2022 Resource Assessment

PPL companies

Generation Planning & Analysis

March 2023 Update

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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 2022 Resource Assessment to ensure the Companies could continue to provide safe, reliable, and low-cost service to their customers while complying with the U.S. Environmental Protection Agency's ("EPA") recent Good Neighbor Plan across a variety of possible future fuel price and carbon price scenarios.

1.1 Good Neighbor Plan and Upcoming Capital Investments Require Revised Portfolio

The EPA promulgated the Good Neighbor Plan in April 2022. As drafted, the Good Neighbor Plan would effectively require two of the Companies' large coal-fired units, the 297 MW Mill Creek Unit 2 ("Mill Creek 2" or "MC2") and the 485 MW Ghent Unit 2 ("Ghent 2" or "GH2") to cease operating during the ozone season (May through September) each year beginning in 2026 unless the Companies install selective catalytic reduction ("SCR") equipment on the units to reduce the units' nitrogen oxides ("NO_x") emissions. SCRs have significant capital costs: $110 million for Mill Creek 2 and $126 million for Ghent 2.

Although unaffected by the Good Neighbor Plan, the 412 MW Brown Unit 3 ("Brown 3" or "BR3") is the Companies' coal unit with the highest operating costs and will require a $26 million overhaul in 2027 to operate safely beyond 2028.

Collectively, these units have a total capacity of 1,194 MW and typically produce 15% or more of customers' annual energy requirements, and they produce just over half of their annual energy during non-daylight hours. Simply retiring these units without reliably replacing their energy production or decreasing demand for the energy they supply would almost certainly result in unserved energy requirements—in other words, blackouts or brownouts.

Because such service would be unacceptable to customers and contrary to the Companies' obligation to provide safe, reliable, and low-cost service, the Companies conducted a holistic, comprehensive assessment of customers' anticipated needs and the available demand- and supply-side means of serving those needs. The result of this resource assessment is a reliability-, risk-, and cost-optimized portfolio of demand- and supply-side resources to meet customers' projected energy needs.

1.2 A Comprehensive Resource Assessment Results in an Optimal Portfolio

The Companies' Resource Assessment made the best use of the Companies' own experience and expertise and state-of-the-art modeling tools and techniques, including sophisticated portfolio development and screening, hourly dispatch, and reliability modeling software platforms.

The assessment began with:

- A fully updated thirty-year hourly load forecast, which accounted for the BlueOval SK Battery Park load (almost 260 MW summer, about 225 MW winter, almost 90% load factor),[1] the effects of the Inflation Reduction Act ("IRA"), and the energy efficiency effects of the Companies' proposed 2024-2030 DSM-EE Program Plan.

[1] As noted in the 2022 Load Forecast, Exhibit TAJ-1, 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.

- Supply-side options resulting from the Companies' June 2022 RFP, which also accounted for IRA impacts and resulted in 22 respondents providing 101 proposals across 39 projects (which were later sub-divided into 110 proposals), including solar, wind, pumped hydro, battery energy storage, and natural gas units.
- Economic demand response programs and components from the Companies' 2024-2030 Demand-Side Management and Energy Efficiency ("DSM-EE") Program Plan.
- A full accounting of current environmental requirements, including the draft Good Neighbor Plan.

After screening the RFP responses for economics and practicability, 43 options proceeded to the assessment, in which the Companies evaluated the demand- and supply-side options in three basic stages:

1. **Creating an economically optimal portfolio consistent with minimum reliability and environmental compliance.** This stage involved using models to develop and screen optimal portfolios across six fuel price scenarios.

   Result: Retiring Mill Creek 2, Ghent 2, and Brown 3 and replacing them with 2 natural gas combined cycle ("NGCC") units, namely the 621 MW Mill Creek Unit 5 ("Mill Creek NGCC" or "MC5") and the 621 MW Brown Unit 12 ("Brown NGCC" or "BR12"), and 637 MW of solar power purchase agreements ("PPAs") is economically optimal at minimum reliability.

2. **Stress-testing the economically optimal portfolio.** This stage involved comparing the economically optimal portfolio to nine other possible portfolios across six fuel price scenarios and three CO_2 price scenarios to compare their economics and reliability.

   Result: Confirmation that retiring Mill Creek 2, Ghent 2, and Brown 3 and replacing them with Mill Creek NGCC, Brown NGCC, and 637 MW of solar PPAs remains economically optimal at minimum reliability.

3. **Fine tuning the portfolio to account for solar PPA execution risk, enhance reliability, and ensure reliability if OVEC retires early.** This stage consisted of three distinct fine-tuning analyses:

   a. **Solar PPA execution risk analysis.** The Companies' own experience with executed solar PPAs, negotiations of PPAs from the June 2022 RFP, and the state of the solar market broadly demonstrates there is real risk that PPA projects might not be built, at least not in a timely manner, at the agreed price. This analysis demonstrates the prudence of adding 240 MW of Companies-owned solar capacity to the optimal portfolio.

   b. **Analysis of reliability enhancements.** This analysis demonstrates that adding the dispatchable DSM programs in the Companies' proposed 2024-2030 DSM-EE Program Plan is a cost-effective reliability enhancement to the optimal portfolio. It further demonstrates that including the proposed Brown battery energy storage system ("Brown BESS") in the optimal portfolio adds reliability and notes that Brown BESS could offer quantifiable operational benefits, including possible reductions in required spinning reserves and reduced wear on fast-ramping units.

c. **Analysis of possible early retirement of Ohio Valley Electric Corp.'s ("OVEC") coal units.** This analysis demonstrates that the optimal portfolio maintains adequate reliability if OVEC retires as early as 2028 without replacement capacity.

Result: Retiring Mill Creek 2, Ghent 2, and Brown 3 and replacing them with Mill Creek NGCC, Brown NGCC, 637 MW of solar PPAs, 240 MW of Companies-owned solar capacity, the 2024-2030 DSM-EE Program Plan, and the Brown BESS is the portfolio that best optimizes reliability, cost, and risk-mitigation, and it positions the Companies to gain vital experience with utility-scale battery technology that is likely key to future large-scale renewable generation integration.

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

As discussed at length herein, the resource portfolio this Resource Assessment recommends optimally blends the reliability, cost, and lower-CO_2-emission benefits of NGCC units, the energy- and CO_2-cost hedging benefits of solar generation, and the demand-reducing and reliability-enhancing benefits of dispatchable DSM from the 2024-2030 DSM-EE Program Plan. It also hedges against the risks of the current solar market—namely that prices are rising and relatively few projects are actually being built—by including a mix of solar PPAs and solar capacity to be owned by the Companies. Finally, it includes Kentucky's first utility-scale battery energy storage system to provide additional reliability benefits and give the Companies invaluable first-hand experience with owning and operating at true utility scale an energy storage technology that will be vital to growing renewable energy generation in the decades to come.

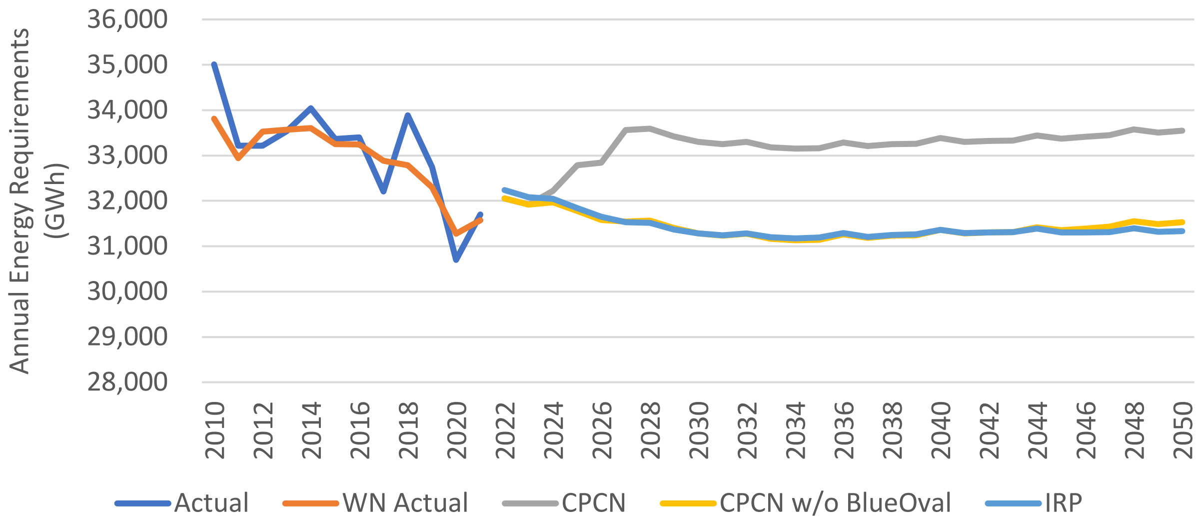
2 Objective: Reliably and Cost-Effectively Serving Customers' Projected Needs

The objective of this Resource Assessment is to develop a resource portfolio to ensure ongoing safe and reliable service at the lowest reasonable cost. An optimal resource portfolio 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 2022 CPCN Load Forecast

The Companies' 2022 CPCN Load Forecast projects customers' energy and demand requirements.[2] Notably, the 2022 CPCN Load Forecast takes full account of IRA impacts, as well as the energy efficiency effects of the Companies' proposed 2024-2030 DSM-EE Program Plan. As shown in the annual energy requirements forecast below, the Companies project customers will require significantly more energy through 2050 than they have recently, due in large part to the BlueOval SK Battery Park to be located in KU's service territory in Glendale, Kentucky:

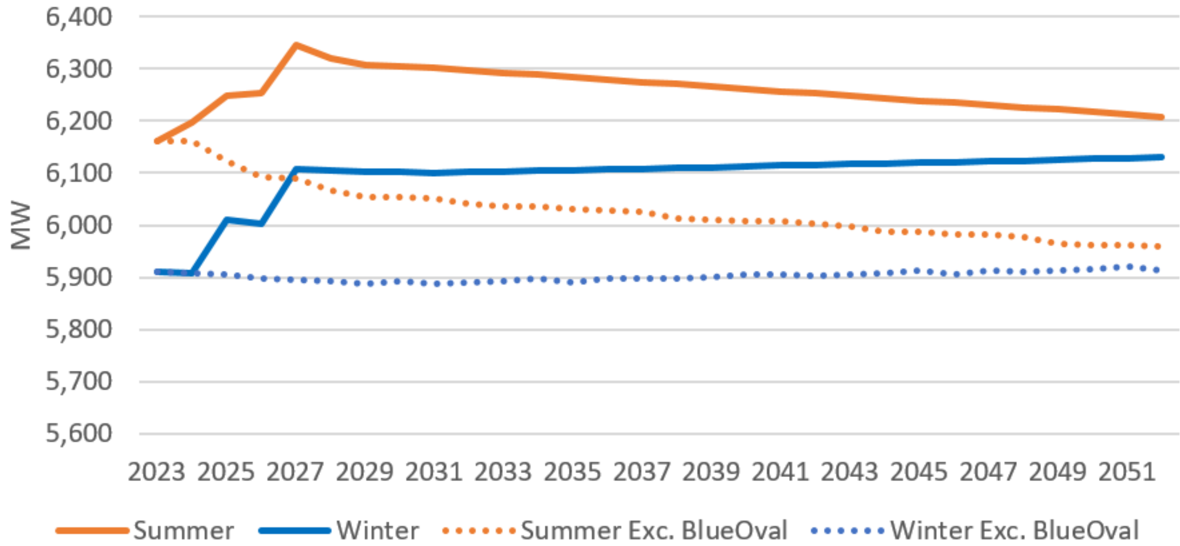
Figure 1: Annual Energy Requirements History and Forecast (exc. Departed Municipal Customers)



The Companies are also forecasting marked increases in seasonal peak demands, again largely driven by BlueOval, though the seasonal peaks converge over time as projected increases in electric heating load gradually increase winter peaks while increasing end-use efficiencies (including DSM-EE programs) and distributed solar generation steadily decrease summer peak load:

[2] Sponsored by Tim A. Jones as Exhibit TAJ-1.

