COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF KENTUCKY	**)**	
UTILITIES COMPANY AND LOUISVILLE GAS	**)**	
AND ELECTRIC COMPANY FOR CERTIFICATES	**)**	**CASE NO.**
OF PUBLIC CONVENIENCE AND NECESSITY	**)**	**2025-00045**
AND SITE COMPATIBILITY CERTIFICATES	**)**	

DIRECT TESTIMONY OF
STUART A. WILSON
DIRECTOR, ENERGY PLANNING, ANALYSIS AND FORECASTING
ON BEHALF OF
KENTUCKY UTILITIES COMPANY AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Filed: February 28, 2025

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INTRODUCTION

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

A. My name is Stuart A. Wilson. I am the Director of Energy Planning, Analysis and Forecasting 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 a number of times, including the Companies' most recent certificate of public convenience and necessity ("CPCN") and demand-side management and energy efficiency ("DSM-EE") plan proceeding, Case No. 2022-00402 ("2022 CPCN-DSM Case").[1]

Q. Please describe your current job responsibilities.

A. I have three primary areas of responsibility: (i) gas and electric sales forecasting, (ii) generation planning, and (iii) economic analysis. Broadly speaking, the ongoing task of the Energy Planning, Analysis and Forecasting group is to ensure the Companies have adequate resources available to reliably and economically meet customers' needs at all times, in every weather condition, and across a wide range of possible future scenarios. To do that, our group regularly refreshes (at least annually) the Companies'

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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 and Approval of a Demand Side Management Plan and Approval of Fossil Fuel-Fired Generation Unit Retirements*, Case No. 2022-00402, Direct Testimony of Stuart A. Wilson (December 15, 2022); Case No. 2022-00402, Rebuttal Testimony of Stuart A. Wilson (Aug. 9, 2023).

load forecast, which is the primary responsibility of Tim A. Jones, who is a witness in this proceeding. Also, we regularly analyze the Companies' existing resources to ensure they can reliably and economically meet forecasted load. As it pertains to this case, I oversaw the development and preparation of the 2025 Resource Assessment (Exhibit SAW-1).

Q. Please describe your experience in performing generation planning analysis and using the software and models that were employed in this case.

A. After working for three years in sales forecasting, I assumed responsibility for generation planning in 2009. Since then, my team has supported the development of five Kentucky integrated resource plans ("IRPs"), three ECR filings, and three generation CPCN filings, including the 2022 CPCN-DSM Case. We have also supported the decisions to enter into power purchase agreements ("PPAs") for the Bluegrass simple-cycle combustion turbines ("SCCTs") and the Rhudes Creek and Ragland solar projects. As the need to evaluate generation planning decisions over a broader range of scenarios has increased, we have adopted new modeling tools and developed new tools internally. For example, prior to developing the 2021 IRP, we replaced Strategist with PLEXOS for generation portfolio development and screening and used it extensively in the 2022 CPCN-DSM Case and the Companies' recently filed 2024 IRP. The analysts who use these tools to model the Companies' generation portfolio all have extensive backgrounds in generation planning and were instrumental in leveraging the strengths of these tools to produce an optimal resource portfolio to provide safe and reliable service at the lowest reasonable cost.

Q. What is the purpose of your direct testimony?

A. The purpose of my testimony is to summarize the Resource Assessment, which recommends adding the following resources as optimal for the Companies' customers:

- Two new 1-on-1 NGCC generation units (645 MW summer-net each):
  - Brown 12, which will be built and in service by 2030; and
  - Mill Creek 6, which will be built and in service by 2031;
- A new 400 MW, four-hour (1,600 MWh) lithium-ion battery energy storage system ("BESS") to be built at the Cane Run Generating Station, which will be in service in 2028; and
- A selective catalytic reduction ("SCR") system for the coal-fired Ghent 2 unit at KU's Ghent Generating Station, which will be operational by 2028 for control of nitrogen oxides ("NO_x") emissions. As Philip A. Imber discusses in his testimony, adding the Ghent 2 SCR will help ensure the Companies' ongoing compliance with ozone National Ambient Air Quality Standards ("NAAQS") and the year-round availability of Ghent 2.

My testimony also describes the methodology used to determine LG&E's and KU's ownership shares for the proposed resources.

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring two exhibits:

Exhibit SAW-1 2025 CPCN Resource Assessment ("Resource Assessment")

Exhibit SAW-2 2025 Resource Assessment Workpapers

Note that Exhibit SAW-2 consists of electronic workpapers that are being provided separately.

IMPETUS FOR THE RESOURCE ASSESSMENT

Q. What caused the Companies to perform the Resource Assessment you are sponsoring in this proceeding?

A. The impetus of the Resource Assessment is the Companies' projected load growth from economic development, primarily resulting from anticipated data center load, reflected in the 2025 CPCN Load Forecast presented by Mr. Jones. As Mr. Jones testifies, the Companies currently anticipate that by 2032 about 2,000 MW of economic development load will be added to the Companies' system compared to the Companies' existing load. Those load additions include 1,750 MW of high load factor data centers and over 250 MW (summer peak) of BlueOval SK ("BOSK") Battery Park load, which the Companies also anticipate will have a high load factor.

Stated plainly, it would be impossible for the Companies to serve all customers reliably while adding large, high-load-factor loads to the Companies' system—both in terms of peak loads and annual energy requirements—without adding supply-side resources to do so. As I explain below, failing to add such resources would result in the Companies being unable to meet their obligation to reliably serve all customers.

Therefore, the Companies conducted the Resource Assessment to determine what resource portfolio would enable the Companies to serve all customers reliably and at the lowest reasonable cost.

Q. Could the Companies serve their existing and new customers' anticipated energy and demand requirements with only existing resources and those approved in the Companies' 2022 CPCN Case?

A. No, the Companies could not reliably serve their existing and new customers' anticipated energy and demand requirements with only existing resources and those approved in the Companies' 2022 CPCN Case. Attempting to do so would result either in enormous off-system power purchases in numerous hours (assuming such energy were available), which would be contrary to the Commission's recent directives,[2] or load shedding or denying service to new customers, both of which would be contrary to the Companies' obligation to provide reliable service to all customers, both existing and new, as Mr. Conroy discusses.

With the resources approved in the 2022 CPCN-DSM Case (removing all solar PPAs for the reasons addressed in Charles R. Schram's testimony), the Companies' 2024 IRP Resource Adequacy Analysis shows their loss of load expectation ("LOLE") with only 1,050 MW of new data center load is approximately 10 times the 1-day-in-10-year LOLE standard.[3] Based on that analysis, the Companies can accommodate the announced 402 MW Camp Ground Road data center, an announced 19.4 MW customer expansion, and BOSK Phase One, but their reserve margins with BOSK Phase Two

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[2] *See 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, Order at 177 (Ky. PSC Nov. 6, 2023) ("This Commission has no interest in allowing our regulated, vertically-integrated utilities to effectively depend on the market for generation or capacity for any sustained period of time."), *quoting Electronic Tariff Filing of East Kentucky Power Cooperative, Inc. and Its Member Distribution Cooperatives for Approval of Proposed Changes to Their Qualified Cogeneration and Small Power Production Facilities Tariffs*, Case No. 2021-00198, Order at 5 n. 10 (Ky. PSC Oct. 26, 2021). *See also id.* ("[T]his Commission expects LG&E/KU to own or contract for the necessary resources, not depend on a capacity market where someone else is in charge of weatherization, maintenance and fuel assurance of those resources.").

Also, as Mr. Conroy notes, KRS 164.2807(1) states in relevant part, "The General Assembly finds and declares that: … (f) It is in the interest of the Commonwealth that it be able to generate sufficient electricity within its borders to serve its own industrial, residential, and commercial demand and to power its own economy[.]" As Mr. Conroy discusses, although this policy interest is stated in terms of Kentucky as a whole, not an individual utility, the magnitude of the load increases the Companies are forecasting would almost certainly require routine large energy purchases from sources outside Kentucky to avoid load shedding, which appears contrary to the General Assembly's stated interest.

[3] *See* 2024 IRP Vol. III, 2024 IRP Resource Adequacy Analysis at 14, Table 5.

would be below minimum levels.[4] In other words, even if the Companies anticipated *zero* net customer load being added beyond what has already been announced or under contract, they would still need to add resources to ensure ongoing reliable service. But it would be unreasonable to assume zero net new load over the next seven years in view of Kentucky's significant efforts and stated policy to attract data center and other economic development loads discussed by John Bevington. The 2025 CPCN Load Forecast more reasonably predicts the Commonwealth's economic development efforts will continue to succeed, as they have with the Camp Ground data center and other economic development projects.

Q. How do the events of Winter Storm Enzo earlier this year impact your view that the Companies need more resources to serve additional data center load?

A. The events of Winter Storm Enzo fully support the need for more resources. During Winter Storm Enzo, hourly loads exceeded 6,000 MW for 18 consecutive hours, and the peak hourly demand was 6,814 MW on the morning of January 22, 2025, with low temperatures in Louisville and Lexington of 4 and -3 degrees Fahrenheit, respectively; intra-hourly loads reached 7,000 MW. Table 1 below contains a summary of load and resources during Winter Storm Enzo and for several other scenarios. During Winter Storm Enzo, the Companies' dispatchable DSM programs reduced the peak demand by an estimated 24 MW. As during Winter Storm Heather in January 2024, the Companies' resources performed excellently: 7,728 of 7,791 MW of resources were available, including an estimated 111 MW of possible Curtailable Service Rider

[4] *See id.* In Table 5, "Load Change" specifies a load reduction from the Mid IRP load scenario with 1,050 MW of data center load. Based on this analysis, the Companies can accommodate 490 MW of economic development load (i.e., 1,050 MW less 560 MW) with CPCN-approved resources and maintain adequate reserves.

("CSR") curtailments. Total resources exceeded the sum of peak demand and operating reserve requirements (230 MW) by 747 MW. Given the possibility of unit outages, the likelihood under these circumstances of an Energy Emergency Alert 1 where the Companies cannot maintain their operating reserves is 10%, and the likelihood of an Energy Emergency Alert 3 where firm load interruption is imminent or in progress is 4%. Notably, however, based on weather year forecasts developed for the 2024 IRP, load could have been 350 MW higher (7,164 MW) with more extreme temperatures experienced historically. With 350 MW more load, total resources would exceed the sum of peak demand and operating reserve requirements by only 397 MW, and the likelihoods of an Energy Emergency Alert 1 and an Energy Emergency Alert 3 would increase to 34% and 17%, respectively. In this case, the loss of one large unit would result in an Energy Emergency Alert 1.

Table 1: Load and Resource Summary (Winter Storm Enzo & Other Scenarios)

	January 2025		**2028 Portfolio with Load Growth**	
	Winter Storm Enzo	**More Extreme Weather**	**Enzo Weather**	**More Extreme Weather**
Peak Hourly Demand[5]	6,814	7,164	7,360	7,710
Operating Reserve Requirement	230	230	230	230
Resource Requirement	7,044	7,394	7,590	7,940
Fully Dispatchable Resources	7,609	7,609	7,985	7,985
Renewable/Limited-Duration Resources[5]	182	182	393	393
Total Resources	7,791	7,791	8,378	8,378
Total Resources less Resource Requirement	747	397	788	438
Likelihood of Energy Emergency Alert 1[6]	10%	34%	8%	30%
Likelihood of Energy Emergency Alert 3[6]	4%	17%	3%	13%

[5] Peak hourly demand is net of 24 MW of dispatchable DSM. Thus, Renewable/Limited-Duration Resources excludes 24 MW of dispatchable DSM.

[6] A Load Serving Entity declares an Energy Emergency Alert 1 when all of its available resources are committed to meet firm load obligations and it is concerned about sustaining its required operating reserves. An Energy Emergency Alert 3 is declared when firm load interruption is imminent or in progress.

With the 2022 CPCN-approved resources, the Companies will have an additional 376 MW of fully dispatchable baseload resources,[7] 125 MW of Brown BESS, and 86 MW of dispatchable DSM.[8] In addition, BOSK Phase One is anticipated to be fully online with a load 125 MW higher than its load on January 22, 2025. With this additional load, the Camp Ground data center, the 19.4 MW customer expansion, and all other loads the same as that experienced on January 22, 2025, total resources would exceed the sum of peak demand and operating reserve requirements by 788 MW, and the likelihoods of an Energy Emergency Alert 1 and Energy Emergency Alert 3 would be 8% and 3%, respectively. With 350 MW more load due to more extreme weather, the likelihoods of an Energy Emergency Alert 1 and an Energy Emergency Alert 3 would increase to 30% and 13%, respectively. While these likelihoods may seem high, they are consistent with a LOLE of one day in ten years given the full range of weather and unit availability scenarios the Companies can experience. But it is clear that the Companies cannot serve an additional 1,350 MW of data center load and BOSK Phase Two (120 MW) with only 2022 CPCN-approved resources.

Therefore, it was necessary to conduct the 2025 CPCN Resource Assessment to help ensure the Companies would have adequate resources to provide safe and reliable service to all customers, existing and new, at the lowest reasonable cost.

[7] Net of retiring Mill Creek 2 and the recent Cane Run 7 performance upgrade.

[8] 376 MW reflects the addition of Mill Creek 5 (660 MW), the planned upgrade to Cane Run 7 (68 MW), the planned retirement of Mill Creek 2 (297 MW) and the assumed retirements of the small-frame CTs (55 MW). The Companies also plan to add 240 MW of solar by 2027, but consistent with their experience during Winter Storms Elliott, Heather, and Enzo, solar is assumed to be unavailable at the time of winter peak.

OBJECTIVE OF THE RESOURCE ASSESSMENT

Q. What was the objective of the Resource Assessment?

A. As discussed above, the Companies must make resource decisions now to ensure they can serve their existing and new customers safely, reliably, and at the lowest reasonable cost. The objective of the Resource Assessment was to inform those decisions.

More specifically, the Companies' objective was to gather and analyze (1) updated load forecasting to understand customers' needs, (2) information about resource alternatives, and (3) information about the Companies' existing resources to inform resource decisions the Companies must make to address the load growth reflected in the 2025 CPCN Load Forecast. Again, the objective was to fully inform resource decisions that must be made *now* to address issues that will affect the Companies' ability to reliably and economically serve customers in the 2028-2031 timeframe while also considering the possible future impacts of those resource decisions.

Q. Do you anticipate the Companies' future resource portfolio could differ from the resource portfolio set out in the Resource Assessment?

A. Yes. As noted in the Resource Assessment, it is helpful to bear in mind this is not the last time the Companies will make resource decisions. Changes in economic development, resource technology and costs, and applicable regulations can and will affect future resource decisions. Therefore, the Resource Assessment focused on the resource decisions that must be made now while thinking carefully about how those choices might be affected by the types of future uncertainties I just mentioned.

HOW THE COMPANIES' 2024 IRP INFORMED THE 2025 CPCN RESOURCE ASSESSMENT

Q. Did the Companies' 2024 IRP inform the 2025 CPCN Resource Assessment?

A. Yes. The degree to which it did so is unusual because the Companies conducted the analysis supporting their 2024 IRP so close in time to when they needed to seek approval for additional resources in this proceeding. Although impactful events have occurred since the Companies performed their 2024 IRP analysis, it nonetheless resulted in a number of insights and foundational elements for the 2025 CPCN Resource Assessment.

First, as Mr. Jones discusses and I summarize below, a blending of elements from the 2024 IRP Load Forecast resulted in the 2025 CPCN Load Forecast, which is the projected load the 2025 CPCN Resource Assessment provides optimal resources to serve.

Second, the 2024 IRP Resource Adequacy study provided the minimum seasonal reserve margins the Companies used in Stage One of their 2025 CPCN Resource Assessment.

Third, the 2024 IRP Resource Assessment, which considered the same fuel price scenarios evaluated in the 2025 CPCN Resource Assessment also evaluated four different environmental regulatory scenarios over a fifteen-year period. The 2024 IRP Resource Assessment demonstrated that NGCC and battery storage charged by existing resources are least-cost for serving economic development load growth in all environmental scenarios. That work allowed the Companies to focus in the 2025 CPCN Resource Assessment on the environmental scenario they believe is most likely to impact immediate resource decisions, namely a scenario in which a regulatory requirement equivalent to the Good Neighbor Plan for the 2015 Ozone National Ambient Air Quality Standard ("NAAQS") is the only new environmental requirement other than those with which the Companies must comply today.

Fourth, based on the IRP analysis, the Companies developed detailed cost estimates for NGCC at Brown and Mill Creek as well as BESS at Cane Run and Ghent, as I discuss further below.

Q. Are the results of the 2025 CPCN Resource Assessment consistent with the results of the 2024 IRP Resource Assessment?

A. Yes. Unsurprisingly, the results of the 2024 IRP Resource Assessment support the Companies' conclusion in the 2025 CPCN Resource Assessment, which focuses only on resource decisions that must be made today, namely that choosing to add the Brown 12 and Mill Creek 6 NGCC units, the 400 MW, 1,600 MWh Cane Run BESS, and a Ghent 2 SCR, is a robust resource decision across a plausible array of future fuel price and load scenarios.

UNDERSTANDING CUSTOMERS' PROJECTED DEMAND AND ENERGY REQUIREMENTS: THE 2025 CPCN LOAD FORECAST

Q. Please describe the Companies' current forecast of customers' energy requirements.

A. The Companies' 2025 CPCN Load Forecast presented by Mr. Jones projects that customers' energy and demand requirements will be significantly above current levels for the duration of the forecast period due to anticipated data center load, which has an assumed load factor of 95% and climbs to 1,750 MW by 2032, as well as the assumed full operation of the BOSK Battery Park by 2032, which has a planned summer peak load of more than 250 MW, a winter peak load of about 225 MW, and a load factor of almost 90%.[9] As Mr. Jones discusses, the Companies' 2025 CPCN Load Forecast is the 2024 IRP Mid load forecast adjusted to include the 2024 IRP High load forecast's economic development load.[10] The 2025 CPCN Load Forecast is in all other respects identical to the 2024 Mid load forecast, including 150 MW of distributed generation by 2032 and annual energy reductions of 1,500 GWh by 2032 from energy efficiency and other energy reductions.[11] As Mr. Jones further notes, the Companies' 2025 CPCN Load Forecast of non-economic development load is essentially unchanged from the load forecast the Commission found reasonable in the Companies' 2022 CPCN-DSM Case and from the 2021 IRP Load Forecast formulated using assumptions and methodologies the Commission Staff found to be "generally reasonable."[12]

The 2025 CPCN Load Forecast also shows customers will continue to require significant amounts of energy in every hour and season. Thus, an optimal resource portfolio must be able to serve customers' considerable energy requirements in all hours, seasons, and weather and daylight conditions.

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[9] The stated peak load figures represent BlueOval's non-coincident, peak hourly usage projections grossed up by a transmission loss factor of 1.02827. BlueOval's anticipated summer billing demand is 254 MW.

[10] *See, e.g.,* Case No. 2024-00326, IRP Vol. I at 5-13 to 5-16 (Oct. 18, 2024).

[11] Includes energy reductions from customer-initiated energy efficiency improvements, advanced metering infrastructure ("AMI") related conservation voltage reduction ("CVR") and ePortal savings, distributed generation, and the energy-efficiency effects of the Companies' 2024-2030 DSM-EE Program Plan and the assumed impacts of DSM-EE programs beyond 2030.

[12] Case No. 2022-00402, Order at 63-65 (Ky. PSC Nov. 6, 2023) ("The Commission finds that LG&E/KU's treatment of economic growth in this load forecast is reasonable despite certain risks acknowledged by LG&E/KU. … Thus, while the Commission does ultimately agree with Kentucky Coal Association that there is a high-side "risk" to the load associated with unexpected economic growth, the Commission finds that such a risk does not render LG&E/KU's load forecast unreasonable. … However, the Commission does not conclude that the low-side risks raised with respect to LG&E/KU's load forecast or its minimum reserve margin analysis materially affected LG&E/KU's need in this matter."); *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).

Notably, the Companies developed the 2025 CPCN Load Forecast assuming normal weather. Extreme weather conditions, including the Companies' recent experience with Winter Storm Elliott, drive a need for additional reliability considerations. The Companies addressed those issues in their 2024 IRP Resource Adequacy Analysis that resulted in revised seasonal reserve margins based on a loss of load expectation ("LOLE") of one day in ten years ("1-in-10 LOLE") standard, which I discuss below and is attached as Appendix D to Exhibit SAW-1.

RESOURCES ANALYZED TO MEET CUSTOMERS' REQUIREMENTS

Q. Please describe how the Companies determined which resources to analyze in the 2025 CPCN Resource Assessment.

A. To meet customers' projected demand and energy requirements discussed above reliably and economically, the Companies gathered information about available supply- and demand-side resources in addition to their existing resources. Unlike an IRP resource assessment that typically exclusively uses generic cost and performance estimates for possible future resources, for the 2025 CPCN Resource Assessment, which informs real resource decisions that must be made now, the Companies gathered and developed cost and performance estimates for actual resources to be considered in the near term to meet real customer needs. The Companies accomplished this on the supply side through a May 2024 request for proposals for renewable energy options ("May 2024 RFP"), which Mr. Schram discusses. As Mr. Tummonds testifies, the Companies also developed site-specific costs for Brown 12 and Mill Creek 6, and they also considered the cost and other considerations of siting an NGCC unit at KU's Green River Generating Station. As Mr. Tummonds further explains, the Companies also developed site-specific cost estimates for Cane Run BESS and a possible BESS facility at Ghent. Finally, for completeness the Companies also updated their cost estimates for generic simple-cycle combustion turbines ("SCCT"), a generic natural gas combined cycle ("NGCC"), and battery energy storage system ("BESS" or "battery storage") resources. On the demand side, consistent with the 2024 IRP, the Companies modeled new dispatchable DSM program measures and an expansion of the Companies' CSR program.

Q. Please describe how the Companies determined which responses from the May 2024 RFP to analyze in the 2025 CPCN Resource Assessment.

A. As Mr. Schram discusses in his testimony, on May 1, 2024, the Companies issued an RFP for renewable energy to 165 potential respondents. The RFP sought non-firm renewable energy from solar, wind, or hydroelectric sources, with a minimum nameplate capacity of 75 MW available no sooner than 2026.[13] In total, 17 parties responded to the RFP with 48 proposals across 22 different projects, which the Companies narrowed to 22 proposals by: (1) eliminating two non-conforming solar projects; (2) excluding the pumped hydro project as not being available until later than needed for currently anticipated energy storage requirements; (3) eliminating a non-conforming standalone battery proposal; and (4) selecting the lowest-cost proposal for each remaining project (three projects had two proposals each advance to the analysis stage because their proposals differed in capacity, not just start date or flat-versus-escalating pricing). Ultimately, the proposals that advanced to the Companies' resource modeling consisted of 11 solar-only proposals, four solar asset development

[13] The testimony of Charles R. Schram addresses the RFP at length, and it includes the RFP itself and all RFP responses as Exhibits CRS-1 and CRS-2, respectively.

proposals, four solar plus four-hour battery proposals, one solar plus eight-hour battery proposal, and two wind with solar option proposals.

Q. Which other supply- and demand-side resources did the Companies analyze in the Resource Assessment?

A. As I noted above, consistent with the results of the 2024 IRP Resource Assessment, the Companies developed cost estimates for two 645 MW 1-on-1 NGCC units (Brown 12 and Mill Creek 6). As Mr. Tummonds explains, the Companies considered other possible sites and NGCC configurations (e.g., a single 2-on-1 NGCC unit), but ultimately selected the Brown 12 and Mill Creek 6 NGCC options as the most economical, reliable, and practicable options.

Regarding BESS options, the Companies developed cost estimates for 100 MW, four-hour BESS increments at Cane Run and Ghent based on the Companies' most recent estimates for the 125 MW, four-hour Brown BESS. The capital cost estimate for the Ghent BESS was higher than the estimate for the Cane Run BESS due to additional site work needed at Ghent to accommodate battery storage. Due to potential site space limitations, the Companies limited Cane Run BESS to 400 MW.

The Companies also included a generic 243 MW SCCT option for their modeling in the 2025 CPCN Resource Assessment. Although SCCT was not part of any least-cost resource plan in any load or environmental scenario through 2032 in the 2024 IRP Resource Assessment,[14] the Companies retained SCCT as an option in this analysis as a proven resource that could be installed in the relevant timeframe.

[14] 2024 IRP Vol. III, 2024 IRP Resource Assessment at 43-48.

One resource type the Companies did not include in the 2025 CPCN Resource Assessment is small modular nuclear reactors ("SMRs"), which the Companies assumed they could not deploy before 2039. Thus, SMR is not a viable option for serving near-term economic development load growth.

Regarding demand-side resources, the Companies modeled such resources in the same way they modeled them in their 2024 IRP Resource Assessment. Thus, as I noted above and Mr. Jones discusses in his testimony, the 2025 CPCN Load Forecast fully accounts for energy-reducing efforts, both those initiated by the Companies and customers, including the energy-efficiency effects of the Companies' DSM-EE programs. The Companies modeled existing dispatchable demand-side resources, i.e., the Companies' demand-response DSM and CSR customer loads, as existing resources. In addition, the Companies modeled three new dispatchable DSM program measures as additional means for customers to participate in existing programs.[15] As such, the Companies modeled these measures as having no incremental fixed costs. The Companies also modeled a 100 MW expansion of their CSR-2 program. Notably, the Companies' ability to require CSR-2 customers to curtail their usage without a buy-through option is limited to 100 hours annually when all available units are dispatched or being dispatched.

Finally, as Mr. Jones discusses, because of the very high load factor of data center load and the economic incentive these energy-intensive customers already have to maximize cost-effective energy efficiency, there is little reason to expect that either

[15] The three additional demand-response program measures the Companies modeled at zero cost were Bring Your Own Device ("BYOD") Energy Storage, BYOD Home Generators, and expanding the existing Business Demand Response program to customers with loads ranging from 50 kW to 200 kW. The total assumed peak demand reduction potential of these program measures was less than 2 MW.

energy efficiency or any form of curtailable or interruptible service will affect the demands or energy requirements of these new loads, which are the primary drivers of change in the 2025 CPCN Load Forecast and therefore the 2025 CPCN Resource Assessment. Consistent with this, Mr. Bevington also notes that his experience indicates data center developers are interested in uninterrupted service.

