.73	224.31	1,902.67	75.32	65.23
12/1/2042	299,152.75	224.32	1,903.03	75.11	65.29
1/1/2043	299,509.29	224.29	1,903.50	74.84	65.38
2/1/2043	299,865.83	224.27	1,903.96	74.58	65.47
3/1/2043	300,222.37	224.24	1,904.43	74.31	65.56
4/1/2043	300,596.43	224.13	1,904.81	74.06	65.62
5/1/2043	300,970.50	224.02	1,905.18	73.80	65.67
6/1/2043	301,344.56	223.91	1,905.55	73.55	65.73
7/1/2043	301,739.59	223.84	1,906.06	73.29	65.79
8/1/2043	302,134.62	223.76	1,906.56	73.03	65.85
9/1/2043	302,529.66	223.69	1,907.06	72.77	65.91
10/1/2043	302,918.27	223.68	1,907.48	72.51	65.97
11/1/2043	303,306.89	223.68	1,907.89	72.25	66.03
12/1/2043	303,695.50	223.67	1,908.31	71.99	66.09
1/1/2044	304,041.29	223.69	1,908.83	71.71	66.19
2/1/2044	304,387.07	223.71	1,909.36	71.43	66.28
3/1/2044	304,732.85	223.73	1,909.88	71.14	66.37
4/1/2044	305,099.77	223.71	1,910.22	70.80	66.43
5/1/2044	305,466.69	223.68	1,910.56	70.46	66.48
6/1/2044	305,833.60	223.65	1,910.89	70.12	66.54
7/1/2044	306,227.47	223.61	1,911.41	69.82	66.60
8/1/2044	306,621.33	223.57	1,911.92	69.52	66.66
9/1/2044	307,015.19	223.53	1,912.43	69.22	66.72
10/1/2044	307,408.10	223.59	1,912.94	68.98	66.78
11/1/2044	307,801.00	223.64	1,913.44	68.75	66.84
12/1/2044	308,193.91	223.69	1,913.94	68.51	66.90
1/1/2045	308,552.16	223.74	1,914.41	68.30	66.99
2/1/2045	308,910.40	223.80	1,914.87	68.09	67.08
3/1/2045	309,268.65	223.85	1,915.34	67.89	67.17
4/1/2045	309,639.94	223.82	1,915.92	67.63	67.23
5/1/2045	310,011.24	223.79	1,916.50	67.37	67.28
6/1/2045	310,382.54	223.76	1,917.09	67.11	67.34
7/1/2045	310,777.88	223.76	1,917.57	66.92	67.40
8/1/2045	311,173.22	223.76	1,918.05	66.72	67.46
9/1/2045	311,568.57	223.75	1,918.54	66.53	67.52
10/1/2045	311,963.69	223.84	1,919.00	66.36	67.58
11/1/2045	312,358.82	223.92	1,919.46	66.18	67.64
12/1/2045	312,753.94	224.00	1,919.92	66.01	67.70
1/1/2046	313,112.00	224.04	1,920.37	65.80	67.79
2/1/2046	313,470.05	224.09	1,920.82	65.58	67.89
3/1/2046	313,828.11	224.13	1,921.28	65.37	67.98
4/1/2046	314,222.39	224.08	1,921.80	65.18	68.04
5/1/2046	314,616.67	224.03	1,922.32	65.00	68.09
6/1/2046	315,010.96	223.98	1,922.84	64.82	68.15
7/1/2046	315,422.40	223.95	1,923.41	64.64	68.21
8/1/2046	315,833.85	223.91	1,923.99	64.46	68.27
9/1/2046	316,245.29	223.87	1,924.56	64.28	68.33
10/1/2046	316,645.13	223.95	1,925.05	64.09	68.39
11/1/2046	317,044.96	224.03	1,925.53	63.90	68.45
12/1/2046	317,444.79	224.10	1,926.01	63.71	68.51
1/1/2047	317,822.41	224.12	1,926.49	63.48	68.60
2/1/2047	318,200.02	224.14	1,926.96	63.26	68.69
3/1/2047	318,577.64	224.15	1,927.43	63.03	68.78
4/1/2047	318,959.70	224.06	1,927.96	62.86	68.84
5/1/2047	319,341.77	223.97	1,928.50	62.69	68.90
6/1/2047	319,723.84	223.88	1,929.03	62.52	68.95
7/1/2047	320,130.91	223.85	1,929.57	62.34	69.01
8/1/2047	320,537.98	223.82	1,930.11	62.16	69.07
9/1/2047	320,945.05	223.79	1,930.64	61.97	69.13
10/1/2047	321,356.29	223.83	1,931.14	61.86	69.19
11/1/2047	321,767.54	223.86	1,931.63	61.74	69.25
12/1/2047	322,178.78	223.90	1,932.13	61.63	69.31

1/1/2048	322,562.77	223.89	1,932.53	61.49	69.40
2/1/2048	322,946.76	223.89	1,932.93	61.34	69.49
3/1/2048	323,330.75	223.89	1,933.33	61.20	69.58
4/1/2048	323,720.72	223.81	1,933.82	61.07	69.63
5/1/2048	324,110.68	223.73	1,934.31	60.94	69.69
6/1/2048	324,500.65	223.65	1,934.80	60.81	69.74
7/1/2048	324,917.55	223.63	1,935.29	60.73	69.80
8/1/2048	325,334.45	223.62	1,935.78	60.64	69.86
9/1/2048	325,751.35	223.61	1,936.28	60.56	69.91
10/1/2048	326,152.08	223.67	1,936.64	60.42	69.97
11/1/2048	326,552.82	223.74	1,937.00	60.28	70.03
12/1/2048	326,953.56	223.80	1,937.36	60.14	70.09
1/1/2049	327,321.37	223.82	1,937.75	59.99	70.17
2/1/2049	327,689.18	223.83	1,938.14	59.84	70.26
3/1/2049	328,056.98	223.84	1,938.53	59.69	70.35
4/1/2049	328,447.40	223.75	1,939.02	59.57	70.40
5/1/2049	328,837.82	223.66	1,939.52	59.45	70.46
6/1/2049	329,228.23	223.57	1,940.02	59.33	70.51
7/1/2049	329,642.04	223.53	1,940.45	59.28	70.56
8/1/2049	330,055.85	223.49	1,940.89	59.24	70.62
9/1/2049	330,469.65	223.46	1,941.33	59.20	70.67
10/1/2049	330,873.55	223.45	1,941.79	59.04	70.73
11/1/2049	331,277.46	223.44	1,942.26	58.89	70.79
12/1/2049	331,681.36	223.43	1,942.72	58.74	70.84
1/1/2050	332,094.11	223.37	1,943.49	58.63	70.93
2/1/2050	332,506.87	223.31	1,944.25	58.51	71.01
3/1/2050	332,919.62	223.25	1,945.02	58.40	71.10
4/1/2050	333,379.58	222.99	1,946.46	58.29	71.16
5/1/2050	333,839.55	222.72	1,947.90	58.18	71.23
6/1/2050	334,299.51	222.46	1,949.34	58.07	71.29
7/1/2050	334,678.50	222.55	1,949.08	57.99	71.34
8/1/2050	335,057.48	222.64	1,948.81	57.92	71.39
9/1/2050	335,436.46	222.73	1,948.55	57.84	71.44
10/1/2050	335,863.64	222.63	1,949.07	57.74	71.50
11/1/2050	336,290.81	222.53	1,949.59	57.64	71.55
12/1/2050	336,717.99	222.43	1,950.11	57.54	71.61
1/1/2051	337,208.00	222.54	1,950.54	57.43	71.70
2/1/2051	337,698.01	222.65	1,950.98	57.31	71.79
3/1/2051	338,188.03	222.75	1,951.41	57.20	71.88
4/1/2051	338,655.25	222.77	1,951.95	57.14	71.94
5/1/2051	339,122.48	222.78	1,952.49	57.08	72.00
6/1/2051	339,589.71	222.80	1,953.02	57.02	72.06
7/1/2051	340,108.53	222.79	1,953.58	56.89	72.12
8/1/2051	340,627.35	222.78	1,954.14	56.77	72.18
9/1/2051	341,146.18	222.78	1,954.69	56.64	72.24
10/1/2051	341,642.73	222.85	1,955.15	56.49	72.30
11/1/2051	342,139.29	222.92	1,955.60	56.33	72.36
12/1/2051	342,635.85	223.00	1,956.05	56.18	72.42
1/1/2052	343,111.50	222.98	1,956.61	56.09	72.53
2/1/2052	343,587.15	222.95	1,957.18	56.00	72.64
3/1/2052	344,062.80	222.93	1,957.74	55.91	72.76
4/1/2052	344,545.17	222.91	1,958.31	55.84	72.82
5/1/2052	345,027.54	222.89	1,958.88	55.77	72.87
6/1/2052	345,509.91	222.88	1,959.45	55.71	72.93
7/1/2052	346,009.89	222.74	1,960.11	55.61	72.99
8/1/2052	346,509.88	222.60	1,960.77	55.52	73.05
9/1/2052	347,009.87	222.46	1,961.43	55.43	73.11
10/1/2052	347,503.68	222.42	1,962.00	55.33	73.17
11/1/2052	347,997.50	222.39	1,962.56	55.23	73.23
12/1/2052	348,491.31	222.35	1,963.13	55.13	73.29
1/1/2053	348,990.03	222.21	1,963.74	55.04	73.40
2/1/2053	349,488.75	222.06	1,964.35	54.94	73.52
3/1/2053	349,987.46	221.92	1,964.96	54.84	73.64
4/1/2053	350,483.40	221.79	1,965.55	54.73	73.69
5/1/2053	350,979.34	221.67	1,966.14	54.62	73.75
6/1/2053	351,475.28	221.54	1,966.73	54.51	73.80
7/1/2053	351,994.85	221.39	1,967.40	54.41	73.85
8/1/2053	352,514.42	221.23	1,968.08	54.31	73.90
9/1/2053	353,033.99	221.08	1,968.75	54.21	73.94
10/1/2053	353,553.54	221.03	1,969.32	54.10	73.99
11/1/2053	354,073.10	220.99	1,969.90	54.00	74.03
12/1/2053	354,592.65	220.95	1,970.47	53.90	74.08