Figure 2: Forecasted Seasonal Peaks



As shown in the following figures, customers will also continue to require significant amounts of energy in every hour and season, during daylight and non-daylight hours:

Figure 3: 2028 Proportion of Energy Consumed During Daylight and Non-Daylight Hours

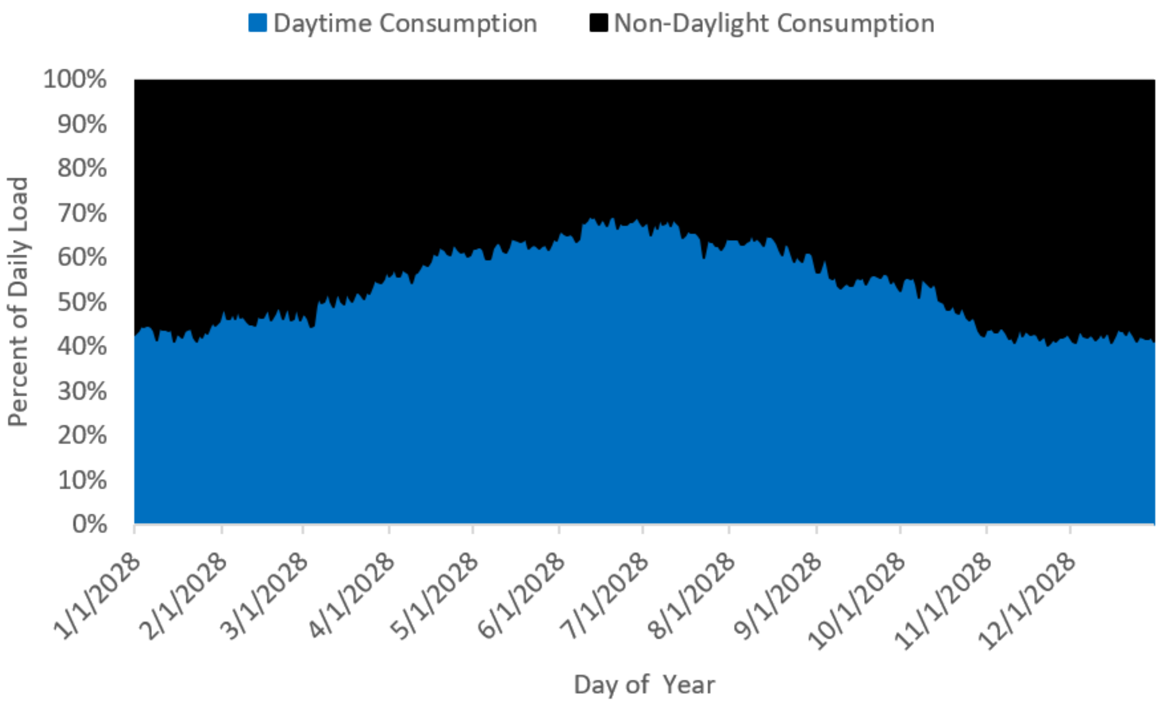
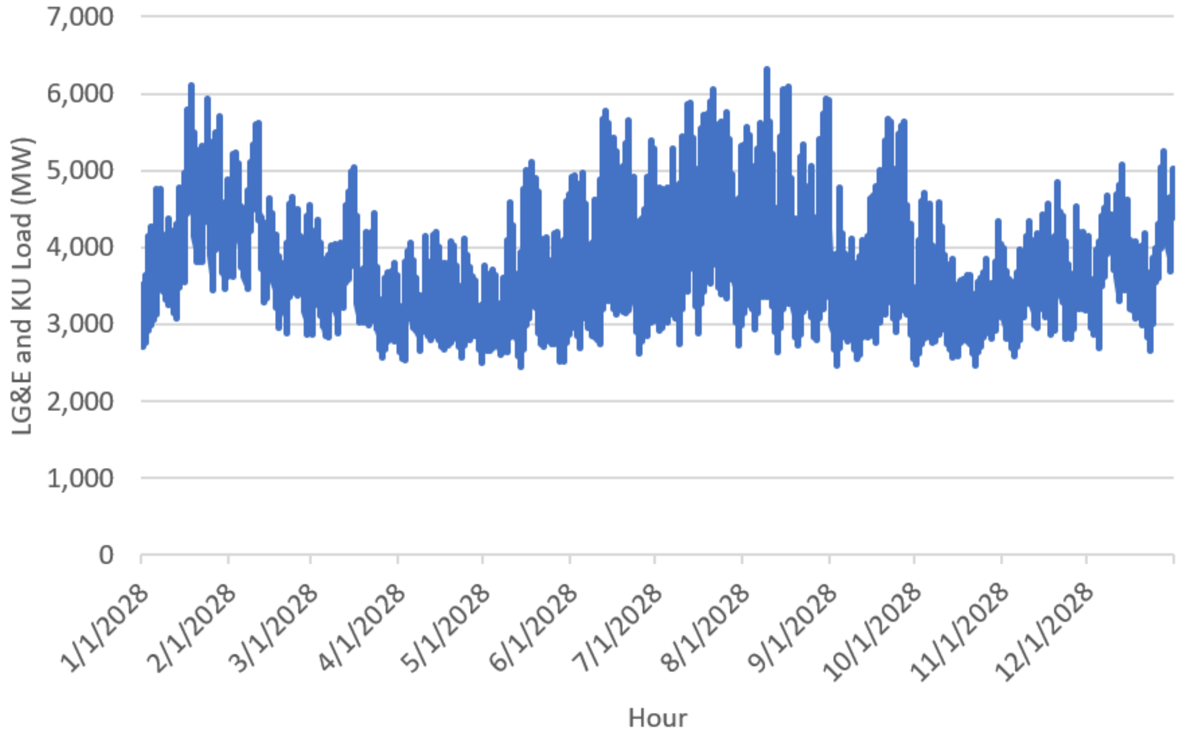


Figure 4: LG&E and KU 2028 Hourly Load

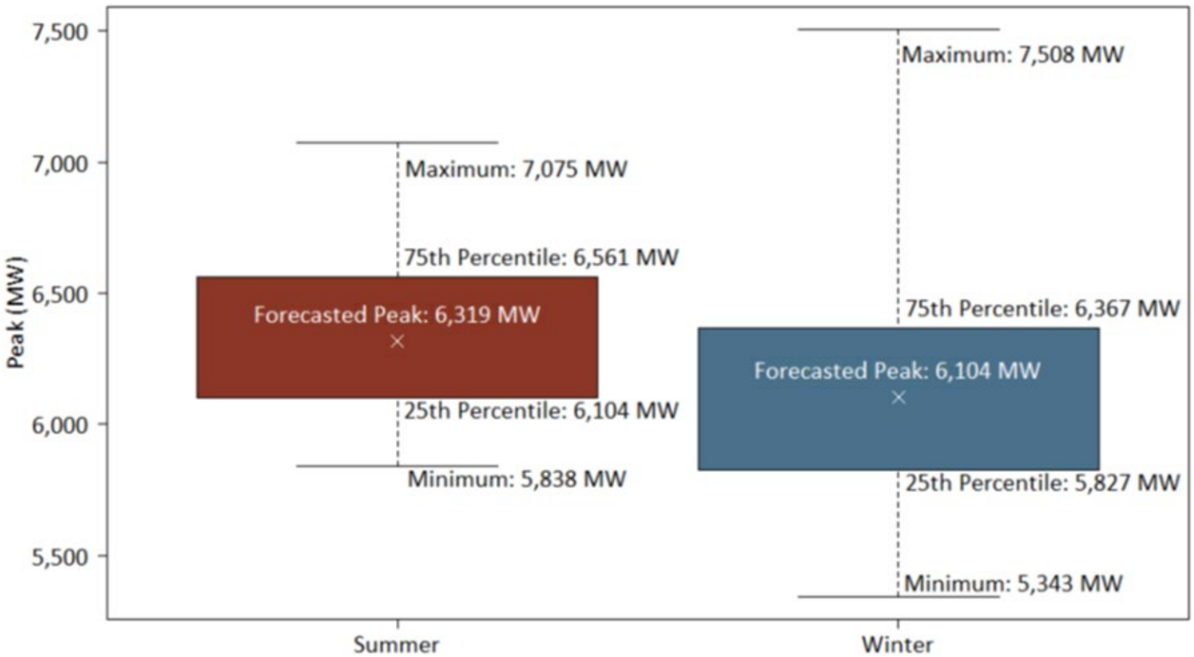


These figures show that an optimal resource portfolio must be able to serve customers' considerable energy requirements in all hours, seasons, and weather and daylight conditions. Notably, the Companies developed the figures above and the 2022 CPCN Load Forecast assuming normal weather. Extreme weather conditions drive a need for additional reliability considerations.

2.2 Serving Customers Reliably: Minimum Reserve Margins

To ensure reliable service, the Companies reanalyzed their reserve margins for this Resource Assessment. The full reserve margin analysis is Appendix D to this document. It demonstrates that the Companies' minimum reserve margins are 17% in the summer and 24% in the winter. This is consistent with the much greater variability of winter peak demands, as Figure 5 below shows:

Figure 5: Distributions of Summer and Winter Peak Demands, 2028



Note that the minimum reserve margins assume a mix of resources that are fully dispatchable for long durations and resources that are intermittent or can be dispatched for only limited durations (primarily solar and DSM). For example, the total summer minimum reserve margin assumes a 12% reserve margin that is fully dispatchable and a 5% reserve margin comprising intermittent and limited-duration resources. Therefore, any portfolio that achieves a total summer reserve margin of 17% but includes significantly less than a 12% reserve margin consisting of fully dispatchable resources raises reliability concerns.

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 due to upcoming environmental regulatory constraints (the Good Neighbor Plan) and major capital investments needed for Brown 3 to continue operating reliably in 2028 and beyond. 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 resource decisions to be made five, ten, or even twenty years from now.