Q. How did the Companies consider their existing supply-side resources in the Resource Assessment?

A. The Companies modeled all of their existing supply-side resources as potentially continuing in operation throughout the analysis period with the exception of the Haefling 1-2 and Paddy's Run 12 small-frame combustion turbines, which the Companies assumed would retire in 2025, and Mill Creek 2, which the Companies assumed would retire in 2027 when the Mill Creek 5 NGCC becomes operational. Otherwise, the Companies' PLEXOS modeling tool could retire any resource at any time subject to the timing and replacement constraint of KRS 278.264 or keep existing coal units in service and incur stay-open costs for each affected unit. A full description of the Companies' existing resources and how the Companies evaluated them is in Appendix A of the 2025 CPCN Resource Assessment.

RESOURCE ASSESSMENT ANALYSIS: KEY CONSTRAINTS, UNCERTAINTIES, AND ASSUMPTIONS

Q. What were the key constraints the Companies considered in the 2025 CPCN Resource Assessment analysis?

A. The Resource Assessment included the following key constraints:

- Portfolios must maintain minimum reserve margins and comply with KRS 278.264.

- Brown 3 cannot operate as a coal-fired generating unit beyond 2034 due to landfill storage capacity limits.
- Mill Creek 3 and 4 cannot operate as coal-fired generating units beyond 2044 due to landfill storage capacity limits.
- The earliest new BESS can be added is 2028, the earliest new NGCC or SCCT can be added is 2030. The availability of each RFP resource is specified in its proposal.

In the 2024 IRP Resource Assessment, the Companies included constraints that limited solar generation to 20% of total energy requirements and the sum of solar and wind generation to 25% of total energy requirements. The Companies removed these constraints in the 2025 CPCN Resource Assessment because they would be nonbinding given the amount of solar and wind proposals received in response to their 2024 RFP.

Q. What were the key uncertainties the Companies considered in the 2025 CPCN Resource Assessment analysis?

A. The key uncertainties the Companies considered in the 2025 CPCN Resource Assessment analysis were economic development load and fuel prices.

To address how higher or lower economic development load might affect the optimal resource portfolio in the near term, in Stage One, Step One of the analysis I describe below the Companies evaluated different amounts of data center load in two steps of 140 MW each above and below the projected 1,750 MW level in the 2025 CPCN Load Forecast, i.e., down to 1,470 MW and up to 2,030 MW of data center load. The Companies evaluated each of these five total load scenarios across five different fuel-price scenarios for a total of 25 combinations of load and fuel prices evaluated in

Stage One, Step One. These load sensitivity cases show the robustness of the Companies' proposed resources in this proceeding.

Regarding fuel prices, the Companies addressed this important uncertainty by evaluating the same five fuel price scenarios used in the 2024 IRP Resource Assessment, which the Companies developed using the same methodology the Commission found to be credible and reasonable in its Final Order in the Companies' 2022 CPCN Case.[16] In these fuel price scenarios, natural gas prices are the primary price-setting factor, with coal prices derived from gas prices beginning in 2025 based on different historical coal-to-gas ("CTG") price ratios. The Companies' three natural gas price cases (low, mid, and high) derive from the U.S. Energy Information Administration's 2023 Annual Energy Outlook's corresponding natural gas price forecasts: High Oil and Gas Supply case (low gas price), Reference case (mid gas price), and Low Oil and Gas Supply case (high gas price). In the first three fuel price scenarios the Companies analyzed, coal prices predominantly varied with gas prices by a ten-year average ratio of coal and gas prices. These cases are the most likely to occur over a long planning period and are called "Low Gas, Mid CTG Ratio," "Mid Gas, Mid CTG Ratio," and "High Gas, Mid CTG Ratio," with the Mid coal-to-gas price ratio approximating the ratio of NGCC and coal energy costs. Therefore, it is reasonable to expect coal-to-gas price ratios to revert to this ratio over the long term, which is why the Companies refer to it as the "Expected CTG Price Ratio."

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[16] *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,* Case No. 2022-00402, Order at 93-4 (Ky. PSC Nov. 6, 2023) ("The Commission finds that LG&E/KU's evidence regarding the relationship between coal and natural gas prices is credible. …[W]hether projected separately or together, the Commission believes that it is reasonable to assume a relationship between coal prices and natural gas prices. …[T]he Commission finds that LG&E/KU's fuel price scenarios were reasonable ….").

The other two fuel price scenarios involve relationships between gas and coal prices that would be atypical for an extended time horizon, essentially as sensitivity cases: (1) low gas prices with a historically high coal-to-gas ratio ("Low Gas, High CTG Ratio"); and (2) high gas prices with a historically low coal-to-gas ratio ("High Gas, Low CTG Ratio"). A full description of the formulation of these gas and coal prices and coal-to-gas price ratios is in the Commodity Prices discussion in Appendix A of the 2025 CPCN Resource Assessment.

Q. How did the Companies address environmental regulatory uncertainty in the 2025 CPCN Resource Assessment?

A. As Mr. Imber discusses in his testimony, it is reasonably clear that the new presidential administration's actions are unlikely to create federal environmental constraints on fossil fuel-fired generation beyond those the Companies evaluated in their 2024 IRP Resource Assessment; what is unclear is precisely how much of the previous administration's rulemaking activity the new administration will seek and be able to reverse.

In their 2024 IRP Resource Assessment, the Companies modeled four different environmental regulatory scenarios: (1) no new regulations; (2) the equivalent of the federal Good Neighbor Plan for the ozone NAAQS ("Ozone NAAQS"); (3) Ozone NAAQS and the 2024 Effluent Limitation Guidelines ("2024 ELG"); and (4) Ozone NAAQS, 2024 ELG, and the recent Greenhouse Gas ("GHG") rules promulgated by the U.S. Environmental Protection Agency ("EPA") under Clean Air Act Sections 111(b) and (d). The Companies' modeling showed that in the High load forecast scenario—which is very similar to the Companies' 2025 CPCN Load Forecast—adding at least two NGCCs and at least 400 MW of BESS by 2032 is least-cost across all four environmental scenarios (and all five fuel scenarios in each of the four environmental scenarios). Therefore, it was not necessary in this analysis to rerun all four environmental scenarios, and the Companies' 2025 CPCN Resource Analysis focused on one environmental scenario that, in accordance with Mr. Imber's testimony, seems most likely in the near term, namely the Ozone NAAQS scenario.

MODELING TOOLS USED IN THE COMPANIES' 2025 CPCN RESOURCE ASSESSMENT

Q. Please briefly describe the modeling tools the Companies used in the Resource Assessment analysis.

A. The Companies used four primary software tools to aid them in their analysis:

- **Resource Adequacy: SERVM.** The Companies used SERVM, a resource adequacy model, to develop minimum reserve margin constraints for resource planning, compute capacity contribution values for limited-duration resources, and evaluate LOLE for different resource portfolios. Resource adequacy is evaluated over a wide range of weather and unit availability scenarios. Specifically, the Companies used SERVM to model generation production costs, reliability costs, and LOLE over 54 load scenarios and 300 unit availability scenarios. The load scenarios were developed based on the weather in each of the last 54 years.

- **Resource Plan Development and Screening: PLEXOS.** The Companies used PLEXOS, a resource planning model, to develop least-cost resource plans over a range of fuel price scenarios. PLEXOS models and evaluates thousands of resource plans to determine which one minimizes the cost of serving customers' load while meeting reserve margin and other constraints. A resource planning model necessarily makes simplifying assumptions to reduce model run times, and a key consideration for any resource planning model is the level of granularity used to develop resource plans. Less granular analyses require more simplifying assumptions and have shorter run times, but too many simplifying assumptions may prevent the model from properly evaluating resources with limited availability or run times. Thus, it is important to evaluate resource plans with an appropriate level of granularity and then check the results with detailed production costs.[17]

- **Production Cost Modeling: PROSYM.** After PLEXOS identifies which resources to include in a resource plan, the Companies model the resource plan's generation production costs in detail using PROSYM, an hourly chronological dispatch model. PLEXOS and PROSYM use the same inputs (e.g., they use the same natural gas and coal prices), but the Companies used PROSYM rather than PLEXOS for detailed production cost modeling because they have used and configured PROSYM over a number of years to do such modeling relatively quickly.

- **Present Value of Revenue Requirements ("PVRR"): Excel Financial Model.** The Companies use a Financial Model developed in Excel to calculate and compare PVRR values for various resource plans. Inputs to the Financial Model include capital and fixed operating costs for new and existing resources as well as generation production costs. Production costs are developed in PROSYM; the costs for new and existing resources are the same costs modeled in PLEXOS and used to develop the least-cost resource plan.

SUMMARY OF 2025 CPCN RESOURCE ASSESSMENT STAGE ONE: PORTFOLIO DEVELOPMENT

Q. Please summarize Stage One of the Companies' 2025 CPCN Resource Assessment: Portfolio Development.

A. In this stage, the Companies determined the optimal mix of resources for serving the level of economic development load in the 2025 CPCN Load Forecast and the four additional economic development load scenarios discussed above (i.e., two 140 MW increments higher and two 140 MW increments lower than the 2025 CPCN Load Forecast) using the same two-step process involving PLEXOS and PROSYM they used in the 2024 IRP. The 2024 IRP demonstrated that the least-cost resources for serving economic development load growth are NGCC resources and battery storage charged by existing resources. But economic development loads such as new data centers can

[17] The Companies develop resource plans in PLEXOS in six blocks of time per day across a series of six-year rolling horizons. With this level of granularity, each model run takes up to 55 hours to complete.

be added faster than new NGCC resources; the earliest a new NGCC can be constructed at the E.W. Brown station is 2030. Therefore, to ensure an optimal mix of resources, the Companies first used PLEXOS to develop resource plans with no technology availability constraints and with the assumption that economic development loads are added in 2030. The Companies did this for each of the five load scenarios across each of the five fuel price scenarios, resulting in 25 total resource plans. From these resource plans, the Companies determined the most viable portfolios for serving economic development load based on the resources added in 2030 ("2030 portfolios"). Then, the Companies evaluated each of these portfolios with detailed production costs over each of the fuel price scenarios (resulting in 25 cases per load scenario, i.e., 125 cases) to determine which resource plan for a given load scenario would be lowest cost on average across all fuel price scenarios.

Importantly, this stage required PLEXOS to use seasonal reserve margins from the 2024 IRP Reliability Assessment, i.e., 29% winter and 23% summer. The Companies revisited that reserve margin assumption in Stage Two.

Q. Please explain what the Companies did in Stage One, Step One: Resource Plan Development and Screening with PLEXOS.

A. The first step of Stage One consisted of allowing PLEXOS to create resource plans subject to reserve margin and other constraints for each load scenario and each of the five fuel price scenarios. In the 2024 IRP, the Companies modeled landfill constraints that limited the Brown and Mill Creek coal units' ability to operate on coal beyond 2034 and 2044, respectively. While these assumptions are entirely reasonable, the Companies developed resource plans with and without these constraints to understand the impact of these constraints on the 2030 portfolios. In addition, to determine which renewable resources are least-cost in the near-term, the Companies allowed PLEXOS to choose any renewable resource at any time after the earliest availability date indicated by the corresponding RFP response.

The key observations from this part of the analysis are:

1. All 2030 portfolios include the Brown 12 and Mill Creek 6 NGCCs, and almost all 2030 Portfolios include some amount of Cane Run BESS or Cane Run BESS plus Ghent BESS. A third NGCC is added in most higher load scenarios.
2. The favorability of renewables predictably correlates with fuel prices. More renewables are added in the High fuel price scenarios.
3. A Ghent 2 SCR is generally favorable in scenarios with Low and Mid fuel prices but not in scenarios with High fuel prices.
4. Landfill constraints have no material impact on the 2030 portfolios.

Q. Please explain what the Companies did in Stage One, Step Two: Least-Cost Portfolios over All Fuel Price Scenarios.

A. In the second step of Stage One, the Companies used PROSYM to evaluate each portfolio with detailed production costs over each of the five fuel price scenarios to determine which portfolio for a given load scenario has the lowest PVRR on average across all fuel price scenarios. This required 25 PROSYM runs for each load scenario (five portfolios from PLEXOS evaluated in each of five fuel-price scenarios in PROSYM), resulting in a total of 125 PROSYM runs for all five load scenarios.

Importantly, to focus the analysis on determining the optimal portfolio for serving economic development load (i.e., the decision that needs to be made today) and ensure any production cost differences are explained entirely by differences between the 2030 portfolios, the Companies evaluated the portfolios in the context of a fixed resource plan beyond 2030. To do this, the Companies modeled the most common replacement resources for Brown 3 and OVEC in all cases. In addition, because the Mill Creek landfill constraint has no impact on the resource plan until 2045, the Companies assumed in this step that Mill Creek 3 and 4 would operate through the end of the analysis period. Thus, the Companies held all resources constant after 2030, with the exception of the retirement of Brown 3 in 2035, the addition of 500 MW of battery storage in 2035, the loss of OVEC capacity coinciding with the end of its contract in 2040, and the addition of one SCCT in 2040.

Table 2 shows the least-cost 2030 portfolio for each load scenario. In the load scenario with 1,470 MW of data center load, adding Brown 12, Mill Creek 6, a Ghent 2 SCR, and 200 MW of Cane Run BESS is the least-cost portfolio. Each 140 MW of data center load results in an incremental 200 MW of battery storage (first reaching 400 MW of Cane Run BESS before adding Ghent BESS), until the load scenario with 1,890 MW of data center load, which prefers a third NGCC, no Ghent 2 SCR, 100 MW of Cane Run BESS, and 265 MW of solar PPAs. Notably, with Ghent 2 unavailable during the ozone season, this portfolio relies on solar to minimally comply with summer reserve margins and may not be an actionable portfolio given challenges the Companies have faced executing solar PPAs. A third NGCC with costs equal to Mill Creek 6 is least-cost at higher load levels, but the Companies' primary focus is the

CPCN load forecast with 1,750 MW of data center load. The additional DSM measures and a Ghent 2 SCR are least-cost in all load scenarios.

Table 2: Stage One Results (Least-Cost Portfolios)

Data Center Load in Load Scenario	Brown 12 NGCC	Mill Creek 6 NGCC	Generic NGCC	Cane Run BESS	Ghent BESS	Solar PPA	Add. DSM (Y/N)	GH2 SCR (Y/N)
2,030 MW	645	645	645	300	-	-	Y	Y
1,890 MW	645	645	645	100	-	265	Y	N
1,750 MW (2025 CPCN)	645	645	-	400	200	-	Y	Y
1,610 MW	645	645	-	400	-	-	Y	Y
1,470 MW	645	645	-	200	-	-	Y	Y

SUMMARY OF 2025 CPCN RESOURCE ASSESSMENT STAGE TWO: ASSESSING RESOURCE ADEQUACY

Q. Please summarize Stage Two of the Companies' 2025 CPCN Resource Assessment: Assessing Resource Adequacy.

A. As I discussed above, the Stage One results demonstrated that Brown 12, Mill Creek 6, and some amount of Cane Run BESS (with or without Ghent BESS) are optimal for serving economic development load growth. In the Stage Two analysis, the Companies used SERVM to assess the reliability of their generation portfolio with various combinations of new resources to determine which combination would be optimal for serving the level of economic development load growth in the 2025 CPCN Load Forecast. This analysis is necessary because the level of reserves needed for reliable service can vary with changes in the load and resource mix. In addition, the impact on a percentage basis of adding high load factor economic development load is greatest in the shoulder months when loads are lower and the Companies perform maintenance on their generation units. This stage of the analysis fully accounts for the need to maintain the Companies' existing and proposed resources.

The Stage Two analysis showed that, in addition to the Companies' "2028 Portfolio,"[18] adding Brown 12, Mill Creek 6, and Cane Run BESS results in an LOLE of approximately one day in ten years for the 2025 CPCN Load Forecast. This is possible without the 200 MW of Ghent BESS from the Stage One results because, as I noted above, the Companies used the reserve margins developed in their 2024 IRP in that stage of the analysis (29% in the winter and 23% in the summer), which derived from a load forecast with less economic development load. Unsurprisingly, the Stage Two results demonstrate that, with the addition of additional non-weather sensitive economic development loads, the level of generation reserves required to ensure reliable service, which is computed as a percent of peak demand under normal peak weather conditions, is slightly lower.

SUMMARY OF 2025 CPCN RESOURCE ASSESSMENT STAGE THREE: MANAGING ECONOMIC DEVELOPMENT LOAD GROWTH

Q. Please summarize Stage Three of the Companies' 2025 CPCN Resource Assessment: Managing Economic Development Load Growth.

[18] The "2028 Portfolio" refers to the Companies' resource portfolio in 2028 and reflects the retirement of Mill Creek 1 (2024), the planned retirement of Mill Creek 2 (2027), the assumed retirement of the small-frame SCCTs (2025), the planned additions of Brown BESS (2027), Mill Creek 5 (2027), two owned solar facilities in 2026 and 2027, and dispatchable demand response programs from the Companies' 2024-2030 DSM-EE Program Plan.

The 2028 Portfolio does not include the six total solar PPAs into which the Companies have entered. Of the six total solar PPAs into which the Companies have entered, including two prior to the 2022 CPCN and DSM-EE case, (a) one has been canceled by the developer due to interconnection issues, (b) one has been canceled by the developer due to a significant project price increase, and (c) one with a price reopener has been contractually terminated due to the Companies' unwillingness to proceed at a much higher price than in the original agreement. The remaining three PPAs appear unlikely to proceed under their approved terms. Therefore, the 2025 CPCN Resource Assessment does not include these PPAs.

A. As I discussed above, the Stage Two results demonstrated that the Companies' 2028 Portfolio plus Brown 12 NGCC, Mill Creek 6 NGCC, 400 MW Cane Run BESS, a Ghent 2 SCR, and the modeled dispatchable DSM measures are optimal for serving the needs of all customers, existing and new, expected by 2032 in the 2025 CPCN Load Forecast.

Importantly, in the two earlier stages of the analysis, the Companies made the simplifying assumption that all new economic development load (i.e., data centers and BOSK Phase Two) would not begin taking service until the Companies could have all new resources operational. In reality, as shown by the recent Camp Ground data center Mr. Bevington discusses, data center customers have shown interest in taking service as soon as possible.

To address this market reality, as well as real-world constraints on how quickly the Companies can add new resources, in Stage Three the Companies used SERVM to determine the pace at which they could add new economic development load while continuing to provide reliable service to existing customers using their 2028 Portfolio plus the resources proposed in this proceeding. In this stage, the new resources became available only at the expected earliest service dates (i.e., accounting for being able to add the Cane Run BESS no sooner than 2028, Brown 12 no sooner than 2030, and Mill Creek 6 no sooner than 2031). This constrained the rate at which new economic development load could come onto the system relative to what the 2025 CPCN Load Forecast projected would come onto the system in a resource-unconstrained environment.

Table 3 below contains the results of Stage Three, which show that the data center load additions in the 2025 CPCN Load Forecast exceed the level of new data center load that can be served reliably in 2029 by 350 MW, which declines to 210 MW in 2030.

Table 3: Stage Three Results (Managing Economic Development Load Growth)

Year	**Resource Additions**	**[A] Data Center Load that Can Be Served**	**[B] Data Center Load in CPCN Load Forecast**	**Difference ([A]-[B])**
2028-2029	CR BESS (400 MW)	630	980	(350)
2030	CR BESS + BR12 (645 MW)	1,190	1,400	(210)
2031+	CR BESS + BR12 + MC6 (645 MW)	1,750	1,750	0

Thus, if load increases more rapidly than the resources the Companies are requesting in this proceeding can accommodate, the Companies will need to consider additional means of meeting customers' needs, including possibly seeking authorization for additional resources in a subsequent CPCN.

<u>2025 CPCN RESOURCE ASSESSMENT CONCLUSION: THE COMPANIES' REQUESTED RESOURCES ARE NO-REGRETS RESOURCE ADDITIONS</u>

Q. How would you describe the final outcome of the Resource Assessment analysis?

A. Ultimately, the 2025 CPCN Resource Assessment shows that the resources the Companies are proposing in this proceeding are no-regrets resources. Brown 12, Mill Creek 6, and 400 MW Cane Run BESS are vital and necessary components of least-cost portfolios across a wide array of load and fuel scenarios, as well as environmental regulatory scenarios. For the reasons Mr. Imber discusses, the proposed Ghent 2 SCR will ensure Ghent 2 can continue to operate year-round in compliance with the 2015

Ozone NAAQS, which will help maintain reliable service for customers, both through direct provision of real-time energy and helping support the reliable charging of the Brown and Cane Run BESS facilities.

I would note again there is an urgent need for these resources. As I discussed near the beginning of my testimony, just accounting for the announced and contracted economic development loads in the Companies' Kentucky service territories would leave the Companies needing additional resources to achieve minimum reserve margins even assuming *zero* net additional load growth—and there is no credible reason to believe *zero* net additional load growth between now and 2032. Instead, the Companies are reasonably predicting that the Commonwealth's economic development efforts will continue to work. Ensuring the Companies will be able to serve the very customers the Commonwealth is working to attract requires adding the resources the Companies are proposing.

Q. Is there additional data confirming the reasonableness of the Companies' proposed resource additions, particularly Brown 12 and Mill Creek 6?

A. Yes. Natural gas-fired capacity provides more than 40% of the nation's electricity today and accounts for more than 40% of installed utility-scale generation capacity in the U.S.[19] More importantly, it is clear that natural gas is the dominant fuel source for generation utilities are installing and planning to install *now* as reliable, around-the-clock, year-round, fully dispatchable capacity. According to the U.S. Energy Information Administration's most recent Preliminary Monthly Electric Generator

[19] *See, e.g.,* https://www.eia.gov/energyexplained/electricity/electricity-in-the-us-generation-capacity-and-sales.php (accessed Feb. 19, 2025).

Inventory,[20] of the 22.9 GW of utility-scale planned generators in December 2024 for the electric utility sector,[21] gas-fired capacity was more than half the total (14 GW), and NGCC capacity was nearly a third (6.8 GW). In that same vein, according to S&P Global:

> As of January 2025, US power providers and developers had plans to add 79.8 GW of fossil fuel-fired plant capacity — a 30% increase since April 2024, data from S&P Global Market Intelligence shows.
>
> Natural gas-powered plants accounted for nearly all new planned capacity, and coal and oil projects called for 700 MW and 52 MW, respectively, the data showed. In all, 159 new fossil fuel-fired plants were either in development or announced.[22]

Relatedly, PJM is warning that a capacity shortage could affect its system as early as the 2026/2027 Delivery Year because demand is significantly increasing while thermal generators, "which provide the dispatchable generation needed to maintain reliability," are rapidly retiring and "[n]ew replacement resources with the needed reliability attributes aren't being built fast enough."[23]

To be sure, none of this data means the Companies should add NGCC capacity without careful analysis. But having done that analysis as I described above and in Exhibit SAW-1, this data confirms the reasonableness of the Companies' plan to add Brown 12 and Mill Creek 6 to their least-cost portfolio to continue to serve customers safely and reliably.

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[20] Available at https://www.eia.gov/electricity/data/eia860m/xls/december_generator2024.xlsx.

[21] The Companies define utility-scale here to be at least 75 MW nameplate capacity.

[22] Susan Dlin & Karin Rives, "US power sector plans 80 GW of new fossil fuel capacity, 159 new plants," S&P Global (Feb. 19, 2025), available at https://www.capitaliq.spglobal.com/apisv3/spg-webplatform-core/news/article?id=87457222 (accessed Feb. 19, 2025).

[23] PJM Inside Lines, "2025 Long-Term Load Forecast Report Predicts Significant Increase in Electricity Demand" (Jan. 30, 2025), available at https://insidelines.pjm.com/2025-long-term-load-forecast-report-predicts-significant-increase-in-electricity-demand/ (accessed Feb. 19, 2025).

UTILITY OWNERSHIP

Q. Do you have a recommendation concerning the Companies' ownership shares of the facilities for which the Companies are seeking CPCNs in this proceeding?

A. Yes. Based on the analysis of this issue in the Resource Assessment, for the Mill Creek 6 and Brown 12 NGCC units, the optimal ownership allocation is 100% for LG&E. Of the 1,750 MW of data center load in the 2025 CPCN Load Forecast, the Companies currently assume 1,400 MW will locate in the LG&E service territory due to the geographic makeup of the currently more than 6,000 MW of possible data center load projects Mr. Bevington discusses. With a 95% load factor, the energy requirements for this load (approximately 11.7 TWh) will exceed the energy produced by Brown 12 and Mill Creek 6. The optimal ownership allocation for the Cane Run BESS is 68% for KU and 32% for LG&E to better balance the Companies' summer and winter reserve margins. KU will own 100% of the Ghent 2 SCR, mirroring its ownership share of Ghent 2.

CONCLUSION

Q. What is your recommendation to the Commission?

A. Based on my extensive experience in performing and supervising generation planning activities as well as the use of generation planning software and models, I am confident that the rigorous analysis discussed in the Resource Assessment can be relied upon by the Companies and the Commission for the decisions that must be made to address the significant load increases reflected in the 2025 CPCN Load Forecast. Therefore, I recommend the Commission approve the CPCNs the Companies are requesting in this proceeding

Q. Does this conclude your testimony?

A. Yes.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

The undersigned, **Stuart A. Wilson**, being duly sworn, deposes and says that he is Director, Energy Planning, Analysis & Forecasting for LG&E and KU Services Company, and 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.