	KY Real Personal Income	KY Population	KY Households, Total	KY Household Average Size
	Millions of 2017 US$, SAAR	Thousand	Thousand	Persons
1/1/2010	176,437.02	4,334.38	1,715.75	2.53
2/1/2010	175,782.32	4,336.86	1,717.86	2.52
3/1/2010	175,127.61	4,339.33	1,719.97	2.52
4/1/2010	175,630.98	4,342.60	1,720.82	2.52
5/1/2010	176,134.36	4,345.88	1,721.67	2.52
6/1/2010	176,637.74	4,349.15	1,722.53	2.52
7/1/2010	176,907.45	4,351.24	1,721.64	2.53
8/1/2010	177,177.16	4,353.34	1,720.76	2.53
9/1/2010	177,446.87	4,355.43	1,719.87	2.53
10/1/2010	177,193.45	4,357.52	1,718.99	2.53
11/1/2010	176,940.04	4,359.62	1,718.10	2.54
12/1/2010	176,686.63	4,361.71	1,717.21	2.54
1/1/2011	177,789.51	4,363.80	1,716.33	2.54
2/1/2011	178,892.40	4,365.90	1,715.44	2.55
3/1/2011	179,995.29	4,367.99	1,714.56	2.55
4/1/2011	179,872.02	4,370.09	1,713.67	2.55
5/1/2011	179,748.75	4,372.18	1,712.78	2.55
6/1/2011	179,625.48	4,374.27	1,711.90	2.56
7/1/2011	179,929.34	4,375.93	1,714.94	2.55
8/1/2011	180,233.20	4,377.58	1,717.98	2.55
9/1/2011	180,537.06	4,379.23	1,721.02	2.54
10/1/2011	180,855.97	4,380.89	1,724.06	2.54
11/1/2011	181,174.88	4,382.54	1,727.11	2.54
12/1/2011	181,493.79	4,384.19	1,730.15	2.53
1/1/2012	182,127.73	4,385.84	1,733.19	2.53
2/1/2012	182,761.66	4,387.50	1,736.24	2.53
3/1/2012	183,395.60	4,389.15	1,739.28	2.52
4/1/2012	183,465.81	4,390.81	1,742.33	2.52
5/1/2012	183,536.03	4,392.46	1,745.37	2.52
6/1/2012	183,606.24	4,394.11	1,748.42	2.51
7/1/2012	182,974.05	4,395.93	1,748.44	2.51
8/1/2012	182,341.86	4,397.75	1,748.46	2.52
9/1/2012	181,709.66	4,399.58	1,748.47	2.52
10/1/2012	181,848.65	4,401.40	1,748.49	2.52
11/1/2012	181,987.63	4,403.22	1,748.51	2.52
12/1/2012	182,126.62	4,405.04	1,748.52	2.52
1/1/2013	182,079.83	4,406.86	1,748.54	2.52
2/1/2013	182,033.05	4,408.68	1,748.56	2.52
3/1/2013	181,986.26	4,410.50	1,748.58	2.52
4/1/2013	181,932.25	4,412.33	1,748.59	2.52
5/1/2013	181,878.24	4,414.15	1,748.61	2.52
6/1/2013	181,824.23	4,415.97	1,748.63	2.53
7/1/2013	181,689.08	4,417.05	1,749.30	2.53
8/1/2013	181,553.93	4,418.12	1,749.98	2.52
9/1/2013	181,418.77	4,419.20	1,750.66	2.52
10/1/2013	181,172.68	4,420.27	1,751.33	2.52
11/1/2013	180,926.58	4,421.35	1,752.01	2.52
12/1/2013	180,680.48	4,422.42	1,752.68	2.52
1/1/2014	181,924.38	4,423.50	1,753.36	2.52
2/1/2014	183,168.28	4,424.57	1,754.03	2.52
3/1/2014	184,412.18	4,425.65	1,754.71	2.52
4/1/2014	184,831.84	4,426.72	1,755.39	2.52
5/1/2014	185,251.51	4,427.80	1,756.06	2.52
6/1/2014	185,671.17	4,428.87	1,756.74	2.52
7/1/2014	185,956.73	4,430.12	1,757.21	2.52
8/1/2014	186,242.30	4,431.37	1,757.69	2.52
9/1/2014	186,527.87	4,432.61	1,758.17	2.52
10/1/2014	187,460.91	4,433.86	1,758.64	2.52
11/1/2014	188,393.95	4,435.11	1,759.12	2.52
12/1/2014	189,326.99	4,436.36	1,759.59	2.52
1/1/2015	190,555.36	4,437.60	1,760.07	2.52
2/1/2015	191,783.72	4,438.85	1,760.55	2.52
3/1/2015	193,012.09	4,440.10	1,761.02	2.52
4/1/2015	193,646.59	4,441.35	1,761.50	2.52
5/1/2015	194,281.09	4,442.60	1,761.97	2.52
6/1/2015	194,915.59	4,443.84	1,762.45	2.52
7/1/2015	195,152.74	4,445.01	1,762.71	2.52
8/1/2015	195,389.89	4,446.18	1,762.98	2.52
9/1/2015	195,627.03	4,447.35	1,763.24	2.52
10/1/2015	196,173.57	4,448.52	1,763.50	2.52
11/1/2015	196,720.10	4,449.69	1,763.77	2.52

12/1/2015	197,266.64	4,450.86	1,764.03	2.52
1/1/2016	196,902.21	4,452.03	1,764.30	2.52
2/1/2016	196,537.78	4,453.19	1,764.56	2.52
3/1/2016	196,173.35	4,454.36	1,764.83	2.52
4/1/2016	196,105.67	4,455.53	1,765.09	2.52
5/1/2016	196,037.98	4,456.70	1,765.35	2.52
6/1/2016	195,970.30	4,457.87	1,765.62	2.52
7/1/2016	196,473.10	4,459.38	1,766.37	2.52
8/1/2016	196,975.90	4,460.90	1,767.12	2.52
9/1/2016	197,478.70	4,462.41	1,767.87	2.52
10/1/2016	197,419.60	4,463.92	1,768.62	2.52
11/1/2016	197,360.50	4,465.44	1,769.37	2.52
12/1/2016	197,301.40	4,466.95	1,770.12	2.52
1/1/2017	197,890.29	4,468.47	1,770.87	2.52
2/1/2017	198,479.18	4,469.98	1,771.62	2.52
3/1/2017	199,068.06	4,471.49	1,772.37	2.52
4/1/2017	199,358.77	4,473.01	1,773.12	2.52
5/1/2017	199,649.47	4,474.52	1,773.87	2.52
6/1/2017	199,940.18	4,476.04	1,774.62	2.52
7/1/2017	200,411.76	4,477.00	1,775.40	2.52
8/1/2017	200,883.35	4,477.96	1,776.18	2.52
9/1/2017	201,354.94	4,478.92	1,776.96	2.52
10/1/2017	201,926.61	4,479.88	1,777.74	2.52
11/1/2017	202,498.28	4,480.85	1,778.52	2.52
12/1/2017	203,069.96	4,481.81	1,779.30	2.52
1/1/2018	203,442.03	4,482.77	1,780.08	2.52
2/1/2018	203,814.11	4,483.73	1,780.86	2.52
3/1/2018	204,186.19	4,484.70	1,781.64	2.52
4/1/2018	204,689.02	4,485.66	1,782.42	2.52
5/1/2018	205,191.86	4,486.62	1,783.20	2.52
6/1/2018	205,694.70	4,487.58	1,783.99	2.52
7/1/2018	205,810.15	4,488.50	1,785.47	2.51
8/1/2018	205,925.61	4,489.41	1,786.95	2.51
9/1/2018	206,041.07	4,490.32	1,788.43	2.51
10/1/2018	206,247.68	4,491.23	1,789.91	2.51
11/1/2018	206,454.29	4,492.14	1,791.40	2.51
12/1/2018	206,660.90	4,493.06	1,792.88	2.51
1/1/2019	207,833.67	4,493.97	1,794.36	2.50
2/1/2019	209,006.45	4,494.88	1,795.85	2.50
3/1/2019	210,179.22	4,495.79	1,797.33	2.50
4/1/2019	210,085.02	4,496.71	1,798.81	2.50
5/1/2019	209,990.81	4,497.62	1,800.30	2.50
6/1/2019	209,896.60	4,498.53	1,801.78	2.50
7/1/2019	210,114.25	4,499.42	1,803.40	2.49
8/1/2019	210,331.89	4,500.32	1,805.02	2.49
9/1/2019	210,549.53	4,501.22	1,806.64	2.49
10/1/2019	211,056.92	4,502.10	1,808.47	2.49
11/1/2019	211,564.30	4,502.98	1,810.29	2.49
12/1/2019	212,071.69	4,503.86	1,812.12	2.49
1/1/2020	213,033.82	4,504.67	1,807.40	2.49
2/1/2020	213,995.96	4,505.49	1,802.68	2.50
3/1/2020	214,958.10	4,506.30	1,797.96	2.51
4/1/2020	224,132.10	4,506.92	1,797.88	2.51
5/1/2020	233,306.10	4,507.54	1,797.81	2.51
6/1/2020	242,480.10	4,508.16	1,797.73	2.51
7/1/2020	237,505.65	4,508.04	1,797.63	2.51
8/1/2020	232,531.20	4,507.92	1,797.52	2.51
9/1/2020	227,556.75	4,507.81	1,797.41	2.51
10/1/2020	226,575.63	4,507.05	1,796.78	2.51
11/1/2020	225,594.52	4,506.29	1,796.15	2.51
12/1/2020	224,613.40	4,505.53	1,795.52	2.51
1/1/2021	235,999.35	4,505.60	1,795.08	2.51
2/1/2021	247,385.30	4,505.67	1,794.63	2.51
3/1/2021	258,771.25	4,505.74	1,794.19	2.51
4/1/2021	250,699.13	4,506.36	1,794.13	2.51
5/1/2021	242,627.00	4,506.98	1,794.07	2.51
6/1/2021	234,554.87	4,507.60	1,794.01	2.51
7/1/2021	234,083.44	4,507.20	1,797.34	2.51
8/1/2021	233,612.00	4,506.81	1,800.66	2.50
9/1/2021	233,140.57	4,506.41	1,803.99	2.50
10/1/2021	232,046.67	4,506.47	1,807.55	2.49
11/1/2021	230,952.78	4,506.53	1,811.12	2.49
12/1/2021	229,858.88	4,506.59	1,814.68	2.48
1/1/2022	229,388.69	4,507.06	1,818.46	2.48
2/1/2022	228,918.51	4,507.53	1,822.24	2.47
3/1/2022	228,448.32	4,508.01	1,826.02	2.47
4/1/2022	227,714.40	4,509.19	1,830.13	2.46