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 a request for proposals ("RFP"). On the demand side, the Companies accomplished this through their own research and experience, engagement with a third-party consultant (Cadmus), and the Companies' DSM-EE Advisory Group. The result was a large array of potential supply-side resources and dispatchable DSM programs that advanced for further analysis in this Resource Assessment.

3.1 Supply Side: RFP Responses and Review

The Companies issued an RFP for new generation capacity and energy in June 2022.[3] In total, 22 parties responded to the RFP with 101 proposals across 39 different projects, some of which the Companies subdivided into a total of 110 proposals. Due to the timing of the responses relative to the passage of the federal Inflation Reduction Act, the Companies asked all respondents to update their responses to account for the IRA. The majority indicated they had already accounted for it or did not need to adjust their responses; five respondents provided updated information.

Appendix B contains a full listing of the 110 proposals; Table 1 below summarizes them by technology:

Table 1: Summary of RFP Responses

Technology	Number of Proposals by Start Year			Nameplate Capacity (MW)	Price
	<=2026	2027	2028+		
Solar	32	2	3	35-685	[redacted]
Solar w/ 4-hr Battery Option	26	16	-	100-750	
Solar + 4-hr Battery	2	-	-	200	
2-hr Battery	3	1	-	120-300	
4-hr Battery	11	1	-	100-300	
Pumped Hydro	-	-	1	287	
Wind	1	-	-	143	
NGCC	-	4	2	643-1,285	
SCCT	2	1	-	556	
Solar Asset Development	2	-	-	120-685	

[3] 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.

The majority of the responses to the RFP were for solar PPAs or solar PPAs with battery storage options. The Companies' Project Engineering group submitted solar and battery storage proposals, as well as the only simple-cycle combustion turbine ("SCCT") and NGCC proposals.

The Companies reviewed the RFP responses and screened them to create a more manageable set of alternatives for modeling based on several factors, reducing the number of proposals evaluated to 43:

- For PPA proposals covering the same project but with different pricing options due to PPA term, start date, and price escalation, the Companies selected the proposal with the lowest levelized cost per MWh. For PPA proposals with similar levelized costs and flat or escalating price options, the Companies selected the proposals with flat prices.

- Certain of the Companies' self-build NGCC and SCCT proposals for the E.W. Brown Generating Station ("Brown") would have required additional land acquisitions. The Companies excluded those proposals due to the development risk associated with land acquisition.

- The NGCC proposals included both single units and sets of two units at both Brown and the Mill Creek Generating Station ("Mill Creek"). The Companies excluded sets of two NGCC units at each site due to the anticipated transmission capacity investment that would be required to accommodate two units at a single site and to allow for gas pipeline diversity among potential new NGCC units.

- The Companies excluded proposals for the purchase or development of solar and battery storage assets from advancing to the modeling analysis due to the economics of the proposals. The Companies revisited these proposals in Stage Three of the analysis described below.

- The Companies excluded a non-conforming self-build 35 MW solar proposal at Trimble County (note that the Companies considered all other non-conforming proposals).

- Some respondents rescinded certain proposals after submitting them. The Companies did not consider rescinded proposals.

The full set of 43 proposals that advanced for modeling analysis is also included in Appendix B. Two important observations concerning the RFP review and screening process are:

- **Solar PPA prices have increased significantly.** The most competitive solar PPA proposals were priced at $36 to $40/MWh, which is 30 to 40 percent higher than the pricing in the Rhudes Creek and Ragland PPAs the Companies executed in 2019 and 2021, respectively. These pricing increases are consistent with broader market indicators, such as the LevelTen Energy PPA Price Index for the third quarter of 2022, indicating that its Solar P25 Market-Averaged National Index rose to $42.21/MWh, up 30.3% ($9.82/MWh) year over year.[4]

[4] *See* LevelTen Energy "Q3 2022 PPA Price Index Executive Summary North America" at 7, available at: https://www.leveltenenergy.com/ppa.

- **The Companies' Muhlenberg Self-Build Solar Proposal Relocated to Mercer County.** One RFP response proposed to sell the Companies a solar project already in advanced stages of development, but not construction, located in Mercer County.[5] Because the proposal was not for a commercially executable transaction for a PPA or to acquire a solar facility per se, the Companies' Project Engineering group reviewed it and determined it would be a more suitable self-build solar site than their originally proposed site in Muhlenberg County, which had become problematic due to land acquisition issues. The Companies' Project Engineering group therefore revised their self-build proposal to suit the proposal at the Mercer County site, resulting in a 120 MW self-build solar proposal in Mercer County rather than a 145 MW self-build solar proposal in Muhlenberg County.

3.2 Demand Side: DSM Resources

Working with their DSM-EE Advisory Group and their outside expert consultant, Cadmus, the Companies formulated a proposed 2024-2030 DSM-EE Program Plan for which the Companies are seeking approval in this proceeding. As noted above, the Companies' 2022 CPCN Load Forecast fully accounts for the energy efficiency effects of the proposed 2024-2030 DSM-EE Program Plan. The dispatchable DSM portion of the 2024-2030 DSM-EE Program Plan, including the existing dispatchable DSM programs the Companies currently have in place, advanced for further analysis to determine their role in the optimal resource portfolio. A full listing of the dispatchable DSM programs and their relevant parameters are in Table 2 below, which is also located in Appendix B.

[5] *See* Response No. 110 in Table 43 in Appendix B.

Table 2: Dispatchable DSM Program Options

No.	Program Name	Variable Costs $/kWh Winter	Variable Costs $/kWh Summer	Time-Dependent Characteristic	2024	2025	2026	2027	2028	2029	2030
1	Peak Time Rebates	2.00	2.00	Summer Capacity MW	-	4	9	17	31	31	31
				Winter Capacity MW	-	4	9	17	31	31	31
				Fixed Cost $/kW-Year	-[6]	344	52	38	32	37	32
2	DLC-Water Heaters	2.50	2.50	Summer Capacity MW	3	3	3	2	2	2	2
				Winter Capacity MW	3	3	3	2	2	2	2
				Fixed Cost $/kW-Year	9	12	11	13	14	16	18
3	DLC-AC[7]	-	1.68	Summer Capacity MW	121	109	98	88	79	71	64
				Winter Capacity MW	-	-	-	-	-	-	-
				Fixed Cost $/kW-Year	9	12	11	13	14	16	18
4	BYOD-Smart Thermostats	4.17	4.93	Summer Capacity MW	1	3	6	10	17	23	29
				Winter Capacity MW	0.4	1	2	3	4	6	7
				Fixed Cost $/kW-Year	740	218	140	109	105	90	86
5	Non-residential Demand Response	7.55	7.55	Summer Capacity MW	29	36	45	56	67	79	79
				Winter Capacity MW	29	36	45	56	67	79	79
				Fixed Cost $/kW-Year	45	39	29	25	21	18	13

[6] The Peak Time Rebates program is projected to cost $250,000 in 2024 before realizing demand reductions starting in 2025.
[7] Summer capacity values are design-day values. Expected load reductions are lower on an average peak day.

3.3 The Companies' Existing Resources

The Companies have a suite of existing supply- and demand-side resources that would continue to serve the bulk of customers' demand and energy requirements over the Resource Assessment analysis period. This includes, for example, the Companies' interruptible load under their Curtailable Service Riders. To focus this analysis on the decision immediately at hand—namely, whether to retire and replace one or more of Mill Creek 2, Ghent 2, and Brown 3—the Companies have assumed that all of their existing resources will continue to operate throughout the analysis period with these exceptions: Mill Creek Unit 1 will retire as planned in 2024, Paddy's Run Unit 12 and Haefling Units 1-2 will retire in 2025, and OVEC will retire as planned in 2040.[8]

Also, as noted above, the Companies did not assume that existing dispatchable DSM programs would automatically continue for the entire Resource Assessment period; rather, those measures advanced for analysis in the Resource Assessment. Ultimately, those measures proved to be beneficial for reliability and are included in the optimal resource portfolio.

Finally, it is important to note the potential impact of retiring Mill Creek 2, Ghent 2, and Brown 3. Collectively, these units have a total capacity of 1,194 MW and typically produce 15% or more of customers' annual energy requirements, and they produce just over half of their annual energy during non-daylight hours:

Table 3: Operational Data for Mill Creek 2, Ghent 2, and Brown 3

Year	Total Energy (GWh)	% Night	% Day	Max Hourly Output (MW)	Average Hourly Output (MW)	% of Total Energy Requirements
2017	5,698	52%	48%	1,235	772	17%
2018	6,230	51%	49%	1,238	842	18%
2019	5,407	51%	49%	1,250	785	16%
2020	4,512	52%	48%	1,229	729	15%
2021	4,610	51%	49%	1,219	752	15%

Filling the energy gap these units will leave if they retire requires careful, thoughtful analysis to ensure the Companies have sufficient resources to continue to serve customers reliably and economically.

Appendix A contains a full discussion of existing resource assumptions.

[8] Due to their age and relative inefficiency, the Companies do not perform major maintenance on their small-frame simple-cycle combustion turbines ("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 2025 for planning purposes.

4 Meeting the Objective: Analysis to Achieve an Optimal Resource Portfolio

The Companies' Resource Assessment analysis described below brought together their 2022 CPCN Load Forecast, their existing resources, the 43 RFP proposals that advanced from the RFP review and screening, and all dispatchable DSM programs from the 2024-2030 DSM-EE Program Plan to achieve an optimal portfolio for meeting the potential capacity need in 2028. The Companies' analysis:

- Ensured compliance with the Good Neighbor Plan and other applicable environmental requirements while maintaining required reliability;
- Accounted for key uncertainties, such as fuel and CO_2 pricing; and
- Used a combination of sophisticated modeling tools (including PLEXOS, PROSYM, and SERVM), as well as the Companies' own expertise and experience.

The Companies conducted their analysis in three stages:

- **Stage One: Economic Optimization.** First, the Companies created an economically optimized portfolio across six fuel price cases that assured minimum reliability and Good Neighbor Plan compliance.
    - **Stage One Result:** An economically optimized portfolio of the 621 MW Mill Creek NGCC, the 621 MW Brown NGCC, and 637 MW of solar PPAs.
- **Stage Two: Stress Testing.** Next, the Companies stress-tested the results of the first stage by comparing the economically optimized portfolio to nine other portfolios, each of which the Companies designed to test whether adjusting in a particular way might improve the results (e.g., a portfolio that could replace any retired coal generation with only DSM, renewable energy resources, and battery storage). The Companies also tested the portfolios across all three CO_2 pricing scenarios and all six fuel price scenarios, all while maintaining minimum reliability.
    - **Stage Two Result:** The economically optimized portfolio of the Mill Creek NGCC, Brown NGCC, and 637 MW of solar PPAs remained optimal and resulted in lower CO_2 emissions than other tested portfolios.
- **Stage Three: Fine Tuning.** Third, the Companies fine-tuned the economically optimal portfolio to address three issues:
    - **Stage Three, Step One: Solar PPA Execution Risk.** The Companies' own experience with solar PPAs, as well as the broader market experience in recent years, is that it is increasingly difficult for contracted solar facilities to be built on time or at all, at least at the contracted price. To address this risk, the Companies demonstrate that adding two Companies-owned solar facilities to the portfolio helps address the risk that, given the current solar market, none of the solar PPAs might come to fruition, at least by 2028.