Stuart A. Wilson

Stuart A. Wilson

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 12th day of February 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

Stuart A. Wilson, CFA
Director, Energy Planning, Analysis and Forecast
LG&E and KU Services Company
2701 Eastpoint Parkway
Louisville, Kentucky 40223

Professional Experience

LG&E and KU Energy LLC

Director, Energy Planning, Analysis and Forecast	Apr. 2016 – present
Manager, Generation Planning & Analysis	Oct. 2009 – Apr. 2016
Manager, Sales Analysis & Forecasting	May 2008 – Oct. 2009
Supervisor, Sales Analysis & Forecasting	Aug. 2006 – Apr. 2008
Economic Analyst	Aug. 2000 – July 2006
Compensation Analyst	Aug. 1999 – July 2000
Business Analyst	June 1997 – July 1999

Professional Certifications and Memberships

CFA Society of Louisville
CFA Charter-holder — September 2003

Education

E.ON Emerging Leaders Program — 2004 – 2006

LG&E Energy Leadership Development Program — 1997 – 2002

Indiana University
Master of Business Administration — May 1997

University of Louisville
Master of Engineering in Electrical Engineering — December 1995
Bachelor of Science in Electrical Engineering — December 1995

Civic Activities

Big Brothers Big Sisters of Kentuckiana
Board of Directors — 2017 – Present

Barren Heights Christian Retreat
Board of Directors — 2015 – 2021

2025 CPCN
Resource Assessment

PPL companies

Generation Planning & Analysis

February 2025

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1 Executive Summary

Louisville Gas & Electric Company ("LG&E") and Kentucky Utilities Company's ("KU") (collectively "Companies") Generation Planning & Analysis group conducted this 2025 Resource Assessment to address resource decisions that must be made now to address large amounts of economic development load growth the Companies are anticipating by 2032. The goal of the Companies' resource planning process is to enable the Companies to provide safe and reliable service to customers at the lowest reasonable cost.

1.1 Economic Development Load Growth Drives Need for New Resources

Kentucky's economic development progress has been historic for the last several years, and the state continues to invest heavily to ensure this progress continues. Notably, the General Assembly, in enacting legislation to encourage data center development, stated that "the inducement of the location of data center projects within the Commonwealth is of *paramount importance* to the economic well-being of the Commonwealth."[1] In that vein, Governor Beshear's administration, particularly Kentucky's Secretary for Economic Development, Jeff Noel, worked with the General Assembly to create tax incentives to induce data centers to locate in Jefferson County.[2]

As John Bevington notes in his testimony, Kentucky's efforts are working, with the first hyperscale data center (402 MW) ever to be located in Kentucky announced just last month. That is only part of the more than 6,000 MW of potential data center projects and about 2,000 MW of other economic development projects in the Companies' current economic development queue.

In view of Kentucky's concerted economic development efforts and the interest of data centers in locating in the Companies' service territories, the Companies' 2025 CPCN Load Forecast includes 1,750 MW of high load factor data center load. Combined with over 250 MW of BlueOval SK Battery Park load and two other industrial customer loads of 19.4 MW and 20 MW, economic development adds over 2,000 MW of load to the Companies' system by 2032. As shown in Figure 1 below, this economic development load is *the* driver of change in the 2025 CPCN Load Forecast as compared to other recent load forecasts.

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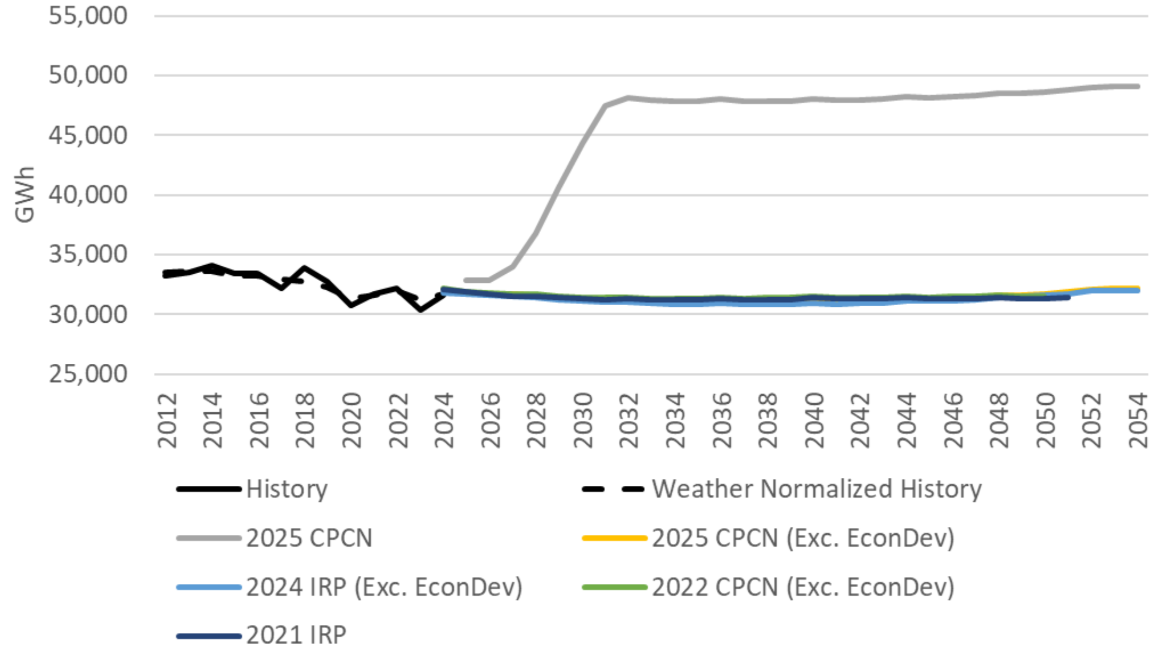
[1] KRS 154.20-222(3) (emphasis added).

[2] Green, Marcus, "Developers unveil plans for large tech data center in Louisville, the 1st of its kind in Kentucky," WDRB (Jan. 16, 2025) ("Bringing data center projects to Kentucky is 'of paramount importance to the economic well-being of the Commonwealth,' according to the legislation passed by state lawmakers. … Kentucky Senate President Robert Stivers, R-Manchester, credited Jeff Noel, secretary of Gov. Andy Beshear's economic development cabinet, and Katie Smith, the agency's deputy secretary, with helping craft the legislation with lawmakers. He called the effort 'a really good example of how the system can work.'"), available at https://www.wdrb.com/in-depth/developers-unveil-plans-for-large-tech-data-center-in-louisville-the-1st-of-its-kind/article_e7adef68-c92f-11ef-b262-bf1780db36c6.html (accessed Jan. 16, 2025). "Stivers on Tax Incentive for Kentucky's First Data Center: Incentive will attract major business to Louisville" (Jan. 16, 2025) ("'I worked closely with Secretary Jeff Noel from the Kentucky Cabinet for Economic Development and top private sector leaders to craft and pass groundbreaking legislation that will spark job creation and expand the tax base, which creates more revenue,' Stivers said. 'This project is a game-changer, driving long-term economic growth in our major metropolitan center and boosting Kentucky as a regional business hub.'"), available at https://kysenaterepublicans.com/press-releases (accessed Jan. 16, 2025).

Figure 1: The Companies' Forecasts Excluding Economic Development



Importantly, the 2025 CPCN Load Forecast includes 150 MW of distributed generation by 2032, annual energy reductions of 1,500 GWh by 2032 from energy efficiency and other energy reductions,[3] and summer and winter peak demand reductions in 2032 of 230 MW and 171 MW, respectively, resulting from energy efficiency (compared to a forecast with flat energy efficiency assumptions).[4]

Meeting these large new energy requirements (and the demand increases shown in Figure 2 on page 11) requires new resources. The Companies' 2024 Integrated Resource Plan ("IRP") Resource Assessment suggested that an optimal resource portfolio for meeting needs of this magnitude would require adding natural gas combined cycle ("NGCC") capacity and battery energy storage system ("BESS") capacity. Although IRP analyses necessarily evaluate hypothetical generic resources, the 2025 CPCN Resource Assessment confirms the 2024 IRP's directional conclusions by analyzing real-world resource options that can be deployed in the near term, resulting in a no-regrets portfolio of resources to meet these new needs.

1.2 A Comprehensive Resource Assessment Results in an Optimal Portfolio

The Companies' 2025 CPCN Resource Assessment made the best use of the Companies' own experience and expertise and state-of-the-art modeling tools and techniques, including sophisticated resource plan development and screening, hourly dispatch, and reliability modeling software platforms. In this assessment, the Companies determined the optimal mix of resources for serving different levels of economic development load and then assessed the reliability of their generation portfolio with various combinations of new resources to determine which combination is optimal for serving the level of

[3] Includes energy reductions from customer-initiated energy efficiency improvements, advanced metering infrastructure ("AMI") related conservation voltage reduction ("CVR") and ePortal savings, distributed generation, and the energy-efficiency effects of the Companies' 2024-2030 DSM-EE Program Plan and the assumed impacts of DSM-EE programs beyond 2030.

[4] Case No. 2024-00326, IRP Vol. I at 7-20 (Oct. 18, 2024).

economic development load in the 2025 CPCN Load Forecast. Finally, given limitations on the availability of these resources, the Companies determined the levels of economic development load they can serve as the optimal resources are placed in service.

The Companies' assessment includes updated assumptions for:

- **Supply-side resource options**. The 2024 IRP demonstrated that NGCC and battery storage charged by existing resources are least-cost for serving economic development load growth. Therefore, the Companies developed detailed cost estimates for NGCC units at the E.W. Brown and Mill Creek Generating Stations ("Brown 12" and "Mill Creek 6," respectively) and battery storage at the Cane Run and Ghent Generating Stations ("Cane Run BESS" and "Ghent BESS," respectively).[5] New supply-side resource options also include the proposals received in response to the Companies' request for proposals ("RFP") issued in May 2024. Section 3.1 contains a summary of supply-side and demand-side resource options. Demand-side resource options are unchanged from the 2024 IRP.[6]
- **Cost of selective catalytic reduction ("SCR") for Ghent 2.** The costs of other retrofit options for existing resources, including the option to convert each of the coal units to burn 100% natural gas, are unchanged from the 2024 IRP.
- **Brown 3 life extension costs**. Brown 3 life extension costs were updated to consider life extension costs that would need to be incurred in order to maintain operations through at least 2035.

Other key inputs and assumptions are unchanged from the 2024 IRP. These inputs and assumptions include:

- **Five fuel price scenarios**. The Companies developed these scenarios using the methodology that was used to develop fuel price scenarios for their 2022 CPCN Resource Assessment.
- **Existing and CPCN-approved resources**. CPCN-approved resources include the Mill Creek 5 natural gas combined cycle ("NGCC") unit, the Brown Battery Energy Storage System ("BESS" or "battery storage"), Mercer County Solar, Marion County Solar, and demand response programs from the Companies' 2024-2030 DSM-EE Program Plan. These resources do not include the six total solar power purchase agreements ("PPAs") into which the Companies have entered due to three having been canceled and the challenges facing the advancement of the remaining three.
- **Modeling constraints**. Key constraints include minimum reserve margins for resource planning, legislative unit retirement restrictions, landfill storage capacity, and technology availability. These constraints are discussed further in Section 4.1.1.

The Companies evaluated the demand- and supply-side options in three stages.

1. Stage One (Portfolio Development): The Companies determined the optimal mix of resources for serving economic development loads in the 2025 CPCN Load Forecast as well as four additional load scenarios using the same two-step process involving PLEXOS and PROSYM they used in the 2024 IRP. The 2024 IRP demonstrated that the least-cost resources for serving economic

[5] The Companies also performed some preliminary analysis of siting an NGCC unit at KU's Green River Generating Station, but it became quickly apparent that the Brown and Mill Creek sites were likely to be lower cost and face fewer challenges of other kinds, including possible environmental permitting issues.
[6] New demand-side resources include new demand response measures and an expansion of the Companies' Curtailable Service Rider ("CSR").

development load growth are new NGCC resources and battery storage charged by existing resources. However, because of technology availability constraints, economic development loads such as new data centers can be added faster than new NGCC resources; the earliest a new NGCC can be constructed at the E.W. Brown station is 2030. Therefore, to ensure an optimal mix of resources for each load scenario, the Companies developed resource plans with no unit availability constraints and with the assumption that economic development loads are added in 2030.

Result:

As seen in Table 1 and consistent with the 2024 IRP, the least-cost resources for serving economic development load growth are new NGCC resources and battery storage charged by existing resources. Each load scenario in Table 1 is labeled based on the amount of data center load in the scenario. The optimal portfolio for all load scenarios includes at least Brown 12 and Mill Creek 6, at least 100 MW of Cane Run BESS, and new demand response measures. A Ghent 2 SCR ("GH2 SCR") is least-cost in all but the load scenario with 1,890 MW of data center load. With Ghent 2 unavailable during the ozone season, the least-cost portfolio for this scenario relies on solar PPAs to minimally comply with summer reserve margins and may not be an actionable portfolio given challenges the Companies have faced executing solar PPAs. A third NGCC with costs equal to Mill Creek 6 is least-cost at higher load levels, but the Companies' primary focus is the CPCN load forecast with 1,750 MW of data center load.

Table 1: Stage One Results (Least-Cost Portfolios)

Data Center Load in Load Scenario	Brown 12 NGCC	Mill Creek 6 NGCC	Generic NGCC	Cane Run BESS	Ghent BESS	Solar PPA	Add. DSM (Y/N)	GH2 SCR (Y/N)
2,030 MW	645	645	645	300	-	-	Y	Y
1,890 MW	645	645	645	100	-	265	Y	N
1,750 MW (CPCN)	645	645	-	400	200	-	Y	Y
1,610 MW	645	645	-	400	-	-	Y	Y
1,470 MW	645	645	-	200	-	-	Y	Y

1. Stage Two (Assessing Resource Adequacy): The Companies assessed the reliability of their generation portfolio with various combinations of NGCC and battery storage to determine which combination is optimal for serving the level of economic development load growth in the 2025 CPCN Load Forecast. This analysis is necessary because the level of reserves needed for reliable service can vary with changes in load and resource mix.

   Result:

   The results of the Stage Two analysis are summarized in Table 2. "2028 Portfolio" refers to the Companies' resource portfolio in 2028 and reflects the retirement of Mill Creek 1 (2024), the planned retirement of Mill Creek 2 (2027), the assumed retirement of the small-frame SCCTs (2026), the planned additions of Brown BESS (2027), Mill Creek 5 (2027), two company-owned solar facilities in 2026 and 2027, and dispatchable demand response programs from the Companies' 2024-2030 DSM-EE Program Plan.[7] The Companies are proposing to add Brown 12 ("BR12"), Mill Creek 6 ("MC6"), and the 400 MW Cane Run BESS because the loss of load expectation ("LOLE") is approximately 1 day in 10 years with these resource additions. In addition, 400 MW of BESS is the maximum amount of battery storage that can be added at Cane Run, and the cost of BESS at the Ghent station is higher due to additional site work needed at Ghent to accommodate battery storage.

Table 2: Stage Two Results (Assessing Resource Adequacy)

Portfolio	LOLE
2028 Portfolio + BR12 NGCC + MC6 NGCC + 400 MW CR BESS + 200 MW GH BESS	0.62
2028 Portfolio + BR12 NGCC + MC6 NGCC + 400 MW CR BESS + 100 MW GH BESS	0.67
2028 Portfolio + BR12 NGCC + MC6 NGCC + 400 MW CR BESS	1.07
2028 Portfolio + BR12 NGCC + MC6 NGCC + 300 MW CR BESS	1.25

In their 2024 IRP, the Companies developed minimum reserve margin constraints for resource planning (29% in the winter and 23% in the summer) based on a load forecast with less economic development load. These reserve margin constraints were utilized in the Stage One analysis above. Unsurprisingly, the Stage Two results demonstrate that, with the addition of non-weather sensitive economic development loads, the reserve margins required for reliable service are slightly lower.

2. Stage Three (Managing Economic Development Load Growth): The Cane Run BESS can be added in 2028, but Brown 12 and Mill Creek 6 cannot be added until 2030 and 2031, respectively. Therefore, the Companies used SERVM to determine the level of economic development load they could serve reliably as the proposed resources are placed in service.

   Result:

   Table 3 compares the level of data center load that can be served with the proposed resources to the data center loads in the 2025 CPCN Load Forecast. In 2029, data center loads in the 2025 CPCN Load Forecast exceed the level of data center load that can be served reliably by 350 MW, and this value reduces to 210 MW in 2030. Therefore, if load increases more rapidly than the resources the Companies are requesting in this proceeding can accommodate, the Companies will need to consider additional means of meeting customers' needs, including possibly seeking authorization for additional resources in a subsequent CPCN.

[7] The Companies do not presently expect that the approved solar PPAs will advance under their approved terms. Of the six total solar PPAs into which the Companies have entered, including two prior to the 2022 CPCN and DSM-EE case, (a) one has been canceled by the developer due to interconnection issues, (b) one has been canceled by the developer due to a significant project price increase, and (c) one with a price reopener has been contractually terminated due to the Companies' unwillingness to proceed at a much higher price than in the original agreement. The remaining three PPAs appear unlikely to proceed under their approved terms. This Resource Assessment therefore does not include these PPAs.

Table 3: Stage Three Results (Managing Economic Development Load Growth)

Year	Resource Additions	[A] Data Center Load that Can Be Served	[B] Data Center Load in CPCN Load Forecast	Difference ([A]-[B])
2028-2029	CR BESS (400 MW)	630	980	(350)
2030	CR BESS + BR12 (645 MW)	1,190	1,400	(210)
2031+	CR BESS + BR12 + MC6 (645 MW)	1,750	1,750	0

1.3 A No-Regrets Portfolio for Serving Customers Now and for Decades to Come

The resources the Companies are proposing (Brown 12, Mill Creek 6, Cane Run BESS, additional DSM measures, and Ghent 2 SCR) are no-regrets resources.

- The Companies' 2024 IRP considered four environmental scenarios and demonstrated that serving economic development load with NGCC and battery storage charged by existing resources is least-cost in all environmental scenarios in the High Load scenario (i.e., at a load level comparable to the 2025 CPCN Load Forecast). According to the U.S. Energy Information Administration ("EIA"), NGCC resources account for the largest share of power generation nationally, and the Companies' NGCC resources will account for 42% of their generation after Brown 12 and Mill Creek 6 are commissioned.[8]
- The proposed Ghent 2 SCR will ensure Ghent 2 can continue to operate year-round in compliance with the 2015 Ozone NAAQS, which will help maintain reliable service for customers, both through direct provision of real-time energy and helping support the reliable charging of the Brown and Cane Run BESS facilities.
- With this CPCN, the Companies are focused only on decisions that have to be made today. If the long-term outlook for data center load growth exceeds current expectations, the Companies can seek authorization to add more resources.

[8] NGCC generation in 2023 was approximately 1,523 TWh (see EIA's Electric Power Annual 2023; https://www.eia.gov/electricity/annual/table.php?t=epa_04_08_a.html) and exceeded the level of generation from any other source (see https://www.eia.gov/electricity/annual/table.php?t=epa_03_01_a.html).

2 Objective: Reliably and Cost-Effectively Serving Customers' Projected Needs

The objective of this Resource Assessment is to determine the optimal mix of resources for serving all customers' needs given the level of economic development load in the Companies' 2025 CPCN Load Forecast, focusing on the resource decisions that must be made today. As always, the goal of the Companies' resource planning process is to enable the Companies to provide safe and reliable service to customers at the lowest reasonable cost. Whereas an IRP contemplates a number of resource decisions over a 15-year planning horizon that do not require immediate action, this Resource Assessment was completed to focus only on decisions regarding actual resources that need to be made today to ensure the Companies can continue to provide reliable service at the lowest reasonable cost. An optimal resource plan must be able to serve customers' needs reliably at all times and in all seasons, weather, and daylight conditions. Achieving that objective begins with an understanding of customers' projected needs, as well as the reserve margins necessary to provide reliable service.

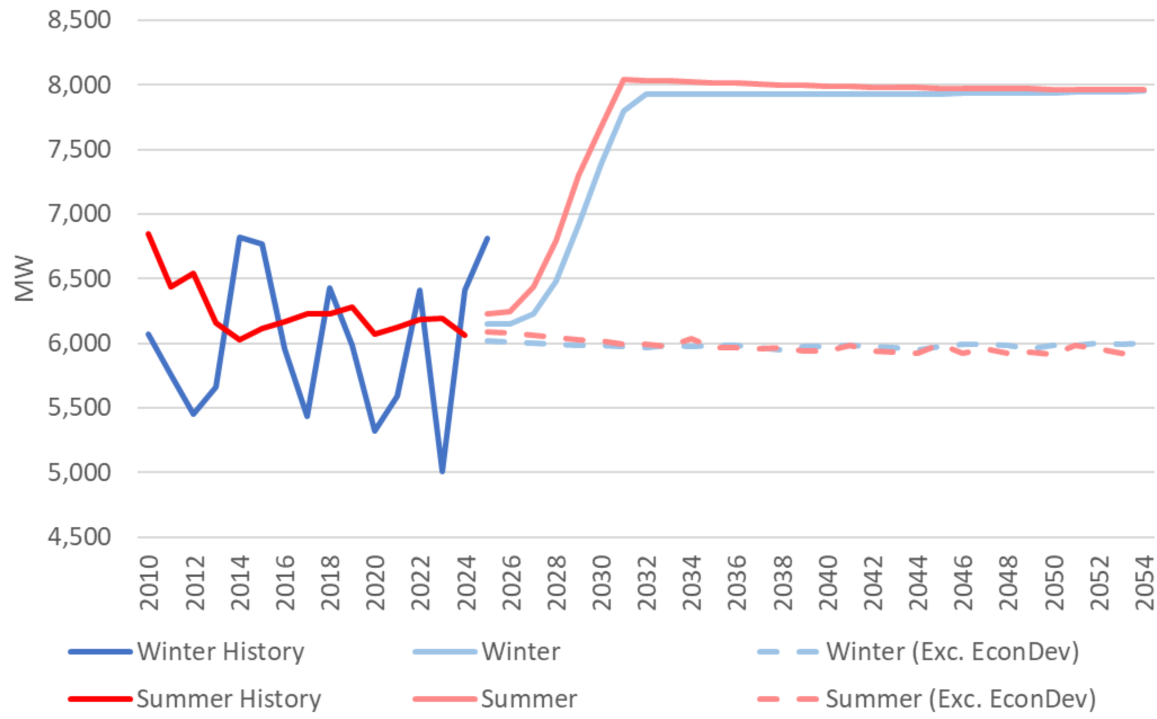
2.1 Customers' Projected Needs: The 2025 CPCN Load Forecast

Due to Kentucky's significant economic development efforts generally and its incentives to attract data centers in particular, the Companies' 2025 CPCN Load Forecast projects a large increase in customers' energy and demand requirements resulting from economic development load additions of about 2,000 MW by 2032. Those load additions consist of 1,750 MW of 95% load factor data centers, more than 250 MW of total BOSK load, and two industrial customers' new facilities of 19.4 MW and 20 MW. To be clear, the Companies are not saying there could not be additional economic development or other load growth by 2032, but the 2025 CPCN Load Forecast is a reasonable, balanced load forecast based on current information.

That economic development load is the driver of change in the 2025 CPCN Load Forecast is graphically illustrated in Figure 1 above (in the Executive Summary) and Figure 2 below. Figure 1 shows that the Companies' forecast of non-economic development load (i.e., minus data center load and BOSK) has remained materially unchanged from the Companies' 2021 IRP load forecast; economic development drives all of the material change.

As shown in Figure 1 above and Figure 2 below, the addition of significant amounts of high-load factor data center load and BOSK greatly increases energy requirements and effectively shifts the entire demand curve up precisely because of such customers' around-the-clock, year-round energy needs.

Figure 2: Seasonal Peaks With and Without Economic Development



For additional context, as Tim A. Jones explains in his testimony, the 2025 CPCN Load Forecast is the Companies' 2024 IRP Mid load forecast adjusted to include the 2024 IRP High load forecast's economic development load, i.e., the 2025 CPCN Load Forecast includes 1,750 MW of data center load by 2032 and the full BOSK load, whereas the 2024 IRP Mid load forecast included only 1,050 MW of data center load and excluded BOSK Phase Two.[9] The 2025 CPCN Load Forecast is in all other respects identical to the 2024 IRP Mid load forecast, including 150 MW of distributed generation by 2032, annual energy reductions of 1,500 GWh by 2032 from energy efficiency and other energy reductions,[10] and summer and winter peak demand reductions in 2032 of 230 MW and 171 MW, respectively, resulting from energy efficiency (compared to a forecast with flat energy efficiency assumptions).[11]

Figure 3 , Figure 4, and Figure 5 below show how the 2025 CPCN Load Forecast compares to the 2024 IRP Mid and High load forecasts.

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[9] *See, e.g.,* Case No. 2024-00326, IRP Vol. I at 5-13 to 5-16 (Oct. 18, 2024).

[10] Includes energy reductions from customer-initiated energy efficiency improvements, advanced metering infrastructure ("AMI") related conservation voltage reduction ("CVR") and ePortal savings, distributed generation, and the energy-efficiency effects of the Companies' 2024-2030 DSM-EE Program Plan and the assumed impacts of DSM-EE programs beyond 2030.

[11] Case No. 2024-00326, IRP Vol. I at 7-20 (Oct. 18, 2024).