5/1/2022	226,980.47	4,510.38	1,834.24	2.46
6/1/2022	226,246.55	4,511.56	1,838.35	2.45
7/1/2022	225,889.14	4,512.53	1,839.10	2.45
8/1/2022	225,531.73	4,513.51	1,839.85	2.45
9/1/2022	225,174.31	4,514.48	1,840.60	2.45
10/1/2022	224,784.23	4,515.42	1,841.10	2.45
11/1/2022	224,394.15	4,516.36	1,841.60	2.45
12/1/2022	224,004.07	4,517.30	1,842.09	2.45
1/1/2023	225,131.29	4,518.71	1,842.68	2.45
2/1/2023	226,258.51	4,520.12	1,843.26	2.45
3/1/2023	227,385.74	4,521.54	1,843.85	2.45
4/1/2023	227,427.18	4,523.08	1,845.82	2.45
5/1/2023	227,468.62	4,524.61	1,847.78	2.45
6/1/2023	227,510.06	4,526.15	1,849.75	2.45
7/1/2023	228,132.51	4,527.85	1,851.58	2.45
8/1/2023	228,754.96	4,529.54	1,853.40	2.44
9/1/2023	229,377.41	4,531.24	1,855.23	2.44
10/1/2023	229,721.62	4,533.13	1,857.06	2.44
11/1/2023	230,065.83	4,535.01	1,858.88	2.44
12/1/2023	230,410.04	4,536.90	1,860.71	2.44
1/1/2024	231,096.31	4,538.98	1,862.28	2.44
2/1/2024	231,782.59	4,541.05	1,863.85	2.44
3/1/2024	232,468.86	4,543.13	1,865.41	2.44
4/1/2024	232,811.67	4,545.32	1,866.88	2.43
5/1/2024	233,154.47	4,547.51	1,868.34	2.43
6/1/2024	233,497.27	4,549.71	1,869.80	2.43
7/1/2024	233,973.10	4,552.03	1,871.42	2.43
8/1/2024	234,448.93	4,554.35	1,873.04	2.43
9/1/2024	234,924.75	4,556.68	1,874.67	2.43
10/1/2024	235,331.04	4,559.02	1,876.41	2.43
11/1/2024	235,737.32	4,561.37	1,878.15	2.43
12/1/2024	236,143.60	4,563.72	1,879.88	2.43
1/1/2025	236,870.08	4,565.98	1,881.50	2.43
2/1/2025	237,596.56	4,568.24	1,883.11	2.43
3/1/2025	238,323.04	4,570.50	1,884.72	2.43
4/1/2025	238,774.81	4,572.66	1,886.26	2.42
5/1/2025	239,226.58	4,574.81	1,887.80	2.42
6/1/2025	239,678.34	4,576.97	1,889.35	2.42
7/1/2025	240,056.69	4,578.99	1,890.60	2.42
8/1/2025	240,435.03	4,581.02	1,891.85	2.42
9/1/2025	240,813.37	4,583.04	1,893.10	2.42
10/1/2025	241,199.63	4,584.90	1,894.40	2.42
11/1/2025	241,585.89	4,586.76	1,895.70	2.42
12/1/2025	241,972.16	4,588.62	1,897.00	2.42
1/1/2026	242,583.61	4,590.29	1,898.49	2.42
2/1/2026	243,195.07	4,591.96	1,899.98	2.42
3/1/2026	243,806.52	4,593.63	1,901.47	2.42
4/1/2026	244,272.90	4,595.11	1,902.80	2.41
5/1/2026	244,739.28	4,596.59	1,904.12	2.41
6/1/2026	245,205.65	4,598.06	1,905.45	2.41
7/1/2026	245,605.06	4,599.36	1,906.61	2.41
8/1/2026	246,004.47	4,600.66	1,907.77	2.41
9/1/2026	246,403.88	4,601.96	1,908.93	2.41
10/1/2026	246,802.83	4,603.11	1,910.03	2.41
11/1/2026	247,201.77	4,604.26	1,911.14	2.41
12/1/2026	247,600.72	4,605.41	1,912.24	2.41
1/1/2027	248,207.18	4,606.43	1,913.49	2.41
2/1/2027	248,813.64	4,607.45	1,914.74	2.41
3/1/2027	249,420.10	4,608.47	1,916.00	2.41
4/1/2027	249,865.92	4,609.37	1,917.16	2.40
5/1/2027	250,311.74	4,610.26	1,918.32	2.40
6/1/2027	250,757.56	4,611.16	1,919.48	2.40
7/1/2027	251,243.66	4,611.97	1,920.56	2.40
8/1/2027	251,729.76	4,612.79	1,921.64	2.40
9/1/2027	252,215.86	4,613.60	1,922.72	2.40
10/1/2027	252,645.39	4,614.38	1,923.66	2.40
11/1/2027	253,074.92	4,615.15	1,924.60	2.40
12/1/2027	253,504.45	4,615.93	1,925.54	2.40
1/1/2028	254,098.66	4,616.70	1,926.57	2.40
2/1/2028	254,692.87	4,617.47	1,927.59	2.40
3/1/2028	255,287.07	4,618.24	1,928.62	2.39
4/1/2028	255,733.91	4,619.01	1,929.56	2.39
5/1/2028	256,180.75	4,619.77	1,930.51	2.39
6/1/2028	256,627.58	4,620.54	1,931.45	2.39
7/1/2028	257,061.66	4,621.29	1,932.31	2.39
8/1/2028	257,495.74	4,622.04	1,933.17	2.39
9/1/2028	257,929.82	4,622.79	1,934.03	2.39

10/1/2028	258,369.18	4,623.54	1,934.91	2.39
11/1/2028	258,808.53	4,624.28	1,935.80	2.39
12/1/2028	259,247.88	4,625.03	1,936.69	2.39
1/1/2029	259,839.48	4,625.77	1,937.65	2.39
2/1/2029	260,431.09	4,626.50	1,938.61	2.39
3/1/2029	261,022.69	4,627.24	1,939.57	2.39
4/1/2029	261,467.08	4,627.96	1,940.44	2.39
5/1/2029	261,911.47	4,628.69	1,941.32	2.38
6/1/2029	262,355.86	4,629.41	1,942.20	2.38
7/1/2029	262,805.09	4,630.13	1,943.03	2.38
8/1/2029	263,254.32	4,630.84	1,943.87	2.38
9/1/2029	263,703.55	4,631.56	1,944.71	2.38
10/1/2029	264,151.29	4,632.27	1,945.59	2.38
11/1/2029	264,599.03	4,632.97	1,946.47	2.38
12/1/2029	265,046.77	4,633.68	1,947.35	2.38
1/1/2030	265,621.72	4,634.37	1,948.24	2.38
2/1/2030	266,196.67	4,635.07	1,949.14	2.38
3/1/2030	266,771.62	4,635.77	1,950.03	2.38
4/1/2030	267,242.42	4,636.46	1,951.08	2.38
5/1/2030	267,713.22	4,637.15	1,952.14	2.38
6/1/2030	268,184.02	4,637.85	1,953.19	2.37
7/1/2030	268,649.50	4,638.53	1,954.18	2.37
8/1/2030	269,114.99	4,639.22	1,955.17	2.37
9/1/2030	269,580.47	4,639.91	1,956.15	2.37
10/1/2030	270,016.11	4,640.59	1,957.22	2.37
11/1/2030	270,451.75	4,641.27	1,958.29	2.37
12/1/2030	270,887.39	4,641.95	1,959.36	2.37
1/1/2031	271,470.44	4,642.63	1,960.31	2.37
2/1/2031	272,053.50	4,643.31	1,961.26	2.37
3/1/2031	272,636.55	4,643.98	1,962.21	2.37
4/1/2031	273,081.24	4,644.65	1,963.07	2.37
5/1/2031	273,525.92	4,645.32	1,963.92	2.37
6/1/2031	273,970.60	4,646.00	1,964.77	2.36
7/1/2031	274,424.21	4,646.66	1,965.69	2.36
8/1/2031	274,877.81	4,647.33	1,966.60	2.36
9/1/2031	275,331.41	4,648.00	1,967.51	2.36
10/1/2031	275,782.67	4,648.66	1,968.38	2.36
11/1/2031	276,233.93	4,649.31	1,969.25	2.36
12/1/2031	276,685.18	4,649.97	1,970.12	2.36
1/1/2032	277,295.66	4,650.63	1,971.07	2.36
2/1/2032	277,906.13	4,651.28	1,972.03	2.36
3/1/2032	278,516.61	4,651.93	1,972.99	2.36
4/1/2032	278,980.68	4,652.58	1,973.84	2.36
5/1/2032	279,444.75	4,653.23	1,974.70	2.36
6/1/2032	279,908.83	4,653.87	1,975.56	2.36
7/1/2032	280,370.40	4,654.52	1,976.44	2.36
8/1/2032	280,831.97	4,655.17	1,977.32	2.35
9/1/2032	281,293.55	4,655.81	1,978.20	2.35
10/1/2032	281,755.73	4,656.45	1,979.03	2.35
11/1/2032	282,217.92	4,657.09	1,979.85	2.35
12/1/2032	282,680.11	4,657.73	1,980.68	2.35
1/1/2033	283,263.17	4,658.36	1,981.61	2.35
2/1/2033	283,846.24	4,658.99	1,982.54	2.35
3/1/2033	284,429.31	4,659.62	1,983.46	2.35
4/1/2033	284,893.37	4,660.24	1,984.28	2.35
5/1/2033	285,357.43	4,660.86	1,985.11	2.35
6/1/2033	285,821.49	4,661.48	1,985.93	2.35
7/1/2033	286,288.72	4,662.09	1,986.81	2.35
8/1/2033	286,755.94	4,662.70	1,987.69	2.35
9/1/2033	287,223.17	4,663.31	1,988.57	2.35
10/1/2033	287,690.50	4,663.90	1,989.37	2.34
11/1/2033	288,157.84	4,664.50	1,990.17	2.34
12/1/2033	288,625.17	4,665.09	1,990.97	2.34
1/1/2034	289,247.91	4,665.67	1,991.82	2.34
2/1/2034	289,870.65	4,666.25	1,992.67	2.34
3/1/2034	290,493.38	4,666.84	1,993.52	2.34
4/1/2034	290,983.60	4,667.41	1,994.35	2.34
5/1/2034	291,473.82	4,667.98	1,995.18	2.34
6/1/2034	291,964.04	4,668.55	1,996.01	2.34
7/1/2034	292,465.49	4,669.11	1,996.82	2.34
8/1/2034	292,966.94	4,669.68	1,997.64	2.34
9/1/2034	293,468.40	4,670.24	1,998.46	2.34
10/1/2034	293,955.36	4,670.79	1,999.25	2.34
11/1/2034	294,442.33	4,671.34	2,000.04	2.34
12/1/2034	294,929.29	4,671.89	2,000.83	2.33
1/1/2035	295,495.25	4,672.43	2,001.79	2.33
2/1/2035	296,061.20	4,672.97	2,002.76	2.33