        - **Stage Three, Step One Result:** Optimal portfolio of the Mill Creek NGCC, Brown NGCC, 240 MW of Companies-owned solar, and 637 MW of solar PPAs.

    - **Stage Three, Step Two: Reliability Enhancement.** In this step, the Companies analyzed the value of adding reliability using dispatchable DSM from the 2024-2030 DSM-EE Program Plan, battery energy storage systems, and SCCT capacity. The Companies concluded that adding all of the dispatchable DSM in the 2024-2030 DSM-EE Program Plan provides cost-effective reliability. They further concluded that adding the proposed 125 MW, 500 MWh Brown BESS, though not as economical as SCCT, would further enhance reliability and provide the Companies valuable experience with battery technology at utility scale, which will likely be instrumental in reliably integrating large quantities of renewable generation in the future. In addition, Brown BESS might have quantifiable benefits that the Companies have not attempted to quantify here, such as reducing fast-ramping wear on gas turbine units and the ability to carry less spinning reserves.

        - **Stage Three, Step Two Result:** Optimal portfolio of the Mill Creek NGCC, Brown NGCC, 240 MW of Companies-owned solar, 637 MW of solar PPAs, 2024-2030 DSM-EE Program Plan, and Brown BESS.

    - **Stage Three, Step Three: OVEC early retirement:** The final consideration was whether an early retirement of the OVEC coal units would reduce reliability such that the Companies would need additional resources solely to address the early retirement. Particularly because the Companies cannot unilaterally control the operation or retirement of OVEC's units, this was an important uncertainty to analyze. The results indicate that an OVEC early retirement, even in 2028, would not require additional resources (assuming no significant changes in actual versus forecasted load).

        - **Stage Three, Step Three Result:** Optimal portfolio remains the Mill Creek NGCC, Brown NGCC, 240 MW of Companies-owned solar, 637 MW of solar PPAs, 2024-2030 DSM-EE Program Plan, and Brown BESS.

The result is a resource portfolio that appropriately balances economics, reliability, and risk; provides valuable experience with new technologies to accommodate greater renewable power generation in the future; and reduces CO_2 emissions considerably, more than other portfolios analyzed, which reduces future regulatory risk and potential cost related to CO_2 emissions. It is a no-regrets portfolio:

- **Low load or increased efficiencies, no regrets.** If actual load is materially lower than projected load for any reason, including if technological advances or economic changes result in additional energy and demand savings (through DSM-EE programs or otherwise), retiring additional aging coal capacity would likely be the most economical option, further reducing CO_2 emissions.

- **High load, no regrets.** If actual load is materially higher than projected load, nothing in the Companies' proposed portfolio precludes adding demand- or supply-side resources to address the need. If the increased load results from electric space heating or electric vehicle charging, the proposed NGCC units could prove to be particularly valuable given their ability to economically produce energy at night.

- **Increased renewable generation or CO_2 constraints, no regrets.** The proposed portfolio's fast-ramping NGCC units and Brown BESS well position the Companies to provide reliable service if renewable energy generation increases, and the lower CO_2 emissions of NGCCs and zero emissions of solar and DSM-EE all improve the Companies' positioning to address any CO_2 emissions pricing or regulations that might eventuate.

4.1 Key Constraints and Uncertainties of Analysis

The Companies' Resource Assessment analysis included addressing a number of important constraints and uncertainties.

4.1.1 Key Constraints

All stages of the Resource Assessment's analysis assumed that compliance with the Good Neighbor Plan and all other environmental requirements and maintaining minimum reserve margins were absolute constraints. As proposed, the Good Neighbor Plan effectively requires installing SCR to operate Mill Creek 2 and Ghent 2 during the ozone season (May through September) beginning in 2026. But because replacement generation may not be available by 2026, the Companies have asked the EPA to extend the compliance deadline in the event that retiring and replacing a resource is lower cost than physical compliance with SCR. To achieve Good Neighbor Plan compliance, the Companies assumed in the Resource Assessment that non-SCR-equipped coal units could not operate during the ozone season beginning in 2026 unless the units were scheduled to be replaced. Specifically, the Companies assumed they could avoid the cost of installing SCR in 2026 if the non-SCR-equipped unit was replaced by the 2028 ozone season.

4.1.2 Key Uncertainty: Fuel Prices

Fuel prices are an important uncertainty in this analysis. To address it, the Companies used six different fuel price scenarios in which natural gas prices were the primary price setting factor, with coal prices derived from gas prices beginning in 2028 based on different historical coal-to-gas ("CTG") price ratios.

The Companies' three natural gas price cases (low, mid, and high) derive from Henry Hub forward prices in the near term (2023-2025), then interpolate to the Energy Information Administration's 2022 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." 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 6 below shows these three fuel price cases in nominal dollars per MMBtu through 2050:

Figure 6: Coal and Natural Gas Price Scenarios with a Mid Coal-to-Gas Price Ratio

[redacted]

The other three 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"); (2) high gas prices with a historically low coal-to-gas ratio ("High Gas, Low CTG Ratio"); and (3) high gas prices with the current, historically aberrant coal-to-gas ratio ("High Gas, Current CTG Ratio"). Figure 7 below illustrates these three fuel price cases in nominal dollars per MMBtu through 2050:

Figure 7: 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 Coal and Natural Gas Prices discussion in Appendix A, as well as Appendix E.

4.1.3 Key Uncertainty: CO_2 Prices

The future of CO_2 regulation is a key uncertainty in this analysis. To address it, the Companies considered three different CO_2 prices as proxies for different possible CO_2 regulations, in accordance with the CO_2 prices Commission Staff asked the Companies to model in the 2021 IRP proceeding: $0/ton, $15/ton, and $25/ton.[9] These pricing cases are also reasonable based on prices in CO_2 markets like the Regional Greenhouse Gas Initiative ("RGGI") and others, as discussed in the CO_2 Prices discussion in Appendix A.

4.1.4 Key Uncertainty: Solar PPA Execution

The Companies' own experience with solar PPAs demonstrates the reality of solar PPA execution risk (i.e., the risk that a contracted facility will not be built on time or at all), as does the experience of the broader solar market in recent years. The Companies were able to execute two attractively priced PPAs (Rhudes Creek and Ragland) with reputable solar developers in 2019 and 2021, respectively. To date, neither project has obtained all necessary approvals to begin construction. Even if they were able to obtain necessary approvals, market prices of polysilicon needed for solar panels and related constraints on panel availability (owing largely to prohibitions on the ability to use certain solar panels made in China) make it

[9] *See* Case No. 2021-00393, Companies' Response to PSC 1-1(b) (Mar. 25, 2022).

unlikely the developers could obtain financing to build the projects at all, and certainly not at the prices prescribed in the PPAs.[10] The Companies address this risk in their analysis below.

But a solar risk the Companies do not directly address is solar intermittency: cloud risk. The modeling the Companies performed in this Resource Assessment took solar to be a resource with a fixed production profile. Although it is a reasonable profile and is correlated with the weather and solar irradiance underlying the load forecast, the models assume solar will reliably and consistently produce according to its profile.

4.1.5 Key Uncertainty: Early OVEC Retirement

A final key uncertainty the Companies' analysis considers is the possibility that the OVEC coal units that provide the Companies over 150 MW of dispatchable capacity might retire prior to the currently expected retirement date of 2040. At the end of the analysis below, the Companies evaluate the impact of OVEC retirement in 2028 on the reliability of the Companies' optimal resource portfolio.

4.2 Modeling Tools Used in the Analysis: PLEXOS, PROSYM, Financial Model, SERVM

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

- **Portfolio Development and Screening: PLEXOS.** The Companies used PLEXOS to develop least-cost resource portfolios over a range of fuel price scenarios. Using simplifying assumptions to increase speed, PLEXOS models and evaluate thousands of resource portfolios to determine which one minimizes the cost of serving customers' load while meeting minimum total summer and total winter reserve margin constraints. Notably, as the Companies use PLEXOS, although it evaluates thousands of possible resource portfolios in each run, its output for each run is only the least-cost portfolio for the assumptions entered; it does not provide a ranked listing or other comparison of runner-up portfolios. (Largely due to this limitation, Stage Two of the Companies' analysis involved comparing PLEXOS-selected portfolios to other portfolios formulated by the Companies to examine their relative reliability and economics.)

- **Production Cost Modeling: PROSYM.** Because production costs are an important component of total costs, after PLEXOS identifies which resources to include in a resource portfolio, the Companies modeled the portfolio'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 used a Financial Model built in Excel to calculate and compare PVRR values for various portfolios. Inputs to the Financial Model include capital and fixed operating costs for new and existing resources as well as generation production costs. Table 4 below lists the primary costs included

[10] *See, e.g.,* "Polysilicon Prices Remain High, No Moderation Until 2023", EnergyTrend, September 2, 2022, available at: https://m.energytrend.com/news/20220902-29845.html#:~:text=While future polysilicon prices are,per kilogram polysilicon price drop.

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 portfolio.

Table 4: 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 OVEC and solar PPAs.
Existing Unit Stay-Open Costs	Ongoing capital and fixed O&M associated with existing generation assets.
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.

- **Reliability Analysis: SERVM.** The Companies used SERVM to evaluate portfolios' reliability across a wide range of weather and unit availability scenarios. Specifically, the Companies used SERVM to model generation production costs, reliability costs, and loss of load expectation ("LOLE") over 49 load scenarios and 300 unit availability scenarios. The load scenarios were developed based on the weather in each of the last 49 years. This allows the Companies to evaluate the economics of improving reliability considering the historical frequency and likelihood of extreme weather events.

4.3 Analytical Framework: Three Stages to Achieve an Optimal Resource Portfolio

As discussed above, the Companies conducted three stages of analysis using the 2022 CPCN Load Forecast, existing resources, RFP responses, dispatchable DSM programs from the 2024-2030 DSM-EE Program Plan, and modeling tools to address the potential retirements of Mill Creek 2, Ghent 2, and Brown 3, as well as the key uncertainties and risks also discussed above, and arrive at an optimal resource portfolio.

4.4 Stage One: Economic Optimization to Achieve Minimum Reliability

The objective of Stage One is an economically optimal resource portfolio across six fuel-price cases consistent with meeting minimum reserve margin requirements and complying with Good Neighbor Plan. All steps of this stage assumed a CO_2 price of zero; Stage Two analyzed other CO_2 prices.

4.4.1 Stage One, Step One: Portfolio Development and Screening with PLEXOS

The first step of Stage One consisted of allowing PLEXOS to create optimal resource portfolios for each of the Companies' six fuel price cases.