Figure 3: Annual Energy Requirements Compared to 2024 IRP Mid and High Forecasts

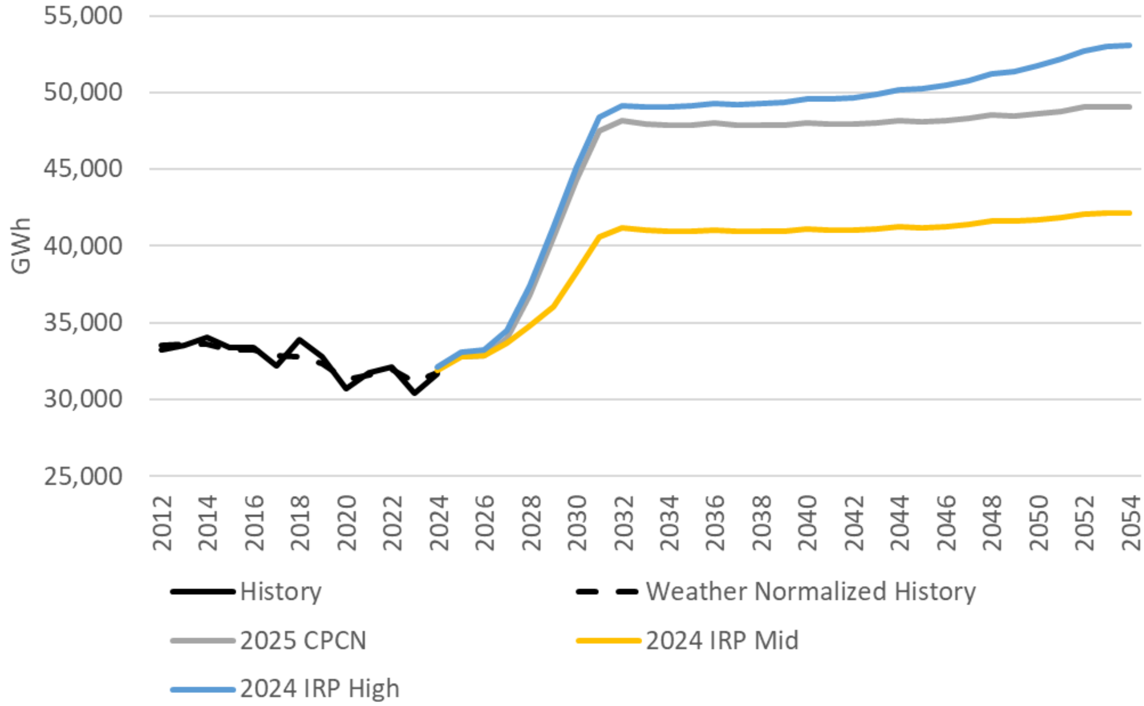


Figure 4: Winter Peaks Compared to 2024 IRP Mid and High Forecasts

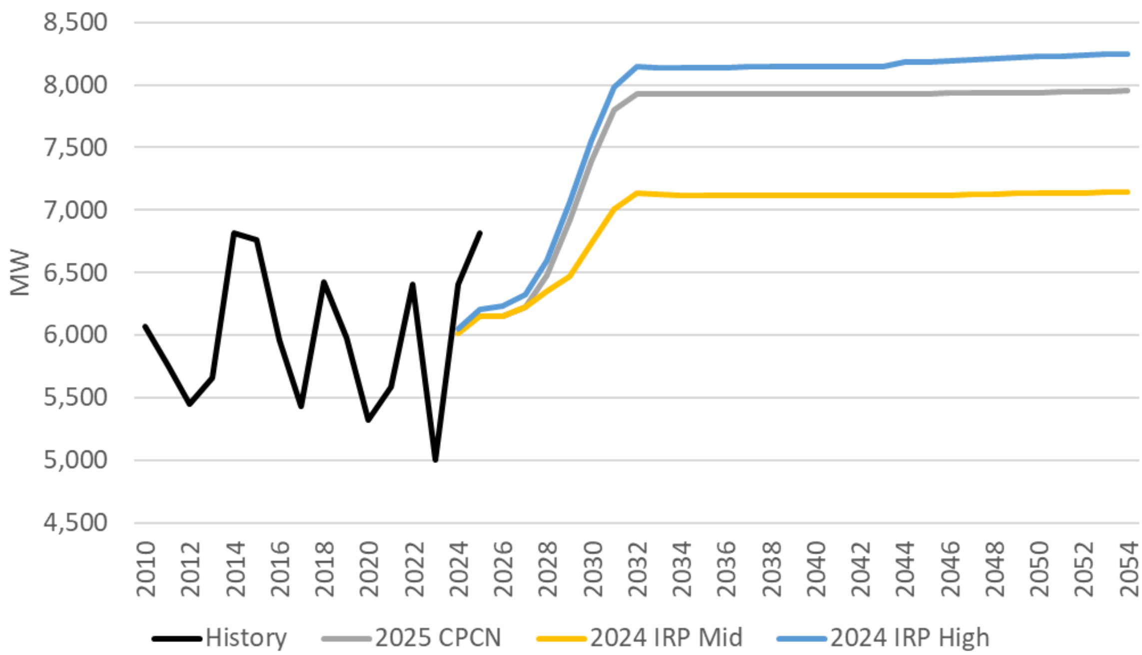


Figure 5: Summer Peaks Compared to 2024 IRP Mid and High Forecasts

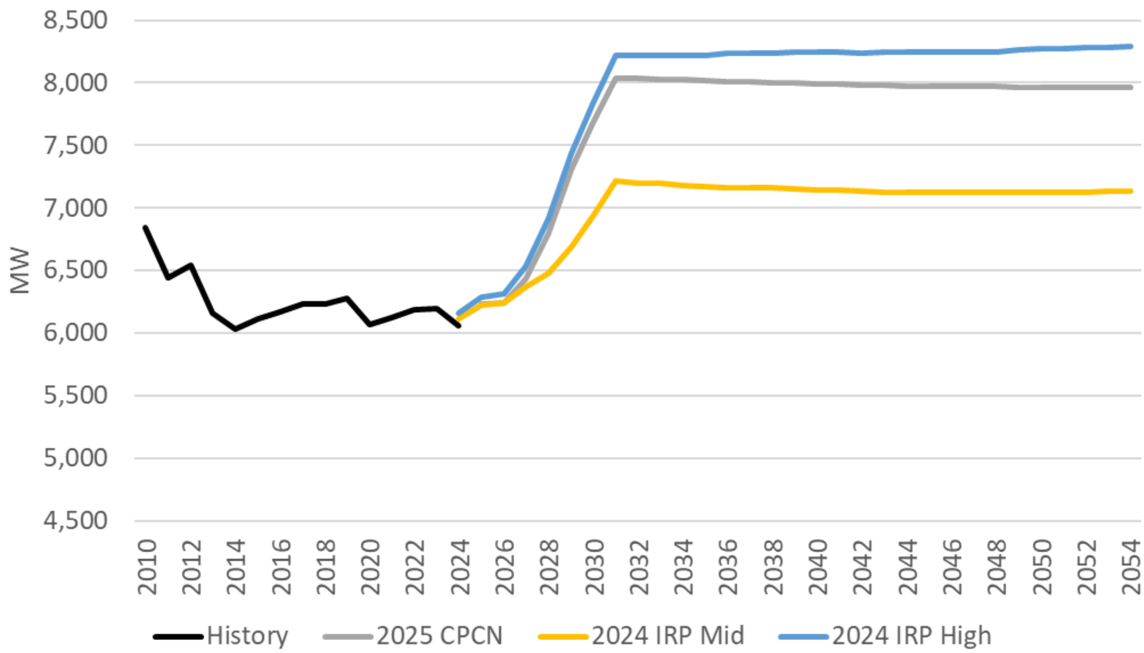


Figure 2 , Figure 4, and Figure 5 above also demonstrate that, historically, winter peaks are much more volatile than summer peaks and that the Companies' system is now consistently dual-peaking. Thus, throughout the forecast period, the Companies' load continues to be dual peaking, which limits the opportunity for generating unit maintenance to the shoulder months. As explained further below, this Resource Assessment fully accounts for generating unit maintenance timing and needs.

As with previous load forecasts, the 2025 CPCN Load Forecast continues to show that the Companies' customers will have large energy needs in all hours, seasons, and daylight conditions. Figure 6 below shows the proportion of energy consumed during daylight and non-daylight hours in 2032.[12] Approximately 43% of annual energy requirements and 53% of winter energy requirements are consumed during non-daylight hours.

[12] 2032 is the first full year in the 2025 CPCN Load Forecast with all economic development load additions.

Figure 6: Proportion of Energy Consumed During Daylight and Non-Daylight Hours (2032)

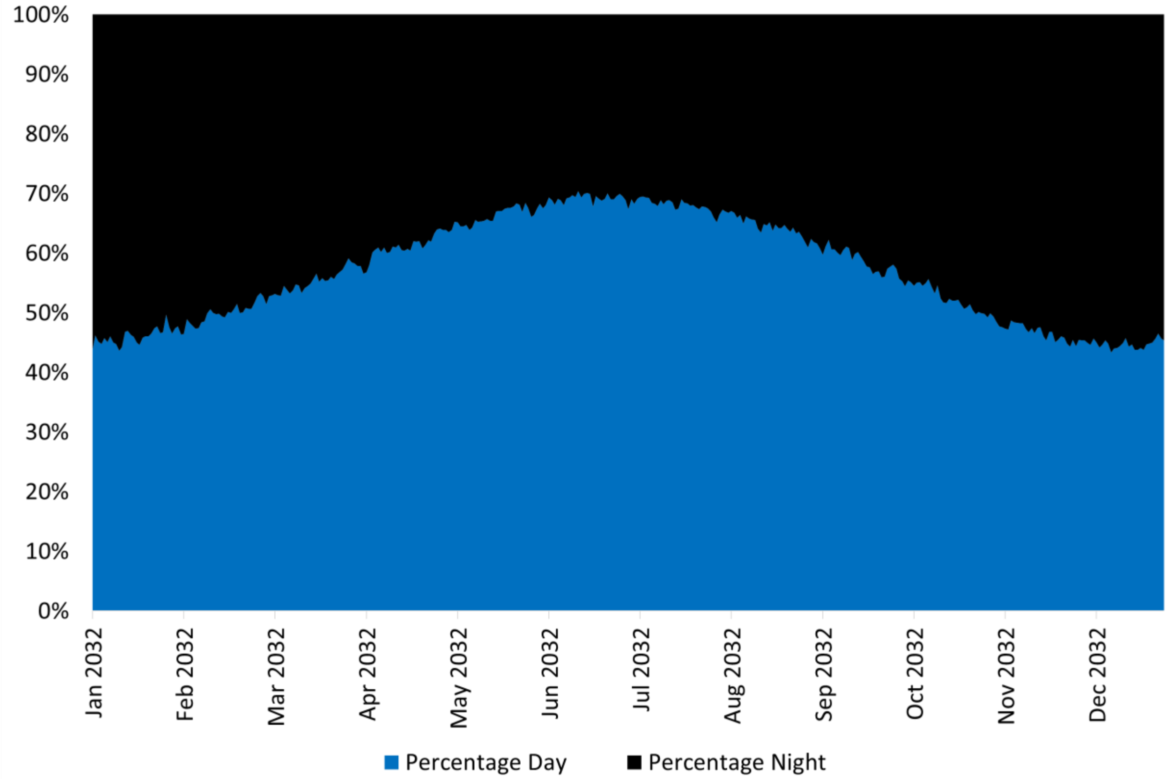


Figure 7 below shows daily peak and minimum load values in both daylight and non-daylight hours for every day in calendar year 2032, ranked from highest to lowest by daily maximum (maximum values are in color; minimum values are gray). It shows there are about 2,137 non-daylight peak hours above 5,000 MW, including a number of which occur in the summer, and more than 433 such hours above 6,000 MW, many of which occur in the winter.

Figure 7: 2032 Daily Maximum and Minimum Loads During Daylight and Non-Daylight Hours

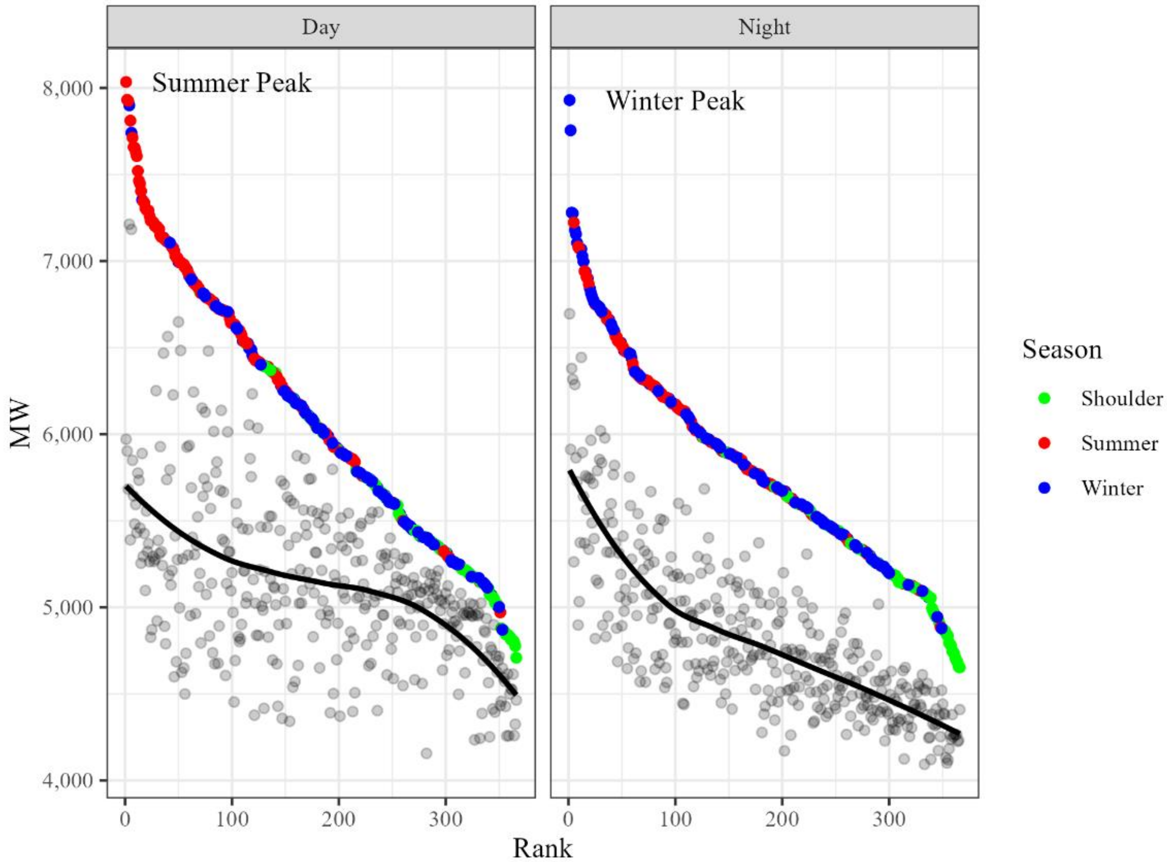


Figure 8 below shows projected hourly demand chronologically in 2032, and Figure 9 is a load duration curve of the same data. They show that the Companies' combined system hourly peak is 8,034 in 2032, minimum hourly demand is 4,093 MW, and that in 2032 there will be 917 hours with demand over 6,500 MW, 3,733 hours with demand over 5,500 MW, and all but 472 hours with demand over 4,500 MW.

Figure 8: LG&E and KU 2032 Hourly Load

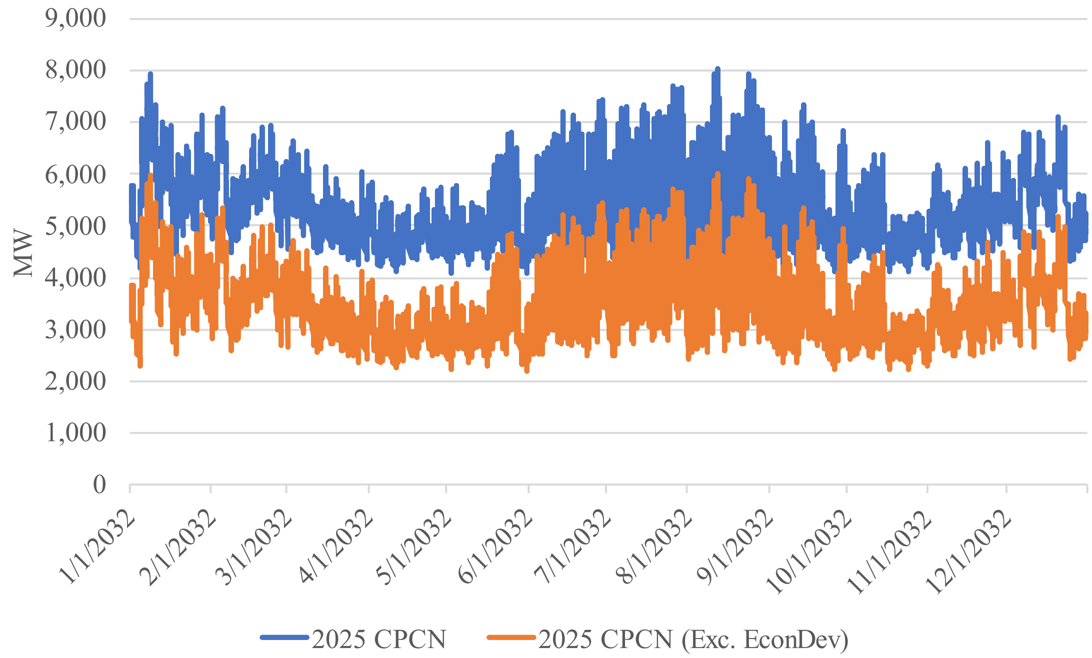
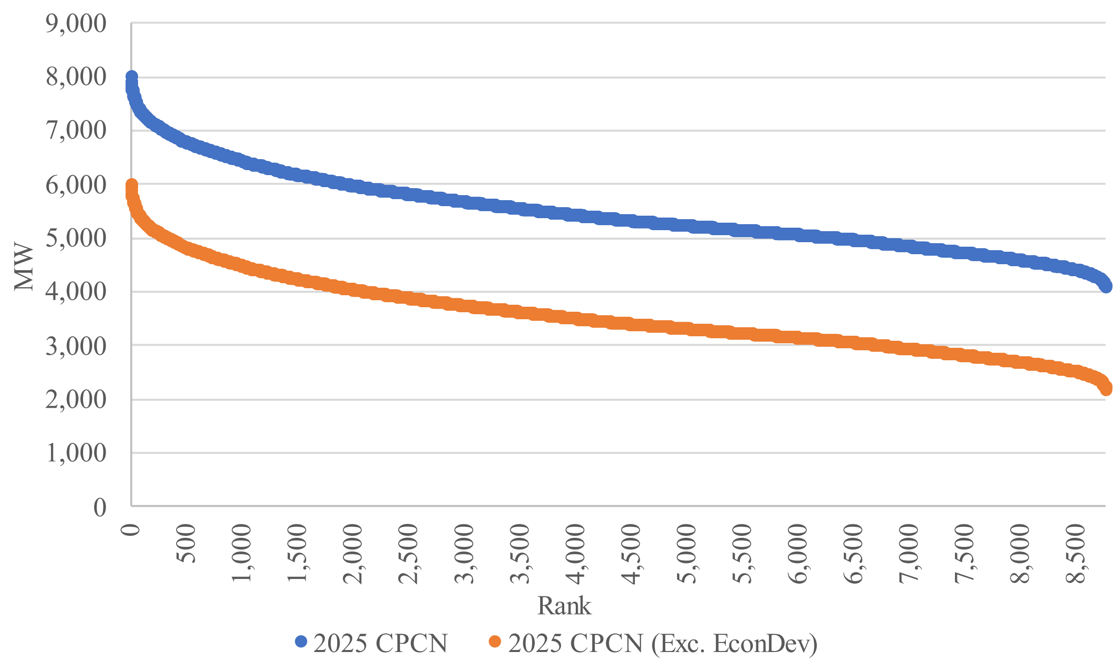


Figure 9: LG&E and KU 2032 Load Duration Curve



This data shows that customers will continue to require large amounts of energy at all times, day and night, and in all seasons and weather conditions. It further shows that system peak demands can occur in summer or winter and in daylight and non-daylight hours. Therefore, a resource portfolio must be able to serve customers' considerable energy requirements in all hours, seasons, and weather and daylight conditions. Notably, the figures above reflect load under normal weather. Extreme weather conditions drive a need for additional reliability considerations, as discussed in the next section.

2.2 Serving Customers Reliably: Minimum Reserve Margins

The Companies' long-term load forecast is developed with the assumption that weather will be normal in every year. While this is a reasonable assumption for long-term resource planning, weather from one year to the next is never the same. Therefore, to account for the possibility of extreme weather events and the uncertainty in generating unit availability, the Companies carry a level of supply-side and demand-side resources that exceeds their forecasted peak demands under normal weather conditions. Reserve margin is the amount of resources carried in excess of forecasted peak demands and is expressed as a percentage of forecasted peak demand under normal weather conditions. In their 2024 IRP, the Companies determined that the reserve margins needed to maintain a loss-of-load expectation ("LOLE") of one or fewer days in 10 years are 29% in the winter and 23% in the summer. Appendix D contains a copy of the 2024 IRP Resource Adequacy Analysis.

Importantly, minimum reserve margin constraints and capacity contributions for limited-duration resources are inputs to the Companies' resource planning process that can vary with changes in load and resource mix. Therefore, after identifying optimal resource additions for a range of data center load scenarios with 2024 IRP reserve margin constraints and capacity contributions, the Companies evaluated the reliability of their generation portfolio with various combinations of these resources to determine which new resources are optimal for serving data center load growth in the 2025 CPCN Load Forecast.

In addition to ensuring adequate reserve margins, the Companies' modeling also ensures their resource plans comply with KRS 278.264, which constrains retirements of fossil fuel-fired generation. KRS 278.264 does not limit the types of resources that could be added to serve load growth, which is the focus of this Resource Assessment.

2.3 Clarifying the Objective: Make Only the Decisions that Must Be Made Today

Finally, it is helpful to bear in mind that this is not the last time the Companies will make resource decisions. Thus, the objective of this Resource Assessment is not to prescribe the ideal resource mix through 2050, but rather to provide an optimal portfolio to address the decisions that must be made today to serve near-term economic development load growth. It is inadvisable to attempt to prescribe today the resource portfolio for the entire period this Resource Assessment addresses; developments in resource technology and applicable regulations can and will affect future resource decisions.

Therefore, the objective of this Resource Assessment is to formulate an optimal resource portfolio to meet customers' projected needs and address resource decisions that must be made today, but also to do so in a way that does not prejudice future resource decisions.

3 Meeting the Objective: Available Demand- and Supply-Side Resources

To meet customers' forecasted demand and energy requirements discussed above reliably and economically, the Companies gathered information about available supply- and demand-side resources in addition to their existing resources. They accomplished this on the supply side through updated cost estimates for simple-cycle combustion turbine ("SCCT"), natural gas combined cycle ("NGCC"), and battery energy storage system ("BESS" or "battery storage") resources and a request for proposals ("RFP") for new renewable generation capacity and energy. On the demand side, consistent with the 2024 IRP, the Companies modeled new dispatchable DSM program measures and an expansion of the Companies' CSR program.

3.1 New Supply-Side and Demand-Side Resources

Table 4 and Table 5 list the fully dispatchable and limited-duration supply-side and demand-side resources considered in this Resource Assessment. Fully dispatchable resources are resources that can be dispatched any time and operated for days or months at a time. Fully dispatchable resources considered in this Resource Assessment include large-frame SCCTs and NGCCs at E.W. Brown ("Brown 12") and Mill Creek ("Mill Creek 6").[13] Limited-duration resources can only be dispatched several hours at a time and in the case of the Companies' dispatchable DSM and CSR programs, have limited availability. Limited-duration resources include 4-hour BESS at Cane Run and Ghent, dispatchable DSM program measures, and an expansion of the Companies' CSR program.[14] Resource costs and assumptions are based on updated cost estimates. The "Moderate" scenario in National Renewable Energy Laboratory's 2024 Annual Technology Baseline ("NREL's 2024 ATB") was used to escalate fully dispatchable and limited-duration resource costs beyond 2031, consistent with the Companies' 2024 IRP.[15]

[13] As the testimony of Mr. Tummonds addresses, favorable transmission costs, a favorable gas supply environment, and the advantages of constructing Mill Creek 6 next to Mill Creek 5 make E.W. Brown and Mill Creek the most desirable sites for additional NGCCs.
[14] The Companies determined Cane Run and Ghent are the most favorable sites for BESS based on assessment by the Project Engineering and Transmission groups.
[15] See https://atb.nrel.gov/ for NREL's 2024 ATB.

Table 4: Fully Dispatchable Resources (2030 Installation; 2030 Dollars)

		NGCC	
	SCCT	**Brown 12**	**Mill Creek 6**
Summer Capacity (MW)[16]	243	645	645
Winter Capacity (MW)[16]	258	660	660
Heat Rate (MMBtu/MWh)[17]	9.5	6.3	6.3
Capital Cost ($/kW)[18]	1,636	2,120	2,138
Fixed O&M ($/kW-yr)[19]	6.9	7.8	7.1
Firm Gas Cost ($/kW-yr)[20]	35	15	27
Variable O&M ($/MWh)[21]	N/A	0.23	0.23
Start Cost ($/Start)[22]	27,398	N/A	N/A
Hourly Operating Cost ($/Hour)[23]	N/A	906	906
Fuel Cost ($/MWh)[24]	40.29	26.58	26.58
Earliest In-Service Year[25]	2030	2030	2031

[16] Capacity is the net installed capacity.
[17] Heat rate is the full load net heat rate.
[18] Capital cost is the overnight capital expenditure required to achieve commercial operation. Cost of financing is modeled through construction profiles for each resource type.
[19] Fixed operation and maintenance costs are operation and maintenance costs that do not vary with generation output. For SCCT and NGCC resources, fixed O&M includes fixed costs for a long-term service agreement ("LTSA").
[20] Firm gas transportation costs are costs associated with reserving firm gas-line capacity. Estimates for SCCT and Mill Creek 6 reflect the need for new interstate pipeline infrastructure, are likely conservative, and are assumed to decrease to $11/kW-yr and $8/kW-yr, respectively, after 20 years.
[21] Variable operation and maintenance costs are operation and maintenance costs incurred on a per-unit-energy basis.
[22] Start costs are starts-based variable LTSA costs for SCCT.
[23] Hourly operating costs are hours-based variable LTSA costs for NGCC.
[24] Fuel cost is the product of the unit's heat rate and the assumed cost of fuel.
[25] Earliest in-service year is the first year the Companies expect a resource can be feasibly built based on permitting and construction timelines as well as lead times for electrical equipment such as generator step-up transformers.