3/1/2035	296,627.16	4,673.51	2,003.73	2.33
4/1/2035	297,089.31	4,674.03	2,004.71	2.33
5/1/2035	297,551.46	4,674.56	2,005.70	2.33
6/1/2035	298,013.62	4,675.09	2,006.69	2.33
7/1/2035	298,498.73	4,675.61	2,007.67	2.33
8/1/2035	298,983.84	4,676.13	2,008.65	2.33
9/1/2035	299,468.95	4,676.64	2,009.63	2.33
10/1/2035	299,963.48	4,677.15	2,010.55	2.33
11/1/2035	300,458.00	4,677.66	2,011.46	2.33
12/1/2035	300,952.53	4,678.16	2,012.38	2.32
1/1/2036	301,614.49	4,678.65	2,013.24	2.32
2/1/2036	302,276.45	4,679.15	2,014.11	2.32
3/1/2036	302,938.41	4,679.64	2,014.97	2.32
4/1/2036	303,432.71	4,680.13	2,015.82	2.32
5/1/2036	303,927.00	4,680.62	2,016.66	2.32
6/1/2036	304,421.30	4,681.10	2,017.50	2.32
7/1/2036	304,940.21	4,681.57	2,018.28	2.32
8/1/2036	305,459.11	4,682.05	2,019.05	2.32
9/1/2036	305,978.01	4,682.52	2,019.82	2.32
10/1/2036	306,484.47	4,682.98	2,020.50	2.32
11/1/2036	306,990.94	4,683.44	2,021.17	2.32
12/1/2036	307,497.40	4,683.90	2,021.84	2.32
1/1/2037	308,128.99	4,684.34	2,022.54	2.32
2/1/2037	308,760.58	4,684.79	2,023.23	2.32
3/1/2037	309,392.16	4,685.24	2,023.92	2.31
4/1/2037	309,888.00	4,685.67	2,024.53	2.31
5/1/2037	310,383.83	4,686.11	2,025.14	2.31
6/1/2037	310,879.67	4,686.55	2,025.74	2.31
7/1/2037	311,408.64	4,686.97	2,026.36	2.31
8/1/2037	311,937.61	4,687.40	2,026.97	2.31
9/1/2037	312,466.58	4,687.83	2,027.58	2.31
10/1/2037	312,974.19	4,688.25	2,028.11	2.31
11/1/2037	313,481.81	4,688.66	2,028.63	2.31
12/1/2037	313,989.42	4,689.08	2,029.16	2.31
1/1/2038	314,640.96	4,689.48	2,029.73	2.31
2/1/2038	315,292.51	4,689.89	2,030.30	2.31
3/1/2038	315,944.05	4,690.29	2,030.87	2.31
4/1/2038	316,461.63	4,690.68	2,031.34	2.31
5/1/2038	316,979.20	4,691.08	2,031.80	2.31
6/1/2038	317,496.77	4,691.47	2,032.27	2.31
7/1/2038	318,030.75	4,691.85	2,032.70	2.31
8/1/2038	318,564.73	4,692.23	2,033.14	2.31
9/1/2038	319,098.70	4,692.61	2,033.57	2.31
10/1/2038	319,615.60	4,692.98	2,033.91	2.31
11/1/2038	320,132.49	4,693.35	2,034.24	2.31
12/1/2038	320,649.39	4,693.72	2,034.58	2.31
1/1/2039	321,317.42	4,694.08	2,034.96	2.31
2/1/2039	321,985.46	4,694.44	2,035.35	2.31
3/1/2039	322,653.49	4,694.80	2,035.73	2.31
4/1/2039	323,186.23	4,695.15	2,036.04	2.31
5/1/2039	323,718.97	4,695.50	2,036.35	2.31
6/1/2039	324,251.70	4,695.84	2,036.65	2.31
7/1/2039	324,812.26	4,696.18	2,036.91	2.31
8/1/2039	325,372.81	4,696.51	2,037.16	2.31
9/1/2039	325,933.36	4,696.84	2,037.41	2.31
10/1/2039	326,463.78	4,697.17	2,037.69	2.31
11/1/2039	326,994.21	4,697.49	2,037.97	2.30
12/1/2039	327,524.63	4,697.81	2,038.24	2.30
1/1/2040	328,233.37	4,698.12	2,038.52	2.30
2/1/2040	328,942.11	4,698.42	2,038.79	2.30
3/1/2040	329,650.85	4,698.73	2,039.06	2.30
4/1/2040	330,240.09	4,699.03	2,039.29	2.30
5/1/2040	330,829.33	4,699.32	2,039.51	2.30
6/1/2040	331,418.58	4,699.62	2,039.74	2.30
7/1/2040	331,958.99	4,699.90	2,039.93	2.30
8/1/2040	332,499.40	4,700.19	2,040.11	2.30
9/1/2040	333,039.81	4,700.47	2,040.30	2.30
10/1/2040	333,530.88	4,700.74	2,040.52	2.30
11/1/2040	334,021.95	4,701.01	2,040.75	2.30
12/1/2040	334,513.02	4,701.28	2,040.98	2.30
1/1/2041	335,196.78	4,701.54	2,041.17	2.30
2/1/2041	335,880.55	4,701.80	2,041.35	2.30
3/1/2041	336,564.32	4,702.05	2,041.54	2.30
4/1/2041	337,114.72	4,702.30	2,041.74	2.30
5/1/2041	337,665.12	4,702.55	2,041.94	2.30
6/1/2041	338,215.52	4,702.79	2,042.14	2.30
7/1/2041	338,770.96	4,703.02	2,042.26	2.30

8/1/2041	339,326.41	4,703.25	2,042.38	2.30
9/1/2041	339,881.85	4,703.49	2,042.51	2.30
10/1/2041	340,422.97	4,703.71	2,042.71	2.30
11/1/2041	340,964.10	4,703.92	2,042.91	2.30
12/1/2041	341,505.22	4,704.14	2,043.11	2.30
1/1/2042	342,272.36	4,704.35	2,043.35	2.30
2/1/2042	343,039.49	4,704.56	2,043.59	2.30
3/1/2042	343,806.63	4,704.76	2,043.84	2.30
4/1/2042	344,382.21	4,704.96	2,044.02	2.30
5/1/2042	344,957.79	4,705.16	2,044.21	2.30
6/1/2042	345,533.37	4,705.35	2,044.40	2.30
7/1/2042	346,119.27	4,705.54	2,044.58	2.30
8/1/2042	346,705.17	4,705.72	2,044.77	2.30
9/1/2042	347,291.07	4,705.91	2,044.96	2.30
10/1/2042	347,877.72	4,706.08	2,045.17	2.30
11/1/2042	348,464.38	4,706.26	2,045.37	2.30
12/1/2042	349,051.04	4,706.43	2,045.57	2.30
1/1/2043	349,812.16	4,706.59	2,045.75	2.30
2/1/2043	350,573.27	4,706.76	2,045.93	2.30
3/1/2043	351,334.39	4,706.92	2,046.12	2.30
4/1/2043	351,922.01	4,707.07	2,046.29	2.30
5/1/2043	352,509.63	4,707.22	2,046.47	2.30
6/1/2043	353,097.25	4,707.38	2,046.65	2.30
7/1/2043	353,703.83	4,707.52	2,046.83	2.30
8/1/2043	354,310.41	4,707.66	2,047.01	2.30
9/1/2043	354,916.99	4,707.81	2,047.19	2.30
10/1/2043	355,524.31	4,707.94	2,047.37	2.30
11/1/2043	356,131.64	4,708.07	2,047.55	2.30
12/1/2043	356,738.96	4,708.21	2,047.73	2.30
1/1/2044	357,513.47	4,708.33	2,047.91	2.30
2/1/2044	358,287.99	4,708.45	2,048.09	2.30
3/1/2044	359,062.50	4,708.58	2,048.27	2.30
4/1/2044	359,653.38	4,708.69	2,048.45	2.30
5/1/2044	360,244.26	4,708.81	2,048.63	2.30
6/1/2044	360,835.13	4,708.93	2,048.81	2.30
7/1/2044	361,448.71	4,709.03	2,048.97	2.30
8/1/2044	362,062.29	4,709.14	2,049.13	2.30
9/1/2044	362,675.86	4,709.25	2,049.30	2.30
10/1/2044	363,292.31	4,709.35	2,049.46	2.30
11/1/2044	363,908.75	4,709.45	2,049.62	2.30
12/1/2044	364,525.20	4,709.55	2,049.79	2.30
1/1/2045	365,307.35	4,709.64	2,049.95	2.30
2/1/2045	366,089.49	4,709.73	2,050.11	2.30
3/1/2045	366,871.64	4,709.82	2,050.28	2.30
4/1/2045	367,474.75	4,709.90	2,050.43	2.30
5/1/2045	368,077.86	4,709.99	2,050.59	2.30
6/1/2045	368,680.97	4,710.07	2,050.75	2.30
7/1/2045	369,306.47	4,710.14	2,050.90	2.30
8/1/2045	369,931.97	4,710.22	2,051.06	2.30
9/1/2045	370,557.47	4,710.29	2,051.21	2.30
10/1/2045	371,186.24	4,710.36	2,051.36	2.30
11/1/2045	371,815.01	4,710.43	2,051.51	2.30
12/1/2045	372,443.78	4,710.49	2,051.66	2.30
1/1/2046	373,255.95	4,710.55	2,051.81	2.30
2/1/2046	374,068.13	4,710.61	2,051.96	2.30
3/1/2046	374,880.30	4,710.67	2,052.11	2.30
4/1/2046	375,485.85	4,710.73	2,052.25	2.30
5/1/2046	376,091.39	4,710.78	2,052.39	2.30
6/1/2046	376,696.94	4,710.83	2,052.53	2.30
7/1/2046	377,325.45	4,710.88	2,052.67	2.29
8/1/2046	377,953.96	4,710.93	2,052.82	2.29
9/1/2046	378,582.47	4,710.97	2,052.97	2.29
10/1/2046	379,219.24	4,711.02	2,053.12	2.29
11/1/2046	379,856.00	4,711.06	2,053.26	2.29
12/1/2046	380,492.77	4,711.10	2,053.40	2.29
1/1/2047	381,288.17	4,711.13	2,053.55	2.29
2/1/2047	382,083.58	4,711.17	2,053.70	2.29
3/1/2047	382,878.98	4,711.21	2,053.85	2.29
4/1/2047	383,488.76	4,711.24	2,054.00	2.29
5/1/2047	384,098.55	4,711.27	2,054.14	2.29
6/1/2047	384,708.33	4,711.31	2,054.29	2.29
7/1/2047	385,341.75	4,711.34	2,054.44	2.29
8/1/2047	385,975.17	4,711.37	2,054.60	2.29
9/1/2047	386,608.58	4,711.40	2,054.75	2.29
10/1/2047	387,244.88	4,711.43	2,054.89	2.29
11/1/2047	387,881.18	4,711.45	2,055.04	2.29
12/1/2047	388,517.48	4,711.48	2,055.18	2.29