In this step, PLEXOS:

- Took the Companies' existing resources to be fixed (except Mill Creek 1 retiring by the end of 2024, the small-frame SCCTs retiring in 2025, OVEC retiring in 2040, and existing dispatchable DSM programs could be retained or retired);
- Could choose to add SCR to or retire either or both of Mill Creek 2 and Ghent 2;
- Could make the $26 million investment to continue operating Brown 3 or retire the unit; and

- Could add any RFP response or dispatchable DSM resource from the 2024-2030 DSM-EE Program Plan at any time, regardless of the operation date specified in the RFP response.

Table 5 below provides the portfolios PLEXOS selected with these assumptions for each fuel price scenario. As mentioned previously, as the Companies use PLEXOS, it provides only the economically optimal portfolio for each model run.

Table 5: Portfolio Development and Screening Results by Fuel Price Scenario

		Least-Cost Resource Portfolio		
	Fuel Price Scenario (Gas, CTG Price Ratio)	**Changes to Dispatchable Resources by 2028**	**Total New Renewables by 2028 (MW)**	**Total New Renewables by 2035 (MW)**
Expected CTG	Low Gas, Mid CTG Ratio	Replace MC2, GH2, BR3 w/ MC5 and BR12	N/A	N/A
Expected CTG	Mid Gas, Mid CTG Ratio	Replace MC2, GH2, BR3 w/ MC5 and BR12	104 Solar	384 Solar
Expected CTG	High Gas, Mid CTG Ratio	Replace MC2, BR3 w/ MC5; Add SCR at GH2	637 Solar	2,322 Solar
Atypical CTG	Low Gas, High CTG Ratio	Replace MC2, GH2, BR3 w/ MC5 and BR12	N/A	N/A
Atypical CTG	High Gas, Low CTG Ratio	Replace MC2, BR3 w/ MC5; Add SCR at GH2	384 Solar	2,322 Solar
Atypical CTG	High Gas, Current CTG Ratio	Replace MC2, GH2, BR3 w/ MC5 and BR12	2,322 Solar	2,717 Solar 143 Wind

Important observations from these results:

- **Adding NGCC capacity is optimal in all fuel price cases.** In four of the six fuel price cases, PLEXOS retired Mill Creek 2, Ghent 2, and Brown 3 and added Mill Creek NGCC and Brown NGCC. In two of the high gas price cases, PLEXOS chose to retire only Mill Creek 2 and Brown 3, add Mill Creek NGCC, and add SCR to Ghent 2. The level of fuel prices does not materially impact the need for resources that can economically produce large amounts of energy at night.

- **The desirability of solar predictably correlates with fossil fuel prices.** Only in the two low gas price cases did PLEXOS add no renewable generation, and it added more in the high gas price cases than it did in the mid gas price case. A significant amount of solar is added after 2028 in two of the three high gas price cases.

- **PLEXOS did not select DSM or batteries in any of the fuel-price cases.** This likely results from the cost of these resources relative to their limited duration, making them uneconomical to achieve minimum reliability and meet the significant need for energy created by coal unit retirements. Also, batteries do not produce energy, but rather move it in time.

4.4.2 Stage One, Step Two: Portfolio Optimization with Detailed Production Costs

The first step of Stage One revealed that only two basic combinations of retirements and replacement resources would be economically optimal in 2028: (1) retiring Mill Creek 2, Ghent 2, and Brown 3 and adding the Mill Creek NGCC, Brown NGCC, and solar PPAs; and (2) retiring Mill Creek 2 and Brown 3, adding SCR to Ghent 2, and adding the Mill Creek NGCC and solar PPAs.

In the second step of Stage One, the Companies sought to optimize the portfolio by evaluating actionable alternatives based on the results of Stage One, Step One.

To achieve this, the Companies identified all of the solar PPA proposals that PLEXOS selected by 2028 (a total of 2,322 MW), listed below in Table 6 in order of increasing PPA price per MWh:[11]

Table 6: Solar PPAs Selected in Portfolio Optimization

Response No. in Appx. B	Respondent	Project	Start Date	Term (Years)	Price ($/MWh)	Capacity (MW)	Cumulative Capacity (MW)
7	[redacted]						
70							
45							
29							
34							
39							
37							
74							
56							
36							

The Companies then created 11 PPA combination options, the first of which had 0 MW solar, with each subsequent PPA combination option adding the next most economical PPA from Table 6 above, resulting in each subsequent PPA combination having more cumulative PPA capacity that prior combinations, all the way to the 11th combination with 2,322 MW cumulative PPA capacity.

The Companies then used the 11 PPA combinations to create 22 total portfolios for detailed production cost runs in PROSYM. As shown in Table 7 below, each portfolio was a combination of one of the two NGCC combinations from the PLEXOS modeling (i.e., Mill Creek NGCC plus Brown NGCC and Mill Creek NGCC plus Ghent 2 with SCR) and one of the 11 PPA combinations described above (2 NGCC options x 11 PPA combinations = 22 portfolios to analyze).

[11] Note that only the first four proposals are at or below the $42.21/MWh P25 price for solar PPAs as reported by LevelTen and discussed in Section 3.1. Despite the higher price of the remaining proposals, they were evaluated in this step of the analysis.

Table 7: Resource Portfolios Evaluated in Detailed Production Cost Analysis

Portfolios Where MC2, GH2, BR3 Replaced w/ MC5 and BR12	Portfolios Where MC2, BR3 Replaced w/ MC5; SCR Added to GH2
MC5/BR12; 0 Solar	MC5/GH2 SCR; 0 Solar
MC5/BR12; 104 Solar	MC5/GH2 SCR; 104 Solar
MC5/BR12; 384 Solar	MC5/GH2 SCR; 384 Solar
MC5/BR12; 499 Solar	MC5/GH2 SCR; 499 Solar
MC5/BR12; 637 Solar	MC5/GH2 SCR; 637 Solar
MC5/BR12; 1,322 Solar	MC5/GH2 SCR; 1,322 Solar
MC5/BR12; 1,522 Solar	MC5/GH2 SCR; 1,522 Solar
MC5/BR12; 1,622 Solar	MC5/GH2 SCR; 1,622 Solar
MC5/BR12; 1,722 Solar	MC5/GH2 SCR; 1,722 Solar
MC5/BR12; 2,222 Solar	MC5/GH2 SCR; 2,222 Solar
MC5/BR12; 2,322 Solar	MC5/GH2 SCR; 2,322 Solar

The Companies then conducted detailed production cost runs in PROSYM for each of these 22 portfolios across all six fuel price cases (a total of 132 runs). Unlike the PLEXOS modeling, in this part of the analysis each solar contract was assumed to begin on its RFP-specified start date. Table 8 below lists the least-cost portfolio for each fuel price scenario.

Table 8: Portfolio Optimization Results

	Fuel Price Scenario (Gas, CTG Price Ratio)	Least-Cost Resource Portfolio
Expected CTG	Low Gas, Mid CTG Ratio	MC5/BR12; 104 Solar
	Mid Gas, Mid CTG Ratio	MC5/BR12; 637 Solar
	High Gas, Mid CTG Ratio	MC5/BR12; 2,322 Solar
	Average Low, Mid, High Gas w/ Mid CTG Ratio	MC5/BR12; 637 Solar
Atypical CTG	Low Gas, High CTG Ratio	MC5/BR12; 104 Solar
	High Gas, Low CTG Ratio	MC5/GH2 SCR; 2,222 Solar
	High Gas, Current CTG Ratio	MC5/BR12; 2,322 Solar
	Average Excluding High Gas, Current CTG Ratio	MC5/BR12; 637 Solar
	Average All Fuel Prices	MC5/BR12; 1,322 Solar

<u>**Important observations from these results**</u>:

- **Mill Creek NGCC and Brown NGCC portfolio appears optimal.** With detailed production cost modeling, only in the atypical fuel price scenario most favorable to coal (High Gas, Low Coal-to-Gas Ratio) is retiring only Mill Creek 2 and Brown 3, adding Mill Creek NGCC, and adding SCR to Ghent 2 least-cost.

- **Solar PPA capacity of 637 MW is optimal.** The three fuel price scenarios with a Mid coal-to-gas price ratio had an average optimal amount of solar of four PPAs totaling 637 MW. The Mid coal-to-gas price ratio is consistent with history and appears most likely to persist over a long analysis period. In addition, the most expensive of these PPAs is $40.02/MWh, which is consistent with broader solar PPA market pricing of solar.[12] Therefore, 637 MW of solar PPAs is the optimal amount to pursue given the responses to the RFP and current solar market conditions.

4.4.3 Stage One, Step Three: Ghent 2 SCR PVRR Analysis

The third step of Stage One built on the results of the previous two steps and sought to determine how long Ghent 2 would have to operate to justify equipping it with an SCR in the single fuel price case in which it was least cost. This would provide a more precise sense of the economics of adding SCR to Ghent 2.

To do this, the Companies evaluated cases where, after being retrofitted with SCR in 2028, Ghent 2 is replaced with the Brown NGCC later in the analysis period. The Companies' generation portfolio after Ghent 2 is replaced with the Brown NGCC is the same as the portfolio with the Mill Creek NGCC and Brown NGCC in 2028; the only material differences in revenue requirements after Ghent 2 is replaced result from the later-commissioned Brown NGCC having higher capital revenue requirements than commissioning it in 2028.

Table 9 compares the difference in PVRR between the portfolio with the Mill Creek NGCC, Ghent 2 with SCR, and 637 MW of solar ("MC5/GH2 SCR; 637 Solar") and the portfolio with the Mill Creek NGCC, Brown NGCC, and 637 MW of solar ("MC5/BR12; 637 Solar") over all six fuel price cases and four different eventual retirement dates for Ghent 2 with SCR.[13] Positive values in Table 9 indicate that the portfolio with the Ghent 2 SCR is more expensive.

Table 9: PVRR Difference; "MC5/GH2 SCR; 637 Solar" less "MC5/BR12; 637 Solar" ($M, 2022 Dollars)

	Fuel Price Scenario (Gas Price, CTG Price Ratio)	Year of GH2 Retirement in "MC5/GH2 SCR; 637 Solar" Portfolio				SCR Break-Even Year
		2035	2040	2045	Indefinite Operation	
Expected CTG	Low Gas, Mid CTG Ratio	77	121	107	96	N/A
	Mid Gas, Mid CTG Ratio	71	110	94	64	N/A
	High Gas, Mid CTG Ratio	75	116	104	91	N/A
Atypical CTG	Low Gas, High CTG Ratio	95	149	144	163	N/A
	High Gas, Low CTG Ratio	33	52	20	-77	2049
	High Gas, Current CTG Ratio	373	595	738	1,390	N/A

This analysis shows there are high costs to adding SCR to Ghent 2 in five of six fuel price scenarios and that adding SCR is unfavorable even in the fuel price scenario most favorable to coal (High Gas, Low CTG Ratio) unless Ghent 2 can continue to operate until at least 2049—all assuming no CO_2 pricing or other constraint. On balance, Stage One, Step Three indicates that the Mill Creek NGCC and Brown NGCC plus

[12] *See* LevelTen Energy "Q3 2022 PPA Price Index Executive Summary North America" at 7 (showing current LevelTen Energy PPA Price Index for third quarter of 2022, Solar P25 Market-Averaged National Index is at $42.21/MWh), available at: https://www.leveltenenergy.com/ppa.