Table 5: Limited-Duration Resources (2030 Installation; 2030 Dollars)

	4-Hour BESS		Dispatchable DSM[26]			
	CR BESS	GH BESS	BYOD Energy Storage	BYOD Home Generators	BDR 50-200 kW	CSR[27]
Summer Capacity (MW)[16]	100+	100+	0.89	0.85	1.45	100
Winter Capacity (MW)[16]	100+	100+	0.89	0.85	1.45	100
Capacity Contribution[28]	85%	85%	39%	39%	39%	39%
Round-Trip Efficiency	87%	87%	N/A	N/A	N/A	N/A
Capital Cost ($/kW)[18]	1,954	2,131	N/A	N/A	N/A	N/A
Fixed O&M ($/kW-yr)[19]	25	25	N/A	N/A	N/A	81
Investment Tax Credit[29]	50%	50%	N/A	N/A	N/A	N/A
Earliest In-Service Year[25]	2028	2028	2027	2027	2028	2028

The Companies' load forecasts fully account for the energy efficiency effects of the proposed 2024-2030 DSM-EE Program Plan as well as such programs beyond 2030; the combined impact of company-sponsored programs and customer-initiated energy efficiency improvements is assumed to grow throughout the planning horizon. The dispatchable DSM programs in the 2024-2030 DSM-EE Program Plan are modeled as existing resources and are assumed to grow throughout the planning horizon. In addition to these resources, the new dispatchable DSM program measures in Table 5 provide alternative means for customers to participate in existing programs. As such, these programs have no incremental fixed costs and were included in all of the Companies' resource plans. The CSR program in Table 2 is modeled as an expansion of the Companies' CSR-2 program. Notably, the Companies' ability to require CSR-2 customers to curtail their usage without a buy-through option is limited to 100 hours annually when all available units are dispatched or being dispatched.

The Companies also issued an RFP for new renewable generation capacity and energy in May 2024.[30] In total, 17 parties responded to the RFP with 48 proposals across 22 different projects. Appendix B contains a full listing of the 48 proposals; Table 6 below summarizes them by technology.

[26] Dispatchable DSM includes three potential enhancements to the Companies' existing DSM programs. Summer and winter capacities reflect 2030 values. These programs do not require incremental capital or fixed O&M.

[27] CSR reflects an expansion of the existing CSR-2 program. Fixed O&M costs reflect the current CSR-2 tariff of $5.90/kW-mo inflated to 2030 dollars at 2.3 percent per year. Capacity contribution for CSR is assumed to be the same as capacity contribution for dispatchable DSM.

[28] The analysis to determine capacity contributions is summarized in the Companies' 2024 IRP Volume III (2024 IRP Resource Adequacy Analysis).

[29] In accordance with the current tax credits, the Companies assumed BESS resources that are in-service by year 2036 would begin construction by year 2033 and receive the full credit; resources that are in-service in year 2037 would begin construction in 2034 and receive 75% of the credit; resources that are in-service in year 2038 would begin construction in 2035 and receive 50% of the credit; and resources that are in-service in year 2039 or later would begin construction in 2036 or later and not receive any tax credits.

[30] The testimony of Charles R. Schram addresses the RFP at length, and it includes the RFP itself and all RFP responses as Exhibits CRS-1 and CRS-2, respectively.

Table 6: Summary of RFP Responses

Technology	Number of Proposals by Start Year			Nameplate Capacity (MW)	Price
	<=2028	2029	2030+		
Solar	27	1	0	40-600	[redacted]
Solar Asset Development[31]	7	0	0	89-600	
Solar w/ 4-hr BESS Option	6	0	0	115-400	
Solar w/ 8-hr BESS Option	1	0	0	400	
Solar + 4-hr BESS	1	0	0	150	
Wind w/ Solar Option	0	2	0	600-800	
4-hr BESS	1	0	0	120	
Pumped Hydro	0	0	2	287	

The majority of the responses to the RFP were for solar power purchase agreements ("PPAs"), solar build transfer agreements ("BTAs"), or solar asset development projects. The Companies reviewed the RFP responses and screened them to create a more manageable set of alternatives, reducing the number of proposals evaluated in the Resource Screening model to 32:

- For proposals covering the same project but with different pricing options due to term or start date, the Companies selected the proposal with the lowest price. For proposals with flat or escalating price options, the Companies selected the proposals with flat prices.
- The Companies excluded two non-conforming solar projects based on capacity (40 and 50 MW each).

The Companies reviewed the Resource Screening model results and further reduced the number of proposals that advanced for modeling analysis in the Resource Assessment to 22:

- For proposals covering the same project, the Companies selected the proposal with the lowest levelized cost per MWh.
- The Companies excluded the non-conforming BESS standalone proposal because it created the same concerns about such contracts in general as discussed in the testimony of Charles R. Schram.
- The Companies excluded the pumped hydro project because it would not be available until later than needed for currently anticipated energy storage requirements.

The full set of 22 proposals that advanced for modeling analysis in the Resource Assessment is also included in Appendix B. These proposals comprise 3,348 MW of solar resources, 435 MW of BESS resources, and 600 MW of wind resources.

[31] For solar asset development proposals, the Companies developed build cost estimates for each project. The total cost of each project, including the project proposal and the build cost estimate, was modeled.

3.2 Capacity and Energy Need with Existing and CPCN-Approved Resources

Table 7 and Table 8 summarize the Companies' winter and summer peak demand and resources with approved changes from the 2022 CPCN Order,[32] though they exclude the six total solar PPAs into which the Companies have entered due to three having been canceled and the challenges facing the advancement of the remaining three.[33] These tables reflect the retirements of Mill Creek 1 (2024) and Mill Creek 2 (2027), the assumed retirement of the small-frame SCCTs (2026), and the planned additions of Brown BESS (2027), Mill Creek 5 (2027), two company-owned solar facilities in 2026 and 2027, and dispatchable demand response programs from the Companies' 2024-2030 DSM-EE Program Plan. The Companies also assumed Brown 3 will retire in 2035 and Mill Creek 3-4 will retire in 2045 based on the 2024 IRP, and OVEC is assumed to retire in 2040 with the end of the Companies' Inter-Company Power Agreement ("ICPA") with OVEC. Reserve margins with the 2025 CPCN Load Forecast indicate a need for new capacity beginning in 2028.[34] However, the 2024 IRP demonstrated that the least-cost resources for serving data center load growth are new NGCC resources and battery storage charged by existing resources, and the earliest a new NGCC can be constructed at the E.W. Brown station is 2030. The Companies address this constraint in their Stage One analysis.

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[32] *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*, Case No. 2022-00402, Order (Ky. PSC Nov. 6, 2023).

[33] Of the six total solar PPAs into which the Companies have entered, including two prior to the 2022 CPCN and DSM-EE case, (a) one has been canceled by the developer due to interconnection issues, (b) one has been canceled by the developer due to a significant project price increase, and (c) one with a price reopener has been contractually terminated due to the Companies' unwillingness to proceed at a much higher price than in the original agreement. The remaining three PPAs appear unlikely to proceed under their approved terms.

[34] Winter and summer peak loads are assumed to occur in January and August. Because the assumed data center load ramps up over time, a greater amount of data center load is reflected in summer (August) 2028 compared to winter (January) 2028. It is for this reason that the Summer Peak Demand and Resource Summary shows a capacity need beginning in 2028, while the Winter Peak Demand and Resource Summary shows a capacity need beginning in 2029.

Table 7: Winter Peak Demand and Resource Summary (2025 CPCN Load Forecast, MW)

	2025	2028	2029	2030	2031	2032	2035	2040	2050
Peak Load	**6,146**	**6,481**	**6,918**	**7,386**	**7,795**	**7,930**	**7,928**	**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[35]	-300	-597	-597	-597	-597	-597	-1,013	-1,013	-2,051
Small-Frame SCCTs[36]	0	-55	-55	-55	-55	-55	-55	-55	-55
NGCC (Mill Creek 5)	0	660	660	660	660	660	660	660	660
Total	7,609	7,985	7,985	7,985	7,985	7,985	7,569	7,569	6,531
Reserve Margin	23.8%	23.2%	15.4%	8.1%	2.4%	0.7%	-4.5%	-4.5%	-17.7%
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[37]	24	110	124	125	135	145	158	163	163
Retirements/Additions									
Solar[38]	0	0	0	0	0	0	0	0	0
BESS[39]	0	125	125	125	125	125	125	125	125
Total	206	417	431	433	442	452	465	471	471
Total Supply	**7,815**	**8,402**	**8,416**	**8,418**	**8,427**	**8,437**	**8,034**	**8,040**	**7,002**
Total Reserve Margin	**27.2%**	**29.6%**	**21.7%**	**14.0%**	**8.1%**	**6.4%**	**1.3%**	**1.4%**	**-11.8%**
Capacity Need[40]	**113**	**-42**	**507**	**1,111**	**1,629**	**1,792**	**2,193**	**2,188**	**3,241**

[35] Mill Creek 1 was retired at the end of 2024. Mill Creek 2 will be retired after Mill Creek 5 is commissioned in 2027. For this resource summary, Brown 3 is assumed to retire in 2035. Mill Creek 3-4 are assumed to retire in 2045. OVEC is assumed to retire in June 2040 at the end of the OVEC ICPA.

[36] 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.

[37] Dispatchable DSM reflects expected load reductions under normal peak weather conditions.

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

[39] Brown BESS is assumed in-service in 2027.

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

Table 8: Summer Peak Demand and Resource Summary (2025 CPCN Load Forecast, MW)

	2025	2028	2029	2030	2031	2032	2035	2040	2050
Peak Load	**6,230**	**6,795**	**7,304**	**7,677**	**8,040**	**8,034**	**8,017**	**7,992**	**7,967**
Fully Dispatchable Generation Resources									
Existing Resources	7,612	7,618	7,618	7,618	7,618	7,618	7,618	7,618	7,618
Retirements/Additions									
Coal[41]	-300	-597	-597	-597	-597	-597	-1,009	-1,161	-2,029
Small-Frame SCCTs[42]	0	-47	-47	-47	-47	-47	-47	-47	-47
NGCC (Mill Creek 5)	0	645	645	645	645	645	645	645	645
Total	7,312	7,619	7,619	7,619	7,619	7,619	7,207	7,055	6,187
Reserve Margin	17.4%	12.1%	4.3%	-0.8%	-5.2%	-5.2%	-10.1%	-11.7%	-22.3%
Renewable/Limited-Duration Resources									
Existing Resources	106	107	107	107	107	107	107	107	107
Existing CSR	107	107	107	107	107	107	107	107	107
Existing Disp. DSM[43]	69	150	166	170	179	190	208	227	227
Retirements/Additions									
Solar[44]	0	201	201	201	201	201	201	201	201
BESS[45]	0	125	125	125	125	125	125	125	125
Total	282	689	705	710	719	730	747	766	766
Total Supply	**7,594**	**8,308**	**8,324**	**8,329**	**8,338**	**8,349**	**7,954**	**7,821**	**6,953**
Total Reserve Margin	**21.9%**	**22.3%**	**14.0%**	**8.5%**	**3.7%**	**3.9%**	**-0.8%**	**-2.1%**	**-12.7%**
Capacity Need[46]	**68**	**50**	**660**	**1,114**	**1,552**	**1,534**	**1,907**	**2,009**	**2,846**

Section 6.3 in Appendix A contains a full discussion of existing resource assumptions including stay-open and life extension costs for existing coal units. In this Resource Assessment, PLEXOS was used to evaluate the continued operation of coal units by comparing these costs to the costs of replacement resources along with the costs of retrofitting alternatives such as natural gas conversion.

[41] Mill Creek 1 was retired at the end of 2024. Mill Creek 2 will be retired after Mill Creek 5 is commissioned in 2027. For this resource summary, Brown 3 is assumed to retire in 2035. Mill Creek 3-4 are assumed to retire in 2045. OVEC is assumed to retire in June 2040 at the end of the OVEC ICPA. These values do not reflect any potential reduction in Ghent 2's summer capacity due to Ozone NAAQS regulations.
[42] 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.
[43] Dispatchable DSM reflects expected load reductions under normal peak weather conditions.
[44] This analysis assumes 120 MW of solar capacity is added in 2026, and an additional 120 MW of solar capacity is added in 2027. Capacity values reflect 83.7% expected contribution to summer peak capacity.
[45] Brown BESS is assumed in-service in 2027.
[46] The summer capacity need is based on a 23% summer minimum reserve margin target. Positive values reflect a capacity deficit.

4 Meeting the Objective: Comprehensive Planning Process

4.1 Constraints and Uncertainties of Analysis

The Companies' Resource Assessment considers a number of important constraints and uncertainties.

4.1.1 Constraints

The Resource Assessment included the following constraints:

- Portfolios must maintain minimum reserve margins and comply with KRS 278.264.
- Brown 3 cannot operate as a coal-fired generating unit beyond 2034 due to landfill storage capacity limits.
- Mill Creek 3 and 4 cannot operate as coal-fired generating units beyond 2044 due to landfill storage capacity limits. These landfill constraints are discussed further in Section 6.3.4.
- The earliest new BESS can be added is 2028, the earliest new NGCC or SCCT can be added is 2030, and the earliest a small modular nuclear reactor ("SMR") can be added is assumed to be 2039. As a result, SMR is not a viable option for serving near-term data center load growth. The availability of each RFP resource is specified in its proposal.

The Companies included constraints in their 2024 IRP Resource Assessment to limit solar generation to 20% of total energy requirements and the sum of solar and wind generation to 25% of total energy requirements, but the Companies removed these constraints in this analysis because they would be nonbinding given the amount of solar and wind proposals received in response to their 2024 RFP.

4.1.2 Economic Development Load Growth

The 2025 CPCN Load Forecast is summarized in Section 2.1 and includes 1,750 MW of new data center load by 2032. To understand the impact of higher or lower data center loads on the optimal resource portfolio, the Companies developed least-cost portfolios for two higher and two lower load scenarios in 140 MW increments (i.e., down to 1,470 MW of data center load and up to 2,030 MW of data center load).

4.1.3 Environmental Regulations

There are a number of reasons why the Companies reasonably focused on one environmental regulatory scenario in the 2025 CPCN Resource Assessment.

First, the Companies' recent 2024 IRP Resource Assessment, conducted before the November 2024 federal elections, considered four different environmental scenarios based on three major regulations the U.S. Environmental Protection Agency ("EPA") had finalized since the Companies' 2021 IRP: the 2023 Good Neighbor Plan relating to the 2015 National Ambient Air Quality Standards ("NAAQS") for ozone ("Ozone NAAQS"); the 2024 updates to the Effluent Limitation Guidelines ("ELG"); and the 2024 Clean Air Act Section 111(b) and (d) Greenhouse Gas Rules ("GHG Rules"). The four different environmental regulatory scenarios the Companies modeled in the 2024 IRP were: (1) a No New Regulations scenario in which none of the recent regulations became enforceable; (2) an Ozone NAAQS-only scenario; (3) an Ozone NAAQS and ELG scenario; and (4) a scenario in which all three of the recent major regulations (or their equivalents) became enforceable. The Companies' 2024 IRP Resource Assessment demonstrated that in the 2024 IRP High load scenario (including adding 1,750 MW of data center load), adding NGCC capacity and battery storage charged by existing resources would be least-cost in all four environmental scenarios.[47] This result

[47] *See, e.g.,* Case No. 2024-00326, IRP Vol. III, 2024 IRP Resource Assessment at 44-48.

enabled the Companies to focus in this Resource Assessment on one environmental scenario, namely the Ozone NAAQS scenario.

Second, as Mr. Imber explains in his testimony, although the Good Neighbor Plan no longer applies to Kentucky, the EPA has an ongoing obligation to drive attainment with the 2015 Ozone NAAQS. Also, the Trump administration has not explicitly stated it intends to relax any ozone NAAQS.

Third, as Mr. Imber explains regarding the 2024 ELG standards, compliance is not required until the end of 2029, and a Notice of Planned Participation for the new permanent cessation of coal combustion subcategory is not due until the end of 2025, giving the Companies time to analyze further the rule and its implications. Also, Mr. Imber states it is reasonably possible that the Trump administration will seek to rescind the 2024 ELG standards.

Fourth, as Mr. Imber explains regarding the GHG Rules, President Trump's day-one executive orders, coupled with his campaign commitment to undo the GHG Rule,[48] cast serious doubt on the near-term need to comply with the GHG Rule.

For all these reasons, it is reasonable to focus on the Ozone NAAQS scenario in this Resource Assessment.

4.1.4 Fuel Prices

Fuel prices are an important uncertainty in any resource assessment. To address it, the Companies used the five fuel price scenarios from their 2024 IRP, which were developed using the methodology the Commission found to be credible and reasonable in its Final Order in the Companies' 2022 CPCN proceeding.[49] In the 2024 IRP fuel price scenarios, natural gas prices are the primary price setting factor, with coal prices derived from gas prices beginning in 2025 based on different historical coal-to-gas ("CTG") price ratios.

The Companies' three natural gas price cases (low, mid, and high) derive from the U.S. Energy Information Administration's 2023 Annual Energy Outlook's corresponding natural gas price forecasts: High Oil and Gas Supply case (low gas price), Reference case (mid gas price), and Low Oil and Gas Supply case (high gas price).[50]

[48] "Trump vows to ax power plant rule, noncommittal on EV tax credit," The Hill (Aug. 20, 2024), available at https://thehill.com/policy/energy-environment/4836812-trump-power-plant-rule-electric-vehicle-tax-credit/.

[49] *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*, Case No. 2022-00402, Order at 93-94 (Ky. PSC Nov. 6, 2023) ("The Commission finds that LG&E/KU's evidence regarding the relationship between coal and natural gas prices is credible. … [W]hether projected separately or together, the Commission believes that it is reasonable to assume a relationship between coal prices and natural gas prices. … [T]he Commission finds that LG&E/KU's fuel price scenarios were reasonable ….").

[50] The EIA did not publish an Annual Energy Outlook in 2024. *See* EIA's "Statement on the Annual Energy Outlook and EIA's plan to enhance long-term modeling capabilities" dated July 26, 2023 ("EIA's National Energy Modeling System (NEMS), which we use to produce our Annual Energy Outlook (AEO), requires substantial updates to better model hydrogen, carbon capture, and other emerging technologies. Our usual AEO publication schedule does not accommodate these necessary model enhancements, which require significant time and resources. As a result, EIA will not publish an AEO in 2024."), available at https://www.eia.gov/pressroom/releases/press537.php (accessed Oct. 2, 2024).

In the first three fuel price scenarios the Companies analyzed, coal prices predominantly varied with gas prices by a ten-year average ratio of coal and gas prices. These cases are the most likely to occur over a long planning period and are called "Low Gas, Mid CTG Ratio," "Mid Gas, Mid CTG Ratio," and "High Gas, Mid CTG Ratio." Note that the Mid coal-to-gas price ratio approximates the ratio of NGCC and coal energy costs. Therefore, it is plausible to expect coal-to-gas price ratios to revert to this ratio over the long term, which is why the Companies refer to it as the "Expected CTG Price Ratio." Figure 10 below shows these three fuel price cases in nominal dollars per MMBtu through 2039:

Figure 10: Coal and Natural Gas Price Scenarios with a Mid Coal-to-Gas Price Ratio

[redacted]

The other two fuel price scenarios involve relationships between gas and coal prices that would be atypical for an extended time horizon, essentially as sensitivity cases: (1) low gas prices with a historically high coal-to-gas ratio ("Low Gas, High CTG Ratio"); and (2) high gas prices with a historically low coal-to-gas ratio ("High Gas, Low CTG Ratio"). Figure 11 below illustrates these two fuel price cases in nominal dollars per MMBtu through 2039:

Figure 11: Coal and Natural Gas Price Scenarios with Atypical Long-Term Coal-to-Gas Price Ratios

[redacted]

A full description of the formulation of these gas and coal prices and coal-to-gas price ratios is in the Commodity Prices discussion in Appendix A.

4.2 Modeling Tools: SERVM, PLEXOS, PROSYM, and Financial Model

The Companies used four primary software tools to aid them in their analysis:

- **Resource Adequacy: SERVM.** The Companies used SERVM, a resource adequacy model, to develop minimum reserve margin constraints for resource planning, compute capacity contribution values for limited-duration resources, and evaluate LOLE for different resource portfolios. Resource adequacy is evaluated over a wide range of weather and unit availability scenarios. Specifically, the Companies used SERVM to model generation production costs, reliability costs, and LOLE over 51 load scenarios and 300 unit availability scenarios. The load scenarios were developed based on the weather in each of the last 51 years (1973–2023).

- **Resource Plan Development and Screening: PLEXOS.** The Companies used PLEXOS, a resource planning model, to develop least-cost resource plans over a range of fuel price scenarios. PLEXOS models and evaluates thousands of resource plans to determine which one minimizes the cost of serving customers' load while meeting reserve margin and other constraints. A resource planning model necessarily makes simplifying assumptions to reduce model run times, and a key consideration for any resource planning model is the level of granularity used to develop resource plans. Less granular analyses require more simplifying assumptions and have shorter run times, but too many simplifying assumptions may prevent the model from properly evaluating resources with limited availability or run times. Thus, it is important to evaluate resource plans with an appropriate level of granularity and then check the results with detailed production costs.[51]

- **Production Cost Modeling: PROSYM.** After PLEXOS identifies which resources to include in a resource plan, the Companies model the resource plan's generation production costs in detail using PROSYM, an hourly chronological dispatch model. PLEXOS and PROSYM use the same inputs (e.g., they use the same natural gas and coal prices), but the Companies used PROSYM rather than PLEXOS for detailed production cost modeling because they have used and configured PROSYM over a number of years to do such modeling relatively quickly.

- **Present Value of Revenue Requirements ("PVRR"): Excel Financial Model.** The Companies use a Financial Model developed in Excel to calculate and compare PVRR values for various resource plans. Inputs to the Financial Model include capital and fixed operating costs for new and existing resources as well as generation production costs. Table 9 below lists the primary costs included in the Financial Model. Production costs are developed in PROSYM; the costs for new and existing resources are the same costs modeled in PLEXOS and used to develop the least-cost resource plan.

Table 9: Financial Model Costs

Cost Item	Description
Generation Production Costs	Variable fuel and reagent costs associated with power generation. Includes costs of purchased power such as Ohio Valley Electric Corporation ("OVEC") and solar PPAs.
CCR Beneficial Re-use	Revenue of CCR sales associated with existing coal generation assets.
Existing Unit Stay-Open Costs	Ongoing capital and fixed O&M associated with existing generation assets, including overhaul costs and life extension costs.
Environmental Compliance Costs	Capital and O&M associated with compliance costs for new regulations, such as SCRs to comply with the Good Neighbor Plan.
New Generation Capital and Stay-Open Costs	Capital and O&M associated with new generation assets.

4.3 Analytical Framework: Resource Assessment Completed in Three Stages

The Companies developed their Resource Assessment in three stages using existing supply-side and demand-side resources, new supply-side resources, new demand-side programs, and modeling tools to evaluate the key uncertainties and risks discussed above.

4.4 Stage One: Portfolio Development

In the Stage One analysis, the Companies determined the optimal mix of resources for serving economic development load in the 2025 CPCN Load Forecast as well as the four additional load scenarios using the same two-step process involving PLEXOS and PROSYM they used in the 2024 IRP. The 2024 IRP demonstrated that the least-cost resources for serving economic development load growth are NGCC

[51] The Companies develop resource plans in PLEXOS in six blocks of time per day across a series of six-year rolling horizons. With this level of granularity, each model run takes up to 55 hours to complete.

resources and battery storage charged by existing resources. But economic development loads such as new data centers can be added faster than new NGCC resources; the earliest a new NGCC can be constructed at the E.W. Brown station is 2030. Therefore, to ensure an optimal mix of resources, the Companies first used PLEXOS to develop resource plans with no technology availability constraints and with the assumption that economic development loads are added in 2030. The Companies did this for each of the five load scenarios across each of the five fuel price scenarios, resulting in 25 total resource plans. From these resource plans, the Companies determined the most viable portfolios for serving economic development load based on the resources added in 2030 ("2030 portfolios"). Then, the Companies evaluated each of these portfolios with detailed production costs beginning in 2030 over each of the fuel price scenarios (resulting in 125 cases, or 25 cases per load scenario) to determine which portfolio for a given load scenario is lowest cost on average across all fuel price scenarios.

4.4.1 Stage One, Step One: Resource Plan Development and Screening with PLEXOS

The first step of Stage One consisted of allowing PLEXOS to create least-cost resource plans subject to reserve margin and other constraints for each load scenario and each of the five fuel price scenarios. As noted above, to ensure an optimal mix of resources for serving economic development load, the Companies developed these resource plans with no unit availability constraints and with the assumption that economic development loads are added in 2030. In addition, to determine which renewable resources are least-cost in the near-term, the Companies allowed PLEXOS to choose any renewable resource at any time after the earliest availability date indicated by the corresponding RFP response. Finally, landfill constraints limit the Brown and Mill Creek coal units' ability to operate on coal beyond 2034 and 2044, respectively. While these constraints are entirely reasonable, the Companies developed resource plans with and without these constraints to understand the impact of these constraints on the 2030 portfolios.

Table 10 summarizes the 2030 portfolios that were developed with the Brown and Mill Creek landfill constraints. Each load scenario in Table 10 is labeled based on the amount of data center load included in the scenario.[52] All 2030 portfolios include the Brown 12 and Mill Creek 6 NGCCs ("BR12 NGCC" and "MC6 NGCC"), and almost all 2030 portfolios includes some amount of battery storage. The 2030 portfolio includes a third NGCC in all fuel price scenarios with 2,030 MW of data center load, three fuel price scenarios with 1,890 MW of data center load, and two fuel price scenarios with 1,750 MW of data center load (2025 CPCN Load Forecast). The favorability of solar predictably correlates with fuel prices; up to 815 MW of solar is added in the High fuel price scenarios and no solar is added in the low fuel price scenarios.