1/1/2048	389,315.38	4,711.51	2,055.33	2.29
2/1/2048	390,113.28	4,711.53	2,055.48	2.29
3/1/2048	390,911.17	4,711.56	2,055.63	2.29
4/1/2048	391,518.25	4,711.59	2,055.78	2.29
5/1/2048	392,125.32	4,711.61	2,055.93	2.29
6/1/2048	392,732.40	4,711.63	2,056.08	2.29
7/1/2048	393,361.38	4,711.66	2,056.22	2.29
8/1/2048	393,990.36	4,711.68	2,056.37	2.29
9/1/2048	394,619.34	4,711.70	2,056.52	2.29
10/1/2048	395,261.77	4,711.73	2,056.67	2.29
11/1/2048	395,904.20	4,711.75	2,056.82	2.29
12/1/2048	396,546.62	4,711.77	2,056.97	2.29
1/1/2049	397,356.87	4,711.79	2,057.12	2.29
2/1/2049	398,167.12	4,711.81	2,057.27	2.29
3/1/2049	398,977.37	4,711.84	2,057.41	2.29
4/1/2049	399,606.85	4,711.86	2,057.56	2.29
5/1/2049	400,236.34	4,711.88	2,057.71	2.29
6/1/2049	400,865.82	4,711.90	2,057.86	2.29
7/1/2049	401,512.61	4,711.92	2,058.02	2.29
8/1/2049	402,159.41	4,711.93	2,058.18	2.29
9/1/2049	402,806.20	4,711.95	2,058.34	2.29
10/1/2049	403,466.21	4,711.97	2,058.50	2.29
11/1/2049	404,126.22	4,711.99	2,058.67	2.29
12/1/2049	404,786.23	4,712.01	2,058.84	2.29
1/1/2050	405,631.92	4,712.02	2,059.01	2.29
2/1/2050	406,477.62	4,712.04	2,059.19	2.29
3/1/2050	407,323.32	4,712.06	2,059.36	2.29
4/1/2050	408,040.17	4,712.08	2,059.55	2.29
5/1/2050	408,757.02	4,712.10	2,059.73	2.29
6/1/2050	409,473.88	4,712.12	2,059.92	2.29
7/1/2050	410,101.95	4,712.14	2,060.09	2.29
8/1/2050	410,730.02	4,712.16	2,060.27	2.29
9/1/2050	411,358.10	4,712.19	2,060.45	2.29
10/1/2050	411,994.92	4,712.21	2,060.62	2.29
11/1/2050	412,631.75	4,712.23	2,060.80	2.29
12/1/2050	413,268.57	4,712.26	2,060.97	2.29
1/1/2051	414,114.88	4,712.28	2,061.14	2.29
2/1/2051	414,961.20	4,712.31	2,061.31	2.29
3/1/2051	415,807.52	4,712.33	2,061.48	2.29
4/1/2051	416,472.22	4,712.36	2,061.65	2.29
5/1/2051	417,136.93	4,712.39	2,061.82	2.29
6/1/2051	417,801.64	4,712.42	2,061.99	2.29
7/1/2051	418,488.61	4,712.45	2,062.16	2.29
8/1/2051	419,175.57	4,712.48	2,062.34	2.29
9/1/2051	419,862.53	4,712.51	2,062.51	2.28
10/1/2051	420,551.70	4,712.54	2,062.69	2.28
11/1/2051	421,240.86	4,712.58	2,062.87	2.28
12/1/2051	421,930.03	4,712.61	2,063.04	2.28
1/1/2052	422,944.37	4,712.65	2,063.23	2.28
2/1/2052	423,958.72	4,712.68	2,063.42	2.28
3/1/2052	424,973.07	4,712.72	2,063.61	2.28
4/1/2052	425,675.10	4,712.76	2,063.80	2.28
5/1/2052	426,377.13	4,712.80	2,063.99	2.28
6/1/2052	427,079.17	4,712.84	2,064.18	2.28
7/1/2052	427,770.24	4,712.88	2,064.38	2.28
8/1/2052	428,461.31	4,712.92	2,064.57	2.28
9/1/2052	429,152.38	4,712.96	2,064.77	2.28
10/1/2052	429,849.88	4,713.01	2,064.96	2.28
11/1/2052	430,547.39	4,713.06	2,065.16	2.28
12/1/2052	431,244.89	4,713.11	2,065.35	2.28
1/1/2053	432,281.03	4,713.16	2,065.55	2.28
2/1/2053	433,317.17	4,713.21	2,065.74	2.28
3/1/2053	434,353.30	4,713.26	2,065.93	2.28
4/1/2053	435,053.29	4,713.32	2,066.13	2.28
5/1/2053	435,753.27	4,713.37	2,066.32	2.28
6/1/2053	436,453.25	4,713.43	2,066.52	2.28
7/1/2053	437,155.63	4,713.49	2,066.72	2.28
8/1/2053	437,858.02	4,713.55	2,066.93	2.28
9/1/2053	438,560.40	4,713.61	2,067.13	2.28
10/1/2053	439,283.02	4,713.67	2,067.34	2.28
11/1/2053	440,005.65	4,713.73	2,067.54	2.28
12/1/2053	440,728.27	4,713.80	2,067.75	2.28

Generation Differences by Unit, Base Period vs. Forecasted Test Period, KU[1]

GWh	Base Period	Forecasted Test Period	Difference	% Difference
Coal				
Brown 3	1,277	1,322	45	4%
Ghent 1	3,082	3,117	35	1%
Ghent 2	2,628	2,787	158	6%
Ghent 3	2,940	2,691	(249)	-8%
Ghent 4	2,444	2,471	27	1%
Mill Creek 1	N/A	N/A		
Mill Creek 2	N/A	N/A		
Mill Creek 3	N/A	N/A		
Mill Creek 4	N/A	N/A		
OVEC	246	219	(27)	-11%
Trimble County 1	N/A	N/A		
Trimble County 2	2,326	2,830	504	22%
SCCT				
Brown 5	39	63	24	61%
Brown 6	58	52	(6)	-10%
Brown 7	47	39	(9)	-18%
Brown 8	10	9	(1)	-11%
Brown 9	7	21	15	228%
Brown 10	9	25	16	174%
Brown 11	9	4	(5)	-56%
Haefling[2]	0.1	0.0	(0)	0%
Paddy's Run 12	N/A	N/A		
Paddy's Run 13	36	34	(2)	-5%
Trimble County 5	155	281	126	81%
Trimble County 6	124	218	94	76%
Trimble County 7	221	136	(85)	-38%
Trimble County 8	39	22	(17)	-43%
Trimble County 9	179	107	(72)	-40%
Trimble County 10	46	12	(34)	-74%
NGCC				
Cane Run 7	4,086	3,909	(177)	-4%
Hydro				
Dix Dam	84	90	6	7%
Ohio Falls	N/A	N/A		
Solar				
Brown Solar	10	10	0	5%
Mercer Co Solar	0	133	133	0%
Simpsonville Solar	2	3	1	29%
Total Coal	14,943	15,437	494	3%
Total SCCT	978	1,023	45	5%
Total NGCC	4,086	3,909	(177)	-4%
Total Hydro	84	90	6	7%
Total Solar	12	146	134	1118%
Grand Total	20,103	20,605	502	2%

[1] Generation volumes reflect KU's ownership share of the unit. "N/A" is shown for units with no KU ownership share. Net battery load/discharge not included.

[2] Due to their age and relative inefficiency, the Companies do not perform major maintenance on the small-frame Haefling SCCT Units 1-2 but continue to operate them until they are uneconomic to repair. This exhibit assumes they will be retired in 2026 for planning purposes.

Generation Differences by Unit, Base Period vs. Forecasted Test Period, LG&E[3]

GWh	Base Period	Forecasted Test Period	Difference	% Difference
Coal				
Brown 3	N/A	N/A		
Ghent 1	N/A	N/A		
Ghent 2	N/A	N/A		
Ghent 3	N/A	N/A		
Ghent 4	N/A	N/A		
Mill Creek 1[4]	205	0	(205)	-100%
Mill Creek 2	1,970	1,777	(192)	-10%
Mill Creek 3	2,460	2,254	(206)	-8%
Mill Creek 4	2,556	2,968	412	16%
OVEC	466	493	27	6%
Trimble County 1	2,633	2,755	122	5%
Trimble County 2	546	664	118	22%
SCCT				
Brown 5	44	71	27	61%
Brown 6	35	32	(3)	-10%
Brown 7	29	24	(5)	-18%
Brown 8	N/A	N/A		
Brown 9	N/A	N/A		
Brown 10	N/A	N/A		
Brown 11	N/A	N/A		
Haefling	N/A	N/A		
Paddy's Run 12[5]	0.04	0.00	-0.04	0%
Paddy's Run 13	40	38	(2)	-6%
Trimble County 5	63	115	51	81%
Trimble County 6	51	89	39	76%
Trimble County 7	130	80	(50)	-38%
Trimble County 8	23	13	(10)	-43%
Trimble County 9	105	63	(42)	-40%
Trimble County 10	27	7	(20)	-74%
NGCC				
Cane Run 7	1,153	1,103	(50)	-4%
Hydro				
Dix Dam	N/A	N/A		
Ohio Falls	269	275	6	2%
Solar				
Brown Solar	6	7	0	5%
Mercer Co Solar	0	78	78	0%
Simpsonville Solar	2	2	0	29%
Total Coal	10,835	10,911	76	1%
Total SCCT	548	531	(16)	-3%
Total NGCC	1,153	1,103	(50)	-4%
Total Hydro	269	275	6	2%
Total Solar	8	87	79	990%
Grand Total	12,812	12,906	94	1%

[3] Generation volumes reflect LG&E's ownership share of the unit. "N/A" is shown for units with no LG&E ownership share. Net battery load/discharge not included.

[4] Mill Creek 1 was retired four months into the base period on 12/31/2024.

[5] Due to its age and relative inefficiency, the Companies do not perform major maintenance on the small-frame Paddy's Run Unit 12 SCCT but continue to operate it until it is uneconomic to repair. This exhibit assumes it will be retired in 2026 for planning purposes.