[13] Focusing solely on the resource portfolio with the Mill Creek NGCC and SCR at Ghent 2, the optimal amount of solar over the fuel price scenarios with a Mid coal-to-gas price ratio is also 637 MW.

637 MW of solar PPAs is the economically optimal portfolio that satisfies both the Good Neighbor Plan and minimum reserve margin requirements.

4.5 Stage Two: Stress-Testing the Economically Optimal Portfolio

As noted above, the results of Stage One of the Companies' analysis strongly indicated that retiring Mill Creek 2, Ghent 2, and Brown 3 and adding the Mill Creek NGCC, Brown NGCC, and 637 MW of solar PPAs would be economically optimal based on fuel price scenario analysis alone.

In Stage Two, the Companies sought to stress-test the Stage One results in two ways simultaneously: (1) by evaluating different CO_2 price scenarios and (2) by comparing the apparently optimal portfolio to other portfolios created by the Companies to test whether certain portfolio constructs might offer additional insights. Particularly because PLEXOS, as the Companies use it, does not provide a listing or ranking of all the portfolios it evaluates, the Companies thought it was particularly important to explicitly evaluate other portfolios and compare their economics.

4.5.1 Stage Two, Step One: Portfolio Creation

As shown in Table 10 below, the Companies developed ten total portfolios to evaluate in Stage Two. The first two are familiar: Portfolio 1 is the apparently economically optimal portfolio from Stage One (Mill Creek NGCC, Brown NGCC, and 637 MW of solar PPAs); Portfolio 2 is the other potentially optimal portfolio from Stage One (Mill Creek NGCC, Ghent 2 with SCR, and 637 MW of solar PPAs). The other eight portfolios have varying levels of NGCC, coal unit retirements, SCR, dispatchable DSM from the 2024-2030 DSM-EE Program Plan, SCCT, and renewables, as well as options to operate non-SCR-equipped coal units only in non-ozone-season months. The Companies' reasoning for the other eight portfolios follows the table below.

Table 10: Stress Testing (Portfolios 1-10)

Port Num	Portfolio Name	Description	NGCC Units	Coal Units	New SCR
1	MC5 & BR12	Replace MC2 in 2027 w/ MC5 Replace BR3 & GH2 in 2028 with 1 NGCC at E.W. Brown Add 637 MW of solar	+2	-3	0
2	MC5/GH2 SCR	Replace MC2 in 2027 w/ MC5 Add SCR at GH2 and retire BR3 in 2028 Add 637 MW of solar	+1	-2	+1
3	MC5; Non-Ozone GH2	Replace MC2 in 2027 w/ MC5 No GH2 SCR; Operate GH2 in non-ozone season only Add optimal portfolio of renewables, battery storage, and dispatchable DSM	+1	-1	0
4	MC5; Non-Ozone GH2 Retire BR3	Replace MC2 in 2027 w/ MC5 No GH2 SCR; Operate GH2 in non-ozone season only Add optimal portfolio of renewables, battery storage, and dispatchable DSM Retire BR3	+1	-2	0
5	MC2/GH2 SCR	No coal retirements Add SCR at MC2 and GH2 in 2026 Complete BR3 overhaul in 2027 Add 637 MW of solar[14]	0	0	+2
6	Non-Ozone MC2/GH2	No SCRs and no coal retirements Operate MC2 and GH2 in non-ozone season only Complete BR3 overhaul in 2027 Add optimal portfolio of renewables, battery storage, and dispatchable DSM	0	0	0
7	Non-Ozone MC2/GH2; Retire BR3	No SCRs; Retire BR3 Operate MC2 and GH2 in non-ozone season only Add optimal portfolio of renewables, battery storage, and dispatchable DSM	0	-1	0
8	All Renewables	Replace MC2, BR3, and GH2 with optimal portfolio of renewables, battery storage, and dispatchable DSM	0	-3	0
9	SCCT + Renewables	Replace MC2, BR3, and GH2 with optimal portfolio of renewables, battery storage, dispatchable DSM, and SCCT	0	-3	0
10	DSM Only	Retire MC2, BR3, and GH2 Meet energy and capacity shortfall with DSM	0	-3	0

As noted in Table 10, Portfolios 3, 4, and 6-9 all required further specification of the renewable, dispatchable DSM from the 2024-2030 DSM-EE Program Plan, and battery resources to be added to address anticipated energy shortfalls (Portfolio 9 also included SCCT as an option). To do that optimally and meet the portfolio specifications, the Companies conducted a PLEXOS run for each portfolio in the high gas price, mid coal-to-gas price ratio case, which tends to favor renewables. As in Stage One, these PLEXOS runs included a zero CO_2 price and attempted to meet minimum reserve margin requirements.

The Companies' reasoning in creating Portfolios 3-10 follows:

[14] Portfolio 5 has the same amount of solar as Portfolios 1 and 2 because the economics of replacing generation that can economically serve nighttime energy requirements are not materially impacted by solar.

- Portfolios 3, 4, 6, and 7 explored different combinations of retaining Ghent 2 or Mill Creek 2 and Ghent 2 to serve only during non-ozone season months, with or without Brown 3. The purpose of these portfolios was to explore the relative reliability and economics of retaining one or both of these units without investing in SCR.
- Portfolio 5 tested the economics and reliability of investing in SCR for Mill Creek 2 and Ghent 2 and conducting the major overhaul of Brown 3, i.e., the reliability and economics of retaining all current coal units (other than Mill Creek Unit 1, which is already scheduled to retire by the end of 2024).
- Portfolio 8 tested the economics and reliability of retiring Mill Creek 2, Ghent 2, and Brown 3 and replacing their energy as needed with only renewables, batteries, and dispatchable DSM from the 2024-2030 DSM-EE Program Plan. The purpose was to test the reliability and economics of a replacement portfolio for complying with the Good Neighbor Plan that excluded all fossil fuel options.
- Portfolio 9 had the same retirements as Portfolio 8 but added SCCT to Portfolio 8's potential replacement resources. This was to test the impact of SCCT as a reliability resource in a replacement portfolio otherwise devoid of fossil fuel units.
- Portfolio 10 retires Mill Creek 2, Ghent 2, and Brown 3 and adds all dispatchable DSM from the 2024-2030 DSM-EE Program Plan for the purpose of assessing the reliability of the portfolio with no replacement resources other than DSM.[15]

Table 11 below summarizes the total generation changes (i.e., retirements and resource additions) in all ten portfolios:

Table 11: Stress Testing (Portfolios 1-10); Generation Changes by 2028 (Net Summer MW)

	Portfolio Name	NGCC	Coal	SCCT	Solar	Wind	DSM[16]	Battery Storage[17]
1	MC5 & BR12	+1,242	-1,194	-	+637	-	-46	-
2	MC5/GH2 SCR	+621	-709	-	+637	-	-46	-
3	MC5; Non-Ozone GH2	+621	-782[18]	-	+637	-	-46	-
4	MC5; Non-Ozone GH2; Ret BR3	+621	-1,194[19]	-	+637	-	-46	-
5	MC2/GH2 SCR	-	-	-	+637	-	-46	-
6	Non-Ozone MC2/GH2	-	-782[20]	-	+637	-	-46	-
7	Non-Ozone MC2/GH2; Ret BR3	-	-1,194[21]	-	+1,422	+143	-46	+400
8	All Renewables	-	-1,194	-	+1,972	+143	-46	+1,270
9	SCCT + Renewables	-	-1,194	+972	+1,522	-	-46	-
10	DSM Only	-	-1,194	-	-	-	+102	-

[15] Note that all portfolios effectively assume the full deployment of all non-dispatchable programs and measures in the 2024-2030 DSM-EE Program Plan because those effects are embedded in the 2022 Load Forecast.
[16] Values reflect expected load reductions under normal peak weather conditions.
[17] In Portfolio 7, battery storage consists of 300 MW of 2-hour duration batteries and 100 MW of 4-hour duration batteries. In Portfolio 8, all battery storage consists of 4-hour duration batteries.
[18] In Portfolio 3, MC2 is retired. GH2 is available only in the non-ozone season.
[19] In Portfolio 4, MC2 and BR3 are retired. GH2 is available only in the non-ozone season.
[20] In Portfolio 6, MC2 and GH2 are available only in the non-ozone season.
[21] In Portfolio 7, BR3 is retired. MC2 and GH2 are available only in the non-ozone season.

The reserve margins achieved by these portfolios are important to observe, which are shown in Table 12 below (note that "fully dispatchable resources" exclude intermittent and limited-duration resources):

Table 12: Stress Testing (Portfolios 1-10); 2028 Summer and Winter Reserve Margins

	Summer	Winter
Minimum Reserve Margin Target	17%	24%
Fully Dispatchable Reserve Margin		
Portfolio 1: MC5 & BR12	15.7%	25.1%
Portfolio 2: MC5/GH2 SCR	13.6%	22.6%
Portfolio 3: MC5; Non-Ozone GH2	12.4%	29.4%
Portfolio 4: MC5; Non-Ozone GH2; Retire BR3	5.9%	22.6%
Portfolio 5: MC2/GH2 SCR	15.0%	23.7%
Portfolio 6: Non-Ozone MC2/GH2	2.6%	23.7%
Portfolio 7: Non-Ozone MC2/GH2; Retire BR3	-3.9%	16.9%
Portfolio 8: All Renewables	-3.9%	4.1%
Portfolio 9: SCCT + Renewables	11.4%	21.0%
Portfolio 10: DSM Only	-3.9%	4.1%
Total Reserve Margin		
Portfolio 1: MC5 & BR12	30.1%	28.4%
Portfolio 2: MC5/GH2 SCR	28.0%	25.8%
Portfolio 3: MC5; Non-Ozone GH2	26.8%	32.6%
Portfolio 4: MC5; Non-Ozone GH2; Retire BR3	20.3%	25.8%
Portfolio 5: MC2/GH2 SCR	29.4%	27.0%
Portfolio 6: Non-Ozone MC2/GH2	17.0%	27.0%
Portfolio 7: Non-Ozone MC2/GH2; Retire BR3	27.1%	27.5%
Portfolio 8: All Renewables	47.7%	28.9%
Portfolio 9: SCCT + Renewables	36.9%	24.3%
Portfolio 10: DSM Only	4.9%	9.2%

Important observations concerning these results:

- **Dispatchable DSM from the 2024-2030 DSM-EE Program Plan is again uneconomical to meet minimum reserve margins.** PLEXOS again did not select any dispatchable DSM from the 2024-2030 DSM-EE Program Plan in any portfolio; rather, it retired existing dispatchable DSM in every portfolio it created as an uneconomical means of satisfying minimum reserve margins. To obtain dispatchable DSM in Portfolio 10, the Companies had to add it outside PLEXOS.