[52] Appendix C contains the resource plans for all scenarios through 2040.

Table 10: 2030 Portfolios (With Landfill Constraints)[53]

Data Center Load in Load Scenario	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**
2,030 MW	Brown 12; Mill Creek 6; Generic NGCC; 300 MW 4hr BESS; GH2 SCR	Brown 12; Mill Creek 6; Generic NGCC; 300 MW 4hr BESS; GH2 Non-Ozone; 265 MW Solar	Brown 12; Mill Creek 6; Generic NGCC; 300 MW 4hr BESS; GH2 Non-Ozone; 815 MW Solar	Brown 12; Mill Creek 6; Generic NGCC; 300 MW 4hr BESS; GH2 SCR	Brown 12; Mill Creek 6; Generic NGCC; 300 MW 4hr BESS; GH2 Non-Ozone; 815 MW Solar
1,890 MW	Brown 12; Mill Creek 6; 800 MW 4hr BESS; GH2 SCR	Brown 12; Mill Creek 6; Generic NGCC; 100 MW 4hr BESS; GH2 Non-Ozone; 265 MW Solar	Brown 12; Mill Creek 6; Generic NGCC; 100 MW 4hr BESS; GH2 Non-Ozone; 815 MW Solar	Brown 12; Mill Creek 6; 800 MW 4hr BESS; GH2 SCR	Brown 12; Mill Creek 6; Generic NGCC; 100 MW 4hr BESS; GH2 Non-Ozone; 600 MW Solar
1,750 MW (2025 CPCN Load Forecast)	Brown 12; Mill Creek 6; 600 MW 4hr BESS; GH2 SCR	Brown 12; Mill Creek 6; Generic NGCC; GH2 Non-Ozone; 215 MW Solar	Brown 12; Mill Creek 6; Generic NGCC; GH2 Non-Ozone; 215 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
1,610 MW	Brown 12; Mill Creek 6; 400 MW 4hr BESS; GH2 SCR	Brown 12; Mill Creek 6; 400 MW 4hr BESS; GH2 SCR	Brown 12; Mill Creek 6; 400 MW 4hr BESS; GH2 Non-Ozone; 815 MW Solar	Brown 12; Mill Creek 6; 400 MW 4hr BESS; GH2 SCR	Brown 12; Mill Creek 6; 400 MW 4hr BESS; GH2 Non-Ozone; 815 MW Solar
1,470 MW	Brown 12; Mill Creek 6; 200 MW 4hr BESS; GH2 SCR	Brown 12; Mill Creek 6; 200 MW 4hr BESS; GH2 SCR	Brown 12; Mill Creek 6; 200 MW 4hr BESS; GH2 Non-Ozone; 815 MW Solar	Brown 12; Mill Creek 6; 200 MW 4hr BESS; GH2 SCR	Brown 12; Mill Creek 6; 200 MW 4hr BESS; GH2 Non-Ozone; 815 MW Solar

Table 11 shows the impact of removing the Brown and Mill Creek landfill constraints on the 2030 portfolios. Red text indicates differences from the 2030 portfolios in Table 10 developed with landfill constraints; gray text indicates no changes from the these portfolios. The portfolios in Table 11 demonstrate that landfill constraints have no material impact on the 2030 Portfolios; 21 of 25 portfolios in Table 11 are unchanged from Table 10. However, in three of the four portfolios with differences, including two portfolios developed for the 2025 CPCN Load Forecast, removing the landfill constraints results in adding only Brown 12 and Mill Creek 6 rather than adding both of those units and a third NGCC. Because the third NGCC in these cases is predicated upon future unit retirements and not economic development load growth, the Companies advanced only the portfolios developed without landfill

[53] PLEXOS was configured to add NGCC (660 net winter MW) and SCCT (258 net winter MW) in one-unit increments and BESS in 100 MW increments. Solar and wind additions represent proposals from the Companies' May 2024 RFP. "GH2 Non-Ozone" indicates that Ghent 2 is operated only in the non-ozone season. All portfolios contain additional dispatchable DSM as described in Section 3.1.

constraints to the Stage One, Step Two analysis. As seen in Table 11, a Ghent 2 SCR is generally favorable in scenarios with Low and Mid fuel prices but not in scenarios with High fuel prices. Instead of a Ghent 2 SCR in cases with 1,890 MW or more data center load and Mid fuel prices, PLEXOS adds a third NGCC and enough solar to minimally comply with summer reserve margin constraints.

Table 11: 2030 Portfolios (Without Landfill Constraints)*,[53]

Data Center Load in Load Scenario	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**
2,030 MW	Brown 12; Mill Creek 6; Generic NGCC; 300 MW 4hr BESS; GH2 SCR	Brown 12; Mill Creek 6; Generic NGCC; 300 MW 4hr BESS; GH2 Non-Ozone; 265 MW Solar	Brown 12; Mill Creek 6; Generic NGCC; 300 MW 4hr BESS; GH2 Non-Ozone; 815 MW Solar	Brown 12; Mill Creek 6; Generic NGCC; 300 MW 4hr BESS; GH2 SCR	Brown 12; Mill Creek 6; Generic NGCC; 300 MW 4hr BESS; GH2 Non-Ozone; 815 MW Solar
1,890 MW	Brown 12; Mill Creek 6; 800 MW 4hr BESS; GH2 SCR	Brown 12; Mill Creek 6; Generic NGCC; 100 MW 4hr BESS; GH2 Non-Ozone; 265 MW Solar	Brown 12; Mill Creek 6; Generic NGCC; 100 MW 4hr BESS; GH2 Non-Ozone; 815 MW Solar	Brown 12; Mill Creek 6; 800 MW 4hr BESS; GH2 SCR	Brown 12; Mill Creek 6; ~~Generic NGCC~~; 800 ~~100~~ MW 4hr BESS; GH2 Non-Ozone; 815 ~~600~~ MW Solar
1,750 MW (2025 CPCN Load Forecast)	Brown 12; Mill Creek 6; 600 MW 4hr BESS; GH2 SCR	Brown 12; Mill Creek 6; ~~Generic NGCC~~; 600 MW 4hr BESS; GH2 SCR ~~Non-Ozone~~; ~~215 MW Solar~~	Brown 12; Mill Creek 6; ~~Generic NGCC~~; 600 MW 4hr BESS; GH2 Non-Ozone; 815 ~~215~~ 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
1,610 MW	Brown 12; Mill Creek 6; 400 MW 4hr BESS; GH2 SCR	Brown 12; Mill Creek 6; 400 MW 4hr BESS; GH2 SCR	Brown 12; Mill Creek 6; 400 MW 4hr BESS; GH2 Non-Ozone; 815 MW Solar	Brown 12; Mill Creek 6; 400 MW 4hr BESS; GH2 SCR	Brown 12; Mill Creek 6; 400 MW 4hr BESS; GH2 Non-Ozone; 815 MW Solar
1,470 MW	Brown 12; Mill Creek 6; 200 MW 4hr BESS; GH2 SCR	Brown 12; Mill Creek 6; 200 MW 4hr BESS; GH2 SCR	Brown 12; Mill Creek 6; 200 MW 4hr BESS; GH2 Non-Ozone; 600 ~~815~~ MW Solar	Brown 12; Mill Creek 6; 200 MW 4hr BESS; GH2 SCR	Brown 12; Mill Creek 6; 200 MW 4hr BESS; GH2 Non-Ozone; 815 MW Solar

*Red text indicates differences from Table 10 portfolios developed with landfill constraints; gray text indicates no change from Table 10 portfolios.

4.4.2 Stage One, Step Two: Least-Cost Portfolios Over All Fuel Price Scenarios

In the second step of Stage One, the Companies evaluated each of the 2030 portfolios in Table 11 with detailed production costs over each of the five fuel price scenarios to determine which resource plan for a given load scenario has the lowest PVRR on average across all fuel price scenarios. Importantly, to focus the analysis on determining the optimal portfolio for serving economic development load (i.e., the decision that needs to be made today) and ensure any production cost differences are explained entirely by differences between the 2030 portfolios, the Companies evaluated the portfolios in the context of a fixed resource plan beyond 2030. To do this, the Companies modeled the most common replacement resources for Brown 3 and OVEC in all cases.[54] In addition, because the Mill Creek landfill constraint has no impact on the resource plan until 2045, the Companies assumed in this step that Mill Creek 3 and 4 would operate through the end of the analysis period. Thus, the Companies held all resources constant after 2030, with the exception of the retirement of Brown 3 in 2035, the addition of 500 MW of battery storage in 2035, the loss of OVEC capacity coinciding with the end of its contract in 2040, and the addition of one SCCT in 2040.

Table 12 shows the least-cost 2030 portfolio for each load scenario. In the load scenario with 1,470 MW of data center load, adding Brown 12, Mill Creek 6, a Ghent 2 SCR, and 200 MW of Cane Run BESS is the least-cost portfolio. Each 140 MW of data center load results in an incremental 200 MW of Cane Run BESS or Cane Run BESS plus Ghent BESS, until the load scenario with 1,890 MW of data center load, which prefers a third NGCC, no Ghent 2 SCR, 100 MW of Cane Run BESS, and 265 MW of solar PPAs. Notably, with Ghent 2 unavailable during the ozone season, this portfolio relies on solar PPAs to minimally comply with summer reserve margins and may not be an actionable portfolio given challenges the Companies have faced executing solar PPAs. In addition, this result is unique to the load scenario with 1,890 MW of data center load. As noted above, PLEXOS also developed a portfolio for the load scenario with 2,030 MW of data center load that relies on solar to minimally comply with summer reserve margins, but this portfolio is not least-cost. With 2,030 MW of data center load, a third NGCC, Ghent 2 SCR, and 300 MW of Cane Run BESS is least-cost. The additional DSM measures are least-cost in all load scenarios.

Table 12: Stage One Results (Least-Cost Portfolios)

Data Center Load in Load Scenario	Brown 12 NGCC ("BR12")	Mill Creek 6 NGCC ("MC6")	Generic NGCC	Cane Run BESS ("CR BESS")	Ghent BESS ("GH BESS")	Solar PPA	Add. DSM (Y/N)	GH2 SCR (Y/N)
2,030 MW	645	645	645	300	-	-	Y	Y
1,890 MW	645	645	645	100	-	265	Y	N
1,750 MW (2025 CPCN)	645	645	-	400	200	-	Y	Y
1,610 MW	645	645	-	400	-	-	Y	Y
1,470 MW	645	645	-	200	-	-	Y	Y

4.5 Stage Two: Assessing Resource Adequacy

The Stage One results demonstrate that adding Brown 12, Mill Creek 6, and some amount of Cane Run BESS (with or without Ghent BESS) are optimal for serving economic development load growth. In the Stage Two analysis, the Companies assessed the reliability of their generation portfolio with various combinations of new resources to determine which combination is optimal for serving the level of economic development load growth in the 2025 CPCN Load Forecast. This analysis is necessary because the level of reserves needed for reliable service can vary with changes in the load and resource mix. In addition, the impact on a percentage basis of adding high load factor economic development load is greatest in the shoulder months when loads are lower and the Companies perform maintenance on their

[54] As seen in Section 8.2, Brown 3 is retired in 2035 in the majority of resource plans even without landfill constraints.

generation units. This analysis fully accounts for the need to maintain the Companies' existing and proposed resources.

The results of the Stage Two analysis are summarized in Table 13. "2028 Portfolio" refers to the Companies' resource portfolio in 2028 and reflects the retirement of Mill Creek 1 (2024), the planned retirement of Mill Creek 2 (2027), the assumed retirement of the small-frame SCCTs (2026), the planned additions of Brown BESS (2027), Mill Creek 5 (2027), two company-owned solar facilities in 2026 and 2027, and dispatchable demand response programs from the Companies' 2024-2030 DSM-EE Program Plan, but it does not include the six total solar PPAs into which the Companies have entered due to three having been canceled and the challenges facing the advancement of the remaining three.[55] The Companies are proposing to add Brown 12 and Mill Creek 6 ("BR12" and "MC6," respectively, in the table below) and 400 MW of Cane Run BESS because the loss of load expectation ("LOLE") is approximately 1 day in 10 years with these resource additions. In addition, 400 MW of BESS is the maximum amount of battery storage that be added at the Cane Run, and the cost of BESS at the Ghent station is higher due to additional site work needed at Ghent to accommodate battery storage.

Table 13: Stage Two Results (Assessing Resource Adequacy)

Portfolio	LOLE
2028 Portfolio + BR12 NGCC + MC6 NGCC + 400 MW CR BESS + 200 MW GH BESS	0.62
2028 Portfolio + BR12 NGCC + MC6 NGCC + 400 MW CR BESS + 100 MW GH BESS	0.67
2028 Portfolio + BR12 NGCC + MC6 NGCC + 400 MW CR BESS	1.07
2028 Portfolio + BR12 NGCC + MC6 NGCC + 300 MW CR BESS	1.25

In their 2024 IRP, the Companies developed minimum reserve margin constraints for resource planning (29% in the winter and 23% in the summer) based on a load forecast with less economic development load. These reserve margin constraints were utilized in the Stage One analysis above. Unsurprisingly, the Stage Two results demonstrate that, with the addition of non-weather sensitive economic development loads, the level of generation reserves required to ensure reliable service, which is computed as a percent of peak demand under normal peak weather conditions, is slightly lower.

4.6 Stage Three: Managing Economic Development Load Growth

The Stage Two results demonstrated that the Brown 12 NGCC, Mill Creek 6 NGCC, and 400 MW Cane Run BESS are optimal for serving the level of economic development load in the 2025 CPCN Load Forecast. The Cane Run BESS can be added in 2028, but the Brown 12 and Mill Creek 6 NGCCs cannot be added until 2030 and 2031, respectively. Therefore, the Companies used SERVM to determine the level of economic development load growth they could serve reliably as the proposed resources are placed in service.

Table 14 compares the level of new data center load that can be served with the proposed resources to the data center loads in the 2025 CPCN Load Forecast. In 2029, the data center loads in the 2025 CPCN

[55] Of the six total solar PPAs into which the Companies have entered, including two prior to the 2022 CPCN and DSM-EE case, (a) one has been canceled by the developer due to interconnection issues, (b) one has been canceled by the developer due to a significant project price increase, and (c) one with a price reopener has been contractually terminated due to the Companies' unwillingness to proceed at a much higher price than in the original agreement. The remaining three PPAs appear unlikely to proceed under their approved terms. This Resource Assessment therefore does not include these PPAs.

Load Forecast exceed the level of new data center load that can be served reliably by 350 MW, and this value is reduced to 210 MW in 2030. If load increases more rapidly than the resources the Companies are requesting in this proceeding can accommodate, the Companies will need to consider additional means of meeting customers' needs, including possibly seeking authorization for additional resources in a subsequent CPCN.

Table 14: Stage Three Results (Managing Economic Development Load Growth)

Year	Resource Additions	[A] Data Center Load that Can Be Served	[B] Data Center Load in CPCN Load Forecast	Difference ([A]-[B])
2028-2029	CR BESS (400 MW)	630	980	(350)
2030	CR BESS + BR12 (645 MW)	1,190	1,400	(210)
2031+	CR BESS + BR12 + MC6 (645 MW)	1,750	1,750	0

5 Utility Ownership

5.1 Background

Since the merger of LG&E and KU, the Companies have commissioned or plan to commission seventeen jointly-owned units: ten SCCTs at the Trimble County, E.W. Brown, and Paddy's Run stations, the Trimble County 2 coal unit, Cane Run 7, Mill Creek 5, Brown BESS, and Brown, Mercer, and Marion Solar. An ownership ratio for each of the jointly-owned SCCTs and Brown BESS was determined so that each utility's projected reserve margin was equalized in the in-service year. Solar facilities' ownerships were assigned by allocating their forecasted generation in each hour based on each company's forecasted share of native load energy requirements for the hour. Because Trimble County 2, Cane Run 7, and Mill Creek 5 were expected to provide significant energy savings to customers, their ownership allocations were based on the expected energy benefits to each company.

5.2 Methodology

5.2.1 Brown 12 and Mill Creek 6 NGCC Units

Depending on natural gas price levels and future CO_2 regulations, the Brown 12 and Mill Creek 6 NGCC units are expected to operate at a 60-85% capacity factor, generating significant amounts of energy. For this reason, the Companies calculated ownership shares for these resources so that each company's energy production equals its load. This method is similar to the method used for Trimble County 2, Cane Run 7, and Mill Creek 5, as well as for the Green River NGCC unit proposed by the Companies in Case No. 2014-0002, which was later canceled.[56]

5.2.2 Battery Storage (Cane Run BESS)

Battery storage is considered to be a capacity resource because it does not produce energy in all hours but rather stores energy for when it is needed most. Therefore, the Cane Run BESS's ownership was assigned using a method similar to the method used for the jointly-owned CTs and Brown BESS by better balancing 2032 seasonal reserve margins based on dispatchable and battery capacity, after assigning the NGCC units' ownership allocation. This was performed by assigning each season's combined company reserve margin need to each company based on each company's contribution to the combined company need.

5.3 Anticipated Ownership Allocations

The optimal ownership allocations based on the 2025 CPCN Load Forecast's assumptions about the service territories in which the generic data center load will locate are shown in Table 15. For the Brown 12 and Mill Creek 6 NGCC units, the optimal ownership allocation is 100% LG&E. Of the 1,750 MW of data center load in the 2025 CPCN Load Forecast, 1,400 MW are assumed to locate in the LG&E service territory. With a 95% load factor, the energy requirements for this load (approximately 11.7 TWh) will exceed the energy produced by Brown 12 and Mill Creek 6. The Cane Run BESS is assigned 62% to KU and 38% to LG&E to better balance the Companies' summer and winter reserve margins.

[56] *In the Matter of: Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for Certificates of Public Convenience and Necessity for the Construction of a Combined Cycle Combustion Turbine at the Green River Generating Station and a Solar Photovoltaic Facility at the E.W. Brown Generating Station*.

Table 15: Optimal Ownership Allocations

	KU	LG&E
NGCC Units • Brown 12 NGCC • Mill Creek 5 NGCC	0%	100%
Cane Run BESS	62%	38%
Reserve Margin with Proposed Allocations		
• Summer	41.8%	6.0%
• Winter	24.1%	32.1%

6 Appendix A – Summary of Inputs

6.1 Load Forecast

Section 2.1 summarizes the Companies' load forecast scenarios. Additional information regarding the Companies' load forecasts is included in Mr. Jones's testimony.

6.2 Minimum Reserve Margin Target

The Companies' minimum reserve margin targets are 23% for summer and 29% for winter. The 2024 IRP Resource Adequacy Study, which is attached as Appendix D, summarizes the analysis used to determine minimum winter and summer reserve margin constraints for resource planning.

6.3 Existing Resource Inputs

Table 16 lists the Companies' forecasted generating resources as of 2032. Resources that are fully dispatchable are listed separately from renewable and limited-duration resources. The Companies' coal, NGCC, and SCCT resources are fully dispatchable. For example, while SCCTs typically operate less than 24 hours each time they are started due to their higher fuel costs, they can operate for longer periods if necessary. The Companies' renewable resources are intermittent. For example, the ability to generate power at the Ohio Falls station is entirely a function of water availability, which is managed by the Corps of Engineers. Finally, the Companies' BESS, dispatchable DSM, and CSR resources can be dispatched when needed but only for limited durations. The operating characteristics of supply-side and demand-side resources are an important consideration in resource planning.

Table 16: 2032 LG&E/KU Generating & DSM Portfolio[57]

Category	Resource Type	Resource Name	Net Max Summer Capacity (MW)	Net Max Winter Capacity (MW)
Fully Dispatchable	Coal[58]	Brown 3	412	416
		Ghent 1	475	479
		Ghent 2	485	486
		Ghent 3	481	476
		Ghent 4	478	478
		Mill Creek 3	391	394
		Mill Creek 4	477	486
		Trimble County 1 (75%)	370	370
		Trimble County 2 (75%)	549	570
	Coal PPA	OVEC	152	158
	NGCC	Cane Run 7	697	759
		Mill Creek 5	645	660
	SCCT[59]	Brown 5	130	130
		Brown 6	146	171
		Brown 7	146	171
		Brown 8	121	128
		Brown 9	121	138
		Brown 10	121	138
		Brown 11	121	128
		Paddy's Run 13	147	175
		Trimble County 5	159	179
		Trimble County 6	159	179
		Trimble County 7	159	179
		Trimble County 8	159	179
		Trimble County 9	159	179
		Trimble County 10	159	179
Renewable[60]	Solar	Brown Solar	10	10
		Business Solar	0.34	0.34
		Solar Share	3.4	3.4
		Mercer County Solar	120	120
		Marion County Solar[61]	120	120
	Wind	Brown Wind	0.09	0.09
	Hydro	Dix Dam 1-3	33.6	33.6
		Ohio Falls 1-8	100.6	100.6
Limited-Duration	BESS	Brown BESS	125	125
	Interruptible	CSR	110	115
	Dispatchable DSM	DCP[62]	190	145

[57] The Resource Assessment assumes Mill Creek 1 is retired at the end of 2024, Haefling 1-2 and Paddy's Run 12 are retired in 2026, and Mill Creek 2 is retired in 2027.
[58] Except Ghent 2, all of the Companies' coal units are equipped with SCR. All of the Companies' coal units are equipped with flue gas desulfurization ("FGD") and baghouses.

6.3.1 Stay-Open Costs

As seen in Table 17, several of the Companies' coal units are over 45 years old and approaching the end of their current book depreciation life. Mill Creek 2 is 50 years old and is slated to retire in 2027 to allow for the commissioning of a new NGCC, Mill Creek 5. Although the other units could theoretically operate beyond their depreciable book life, doing so would require a higher level of capital investments.[63] To properly evaluate the economics of the existing fleet, the Companies identified the types of projects and associated costs that would be needed to extend the lives of units beyond their current depreciable book lives to at least the end of the analysis period. To be clear, the Companies are not proposing to extend these units' lives; rather, this analytical approach is necessary to properly evaluate the fleet's economics.

Table 17: Age of Existing Coal Units

Unit	Age as of 1/1/2025	Age as of 1/1/2040	End of Book Depreciation Life
Brown 3	53	68	2035
Ghent 1	50	65	2034
Ghent 2	47	62	2034
Ghent 3	43	58	2037
Ghent 4	40	55	2037
Mill Creek 2	50	65	2034
Mill Creek 3	46	61	2039
Mill Creek 4	42	57	2039
Trimble County 1	33	48	2045
Trimble County 2	13	28	2066

Stay-open costs for existing generating units include each unit's ongoing capital and fixed operating and maintenance ("O&M") costs. These costs are required to continue operating a unit and are avoided if a unit is retired. Costs that are shared by all units at a station (i.e., "common" costs) are allocated to units in proportion to how they would be reduced as units retire.[64] Stay-open costs include costs for routine

[59] The Companies' simple cycle combustion turbines at Brown and Paddy's Run have annual operating limits based on their emissions permits but are fully available to serve load for long stretches of time such as a weeklong period of extremely cold weather.

[60] Nameplate capacity is shown for renewable resources rather than their contribution to seasonal peak.

[61] With the Build and Transfer Agreement (BTA) for Marion Solar fully executed, the Companies assume the BTA milestones will be achieved, and the project completed. A critical milestone unique to a BTA is the Firm Date milestone contractually set to no later than December 31, 2025. Prior to the Firm Date, a BTA carries notable uncertainty, which the Companies are tracking closely. After this Firm Date, uncertainty will revert to a more typical level associated with any major construction project.

[62] Residential and Nonresidential Demand Conservation Program ("DCP"). Capacity values reflect expected load reductions under normal peak weather conditions.

[63] According to the EIA, since 2002 the capacity-weighted average age of coal units at retirement was 50 years. See https://www.eia.gov/todayinenergy/detail.php?id=50658.

[64] The allocation of common costs requires an assumed order of retirement at a given station. The lack of SCRs for Ghent 2 and Mill Creek 2 results in those units being retired first relative to other units at their respective stations. The remaining units have the same controls and similar efficiencies (with the exception of Trimble County 2, which is a supercritical unit and the most efficient in the Companies' coal fleet), so the likely retirement order would be driven by age of the units. At Ghent, this results in a retirement order of Ghent 2 first, followed by Ghent 1, then

maintenance and major overhauls, and do not include carrying costs for prior investments or costs for projects that would not be affected by unit retirements in this analysis, such as ash pond closures. Stay-open costs differentiate between "standard" major overhaul costs and the costs for projects that would be needed to operate the unit through at least the end of the analysis period.[65] For Brown 3 specifically, the Companies evaluated the costs of projects needed to operate through 2035 (the timing of the next overhaul after 2027 and the estimated timing of landfill space being exhausted) as well as the costs needed to operate through at least the end of the analysis period, which resulted in deferring over $100 million in capital to 2035 when compared to the 2024 IRP analysis. When evaluating the retirement of these coal units, the Companies assume that costs for routine maintenance and major overhauls will be reduced in the years leading up to a unit's retirement and that all future spending would be avoided after a unit's retirement.

6.3.2 Retrofitting Alternatives

In addition to continued operation of coal units using existing environmental controls, this analysis considers two retrofitting alternatives that allow for continued or less restrictive operation in certain environmental regulation scenarios: adding an SCR to Ghent 2 and modifying an existing coal-fired unit to fully transition its fuel source from coal to natural gas ("gas conversion").