Generation Differences by Unit, Base Period vs. Forecasted Test Period, Combined Company[6]

GWh	Base Period	Forecasted Test Period	Difference	% Difference
Coal				
Brown 3	1,277	1,322	45	4%
Ghent 1	3,082	3,117	35	1%
Ghent 2	2,628	2,787	158	6%
Ghent 3	2,940	2,691	(249)	-8%
Ghent 4	2,444	2,471	27	1%
Mill Creek 1	205	0	(205)	-100%
Mill Creek 2	1,970	1,777	(192)	-10%
Mill Creek 3	2,460	2,254	(206)	-8%
Mill Creek 4[7]	2,556	2,968	412	16%
OVEC	712	712	(0)	0%
Trimble County 1	2,633	2,755	122	5%
Trimble County 2	2,871	3,493	622	22%
SCCT				
Brown 5	83	133	50	61%
Brown 6	93	84	(9)	-10%
Brown 7	76	62	(14)	-18%
Brown 8	10	9	(1)	-11%
Brown 9	7	21	15	228%
Brown 10	9	25	16	174%
Brown 11	9	4	(5)	-56%
Haefling[8]	0.1	0.0	-0.1	0%
Paddy's Run 12[8]	0.04	0.00	-0.04	0%
Paddy's Run 13	76	72	(4)	-6%
Trimble County 5	218	395	177	81%
Trimble County 6	175	308	133	76%
Trimble County 7	351	216	(135)	-38%
Trimble County 8	62	36	(27)	-43%
Trimble County 9	285	170	(114)	-40%
Trimble County 10	73	19	(54)	-74%
NGCC				
Cane Run 7	5,239	5,012	(227)	-4%
Hydro				
Dix Dam	84	90	6	7%
Ohio Falls	269	275	6	2%
Solar				
Brown Solar	16	17	1	5%
Mercer Co Solar	0	211	211	N/A
Simpsonville Solar	4	5	1	29%
Total Coal	25,778	26,348	570	2%
Total SCCT	1,526	1,554	28	2%
Total NGCC	5,239	5,012	(227)	-4%
Total Hydro	353	364	12	3%
Total Solar	20	233	213	1067%
Grand Total	32,915	33,512	596	2%

[6] Generation volumes reflect the Companies' ownership share of the unit. Net battery load/discharge not included.
[7] Mill Creek 1 was retired four months into the base period on 12/31/2024.
[8] Due to their age and relative inefficiency, the Companies do not perform major maintenance on their small-frame SCCTs, Paddy's Run Unit 12 and Haefling Units 1-2, but continue to operate them until they are uneconomic to repair. This exhibit assumes they will be retired in 2026 for planning purposes.

2026-2027
Qualifying Facilities Rates & Net Metering Service-2 Bill Credit

LG&E KU
PPL companies

Generation Planning & Analysis

May 2025

Table of Contents

1 Introduction

According to the Public Utility Regulatory Policies Act of 1978 ("PURPA") as implemented in Kentucky by Commission regulations, Louisville Gas and Electric Company and Kentucky Utilities Company (collectively, "the Companies") have an obligation to purchase the electrical output of certain types and sizes of renewable or cogeneration electric generating facilities at the utility's avoided cost; such facilities are qualifying facilities ("QFs").[1] For example, the Commission's QF regulation obligates a serving utility to purchase the output of a renewable generator of up to 80 MW under certain conditions.[2] In compliance with the Commission's QF regulation, the Companies' have two QF standard rate riders:

- SQF – for small (100 kW or less) QFs and
- LQF – for QFs greater than 100 kW.

The Commission's QF regulation is clear that compensation for QFs "shall be based on avoided costs."[3] The regulation defines avoided costs to be "incremental costs to an electric utility of electric energy or capacity or both which, if not for the purchase from the qualifying facility, the utility would generate itself or purchase from another source."[4] Avoided energy and capacity costs are provided for the following QF technologies: single-axis tracking solar ("Solar SAT"), fixed tilt solar ("Solar FT"), wind, and other fully-dispatchable technologies ("Other Technologies" or "Other").

2 Avoided Energy Cost

The Companies evaluated the impact on system energy costs for each Qualifying Facility ("QF") technology using forecasted hourly energy costs developed in PROSYM. Assumptions for computing hourly energy costs included the resource-constrained load forecast and approval of the resource portfolio the Companies proposed in Case No. 2025-00045 ("2025 CPCN Plan").[5,6] To focus the analysis on the cost of the Companies' resources serving native load, market electricity purchases and off-system sales were not permitted in PROSYM.

Avoided energy costs include the cost of fuel, emission control reagents (e.g., limestone, ammonia), emission allowance costs, and an opportunity cost for lost CCR revenues.[7] Table 1 lists the QF technologies for which avoided energy costs were computed and their assumed capacity factors for resources sited in Kentucky. The QF generation profiles were developed to ensure the profiles are properly correlated with load (i.e., both load and the renewable generation profiles are forecasted based on a common set of temperature, solar irradiance, and wind speed data). A generation profile was developed for each QF technology with an assumed nameplate capacity of 80 MW, the maximum nameplate capacity for a QF.

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[1] *See* 807 KAR 5:054.
[2] *See, e.g.,* 807 KAR 5:054 Section 1(10).
[3] *See* 807 KAR 5:054 Section 7(2) and (4).
[4] 807 KAR 5:054 Section 1(1).
[5] Attachment A contains a description of the Companies' generation forecast process. Attachments B-E contain model inputs and outputs in Excel and native formats.
[6] *See, e.g., Electronic Application of Kentucky Utilities Company and Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity and Site Compatibility Certificates*, Case No. 2025-00045, Application (Feb. 28, 2025).
[7] The cost of fuel accounts for approximately 90% of total avoided energy costs.

Table 1: QF Generation Technologies

Technology	Capacity Factor
Solar: Single-Axis Tracking	24.7%
Solar: Fixed Tilt	15.5%
Wind	31.7%
Other Technologies	Varies

To compute the avoided cost of energy for each generation technology, the Companies first computed the decremental cost of energy for each megawatt-hour ("MWh") of generation in each hour of the forecast period (2026-2033). Then, for each hour and generation technology, the avoided cost of energy was computed with the assumption that the highest-cost energy would be avoided first. For example, in an hour where the QF technology was assumed to produce 40 MWh, the Companies sorted each MWh from highest to lowest cost and computed the avoided cost of energy as the sum of decremental energy costs for the top 40 MWh.

The Companies performed this analysis using the three "Expected Coal-to-Gas ("CTG") Ratio" fuel price scenarios presented in their 2024 IRP and Case No. 2025-00045:

- Low Gas, Mid CTG ("Low Fuel")
- Mid Gas, Mid CTG ("Mid Fuel")
- High Gas, Mid CTG ("High Fuel")

The results of this analysis are summarized in Table 2. For each technology, the average avoided energy cost for each year of the analysis period was computed by dividing total avoided costs by total QF generation. Avoided energy costs for the QF technologies are very similar.

Table 2: Annual Avoided Energy Cost by Fuel Price Scenario ($/MWh)

	Low Fuel				Mid Fuel				High Fuel			
Year	Solar SAT	Solar FT	Wind	Other	Solar SAT	Solar FT	Wind	Other	Solar SAT	Solar FT	Wind	Other
2026	22.89	22.92	22.06	22.15	27.96	28.01	27.00	27.07	44.68	44.74	42.99	43.07
2027	21.50	21.54	20.82	20.68	27.63	27.63	27.06	26.86	44.49	44.47	43.78	43.39
2028	26.32	26.42	24.13	24.75	33.27	33.39	31.24	31.74	51.28	51.52	49.24	49.53
2029	27.25	27.39	24.73	25.97	34.93	35.18	32.38	33.51	53.00	53.42	50.45	51.43
2030	26.18	26.22	23.61	24.54	35.20	35.25	32.81	33.58	54.24	54.31	52.03	52.45
2031	25.79	25.73	23.72	24.25	35.90	35.83	34.16	34.50	55.73	55.74	54.16	54.23
2032	25.44	25.58	23.13	24.14	36.45	36.53	34.30	35.06	56.79	56.76	54.97	55.28
2033	24.97	25.18	23.11	23.70	36.70	36.86	35.06	35.41	57.54	57.70	55.92	56.05

To develop QF rates, the annual avoided energy costs were averaged over the three fuel price scenarios. Table 3 shows the average annual avoided energy cost for each QF technology.

Table 3: Average Annual Avoided Energy Cost ($/MWh)

Year	Solar SAT	Solar FT	Wind	Other
2026	31.84	31.89	30.68	30.76
2027	31.21	31.21	30.55	30.31
2028	36.96	37.11	34.87	35.34
2029	38.39	38.66	35.85	36.97
2030	38.54	38.59	36.15	36.86
2031	39.14	39.10	37.35	37.66
2032	39.56	39.63	37.47	38.16
2033	39.74	39.91	38.03	38.39

To simplify administration, the average avoided energy costs in Table 3 were levelized to produce the avoided energy prices shown in Table 4.[8] Table 4 shows the avoided energy prices for a 2-year PPA effective in 2026 through 2027 and for 7-year PPAs beginning in 2026 and 2027.[9]

Table 4: Avoided Energy Costs ($/MWh)

Technology	2-Year PPA (2026-2027)	7-Year Level Price for PPAs Beginning: 2026	7-Year Level Price for PPAs Beginning: 2027
Solar: Single-Axis Tracking	31.52	36.15	37.35
Solar: Fixed Tilt	31.55	36.23	37.45
Wind	30.62	34.38	35.48
Other Technologies	30.54	34.80	35.95

3 Avoided Capacity Cost

For a given technology and PPA term, an avoided capacity price (in $/MWh) is computed as a function of the QF PPA's contribution to the timing and size of the Companies' future need for capacity and the cost of new capacity. Each of these items and the method for computing levelized costs for tariff purposes are discussed in the following sections.

3.1 Contribution to Timing and Size of Future Need for Capacity

Avoided capacity cost represents capacity costs that can be avoided by adding a QF PPA to the Companies' resource portfolio. Capacity costs can be avoided by deferring the need for additional capacity or decreasing the amount of capacity needed.

Consistent with the 2024 IRP, the Companies assumed 84% and 0% contribution to peak for solar in summer and winter, respectively. As discussed in Section 3.1 of the 2024 IRP Volume III Resource Assessment, the Companies model wind resources as energy-only resources. However, for the purposes of this analysis, the Companies assumed 11% and 35% contribution to peak for wind in summer and

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[8] The levelized cost of energy was computed with the discount rate used to compute the present value of revenue requirements (6.56%).

[9] Avoided energy prices for the 2-year PPA are computed as the average of avoided energy costs in 2026 and 2027.

winter, respectively.[10] The capacity contribution of "other technologies" was assumed to be 100% in summer and winter.

To evaluate each technology's contribution to the timing and size of the Companies' future need for capacity, 80 MW of each QF technology was added to the Companies' currently approved resource portfolio in PLEXOS and resulting optimal resource plans were compared to the portfolio with no QF PPAs.[11] Table 5 shows the results of this analysis. The 2025 CPCN Resource Plan is shown on the top row with results from individually adding each QF resource displayed in the rows below. Results that are consistent with the base portfolio are shown in grey while changes resulting from the addition of the 80 MW QF are shown in red.