- **Some portfolios rely heavily on intermittent and limited-duration resources to meet reserve margins.** The non-ozone-operation portfolios and the renewables-only portfolio rely heavily on intermittent and limited-duration resources to meet summer reserve margins, and the renewables-only portfolio relies heavily on intermittent and limited-duration resources to meet *winter* reserve margins. Although these portfolios meet minimum reserve margin constraints in total, the differences in their fully dispatchable reserve margins indicate that the reliability of these portfolios is very different. As previously discussed, there is real risk to this approach, including solar execution risk and intermittency (cloud) risk.

- **Portfolio 10 (all DSM) did not meet any reserve margin requirement.** With no replacement resources other than the proposed 2024-2030 Program Plan's dispatchable DSM programs, Portfolio 10 does not meet any reserve margin requirement. The Companies' loss-of-load expectation with this portfolio increases to more than 130 days in ten years. Thus, Portfolio 10 did not advance to the next step of the Stage 2 analysis; if Mill Creek 2, Ghent 2, and Brown 3 are retired, the Companies must procure resources in addition to dispatchable DSM from the 2024-2030 DSM-EE Program Plan to reliably serve load. A further discussion of this portfolio is in Appendix C.

4.5.2 Stage Two, Step Two: CO_2 Pricing Analysis

Next, the Companies conducted detailed production cost modeling with PROSYM and developed revenue requirements for each of the nine portfolios that advanced from the first step of Stage 2. They performed PROSYM runs and developed revenue requirements for each portfolio across the six fuel price cases previously discussed and three CO_2 pricing cases ($0/MWh, $15/MWh, and $25/MWh) for a total of 18 cases analyzed per portfolio.

Table 13 below summarizes the differences in PVRR for Portfolios 1-9. Note that non-zero CO_2 prices begin in 2028 and that these results do not include all potential transmission system upgrade costs, which tends to favor Portfolios 3, 4, and 6 through 9.[22] As in Stage One, detailed production costs were modeled only for the renewables added in PLEXOS by 2028. For each fuel price scenario, the PVRR differences are presented as differences from the least-cost portfolio.

[22] To this point in the analysis, the Companies considered only transmission system upgrade costs associated with the fully dispatchable replacement resources (NGCCs and SCCTs at the Mill Creek and Brown stations). Due to the volume of RFP responses, it was not practical to evaluate transmission system upgrade costs for all proposals and potential retirements. Therefore, the evaluated transmission system upgrade costs for the other resources (e.g., solar, wind, and battery storage) was zero.

Table 13: Stress Testing Results (PVRR Difference from Best Case, $M, 2022 Dollars)

		Difference from Best Case (PVRR, $M, 2023-2050)								
		1	2	3	4	5	6	7	8	9
Fuel Price Scenario (Gas, CTG Price Ratio)	CO_2 Price	MC5 and BR12; 637 Solar	MC5 & GH2 SCR; 637 Solar	MC5; Non-Ozone GH2	MC5; Non-Ozone GH2; Ret BR3	MC2/ GH2 SCR	Non-Ozone MC2/ GH2	Non-Ozone MC2/ GH2 Ret BR3	All Renew	SCCT+ Renew
Low Gas, Mid CTG	0	0	96	561	117	604	697	1,019	2,375	1,568
Mid Gas, Mid CTG	0	0	64	540	126	583	728	844	2,096	1,580
High Gas, Mid CTG	0	0	91	499	218	571	844	428	1,521	1,712
Low Gas, High CTG	0	0	163	627	181	749	835	1,116	2,439	1,653
High Gas, Low CTG	0	77	0	372	166	265	599	216	1,301	1,620
High Gas, Curr CTG	0	0	1,390	1,885	1,376	3,459	3,481	2,379	2,958	3,212
Low Gas, Mid CTG	15	0	644	1,121	654	1,796	1,851	1,812	2,865	2,278
Mid Gas, Mid CTG	15	0	634	1,113	663	1,781	1,877	1,643	2,638	2,281
High Gas, Mid CTG	15	0	603	1,057	706	1,705	1,929	1,187	2,087	2,337
Low Gas, High CTG	15	0	714	1,188	720	1,940	1,987	1,920	2,927	2,361
High Gas, Low CTG	15	0	393	823	510	1,231	1,488	854	1,821	2,102
High Gas, Curr CTG	15	0	1,940	2,466	1,852	4,637	4,528	3,019	3,348	3,812
Low Gas, Mid CTG	25	0	1,009	1,511	997	2,591	2,609	2,291	3,154	2,703
Mid Gas, Mid CTG	25	0	996	1,493	1,010	2,569	2,651	2,117	2,980	2,736
High Gas, Mid CTG	25	0	979	1,447	1,056	2,488	2,678	1,696	2,433	2,800
Low Gas, High CTG	25	0	1,074	1,601	1,054	2,752	2,764	2,383	3,206	2,766
High Gas, Low CTG	25	0	755	1,202	856	2,012	2,239	1,367	2,189	2,553
High Gas, Curr CTG	25	0	2,269	2,834	2,131	5,385	5,237	3,437	3,544	4,124

Interestingly, the lowest-cost portfolio across 17 of 18 scenarios (Portfolio 1: Mill Creek NGCC, Brown NGCC, and 637 MW solar PPAs) is also the least CO_2-emitting, as shown in Table 14 below:

Table 14: 2030 CO_2 Emissions (Million Short Tons, Fuel Price Scenario: Mid Gas, Mid CTG Price Ratio)

		Total CO_2 Emissions	Difference from $0/MWh CO_2 Price Scenario	
Port Number	Portfolio Name	CO_2 Price: $0/MWh	CO_2 Price: $15/MWh	CO_2 Price: $25/MWh
1	MC5 & BR12; 637 Solar	22.8	-0.5	-0.5
2	MC5 & GH2 SCR; 637 Solar	25.4	-0.3	-0.3
3	MC5; Non-Ozone GH2	25.6	-0.3	-0.4
4	MC5; Non-Ozone GH2; Ret BR3	25.2	-0.3	-0.4
5	MC2/GH2 SCR	28.5	-0.2	-0.2
6	Non-Ozone MC2/GH2	28.1	-0.1	-0.2
7	Non-Ozone MC2/GH2; Ret BR3	25.9	-0.2	-0.2
8	All Renewables	24.3	-0.1	-0.1
9	SCCT + Renewables	25.1	-0.1	-0.1

These CO_2 emissions results tie directly to the energy mix each portfolio produces, as Table 15 below illustrates by comparing Portfolio 1 (Mill Creek NGCC, Brown NGCC, and 637 MW solar PPAs) to Portfolio 8 (all renewables):

Table 15: 2030 Energy Mix Comparison (Fuel Price Scenario: Mid Gas, Mid Coal-to-Gas Price Ratio)

	Portfolio 1: MC5 & BR12; 637 Solar			Portfolio 8: All Renewables		
Resource Type	\$0/MWh CO_2 Price	\$15/MWh CO_2 Price	\$25/MWh CO_2 Price	\$0/MWh CO_2 Price	\$15/MWh CO_2 Price	\$25/MWh CO_2 Price
Coal	50%	47%	47%	60%	59%	58%
NGCC	41%	42%	42%	15%	15%	15%
SCCT	2%	3%	4%	8%	10%	10%
Solar	6%	6%	6%	15%	15%	15%
Wind	0%	0%	0%	1%	1%	1%
Hydro	1%	1%	1%	1%	1%	1%

Important observations concerning these results:

- **The Stage One *apparently* optimal portfolio (Mill Creek NGCC, Brown NGCC, and 637 MW solar PPAs) is *clearly* optimal in non-zero CO_2 pricing scenarios.** This result is unsurprising; adding SCR to Ghent 2 allows a coal unit to continue operating, which is unfavorable in CO_2 pricing scenarios due to its higher CO_2 emissions per MWh.

- **The all-renewables replacement portfolio (Portfolio 8) is markedly more expensive than all other portfolios except the renewables plus SCCT portfolio (Portfolio 9), and then only with high gas price cases.** The cost of adding large amounts of renewables and batteries to serve load—under *normal* weather conditions—far exceeds the cost of paying even \$25/MWh in CO_2 costs for all other portfolios except the portfolio that adds only renewables and SCCT. Even that portfolio is less expensive than the all-renewables portfolio in all cases except high gas cost cases.

- **Increasing amounts of renewables require increasing dispatch of existing coal and SCCT generation, *increasing* CO_2 emissions relative to two NGCCs.** Table 14 shows that the inability of solar to provide energy in non-daylight hours, as well as its limited daylight production profile, requires more dispatch of coal and SCCT. This results in increased CO_2 emissions because coal and SCCT have higher CO_2 emissions per MWh than NGCC.

4.6 Stage Three: Fine-Tuning Optimal Portfolio for Risk and Reliability

In Stages One and Two, the Companies identified and confirmed the economically optimal portfolio that achieves Good Neighbor Plan compliance and satisfies minimum reserve margin requirements across a variety of fuel price and CO_2 price cases.

In Stage Three, the Companies sought to fine-tune the economically optimal portfolio to address certain risks not yet addressed and to add reliability to the extent it would be cost-effective or otherwise advisable to do so.

4.6.1 Stage Three, Step One: Mitigating Solar PPA Execution Risk through Solar Ownership

As previously discussed, one uncertainty associated with solar PPAs is execution risk, i.e., the risk that the contracted capacity is not built on time or at all. The modeling of Stages One and Two assumed the PPAs' capacity would be installed and operational as specified in the PPA proposal; it assumed zero solar PPA execution risk.

Other than the rights agreed to by the parties to the PPA, the Companies have no direct control over project development and construction. Project execution is a particularly acute risk in the current solar market, as the Companies have experienced with the two solar PPAs they executed in 2019 and 2021 (Rhudes Creek and Ragland, respectively); neither project has received all necessary approvals, neither is on schedule or has begun construction, and neither is likely to proceed any time soon because it will be difficult or impossible to finance the projects at the contracted price in today's solar market and interest rate environment. To help reduce the risk that future adverse changes in the solar market and interest rates negatively impact PPA project development, the Companies have negotiated a market price re-opener for the Grays Branch and Nacke Pike PPAs. This market price re-opener will also allow the Companies to request a lower price should the solar market and interest rates move lower.

One means of mitigating solar PPA execution risk would be to add solar capacity the Companies would be involved in developing and owning, either through acquisition or self-building. Ownership would allow the Companies and their customers to benefit from lower solar costs if the market changes favorably in the next several years when materials for the project would be purchased. This is especially important because the assumed costs for the owned solar projects are reflective of today's cost of materials, particularly solar panels.

Thus, this first step of Stage Three analyzes the economic impacts of adding a 120 MW self-build solar facility (originally Muhlenberg Solar, now Mercer County Solar Facility) and a 120 MW asset purchase facility (the BrightNight Frontier project, also called the Marion County Solar Facility) to a portfolio where Mill Creek 2, Ghent 2, and Brown 3 are replaced with two NGCC units and no solar PPAs, including the Rhudes Creek and Ragland PPAs. The portfolios the Companies analyzed are in Table 16 below. Portfolio 11 includes no solar PPAs. Portfolio 12 builds on Portfolio 11 as described in Table 16.