Adding an SCR to Ghent 2 would reduce its NO_x emissions and allow for year-round operation under Ozone NAAQS environmental regulations. The capital cost of an SCR for Ghent 2 is estimated at $152.3 million for a 2028 commissioning, with ongoing incremental capital and fixed O&M costs of approximately $1.3 million in 2028 dollars. An SCR is assumed to decrease the net maximum available generation by 4 MW, reduce net unit efficiency (i.e., increase heat rates) by 1%, and increase the variable operating cost by approximately $0.41/MWh in 2028 dollars due to anhydrous ammonia needs for SCR operation. Under Ozone NAAQS environmental regulations scenarios, PLEXOS has the option to add an SCR (allowing for year-round operation), not to add an SCR and allow Ghent 2 to operate only during the non-ozone season (October through April), or to retire Ghent 2.

Gas conversion obviates the need for CCR landfill storage given the ceased combustion of coal. Estimates for capital costs of gas conversion inclusive of pipeline modifications are summarized in Table 18. Gas conversion is assumed to eliminate many mechanical components related to the combustion of coal and is assumed to reduce ongoing O&M by approximately 30%. Reductions in auxiliary load are offset by loss of boiler efficiency, resulting in a 2% loss in net seasonal maximum capacity and a reduction in net unit efficiency (i.e., increase in heat rates) of 13.6%. Minimum capacities are assumed to be reduced by 25% from current levels, providing increased operational capability for managing minimum generation issues. Fuel costs would be higher on a $/MMBtu basis as a function of coal-to-gas price ratios, and fuel transportation costs reflect the addition of firm gas transportation. SCRs are assumed to remain in service

Ghent 3, and finally Ghent 4. At Mill Creek, this results in a retirement order of Mill Creek 2 first, followed by Mill Creek 3, and finally Mill Creek 4. At Trimble, this results in a retirement order of Trimble County 1 first, followed by Trimble County 2.

[65] Examples of projects that would be needed to extend the life of a generating unit are replacement of major high temperature components such as superheater and reheater headers and seamed main steam and hot reheat piping, condenser re-tubing, generator stator rewinds, generator step-up transformer replacements, and ID fan variable frequency drive replacements.

and maintain existing emissions levels, but anhydrous ammonia costs are assumed to be reduced by 50% given lower levels of NO_x in natural gas combustion compared to coal combustion. Other emissions controls, such as FGDs and baghouses, are assumed to be removed from service, associated emissions are assumed to be reduced consistent with the change from coal combustion to natural gas combustion, and reagent costs are assumed to be eliminated. Given the increased fuel costs and heat rates, gas conversion typically results in increased operating costs but may be warranted to allow a unit to operate after available landfill capacity has been exhausted.

Table 18: Capital Costs of Gas Conversion, 2030 Commissioning ($M)[66]

Unit	Gas Conversion Capital
Brown 3	$46.4
Ghent 1	$72.3
Ghent 2	$73.0
Ghent 3	$72.4
Ghent 4	$72.4
Mill Creek 3	$36.5
Mill Creek 4	$39.3
Trimble County 1[67]	$36.1
Trimble County 2[67]	$50.8

6.3.3 CCR Revenue Assumptions

Coal combustion residuals ("CCR") include fly ash, bottom ash, and gypsum. CCR is either used for onsite construction projects, sold to third parties for use in the production of products like cement and wallboard, or stored in onsite landfills. When sold to third parties, the revenue from beneficial use of CCR materials is included in the Environmental Surcharge Mechanism as a credit to offset environmental compliance costs. In 2024, CCR sales revenues totaled over $50 million.

In recent years, as coal units have retired in the U.S., the market supply of CCR has decreased and the market price of CCR has increased. Table 19 lists the assumed CCR sales prices in this analysis.[68] The 2025 values are weighted average prices based on existing contracts. CCR sales prices are expected to approach market prices as existing contracts expire. Market prices vary by station based on the station's proximity to local markets and are assumed to escalate at 2.3 percent per year.

[66] Includes pipeline capital. Station costs for pipeline capital are allocated across units as a simplifying assumption, so costs may be understated if some units at a station are retrofitted and others are not.
[67] Costs for Trimble County reflect the Companies' 75% ownership share of full unit costs.
[68] No sales prices for any CCR at Brown or for bottom ash at any station are included because there is currently very little or no market for these materials at these stations.

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Table 19: Sales Prices for CCR Sales ($/ton)

Year	Mill Creek		Ghent		Trimble	
	Fly Ash	Gypsum	Fly Ash	Gypsum	Fly Ash	Gypsum
2025	[redacted]					
2026						
2027						
2028						
2029						
2030						
2031						
2032						
2033						
2034						
2035						
2036						
2037						
2038						
2039						
2040						
2041						
2042						
2043						
2044						
2045						
2046						
2047						
2048						
2049						
2050						

Table 20 lists the percent of CCR produced at each station that is assumed to be sold to third parties, based on current sales levels. The Ghent station requires additional loading facilities to increase its fly ash sales. The Companies continue to evaluate alternatives for doing this, but no costs or revenue impacts associated with these facilities are considered in this analysis.

Table 20: Percent of CCR Production Sold to Third Parties

Station	Fly Ash	Gypsum	Bottom Ash
Mill Creek	67%	97%	0%
Ghent	10%	95%	0%
Trimble County	60%	95%	0%
Brown	0%	0%	0%

6.3.4 Landfill Storage Constraints

Table 21 shows the Companies' assumptions regarding landfill space at Brown and Mill Creek.[69] Because Brown 3 is a marginal unit, its generation and CCR production are more variable; therefore, the Companies assume a four-year buffer for planning purposes, compared to two years at Mill Creek. As shown, the Companies assume the last year of landfill availability is 2035 for Brown and 2045 for Mill Creek.

Table 21: Landfill Storage Constraints at Brown and Mill Creek

	Brown	Mill Creek
Landfill Capacity Beg. 2024 (CY)	1,710,081	4,843,807
Average Annual Volumes Stored (CY)	110,000	200,000
Years of Remaining Capacity	15.5	24.2
Year Landfill is at Capacity	2039	2047
Years of Buffer	4	2
Last Year of Landfill Availability	2035	2045

6.4 Solar and Wind Generation Profiles

The Companies developed solar and wind generation profiles to align with the weather underlying the hourly load forecast. For solar profiles, the Companies used NREL's PVWatts model to develop historical profiles for the years 1998 to 2022 based on historical solar irradiance data from NREL's National Solar Radiation Database ("NSRDB").[70] Hourly loads in each month of the long-term load forecast are ordered based on the hourly loads in a historical month with the same weekday-weekend profile and approximately normal weather. Therefore, the solar generation forecast for each month of the long-term forecast is based on the solar profile for the same historical month.

NREL's PVWatts model can be used to develop net generation profiles for different types of solar arrays (e.g., fixed-tilt and single-axis tracking). For projects in development (e.g., Mercer County Solar) as well as specific projects proposed in response to the Companies' May 2024 RFP, generation profiles are based on historical solar irradiance from the NSRDB at the project site.

The Companies developed wind generation profiles using NREL's System Advisor Model ("SAM") and modeled wind speed data from the NREL WIND Toolkit. The NREL WIND Toolkit provides modeled wind data (including speed and direction) for a given location at various elevations from 2007 through 2013. This data was used as input for the SAM model to simulate generation output for the wind farm proposed in response to the Companies' 2024 RFP. This model incorporated developer specifications from the proposed wind farm and utilized the Park WASP model to simulate wake effects along with default operating and loss assumptions from NREL. The resulting generation profile was calibrated to match the capacity factor provided by the developer.

Like the solar profiles, the Companies developed the historical wind profile first and then used the historical profile to develop a forecasted profile that aligns with the weather underlying the hourly load forecast.

[69] Landfill space is not a concern at Ghent and Trimble County.
[70] 1998 to 2022 is the period of history for which irradiance data is available.

6.5 Transmission System Upgrade Costs

The 2024 IRP demonstrated that NGCC and battery storage charged by existing resources are least-cost for serving economic development load growth. After Mill Creek 5 is commissioned in 2027, the optimal location for the next NGCC is the E.W. Brown Generating Station. To determine the optimal locations for an additional NGCC and battery storage, the Companies performed a transmission siting study that evaluated siting the additional NGCC at the Mill Creek and Green River Generating Stations, as well as siting different battery storage configurations at the Cane Run and Ghent Generating Stations. Compared to siting the additional NGCC at the Green River Station, transmission system upgrade costs for siting the additional NGCC at the Mill Creek Generation Station are approximately $50-60 million lower. In addition, as noted in the testimony of Mr. Tummonds, the Mill Creek Generating Station has a more favorable gas supply environment and there are a number of advantages to constructing the additional NGCC (Mill Creek 6) next to Mill Creek 5.

Regarding battery storage, Table 22 shows the sum of transmission system upgrade costs and overnight construction costs for three battery storage siting scenarios. Importantly, the transmission system upgrade costs for each scenario reflect the additions of the Brown 12 and Mill Creek 6 NGCCs. As seen in the table, due to lower construction costs at the Cane Run Station, the Cane Run Station is the best location for 400 MW of battery storage.

Table 22: Comparison of Battery Storage Costs Across Cane Run and Ghent ($M, 2028 Dollars)

Siting Scenario	Cane Run BESS MW	Ghent BESS MW	[A] Transmission System Upgrade Cost[71]	[B] Overnight Construction Cost	Total Cost [A]+[B]
Scenario 1	200	200	65.9	809.9	875.8
Scenario 2	400	0	74.8	774.7	849.6
Scenario 3	0	400	97.4	845.1	942.5

6.6 Commodity Prices

6.6.1 Natural Gas and Coal Price Forecasts

Natural gas and coal prices are an important input to this analysis as the level of coal and natural gas prices impacts the economics of renewables and the relationship between coal and natural gas prices impacts the economics of continuing to operate an existing coal unit versus replacing the unit with new natural gas-fired generation. The Companies developed the fuel price forecasts for this analysis in mid-2024.

Using several combinations of these forecasts, the Companies developed the following five fuel price scenarios for the Resource Assessment:

- Expected Coal-to-Gas ("CTG") Ratio
  - Low Gas, Mid CTG Ratio
  - Mid Gas, Mid CTG Ratio
  - High Gas, Mid CTG Ratio
- Atypical CTG Ratios
  - Low Gas, High CTG Ratio

[71] Transmission system upgrade costs also reflect the additions of the Brown 12 and Mill Creek 6 NGCCs.

- High Gas, Low CTG Ratio

The Companies' range of three gas price forecasts, shown in Figure 12, is based on the U.S. Energy Information Administration's ("EIA") forecasts in its 2023 Annual Energy Outlook ("AEO2023").[72] These forecasts are consistent with forecasts prepared by industry consultants, as discussed in Section 6.6.2.4.

Figure 12: Natural Gas Price Forecasts (Henry Hub; Nominal $/MMBtu)

[redacted]

The gas price forecasts and the coal price forecasts with high gas paired with a Mid CTG ratio generally assume that some level of elevated demand in the international fuel markets will remain intact through the long-term period. The Low Gas, Mid CTG and Mid Gas, Mid CTG coal price forecasts reflect a more domestic focus for coal demand. The High Gas, Low CTG and Low Gas, High CTG forecasts show scenarios where market conditions cause price trends to diverge between coal and natural gas.

The scenarios with Mid CTG ratio assume a return to the average historical ratio between Illinois Basin coal and gas prices experienced between 2012 and 2021 compared to the corresponding gas prices. Note that the Mid CTG price ratio approximates the ratio of NGCC and coal operating costs. Therefore, it is plausible to expect coal-to-gas price ratios to revert to this ratio over the long term, which is why the Companies refer to it as the "Expected CTG Price Ratio" throughout the Resource Assessment. The High Gas, Low CTG and Low Gas, High CTG price forecasts model variations from the long-term average in the ratio between the price of coal and natural gas.

The majority of the Companies' coal supply is sourced from the Illinois Basin. The Companies developed Illinois Basin coal prices for the 2023 AEO natural gas prices based on the historical ratio of Illinois Basin coal and Henry Hub natural gas prices ("coal-to-gas price ratio" or "CTG price ratio") using publicly

[72] EIA released the AEO2023 in March 2023. See https://www.eia.gov/outlooks/aeo/. The EIA did not publish an Annual Energy Outlook in 2024. *See* EIA's "Statement on the Annual Energy Outlook and EIA's plan to enhance long-term modeling capabilities" dated July 26, 2023, available at https://www.eia.gov/pressroom/releases/press537.php (accessed Oct. 2, 2024).

available historical price data. Figure 13 shows Illinois Basin coal prices and Henry Hub natural gas prices as well as the coal-to-gas price ratio since 2012. Coal and gas prices generally move together, but coal markets are slower to respond to changing market fundamentals than gas. As a result, periods of increasing gas prices are generally associated with lower coal-to-gas price ratios, and periods of decreasing gas prices are generally associated with higher coal-to-gas price ratios. In addition, the coal-to-gas price ratio is mean reverting (i.e., after hitting a high or low point, it reverts back toward the mean) and does not remain at high or low levels for long periods of time. In 2022, U.S. coal supply became tightly balanced with demand as export demand from Europe remained elevated due to reduction in the supply of Russian coal and gas. This resulted in the highest coal-to-gas ratio since before 2012, but this ratio is not expected to persist through the end of the analysis period; indeed, it began moving back toward the recent historical mean in 2024.

Figure 13: Illinois Basin Coal and Henry Hub Gas Prices (2012-2024)

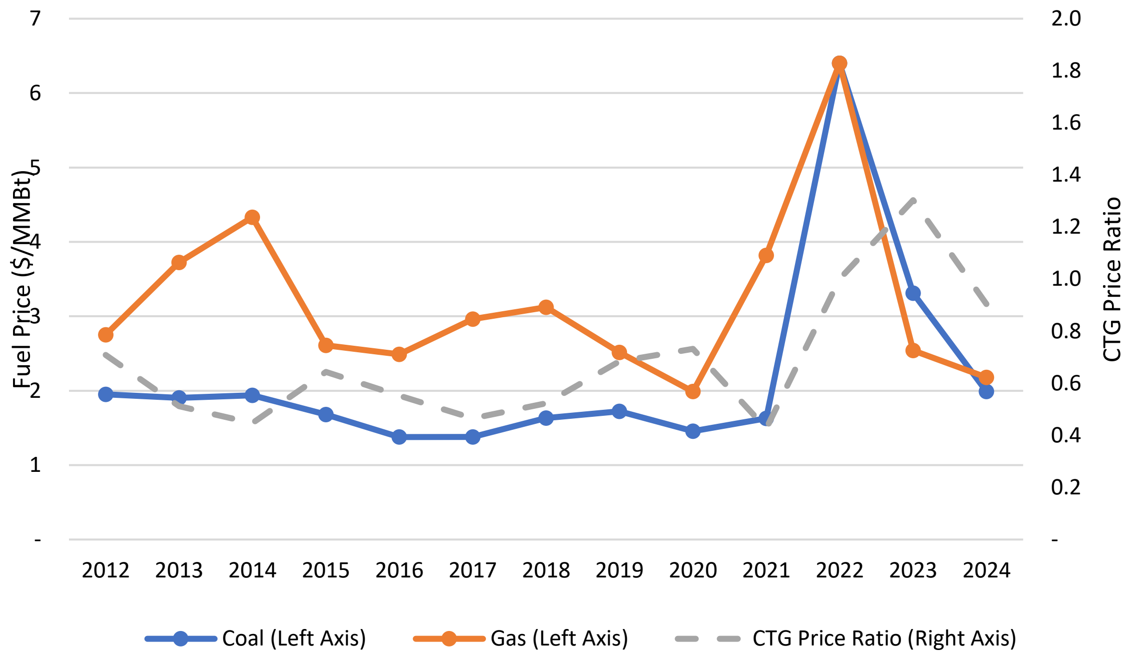


Table 23 summarizes the coal-to-gas price ratio in tabular form. The Companies' pricing analysis was focused on the period from 2012 through 2021 because the CTG price ratio resulting from spot market pricing between 2022 and 2024 reflects extreme and aberrant market conditions that would inappropriately skew long-term price forecasts. While spot market prices continued to show an above-average ratio through 2024, the Companies' Business Plan open position shows prices returning to the historical average ratio of 0.57 observed over the ten-year period from 2012 to 2021. At this coal-to-gas price ratio, the cost of coal and NGCC energy is very similar, regardless of the level of gas prices. Furthermore, this average coal-to-gas price ratio is unsurprising because coal and NGCC energy are economic substitutes, and a coal-to-gas price ratio of 0.57 approximates the ratio of NGCC and coal operating costs. Over a long analysis period, despite changing natural gas prices, the average coal-to-gas price ratio is expected to continue at this level. In addition to the 10-year average coal-to-gas price ratio,

Table 23 contains the six-year average ratios. These six-year averages were used to evaluate short-term variations in the coal-to-gas price ratio.[73]

Table 23: Illinois Basis Coal to Henry Hub Natural Gas Price Ratio ("CTG Price Ratio")

Year	CTG Price Ratio	10-Year Average	6-Year Average
2012	0.71		
2013	0.51		
2014	0.45		
2015	0.64		
2016	0.55		
2017	0.46		0.55 (2012-2017)
2018	0.52		0.52 (2013-2018)
2019	0.68		0.55 (2014-2019)
2020	0.73		0.60 (2015-2020)
2021	0.43	0.57 (2012-2021)	0.56 (2016-2021)
2022	1.00		
2023	1.31		
2024	0.90		

Table 24 summarizes the five fuel price scenarios considered in this analysis. For the first three fuel price scenarios (the "Mid" coal-to-gas price ratios), coal prices were forecasted beyond 2029 with the assumption that the coal-to-gas ratio would continue, on average, to approximate the average coal-to-gas price ratio from 2012 to 2021 (0.57). Again, note that the Mid coal-to-gas price ratio (0.57) approximates the ratio of NGCC and coal operating costs. Therefore, it is plausible to expect coal-to-gas price ratios to revert to this ratio over the long term, which is why the Companies refer to it as the "Expected CTG Price Ratio."

The last two fuel price scenarios were developed primarily to evaluate short-term, atypical variations in the coal-to-gas price ratio. Because periods of decreasing gas prices are generally associated with higher coal-to-gas price ratios, fuel price scenario 4 pairs low gas prices with a high coal-to-gas price ratio. Likewise, fuel price scenario 5 pairs high gas prices with a low coal-to-gas ratio. The High and Low coal-to-gas price ratios are the maximum and minimum, respectively, of the six-year average coal-to-gas ratios during the 2012-2021 analysis period in Table 23. Fuel price scenario 4 ("Low Gas, High CTG") is favorable to gas-fired generation; fuel price scenario 5 ("High Gas, Low CTG") is favorable to coal-fired generation.

[73] The Companies considered periods of five and six years to evaluate short-term variations in the average coal-to-gas ratio but a period of six years provides a wider range of ratios.

Table 24: Fuel Price Scenarios

Scenario Type	Scenario Number	Natural Gas Forecast	Coal-to-Gas Price Ratio	Fuel Price Scenario Name (Gas, CTG Price Ratio)
Expected CTG Price Ratio	1	Low (2023 AEO)	Mid (0.57)[74]	Low Gas, Mid CTG
	2	Mid (2023 AEO)	Mid (0.57)[74]	Mid Gas, Mid CTG
	3	High (2023 AEO)	Mid (0.57)[74]	High Gas, Mid CTG
Atypical CTG Price Ratios	4	Low (2023 AEO)	High (0.60)[75]	Low Gas, High CTG
	5	High (2023 AEO)	Low (0.52)[75]	High Gas, Low CTG

Table 25 summarizes the coal and natural gas price scenarios evaluated in this analysis. These fuel prices reflect undelivered (Illinois Basin minemouth coal; Henry Hub gas) pricing for the Companies' open fuel positions (i.e., fuel not yet under contract). The Mid Gas, Mid CTG Ratio scenario reflects a blend of coal price bids and a third-party coal price forecast for 2025-2029 and a constant 0.57 CTG ratio thereafter. All other scenarios reflect constant CTG ratios in all years.

[74] The mid coal-to-gas price ratio (0.57) is the average coal-to-gas ratio over the ten-year period from 2012 to 2021 and approximates the ratio of NGCC and coal operating costs.
[75] The High and Low coal-to-gas price ratios are the maximum and minimum, respectively, of the six-year rolling average coal-to-gas ratio from 2012 to 2021.

Table 25: Coal and Natural Gas Price Scenarios ($/mmBtu)

	Expected CTG Price Ratios						Atypical CTG Price Ratios			
	Low Gas, Mid CTG Ratio		Mid Gas, Mid CTG Ratio		High Gas, Mid CTG Ratio		Low Gas, High CTG Ratio		High Gas, Low CTG Ratio	
Year	Coal	Gas	Coal	Gas	Coal	Gas	Coal	Gas	Coal	Gas
2025	[redacted]									
2026										
2027										
2028										
2029										
2030										
2031										
2032										
2033										
2034										
2035	[redacted]									
2036										
2037										
2038										
2039										
2040										
2041										
2042										
2043										
2044										
2045										
2046										
2047										
2048										
2049										
2050										

6.6.2 Natural Gas Price Forecast Methodology

The Henry Hub natural gas price forecasts were developed as combinations of short-term and long-term forecasts and based on EIA's forecasts in its 2023 Annual Energy Outlook ("AEO2023").

6.6.2.1 Gas Price Scenarios

- **Mid Gas**
  - **2025-2027**: Henry Hub Natural Gas forwards, 6/18/2024 market quote date, reflecting the most recent forward market prices when the Companies' 2025 Business Plan forecasts were being finalized.
  - **2028-2049**: Interpolation to the EIA's AEO2023 Reference case, inflation-adjusted, 2050 forecast.
- **High Gas**

    - **2025-2049**: Interpolation to the EIA's AEO2023 Low Oil and Gas Supply case, inflation-adjusted, 2050 forecast.
- **Low Gas**
    - **2025-2049**: Deescalated by the Mid Gas price scenario CAGR from the EIA's AEO2023 High Oil and Gas Supply case, inflation-adjusted, 2050 forecast.

6.6.2.2 Conversion of annual price curves to monthly

Monthly and annual pricing ratios were calculated using NYMEX Henry Hub forwards for the respective market date. These monthly average "factors" were then applied to the annual prices of each gas price case to derive a monthly price curve.

6.6.2.3 EIA AEO2023 Cases

6.6.2.3.1 EIA AEO2023 Reference case (Mid Gas Price Case)[76]

- **Supply.** Natural gas production grows by 15%, outpacing consumption in all cases. US natural gas production increases in all cases except in the Low Oil and Gas Supply case. Production growth is largely due to associated natural gas from tight oil plays and shale natural gas resources.
- **Demand.**
    - Projected US natural gas exports rise through 2050, primarily driven by increased LNG capacity and growing global natural gas consumption. Increases in pipeline exports to Mexico also contribute to the increase in US natural gas exports. LNG capacity expansions, coupled with high demand for natural gas abroad, results in LNG exports more than doubling by 2039 compared to 2024 levels.
    - As more electricity generation shifts to renewables and batteries, demand for natural gas for electricity generation is expected to fall.
- **Electricity consumption.** US annual average electricity growth rate remains below 1% over the projection period through 2050. Transportation is the fastest-growing electricity demand sector, growing at an average annual rate of 9.7%.
- **Generation mix.** In all cases, the EIA projects that renewable energy will be the fastest-growing US energy source through 2050 due to operating cost advantages and Inflation Reduction Act incentives. Photovoltaic solar generating capacity is expected to grow by more than 400% through 2050 while onshore and offshore wind generation capacity is expected to grow 141% over the same timeframe. Coal generating units continue to lead thermal generation unit retirements, averaging 3.9% annual decline in capacity through 2050.

6.6.2.3.2 EIA AEO2023 Low Oil and Gas Supply Case (High gas price case)

- Compared to the Reference case, the Low Oil and Gas Supply case assumes the following are all 50% lower: the estimated ultimate recovery per well for tight oil, tight gas, or shale gas in the US; the undiscovered resources in Alaska and the offshore lower 48 states; and the rates of technological improvement that reduce costs and increase productivity in the US.
- Declining oil production growth leads to decreased associated natural gas and shale gas production.
- In 2050, the projected natural gas price is 68% higher in the Low Oil and Gas Supply case compared to the Reference case.
-

[76] https://www.eia.gov/outlooks/aeo/pdf/AEO2023_Narrative.pdf

6.6.2.3.3 EIA AEO2023 High Oil and Gas Supply Case (Low gas price case)

- Compared to the Reference case, the High Oil and Gas Supply case assumes the following are all 50% higher: the estimated ultimate recovery per well for tight oil, tight gas, or shale gas in the US; the undiscovered resources in Alaska and the offshore lower 48 states; and the rates of technological improvement.
- Oil production growth leads to increased associated natural gas and shale gas production.
- In 2050, the price is approximately 35% lower than in the Reference case.

6.6.2.4 Gas Price Forecasts Reasonableness

The range of natural gas price forecasts compares reasonably to the market expectations of reputable industry consultants, as shown in Figure 14.[77] The range between the Low and High scenarios reasonably bounds these consultants' forecasts, while the Mid scenario approximates the AEO's Reference case in the long term.