Table 5: PLEXOS Results

	Expected CTG Ratio			**Atypical CTG Ratio**	
	Low Gas, Mid CTG	**Mid Gas, Mid CTG**	**High Gas, Mid CTG**	**Low Gas, High CTG**	**High Gas, Low CTG**
2025 CPCN Resource Plan	Brown 12; Mill Creek 6; 600 MW 4hr BESS; GH2 SCR	Brown 12; Mill Creek 6; 600 MW 4hr BESS; GH2 SCR	Brown 12; Mill Creek 6; 600 MW 4hr BESS; GH2 Non-Ozone; 815 MW Solar	Brown 12; Mill Creek 6; 600 MW 4hr BESS; GH2 SCR	Brown 12; Mill Creek 6; 600 MW 4hr BESS; GH2 Non-Ozone; 815 MW Solar
Base + 80 MW Single-Axis Tracking Solar	Brown 12; Mill Creek 6; 600 MW 4hr BESS; GH2 SCR	Brown 12; Mill Creek 6; 600 MW 4hr BESS; GH2 SCR	Brown 12; Mill Creek 6; 600 MW 4hr BESS; GH2 Non-Ozone; 815 MW Solar	Brown 12; Mill Creek 6; 600 MW 4hr BESS; GH2 SCR	Brown 12; Mill Creek 6; 600 MW 4hr BESS; GH2 Non-Ozone; 815 MW Solar
Base + 80 MW Fixed-Tilt Solar	Brown 12; Mill Creek 6; 600 MW 4hr BESS; GH2 SCR	Brown 12; Mill Creek 6; 600 MW 4hr BESS; GH2 SCR	Brown 12; Mill Creek 6; 600 MW 4hr BESS; GH2 Non-Ozone; 815 MW Solar	Brown 12; Mill Creek 6; 600 MW 4hr BESS; GH2 SCR	Brown 12; Mill Creek 6; 600 MW 4hr BESS; GH2 Non-Ozone; 815 MW Solar
Base + 80 MW Wind	Brown 12; Mill Creek 6; 600 MW 4hr BESS; GH2 SCR	Brown 12; Mill Creek 6; 600 MW 4hr BESS; GH2 SCR	Brown 12; Mill Creek 6; 600 MW 4hr BESS; GH2 Non-Ozone; 815 MW Solar	Brown 12; Mill Creek 6; 600 MW 4hr BESS; GH2 SCR	Brown 12; Mill Creek 6; 600 MW 4hr BESS; GH2 Non-Ozone; 815 MW Solar
Base + 80 MW Other Tech	Brown 12; Mill Creek 6; 200 MW 4hr BESS; 1 SCCT; GH2 SCR	Brown 12; Mill Creek 6; 600 MW 4hr BESS; GH2 SCR	Brown 12; Mill Creek 6; 500 MW 4hr BESS; GH2 Non-Ozone; 815 MW Solar	Brown 12; Mill Creek 6; 200 MW 4hr BESS; 1 SCCT; GH2 SCR	Brown 12; Mill Creek 6; 500 MW 4hr BESS; GH2 Non-Ozone; 815 MW Solar

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[10] Wind capacity contributions are based on the median generation output during the most common peak hour in winter and summer months. This differs from the Companies' assumption of zero winter and summer capacity contribution from wind in the 2024 IRP due to the need to model some capacity contribution for the purpose of this analysis.

[11] The Companies' currently approved resource portfolio includes the retirement of Mill Creek 2 and the addition of Mill Creek 5 and Brown BESS in 2027, and the addition of Mercer County and Marion County solar facilities in 2026 and 2027, respectively.

As Table 5 shows, 80 MW QF PPAs of single-axis tracking solar, fixed tilt solar, and wind do not result in any changes to the Companies' optimal resource plan. For this reason, the Companies recommend the avoided capacity cost for single-axis tracking solar, fixed tilt solar, and wind QF PPAs be zero. However, 80 MW of "other" fully dispatchable technologies does result in a decreased amount of Cane Run BESS in four out of five fuel price scenarios. Therefore, the Companies recommend an avoided capacity cost for Other Technologies based on Cane Run BESS costs. Furthermore, because the Companies are transitioning from lower economic minimum reserve margins to higher minimum reserve margins developed to reduce the loss of load expectation to one day in ten years, the capacity need is assumed to be immediate, in 2026.[12]

3.2 Cost of New Capacity

Because 80 MW of "other" fully dispatchable technologies results in a decreased amount of Cane Run BESS in four out of five fuel price scenarios, the Companies recommend using the cost of Cane Run BESS as the cost of new capacity to calculate avoided capacity costs. Table 6 summarizes the capital and fixed operating costs for Cane Run BESS, consistent with the Companies' cost assumptions in Case No. 2025-00045.

Table 6: Cane Run BESS Capital and Fixed Operating Costs (2030 Installation; 2030 Dollars)

Cost	Cane Run BESS
Capital Cost ($/kW)	1,954
Fixed O&M ($/kW-yr)	25
Investment Tax Credit[13]	50%

Table 7 contains the economic carrying charge for Cane Run BESS based on the cost assumptions in Table 6**Error! Reference source not found.**.

Table 7: Cane Run BESS Economic Carrying Charge ($/MW-Year)

Year	Cane Run BESS Economic Carrying Charge
2026	127,684
2027	128,236
2028	128,437
2029	129,345
2030	129,904
2031	130,465
2032	130,670
2033	131,594

[12] Appendix A contains Summer and Winter Peak Demand and Resource Summary tables showing capacity need by year for the 2025 CPCN Plan.

[13] Cane Run BESS is assumed to be eligible for 50% ITC. However, due to tariff changes, the project may not be able to meet the domestic content requirements for the 10% bonus credit, in which case the project would be eligible for 40% ITC instead of 50%.

Because "other" technologies are assumed to be fully dispatchable, the Companies assume 120% of these costs could be avoided.[14] Table 8 shows the resulting annual avoided capacity costs based on the cost of Cane Run BESS.

Table 8: Annual Avoided Capacity Costs Based on Cane Run BESS Cost ($/MW-Year)

Year	Other Technologies
2026	153,837
2027	154,501
2028	154,744
2029	155,838
2030	156,510
2031	157,186
2032	157,434
2033	158,546

To compute avoided capacity costs on a $/MWh basis, the annual values in Table 8 were divided by 8,760 hours.

Table 9: Avoided Capacity Costs Based on Cane Run BESS Cost ($/MWh)

Year	Other Technologies
2026	17.56
2027	17.64
2028	17.66
2029	17.79
2030	17.87
2031	17.94
2032	17.97
2033	18.10

3.3 Calculation of Avoided Capacity Prices

As noted previously, for a given technology and PPA term, the avoided capacity price is computed as a function of the QF PPA's contribution to the timing and size of the Companies' future need for capacity and the cost of new capacity. For example, a 7-year QF PPA beginning 2026 would defer the need for capacity in 2026 by 7 years to 2033.

Table 9**Error! Reference source not found.** shows the avoided capacity costs for 7-year QF PPAs beginning in 2026 based on the cost of Cane Run BESS. Because the Companies are transitioning from lower economic reserve margins to higher minimum reserve margins developed to reduce the loss of load expectation to one day in ten years, the capacity need is assumed to be immediate, in 2026. Therefore,

[14] The capacity contribution of BESS assuming the resources in the 2025 CPCN Plan was determined to be 83%. To scale the BESS capital cost to fully dispatchable "other technologies," an availability factor of 120% (100% divided by 83%) was used to calculate avoided capacity costs based on BESS.

the avoided capacity costs in Table 9 represent the annual avoided capacity costs for a 7-year QF PPA for other technologies.

To compute the avoided capacity price for a 7-year QF PPA beginning in 2026, the Companies levelized the values in Table 9**Error! Reference source not found.** over the period 2026 to 2032, resulting in a 2026-2032 levelized avoided capacity price for a 7-year QF PPA for other technologies beginning in 2026 of $17.76/MWh.

This calculation was completed for 7-year QF PPAs for other technologies beginning in 2026 and 2027. The results are summarized in **Error! Reference source not found.**.

Table 10: Avoided Capacity Prices, 2026 Capacity Need ($/MWh)

	2-Year PPA	**7-Year PPA Beginning:**	
Technology	**(2026-2027)**	**2026**	**2027**
Solar: Single-Axis Tracking	0.00	0.00	0.00
Solar: Fixed Tilt	0.00	0.00	0.00
Wind	0.00	0.00	0.00
Other Technologies	0.00	17.76	17.83

4 Total Avoided Cost

Table 11 contains the Companies' all-in avoided cost rates as the sum of the avoided energy costs in Table 4 and avoided capacity prices in **Error! Reference source not found.**.

Table 11: All-In Avoided Cost Rates, 2026 Capacity Need ($/MWh)

	2-Year PPA	**7-Year PPA Beginning:**	
Technology	**(2026-2027)**	**2026**	**2027**
Solar: Single-Axis Tracking	31.52	36.15	37.35
Solar: Fixed Tilt	31.55	36.23	37.45
Wind	30.62	34.38	35.48
Other Technologies	30.54	52.55	53.79

5 QF Rates

Table 12 through Table 18 show the Companies' recommended QF Avoided Cost Rates based on the Companies' 2025 CPCN Plan, the levelized cost of Cane Run BESS for avoided capacity cost for other technologies, and a 2026 capacity need.

Table 12: Qualifying Facility Avoided Energy Rates for Transmission Connected Projects, without Line Losses ($/MWh)

	QF Avoided Energy (without line losses for transmission connected projects)		
		7-Year PPA Beginning:	
Technology	**2-Year PPA**	**2026**	**2027**
Solar: Single-Axis Tracking	31.52	36.15	37.35
Solar: Fixed Tilt	31.55	36.23	37.45
Wind	30.62	34.38	35.48
Other Technologies	30.54	34.80	35.95

Table 13: Qualifying Facility Avoided Capacity Rates for Transmission Connected Projects, without Line Losses ($/MWh)

	QF Avoided Capacity, 2026 Need (without line losses for transmission connected projects)		
		7-Year PPA Beginning:	
Technology	**2-Year PPA**	**2026**	**2027**
Solar: Single-Axis Tracking	0.00	0.00	0.00
Solar: Fixed Tilt	0.00	0.00	0.00
Wind	0.00	0.00	0.00
Other Technologies	0.00	17.76	17.83

Table 14: Qualifying Facility Avoided Cost Rates for Transmission Connected Projects, without Line Losses ($/MWh)

	QF All-In Avoided Cost Rates (without line losses for transmission connected projects)	
Technology	**2-Year PPA**	**2026/2027 Avoided Cost Rate**
Solar: Single-Axis Tracking	31.52	36.75
Solar: Fixed Tilt	31.55	36.84
Wind	30.62	34.93
Other Technologies	30.54	53.17

Table 15 contains the Companies' assumptions for line losses used to calculate QF rates with line losses.

Table 15: Line Losses

	KU	**LG&E**
Energy Losses	4.748%	2.772%
Capacity Losses	6.449%	4.139%

Table 16: Qualifying Facility Avoided Energy Rates by Company, with Line Losses ($/MWh)

Technology	QF Avoided Energy, KU (with line losses)			QF Avoided Energy, LG&E (with line losses)		
	2-Year PPA	7-Year PPA Beginning: 2026	7-Year PPA Beginning: 2027	2-Year PPA	7-Year PPA Beginning: 2026	7-Year PPA Beginning: 2027
Solar: Single-Axis Tracking	33.02	37.86	39.13	32.40	37.15	38.39
Solar: Fixed Tilt	33.05	37.95	39.23	32.43	37.23	38.49
Wind	32.07	36.01	37.17	31.47	35.33	36.47
Other Technologies	31.99	36.45	37.66	31.38	35.76	36.95

Table 17: Qualifying Facility Avoided Capacity Rates by Company, with Line Losses ($/MWh)

Technology	QF Avoided Capacity, 2026 Need, KU (with line losses)			QF Avoided Capacity, 2026 Need, LG&E (with line losses)		
	2-Year PPA	7-Year PPA Beginning: 2026	7-Year PPA Beginning: 2027	2-Year PPA	7-Year PPA Beginning: 2026	7-Year PPA Beginning: 2027
Solar: Single-Axis Tracking	0.00	0.00	0.00	0.00	0.00	0.00
Solar: Fixed Tilt	0.00	0.00	0.00	0.00	0.00	0.00
Wind	0.00	0.00	0.00	0.00	0.00	0.00
Other Technologies	0.00	18.90	18.98	0.00	18.49	18.57

Table 18: Qualifying Facility All-In Avoided Cost Rates for 2-Year and 7-Year PPAs by Company, with Line Losses ($/MWh)

	QF All-In Avoided Cost Rate, KU		QF All-In Avoided Cost Rate, LG&E	
	2-Year PPA	2026/2027 Avoided Cost Rate	2-Year PPA	2026/2027 Avoided Cost Rate
Solar: Single-Axis Tracking	33.02	38.50	32.40	37.77
Solar: Fixed Tilt	33.05	38.59	32.43	37.86
Wind	32.07	36.59	31.47	35.90
Other Technologies	31.99	56.00	31.38	54.89

The Companies continue to recommend limiting QF capacity to the lower of the actual need or 1,000 MW. Like the capacity limits in the Companies' Green Tariff Option #3, the 1,000 MW limit will provide an intermittent generation "circuit breaker" for assessing grid reliability in a scenario where a large amount of QFs are constructed in the Companies' service territories.

6 NMS-2 Bill Credit

The Companies continue to recommend the energy and generation capacity components of the Companies' NMS-2 bill credits be based on QF rates for the fixed tilt solar technology. Table 19 shows those two components of the NMS-2 bill credits using the updated QF rates presented here, based on the average of the 7-year PPA prices (with line losses) for fixed-tilt solar PPAs beginning in 2026 and 2027 (see Table 16 and Table 17).[15]

[15] For example, the energy component of LG&E's NMS-2 bill credit ($0.03786/kWh) is the average of the 7-year QF PPA prices in Table 16 for fixed-tilt solar PPAs beginning in 2026 ($37.23/MWh or $0.03723/kWh) and 2027 ($38.49/MWh or $0.03849/kWh). Furthermore, the sum of the energy and generation capacity components is equal to the QF all-in avoided cost rate for fixed-tilt solar ($37.86/MWh or $0.03786/kWh) in Table 18.

Table 19: Energy and Generation Capacity Components of NMS-2 Bill Credits ($/kWh)

LG&E NMS-2 Bill Credit	
Energy	0.03786
Generation Capacity	-
KU NMS-2 Bill Credit	
Energy	0.03859
Generation Capacity	-

7 Appendix A

Table 20: Winter Peak Demand and Resource Summary (2025 CPCN Plan, MW)

	2026	2027	2028	2029	2030	2031	2032	2040	2050
Peak Load	**6,150**	**6,227**	**6,481**	**6,851**	**6,846**	**7,388**	**7,930**	**7,928**	**7,940**
Fully Dispatchable Generation Resources									
Existing Resources	7,909	7,977	7,977	7,977	7,977	7,977	7,977	7,977	7,977
Retirements/Additions									
Coal[16]	-300	-300	-597	-601	-601	-601	-601	-1,017	-1,175
Large-Frame SCCTs[17]	0	0	0	0	0	0	0	0	258
Small-Frame SCCTs[18]	-55	-55	-55	-55	-55	-55	-55	-55	-55
NGCC[19]	0	0	660	660	660	1,320	1,980	1,980	1,980
Total	7,554	7,622	7,985	7,981	7,981	8,641	9,301	8,885	8,985
Reserve Margin	22.8%	22.4%	23.2%	16.5%	16.6%	17.0%	17.3%	12.1%	13.2%
Renewable/Limited-Duration Resources									
Existing Resources	72	72	72	72	72	72	72	72	72
Existing CSR	111	111	111	111	111	111	111	111	111
Existing Disp. DSM[20]	60	82	110	124	125	135	145	163	163
Retirements/Additions									
Solar[21]	0	0	0	0	0	0	0	0	0
BESS[22]	0	125	125	525	525	525	525	940	940
Disp. DSM[20]	0	0	1	1	1	2	2	5	5
Total	242	389	418	832	834	843	854	1,290	1,290
Total Supply	**7,796**	**8,011**	**8,403**	**8,813**	**8,815**	**9,484**	**10,155**	**10,175**	**10,275**
Total Reserve Margin	**26.8%**	**28.7%**	**29.7%**	**28.6%**	**28.8%**	**28.4%**	**28.1%**	**28.3%**	**29.4%**
Capacity Need[23]	**137**	**22**	**-43**	**24**	**16**	**46**	**74**	**52**	**-33**

[16] Mill Creek 1 was retired at the end of 2024. Mill Creek 2 is assumed to retire after Mill Creek 5 is commissioned in 2027. The Ghent 2 SCR is assumed to be in-service in March 2028. Brown 3 is assumed to retire in 2035. OVEC is assumed to retire in June 2040 at the end of the OVEC ICPA.

[17] This analysis assumes one SCCT is added in June 2040 with the end of the OVEC ICPA.

[18] Due to their age and relative inefficiency, the Companies do not perform major maintenance on their small-frame SCCTs, Paddy's Run Unit 12 and Haefling Units 1-2, but continue to operate them until they are uneconomic to repair. This analysis assumes that they will be retired in 2026 for planning purposes.

[19] Mill Creek 5 is assumed in-service in June 2027, Brown 12 is assumed in-service in June 2030, and Mill Creek 6 is assumed in-service in June 2031.

[20] Dispatchable DSM reflects expected load reductions under normal peak weather conditions. New dispatchable DSM reflects 39% capacity contribution.

[21] This analysis assumes 120 MW of company-owned solar capacity is added in December 2026, and an additional 120 MW of company-owned solar capacity is added in June 2027. Solar capacity values reflect 0% expected contribution to winter peak capacity.

[22] Brown BESS is assumed in-service in January 2027. Cane Run BESS is assumed in-service in March 2028. An additional 500 MW 4-hr BESS is assumed in-service in March 2035 with the assumed retirement of Brown 3 and reflects 83% capacity contribution.

[23] The winter capacity need is based on a 29% winter minimum reserve margin target. Positive values reflect a capacity deficit.

Table 21: Summer Peak Demand and Resource Summary (2025 CPCN Plan, MW)

	2026	2027	2028	2029	2030	2031	2032	2040	2050
Peak Load	**6,242**	**6,434**	**6,795**	**6,951**	**7,469**	**8,040**	**8,034**	**7,992**	**7,967**
Fully Dispatchable Generation Resources									
Existing Resources	7,618	7,618	7,618	7,618	7,618	7,618	7,618	7,618	7,618
Retirements/Additions									
Coal[24]	-300	-597	-601	-601	-601	-601	-601	-1,165	-1,165
Large-Frame SCCTs[25]	0	0	0	0	0	0	0	243	243
Small-Frame SCCTs[26]	-47	-47	-47	-47	-47	-47	-47	-47	-47
NGCC[27]	0	645	645	645	1,290	1,935	1,935	1,935	1,935
Total	7,271	7,619	7,615	7,615	8,260	8,905	8,905	8,584	8,584
Reserve Margin	16.5%	18.4%	12.1%	9.5%	10.6%	10.8%	10.8%	7.4%	7.7%
Renewable/Limited-Duration Resources									
Existing Resources	107	107	107	107	107	107	107	107	107
Existing CSR	107	107	107	107	107	107	107	107	107
Existing Disp. DSM[28]	97	119	150	166	170	179	190	227	227
Retirements/Additions									
Solar[29]	0	201	201	201	201	201	201	201	201
BESS[30]	0	125	525	525	525	525	525	940	940
Disp. DSM[28]	0	0	1	1	1	2	2	5	5
Total	310	659	1,090	1,106	1,111	1,120	1,132	1,586	1,586
Total Supply	**7,581**	**8,278**	**8,705**	**8,721**	**9,371**	**10,025**	**10,037**	**10,170**	**10,170**
Total Reserve Margin	**21.5%**	**28.7%**	**28.1%**	**25.5%**	**25.5%**	**24.7%**	**24.9%**	**27.3%**	**27.7%**
Capacity Need[31]	**96**	**-364**	**-347**	**-171**	**-185**	**-136**	**-154**	**-340**	**-371**

[24] Mill Creek 1 was retired at the end of 2024. Mill Creek 2 is assumed to retire after Mill Creek 5 is commissioned in 2027. The Ghent 2 SCR is assumed to be in-service in March 2028. Brown 3 is assumed to retire in 2035. OVEC is assumed to retire in June 2040 at the end of the OVEC ICPA.

[25] This analysis assumes one SCCT is added in June 2040 with the end of the OVEC ICPA.

[26] Due to their age and relative inefficiency, the Companies do not perform major maintenance on their small-frame SCCTs, Paddy's Run Unit 12 and Haefling Units 1-2, but continue to operate them until they are uneconomic to repair. This analysis assumes that they will be retired in 2026 for planning purposes.

[27] Mill Creek 5 is assumed in-service in June 2027, Brown 12 is assumed in-service in June 2030, and Mill Creek 6 is assumed in-service in June 2031.

[28] Dispatchable DSM reflects expected load reductions under normal peak weather conditions. New dispatchable DSM reflects 39% capacity contribution.

[29] This analysis assumes 120 MW of company-owned solar capacity is added in December 2026, and an additional 120 MW of company-owned solar capacity is added in June 2027. Solar capacity values reflect 83.7% expected contribution to summer peak capacity.

[30] Brown BESS is assumed in-service in January 2027. Cane Run BESS is assumed in-service in March 2028. An additional 500 MW 4-hr BESS is assumed in-service in March 2035 with the assumed retirement of Brown 3 and reflects 83% capacity contribution.

[31] The summer capacity need is based on a 23% summer minimum reserve margin target. Positive values reflect a capacity deficit.