Figure 14: Comparison of Henry Hub Natural Gas Price History and Forecasts (Nominal $/MMBtu)

[redacted]

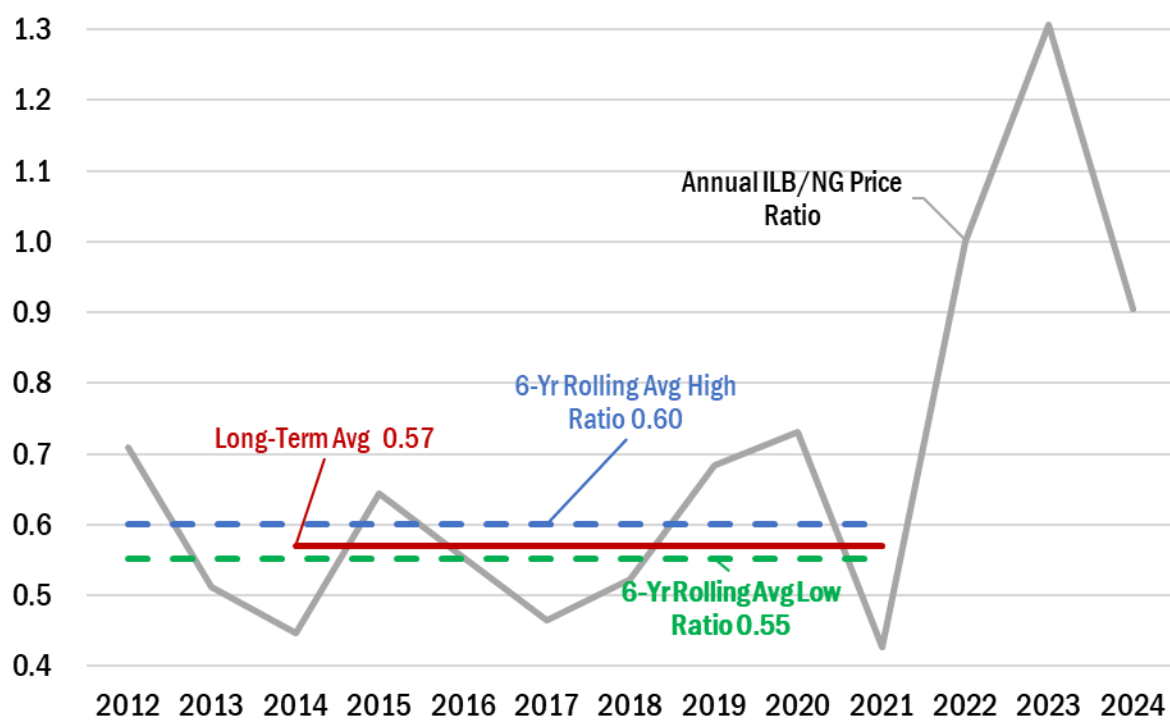
[77] The consultants' forecasts were published in February and March 2023.

6.6.3 ILB Coal Price Forecast Methodology

The Illinois Basin ("ILB") coal open position price forecasts were created using bid prices solicited by LG&E-KU's Fuels group and historical ILB coal/gas price ratios. For the Mid Gas, Mid CTG coal price forecast, bid pricing sourced from LG&E-KU's Fuels group reflects minemouth quotations supplied by coal suppliers for delivery in each year through 2029. The fuels group received these quotations in response to a request for quotation issued in the second quarter of 2024.

The long-term ILB price forecasts comprise five scenarios that were developed by applying historical relationships between ILB coal and natural gas prices to the natural gas price forecasts. Figure 15 shows that relationship over the past decade.

Figure 15: Historical ILB Coal/Henry Hub Gas Ratios (CTG)



The ILB coal/Henry Hub natural gas ratio (referred to as "CTG") is the ratio between yearly average ILB coal prices and natural gas prices. The long-term average CTG of 0.57 over the decade through 2021 (referred to as the "Mid CTG") reflects a relatively stable coal market with ample supply versus demand as depicted by the red line on Figure 15. This average is the basis for the Mid CTG coal price forecasts. As noted above, the Mid coal-to-gas price ratio (0.57) approximates the ratio of NGCC and coal energy costs. Therefore, it is plausible to expect coal-to-gas price ratios to revert to this ratio over the long term, which is why the Companies refer to it as the "Expected CTG Price Ratio" throughout the Resource Assessment.

The High and Low rolling six-year average ratios (referred to as the “High CTG” and “Low CTG”) depicted on the graph at 0.60 and 0.52, respectively, are considered atypical. They are the maximum and minimum rolling six-year average ILB coal/Henry Hub gas price ratio over the reference decade. These ratios are used to create the High Gas, Low-CTG and Low-Gas, High CTG coal price forecasts, which are intended to model a range of scenarios where coal and gas prices diverge from their historical correlation.

6.6.3.1 ILB Coal Price Scenario Assumptions

- **Mid Gas, Mid CTG**
  - **2025-2029**: blend of bid prices and the adjusted SPG forecast using the following weightings.
    - 2025-2026: 100% bid pricing
    - 2027: 75% bid pricing/25% CTG Ratio
    - 2028: 50% bid pricing/50% CTG Ratio
    - 2029: 25% bid pricing/75% CTG Ratio

Figure 16 shows the resulting near-term ILB price forecast and its components.

Figure 16: Mid ILB Coal Price Forecast, 2023-2027 (Nominal $/MMBtu)

[redacted]

  - **2028-2050:** The Mid gas price forecast multiplied by the long-term average CTG ratio of 0.57.

- **Low Gas, Mid CTG and High Gas, Mid CTG:** The Low and High gas price forecasts, respectively, were multiplied by the Mid CTG of 0.57 throughout the planning period.
- **High Gas, Low CTG** was developed by multiplying the High gas price forecast by the Low CTG ratio, which is 0.52.
- **Low Gas, High CTG** was developed by multiplying the Low gas price forecast by the High CTG ratio, which is 0.60.

6.6.4 Ammonia Prices

Anhydrous ammonia ("ammonia") is used to reduce NO_x emissions from coal-fired generating units. Ammonia and natural gas prices are highly correlated given that natural gas is used to manufacture ammonia. Therefore, the Companies evaluated different levels of ammonia prices based on the level of natural gas prices.

Table 26 contains the wholesale ammonia price scenarios evaluated in this analysis. In the Mid Ammonia case, ammonia prices are assumed to increase on average by 2.2% from 2025 to 2029 and then escalate at the Companies' inflation assumption of 2.3% per year thereafter. The Low and High Ammonia price cases reflect the relationship between the Mid Gas price forecast and the Low and High Gas Price forecasts, respectively.

Table 26: Ammonia Prices (Wholesale Nominal $/ton)

Year	Low Ammonia		Mid Ammonia	High Ammonia	
	Low Gas, Mid CTG Ratio	Low Gas, High CTG Ratio	Mid Gas, Mid CTG Ratio	High Gas, Mid CTG Ratio	High Gas, Low CTG Ratio
2025	[redacted]				
2026					
2027					
2028					
2029					
2030					
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2050					

6.6.5 Emission Allowance Prices

Table 27 summarizes the emission allowance price forecasts used in this analysis. The SO_2 Group 1, NO_x Seasonal Group 3, and NO_x Annual forecasts were based on a consultant's December 2023 forecasts. Because the Companies focused on the Ozone NAAQS environmental regulations scenario, the NO_x Seasonal Group 3 forecast was the only seasonal NO_x price forecast used in the 2025 CPCN Resource Assessment.

Table 27: Emission Allowance Prices (Nominal $/ton)

Year	SO_2 Group 1	NO_x Seasonal Group 3	NO_x Annual
2025	[redacted]		
2026			
2027			
2028			
2029			
2030			
2031			
2032			
2033			
2034			
2035			
2036			
2037			
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2050			

6.7 Financial Inputs

Table 28 lists the financial inputs used to compute capital revenue requirements in this analysis.

Table 28: Financial Inputs

	Combined Companies
% Debt	46.73%
% Equity	53.27%
Cost of Debt	4.38%
Cost of Equity	9.425%
Tax Rate	24.95%
Property Tax Rate	0.15%
WACC (After-Tax)	6.56%

7 Appendix B – RFP Proposals

Table 29: RFP Proposals that Advanced to Modeling Analysis

Technology	No.	Resource ID and Respondent	Project Name	Location (County, State)	Nameplate Capacity (MW)	Start Date	Term (Years)	Purchase Price ($/kW)	Capacity Price ($/kW-month)	Energy Price ($/MWh)
Solar	1	[redacted]								
	9	[redacted]								
	10	[redacted]								
	12	[redacted]								
	14	[redacted]								
	16	[redacted]								
	17	[redacted]								
	19	[redacted]								
	20	[redacted]								
	22	[redacted]								
	24	[redacted]								
Solar Asset Development	29	[redacted]								
	33	[redacted]								
	34	[redacted]								
	35	[redacted]								
Solar w/ 4-hr BESS Option	36	[redacted]								
	37	[redacted]								
	38	[redacted]								
	39	[redacted]								
Solar w/ 8-hr BESS Option	42	[redacted]								

Technology	No.	Resource ID and Respondent	Project Name	Location (County, State)	Nameplate Capacity (MW)	Start Date	Term (Years)	Purchase Price ($/kW)	Capacity Price ($/kW-month)	Energy Price ($/MWh)
Wind w/ Solar Option	**44**	[redacted]								
	45	[redacted]								

Table 30: All RFP Proposals

Technology	No.	Resource ID and Respondent	Project Name	Location (County, State)	Nameplate Capacity (MW)	Start Date	Term (Years)	Purchase Price ($/kW)	Capacity Price ($/kW-month)	Energy Price ($/MWh)
Solar	**1**	[redacted]								
	2	[redacted]								
	3	[redacted]								
	4	[redacted]								
	5	[redacted]								
	6	[redacted]								
	7	[redacted]								
	8	[redacted]								
	9	[redacted]								
	10	[redacted]								
	11	[redacted]								
	12	[redacted]								
	13	[redacted]								
	14	[redacted]								
	15	[redacted]								
	16	[redacted]								
	17	[redacted]								
	18	[redacted]								
	19	[redacted]								
	20	[redacted]								

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Technology	No.	Resource ID and Respondent	Project Name	Location (County, State)	Nameplate Capacity (MW)	Start Date	Term (Years)	Purchase Price ($/kW)	Capacity Price ($/kW-month)	Energy Price ($/MWh)
	21	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	22	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	23	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	24	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	25	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	26	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	27	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	28	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Solar Asset Development	**29**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	30	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	31	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	32	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	33	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	34	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	35	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Solar w/ 4-hr BESS Option	**36**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	37	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	38	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	39	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	40	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	41	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Solar w/ 8-hr BESS Option	**42**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Solar + 4-hr BESS	43	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Technology	No.	Resource ID and Respondent	Project Name	Location (County, State)	Nameplate Capacity (MW)	Start Date	Term (Years)	Purchase Price ($/kW)	Capacity Price ($/kW-month)	Energy Price ($/MWh)
Wind w/ Solar Option	**44**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	45	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
4-hr BESS	46	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Pumped Hydro	47	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	48	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

8 Appendix C – Stage One, Step One Resource Plans

As noted in Section 4.4.1, the Companies used PLEXOS to develop resource plans in their Stage One, Step One analysis with and without the Brown and Mill Creek landfill constraints to understand the impact of these constraints on the 2030 portfolio. The tables in this section contain the resource plans from this analysis. Section 4.4.1 contains a summary of these plans and key takeaways.

Table 31 through Table 35 below provide the resource plans PLEXOS developed for each of the load scenarios with landfill constraints; Table 36 through Table 40 below provide the resource plans PLEXOS developed for each of the load scenarios without landfill constraints.

8.1 Resource Plans with Landfill Constraints

Table 31: PLEXOS Resource Plans (1,470 MW Data Center Load; With Landfill Constraints)[78]

Year	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**
2030	Add GH2 SCR; + Brown 12; + Mill Creek 6; +200 MW 4hr BESS	Add GH2 SCR; + Brown 12; + Mill Creek 6; +200 MW 4hr BESS	GH2 Non-Ozone; + Brown 12; + Mill Creek 6; +200 MW 4hr BESS; +815 MW Solar	Add GH2 SCR; + Brown 12; + Mill Creek 6; +200 MW 4hr BESS	GH2 Non-Ozone; + Brown 12; + Mill Creek 6; +200 MW 4hr BESS; +815 MW Solar
2031					
2032					
2033					
2034			+150 MW Solar		
2035	Retire BR3; +500 MW 4hr BESS	Retire BR3; +500 MW 4hr BESS	Retire BR3; +500 MW 4hr BESS	Retire BR3; +500 MW 4hr BESS	Retire BR3; +500 MW 4hr BESS; +150 MW Solar
2036					
2037			+175 MW Solar		
2038					
2039			+100 MW Solar		+175 MW Solar
2040	End OVEC ICPA; +1 SCCT	End OVEC ICPA; +1 SCCT	End OVEC ICPA; +200 MW 4hr BESS; +200 MW Solar	End OVEC ICPA; +1 SCCT	End OVEC ICPA; +200 MW 4hr BESS; +300 MW Solar

[78] PLEXOS was configured to add NGCC (660 net winter MW) and SCCT (258 net winter MW) in one-unit increments and BESS in 100 MW increments. Solar and wind additions represent proposals from the Companies' May 2024 RFP. "GH2 Non-Ozone" indicates that Ghent 2 is operated only in the non-ozone season. "End OVEC ICPA" indicates that the Companies' Inter-Company Power Agreement comes to an end on June 30, 2040. All portfolios contain additional dispatchable DSM as described in Section 3.1.

Table 32: PLEXOS Resource Plans (1,610 MW Data Center Load; With Landfill Constraints)[78]

Year	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**
2030	Add GH2 SCR; + Brown 12; + Mill Creek 6; +400 MW 4hr BESS	Add GH2 SCR; + Brown 12; + Mill Creek 6; +400 MW 4hr BESS	GH2 Non-Ozone; + Brown 12; + Mill Creek 6; +400 MW 4hr BESS; +815 MW Solar	Add GH2 SCR; + Brown 12; + Mill Creek 6; +400 MW 4hr BESS	GH2 Non-Ozone; + Brown 12; + Mill Creek 6; +400 MW 4hr BESS; +815 MW Solar
2031					
2032			+150 MW Solar		
2033					
2034					+150 MW Solar
2035	Retire BR3; +500 MW 4hr BESS	Retire BR3; +500 MW 4hr BESS	Retire BR3; +500 MW 4hr BESS	Retire BR3; +500 MW 4hr BESS	Retire BR3; +500 MW 4hr BESS;
2036			+175 MW Solar		+175 MW Solar
2037			+100 MW Solar		
2038			+220 MW Solar		
2039					+100 MW Solar
2040	End OVEC ICPA; +1 SCCT	End OVEC ICPA; +1 SCCT	End OVEC ICPA; +200 MW 4hr BESS; +200 MW Solar	End OVEC ICPA; +1 SCCT	End OVEC ICPA; +200 MW 4hr BESS; +420 MW Solar

Table 33: PLEXOS Resource Plans (1,750 MW Data Center Load; With Landfill Constraints)[78]

Year	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**
2030	Add GH2 SCR; + Brown 12; + Mill Creek 6; +600 MW 4hr BESS	GH2 Non-Ozone; + Brown 12; + Mill Creek 6; + Generic NGCC; +215 MW Solar	GH2 Non-Ozone; + Brown 12; + Mill Creek 6; + Generic NGCC; +215 MW Solar	Add GH2 SCR; + Brown 12; + Mill Creek 6; +600 MW 4hr BESS	GH2 Non-Ozone; + Brown 12; + Mill Creek 6; +600 MW 4hr BESS; +815 MW Solar
2031			+600 MW Solar		
2032					
2033					
2034					+150 MW Solar
2035	Retire BR3; +500 MW 4hr BESS	Retire BR3; +400 MW 4hr BESS	Retire BR3; +300 MW 4hr BESS; +150 MW Solar	Retire BR3; +500 MW 4hr BESS	Retire BR3; +500 MW 4hr BESS;
2036					+175 MW Solar
2037					+100 MW Solar
2038					+220 MW Solar
2039					
2040	End OVEC ICPA; +1 SCCT	End OVEC ICPA; +200 MW 4hr BESS; +200 MW Solar	End OVEC ICPA; +200 MW 4hr BESS; +200 MW Solar	End OVEC ICPA; +1 SCCT	End OVEC ICPA; +200 MW 4hr BESS; +325 MW Solar

Table 34: PLEXOS Resource Plans (1,890 MW Data Center Load; With Landfill Constraints)[78]

Year	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**
2030	Add GH2 SCR; + Brown 12; + Mill Creek 6; +800 MW 4hr BESS	GH2 Non-Ozone; + Brown 12; + Mill Creek 6; + Generic NGCC; +100 MW 4hr BESS; +265 MW Solar	GH2 Non-Ozone; + Brown 12; + Mill Creek 6; + Generic NGCC; +100 MW 4hr BESS; +815 MW Solar	Add GH2 SCR; + Brown 12; + Mill Creek 6; +800 MW 4hr BESS	GH2 Non-Ozone; + Brown 12; + Mill Creek 6; + Generic NGCC; +100 MW 4hr BESS; +600 MW Solar
2031					+215 MW Solar
2032					
2033					
2034					
2035	Retire BR3; +500 MW 4hr BESS	Retire BR3; +400 MW 4hr BESS	Retire BR3; +400 MW 4hr BESS; +150 MW Solar	Retire BR3; +500 MW 4hr BESS	Retire BR3; +400 MW 4hr BESS; +150 MW Solar
2036					
2037					
2038					
2039			+175 MW Solar		
2040	End OVEC ICPA; Retire MC3; + Generic NGCC	End OVEC ICPA; +1 SCCT	End OVEC ICPA; +200 MW 4hr BESS; +300 MW Solar	End OVEC ICPA; Retire MC3; + Generic NGCC	End OVEC ICPA; +200 MW 4hr BESS; +375 MW Solar

Table 35: PLEXOS Resource Plans (2,030 MW Data Center Load; With Landfill Constraints)[78]

Year	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**
2030	Add GH2 SCR; + Brown 12; + Mill Creek 6; + Generic NGCC; +300 MW 4hr BESS	GH2 Non-Ozone; + Brown 12; + Mill Creek 6; + Generic NGCC; +300 MW 4hr BESS; +265 MW Solar	GH2 Non-Ozone; + Brown 12; + Mill Creek 6; + Generic NGCC; +300 MW 4hr BESS; +815 MW Solar	Add GH2 SCR; + Brown 12; + Mill Creek 6; + Generic NGCC; +300 MW 4hr BESS	GH2 Non-Ozone; + Brown 12; + Mill Creek 6; + Generic NGCC; +300 MW 4hr BESS; +815 MW Solar
2031					
2032					
2033					
2034			+150 MW Solar		
2035	Retire BR3; +400 MW 4hr BESS	Retire BR3; +400 MW 4hr BESS	Retire BR3; +400 MW 4hr BESS	Retire BR3; +400 MW 4hr BESS	Retire BR3; +400 MW 4hr BESS; +150 MW Solar
2036					
2037			+175 MW Solar		
2038					
2039			+100 MW Solar		+175 MW Solar
2040	End OVEC ICPA; +1 SCCT	End OVEC ICPA; +1 SCCT	End OVEC ICPA; +1 SCCT;	End OVEC ICPA; +1 SCCT	End OVEC ICPA; +200 MW 4hr BESS; +300 MW Solar

8.2 Resource Plans without Landfill Constraints

Table 36: PLEXOS Resource Plans (1,470 MW Data Center Load; Without Landfill Constraints)[78]

	Expected CTG Ratio			Atypical CTG Ratio	
Year	Low Gas, Mid CTG	Mid Gas, Mid CTG	High Gas, Mid CTG	Low Gas, High CTG	High Gas, Low CTG
2030	Add GH2 SCR; + Brown 12; + Mill Creek 6; +200 MW 4hr BESS	Add GH2 SCR; + Brown 12; + Mill Creek 6; +200 MW 4hr BESS	GH2 Non-Ozone; + Brown 12; + Mill Creek 6; +200 MW 4hr BESS; +600 MW Solar	Add GH2 SCR; + Brown 12; + Mill Creek 6; +200 MW 4hr BESS	GH2 Non-Ozone; + Brown 12; + Mill Creek 6; +200 MW 4hr BESS; +815 MW Solar
2031			+215 MW Solar		
2032					
2033					
2034					+150 MW Solar
2035	Retire BR3; +500 MW 4hr BESS	Retire BR3; +500 MW 4hr BESS		Retire BR3; +500 MW 4hr BESS	
2036			+150 MW Solar		
2037					
2038					
2039					
2040	End OVEC ICPA; +1 SCCT	End OVEC ICPA; +1 SCCT	End OVEC ICPA; +200 MW 4hr BESS; +200 MW Solar	End OVEC ICPA; +1 SCCT	End OVEC ICPA; +200 MW 4hr BESS; +375 MW Solar

Table 37: PLEXOS Resource Plans (1,610 MW Data Center Load; Without Landfill Constraints)[78]

	Expected CTG Ratio			Atypical CTG Ratio	
Year	Low Gas, Mid CTG	Mid Gas, Mid CTG	High Gas, Mid CTG	Low Gas, High CTG	High Gas, Low CTG
2030	Add GH2 SCR; + Brown 12; + Mill Creek 6; +400 MW 4hr BESS	Add GH2 SCR; + Brown 12; + Mill Creek 6; +400 MW 4hr BESS	GH2 Non-Ozone; + Brown 12; + Mill Creek 6; +400 MW 4hr BESS; +815 MW Solar	Add GH2 SCR; + Brown 12; + Mill Creek 6; +400 MW 4hr BESS	GH2 Non-Ozone; + Brown 12; + Mill Creek 6; +400 MW 4hr BESS; +815 MW Solar
2031					
2032			+150 MW Solar		
2033					
2034					+150 MW Solar
2035	Retire BR3; +500 MW 4hr BESS			Retire BR3; +500 MW 4hr BESS	
2036					
2037					
2038					
2039			+175 MW Solar		
2040	End OVEC ICPA; +1 SCCT	End OVEC ICPA; +1 SCCT	End OVEC ICPA; +200 MW 4hr BESS; +300 MW Solar	End OVEC ICPA; +1 SCCT	End OVEC ICPA; +200 MW 4hr BESS; +375 MW Solar

Table 38: PLEXOS Resource Plans (1,750 MW Data Center Load; Without Landfill Constraints)[78]

Year	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
2030	Add GH2 SCR; + Brown 12; + Mill Creek 6; +600 MW 4hr BESS	Add GH2 SCR; + Brown 12; + Mill Creek 6; +600 MW 4hr BESS	GH2 Non-Ozone; + Brown 12; + Mill Creek 6; +600 MW 4hr BESS; +815 MW Solar	Add GH2 SCR; + Brown 12; + Mill Creek 6; +600 MW 4hr BESS	GH2 Non-Ozone; + Brown 12; + Mill Creek 6; +600 MW 4hr BESS; +815 MW Solar
2031					
2032			+150 MW Solar		+150 MW Solar
2033					
2034					
2035	Retire BR3; +500 MW 4hr BESS			Retire BR3; +500 MW 4hr BESS	
2036					
2037			+175 MW Solar		
2038					
2039			+100 MW Solar		+175 MW Solar
2040	End OVEC ICPA; +1 SCCT	End OVEC ICPA; +1 SCCT	End OVEC ICPA; +200 MW 4hr BESS; +200 MW Solar	End OVEC ICPA; +1 SCCT	End OVEC ICPA; +200 MW 4hr BESS; +300 MW Solar

Table 39: PLEXOS Resource Plans (1,890 MW Data Center Load; Without Landfill Constraints)[78]

Year	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
2030	Add GH2 SCR; + Brown 12; + Mill Creek 6; +800 MW 4hr BESS	GH2 Non-Ozone; + Brown 12; + Mill Creek 6; + Generic NGCC; +100 MW 4hr BESS; +265 MW Solar	GH2 Non-Ozone; + Brown 12; + Mill Creek 6; + Generic NGCC; +100 MW 4hr BESS; +815 MW Solar	Add GH2 SCR; + Brown 12; + Mill Creek 6; +800 MW 4hr BESS	GH2 Non-Ozone; + Brown 12; + Mill Creek 6; +800 MW 4hr BESS; +815 MW Solar
2031					
2032					+150 MW Solar
2033					
2034					
2035	Retire BR3; +500 MW 4hr BESS	Retire BR3; +400 MW 4hr BESS	Retire BR3; +400 MW 4hr BESS; +150 MW Solar	Retire BR3; +500 MW 4hr BESS	
2036					+175 MW Solar
2037					
2038					+100 MW Solar
2039					
2040	End OVEC ICPA; +1 SCCT	End OVEC ICPA; +1 SCCT	End OVEC ICPA; +1 SCCT; +275 MW Solar	End OVEC ICPA; +1 SCCT	End OVEC ICPA; +200 MW 4hr BESS; +420 MW Solar

Table 40: PLEXOS Resource Plans (2,030 MW Data Center Load; Without Landfill Constraints)[78]

	Expected CTG Ratio			Atypical CTG Ratio	
Year	**Low Gas, Mid CTG**	**Mid Gas, Mid CTG**	**High Gas, Mid CTG**	**Low Gas, High CTG**	**High Gas, Low CTG**
2030	Add GH2 SCR; + Brown 12; + Mill Creek 6; + Generic NGCC; +300 MW 4hr BESS	GH2 Non-Ozone; + Brown 12; + Mill Creek 6; + Generic NGCC; +300 MW 4hr BESS; +265 MW Solar	GH2 Non-Ozone; + Brown 12; + Mill Creek 6; + Generic NGCC; +300 MW 4hr BESS; +815 MW Solar	Add GH2 SCR; + Brown 12; + Mill Creek 6; + Generic NGCC; +300 MW 4hr BESS	GH2 Non-Ozone; + Brown 12; + Mill Creek 6; + Generic NGCC; +300 MW 4hr BESS; +815 MW Solar
2031					
2032					+150 MW Solar
2033					
2034			+150 MW Solar		
2035	Retire BR3; +400 MW 4hr BESS	Retire BR3; +400 MW 4hr BESS	Retire BR3; +400 MW 4hr BESS	Retire BR3; +400 MW 4hr BESS	
2036					
2037					
2038					
2039			+175 MW Solar		
2040	End OVEC ICPA; +1 SCCT	End OVEC ICPA; +1 SCCT	End OVEC ICPA; +1 SCCT; +320 MW Solar	End OVEC ICPA; +1 SCCT	End OVEC ICPA; +200 MW 4hr BESS; +200 MW Solar

Exhibit SAW-2

Information in the exhibit is confidential and proprietary and is provided under seal pursuant to a petition for confidential protection. In addition, portions of the exhibit are voluminous and are provided pursuant to a motion to deviate.