Table 16: Solar PPA Execution Risk (Portfolios 11-12); Solar Added (Nameplate MW)

Port Num	Portfolio Name	Description	Total Solar Added
11	MC5 & BR12; No Solar	Replace MC2 in 2027 w/ MC5 Replace BR3 & GH2 in 2028 with BR12 No Solar (i.e., No Rhudes Creek or Ragland PPAs)	-
12	Portfolio 11 +Asset Purchase +Self-Build	Portfolio 11 + 120 MW Solar Asset (Asset Purchase) + 120 MW Solar Asset (Self-Build)	+240

The Companies conducted PROSYM runs for the portfolios listed in Table 16 across all six fuel price cases and all three CO_2 price cases, then used the Companies' financial model to create revenue requirements for each portfolio in each run over three cases for the price of renewable energy certificates ("REC"), namely $0, $5, and $10 per REC. (Over the last three years, the Companies have sold Brown Solar RECs for between $8 and $13 per REC.) All proceeds from the sale of RECs are returned to customers. Table

17 below shows the results of adding the self-build and asset purchase resources to Portfolio 11 (with no solar). Negative values are highlighted in green and indicate that the solar self-build and asset purchase favorably impact PVRR, e.g., adding the solar self-build and asset purchase to Portfolio 11 in the High Gas, Mid CTG case with \$0 CO_2 price decreases Portfolio 11's PVRR by \$78 million.

Table 17: Solar PPA Execution Risk Analysis Results (PVRR Differences, \$M, 2022 Dollars)

	Fuel Price Scenario (Gas, CTG Price Ratio)	CO_2 Price	Impact of Adding Self-Build and Asset Purchase to Portfolio 11 (w/ No Solar) (Portfolio 12 minus Portfolio 11) REC Price \$0/MWh	\$5/MWh	\$10/MWh
Expected CTG	Low Gas, Mid CTG	0	165	129	93
	Mid Gas, Mid CTG	0	93	57	21
	High Gas, Mid CTG	0	-78	-114	-150
	Avg Low-High, Mid CTG	0	60	24	-12
Atypical CTG	Low Gas, High CTG	0	153	117	81
	High Gas, Low CTG	0	-62	-98	-134
	High Gas, Curr CTG	0	-221	-257	-293
	Avg Excl High Gas, Curr CTG	0	54	18	-18
Expected CTG	Low Gas, Mid CTG	15	53	17	-19
	Mid Gas, Mid CTG	15	-12	-48	-84
	High Gas, Mid CTG	15	-181	-217	-253
	Avg Low-High, Mid CTG	15	-47	-83	-119
Atypical CTG	Low Gas, High CTG	15	47	11	-25
	High Gas, Low CTG	15	-151	-187	-224
	High Gas, Curr CTG	15	-297	-333	-369
	Avg Excl High Gas, Curr CTG	15	-49	-85	-121
Expected CTG	Low Gas, Mid CTG	25	-6	-43	-79
	Mid Gas, Mid CTG	25	-82	-118	-154
	High Gas, Mid CTG	25	-258	-294	-330
	Avg Low-High, Mid CTG	25	-115	-151	-188
Atypical CTG	Low Gas, High CTG	25	-14	-50	-86
	High Gas, Low CTG	25	-224	-260	-296
	High Gas, Curr CTG	25	-360	-396	-432
	Avg Excl High Gas, Curr CTG	25	-117	-153	-189

Important observations concerning these results:

- **Adding the solar self-build and asset purchase is favorable in the majority of cases evaluated.** In the nine cases comprising expected fuel prices (i.e., low, mid, and high gas prices with a mid coal-to-gas price ratio) and \$0 to \$10 REC prices, adding the solar assets is favorable in 3 of 9 cases with a \$0/MWh CO_2 price, 7 of 9 cases with a \$15/MWh CO_2 price, and 9 of 9 cases with a \$25/MWh CO_2 price.

- **The economics of the solar self-build improve with higher gas prices, higher REC prices, and higher CO_2 prices.** The PVRR improves by approximately \$35 million for every \$5 increase in REC prices. Compared to cases with no CO_2 price, the favorability of the solar assets improves by approximately $100 million with a $15 CO_2 price.

On the whole, based on the PVRR results and given the uncertainties concerning the solar industry, gas prices, and future carbon regulations (for which CO_2 prices are a proxy), the Companies concluded that adding the solar asset purchase proposal (Marion County Solar Facility) and their self-build solar project (Mercer County Solar Facility) to the optimal portfolio of the Mill Creek NGCC, Brown NGCC, and 637 MW of solar PPAs is a reasonable hedge against these market uncertainties in the transition to a lower carbon future.

4.6.2 Stage Three, Step Two: Increasing Reliability through DSM and Battery Storage

All stages and steps of the Companies' analysis to this point have concerned optimizing the portfolio to achieve Good Neighbor Plan compliance and to satisfy *minimum* reserve margin requirements. The result is an optimized portfolio consisting of the Companies' existing resources and the Mill Creek NGCC, Brown NGCC, 637 MW of solar PPAs, the least-cost solar asset purchase proposal (Marion County Solar Facility), and the Companies' self-build solar project (Mercer County Solar Facility).

In the second step of Stage Three, the Companies' goal was to optimally enhance reliability. To do this, the Companies evaluated SCCT, batteries, and dispatchable DSM programs as potential reliability-enhancing resources.

The SCCT and battery options the Companies evaluated were the SCCT and Brown BESS proposals provided as RFP responses by the Companies' Project Engineering group with input from HDR, an engineering consulting firm. The Companies chose the Brown BESS to evaluate over other battery options because battery ownership will allow the Companies to gain valuable operational experience with such systems at utility scale, which will likely be an integral part of integrating increasing amounts of renewable generation in future.

The dispatchable DSM programs the Companies considered are the Companies' existing dispatchable DSM programs (DSM-2, DSM-3 and 20 MW of DSM-5 in Table 5 below) and the proposed dispatchable DSM programs included in the Companies' 2024-2030 DSM-EE Program Plan. In total, the capacity of the DSM programs is 192 MW in the summer and 102 MW in the winter. Note that in this analysis, the Companies treated all dispatchable DSM as being 100% available when needed.

Table 18 below lists the reliability resources evaluated in this step.

Table 18: Resources Evaluated in Reliability Assessment

Response No.	Resource	2028 Capacity (Summer/Winter MW)	2028 Carrying Cost ($M)	Max Operating Hours per Start/Event
107	SCCT	243/258	18.5	N/A
96	Brown BESS	125/125	16.9	4
DSM-1	Peak Time Rebates	30.8/30.8	1.0	25 4-hour events per year
DSM-2	DLC – Water Heaters	1.9/1.9	1.2	25 4-hour events per year
DSM-3	DLC - AC	79.0/0		20 4-hour events per year
DSM-4	BYOD – Smart Thermostats	16.7/4.2	1.7	25 4-hour events per year
DSM-5	Nonres Demand Response	67.1/67.1	1.4	25 4-hour events per year

The Companies then determined that, given the solar execution risk previously discussed, they would evaluate the resources in Table 18 in one case as additions to the Mill Creek NGCC and Brown NGCC only and in a second case as additions to the Mill Creek NGCC and Brown NGCC with 1,127 MW of solar consisting of the four new PPAs totaling 637 MW, the Rhudes Creek and Ragland PPAs, and two owned assets (Marion County Solar Facility and the Mercer County Solar Facility). Table 19 lists all the portfolios evaluated.

Table 19: Portfolios Evaluated in Reliability Assessment

Portfolios with 2 NGCCs Only	Portfolios with 2 NGCCs & Solar
MC5 & BR12	MC5 & BR12; 1,127 MW Solar
MC5 & BR12 + SCCT	MC5 & BR12; 1,127 MW Solar + SCCT
MC5 & BR12 + DSM	MC5 & BR12; 1,127 MW Solar + DSM
MC5 & BR12 + BESS	MC5 & BR12; 1,127 MW Solar + BESS
MC5 & BR12 + DSM + BESS	MC5 & BR12; 1,127 MW Solar + DSM + BESS

The Companies then used SERVM to model the loss of load expectation ("LOLE") impact and average reliability and production costs of each portfolio listed in Table 19 over a range of load and unit availability scenarios. Note that the industry standard reliability goal is an LOLE of no more than one day in ten years.

Table 20 below summarizes the results of this analysis for the portfolios without solar; Table 21 below summarizes the results of this analysis for the portfolios with solar.[23] Capacity costs reflect the annual carrying cost of each resource (e.g., the annual carrying cost of the SCCT in 2028 is $18.5 million). Average reliability and generation production costs were computed over all load and unit availability scenarios. Total costs are the sum of capacity costs and average reliability and generation production costs.

Table 20: Reliability Assessment Results without Solar

	LOLE (10 Years)			Difference from MC5/BR12 Portfolio:		
Generation Portfolio	**Summer**	**Winter**	**Total**	**Capacity Cost ($M/year)**	**Average Reliability and Generation Production Costs ($M/year)**	**Total Cost: Capacity Costs + Avg Reliability and Generation Production Costs ($M/year)**
MC5/BR12	1.32	0.51	2.00	-	-	-
MC5/BR12 + SCCT	0.45	0.18	0.66	19	-4	15
MC5/BR12 + DSM	0.74	0.39	1.20	5	0	5
MC5/BR12 + BESS	0.77	0.32	1.16	17	-3	14
MC5/BR12 + DSM + BESS	0.43	0.28	0.75	22	-3	19

[23] The modeling the Companies performed in this Resource Assessment took solar to be a resource with a fixed production profile (i.e., for a given load scenario, the Companies evaluated over 300 unit availability scenarios for dispatchable resources, but the generation profile for solar was assumed to be unchanging).

Table 21: Reliability Assessment Results with 1,127 MW Solar

Generation Portfolio	LOLE (10 Years)			Difference from MC5/BR12 + Solar Portfolio:		
	Summer	Winter	Total	Capacity Cost ($M/year)	Average Reliability and Generation Production Costs ($M/year)	Total Cost: Capacity Costs + Avg Reliability and Generation Production Costs ($M/year)
MC5/BR12 + Solar	0.09	0.41	0.51	-	-	-
MC5/BR12 + Solar + SCCT	0.02	0.15	0.18	19	-2	17
MC5/BR12 + Solar + DSM	0.04	0.32	0.36	5	0	5
MC5/BR12 + Solar + BESS	0.05	0.29	0.34	17	-2	15
MC5/BR12 + Solar + DSM + BESS	0.02	0.22	0.24	22	-2	20

__Important observations concerning these results__:

- **Adding dispatchable DSM from the 2024-2030 DSM-EE Program Plan is the most cost-effective means of enhancing reliability in these portfolios.** Table 20 shows that with only the Mill Creek NGCC and Brown NGCC, the Companies' expected LOLE is 2.00 days in 10 years, which is higher than the physical reliability guideline of one day in 10 years. Adding an SCCT reduces LOLE 67% to 0.66, but at a cost of $15 million per year, whereas adding dispatchable DSM from the 2024-2030 DSM-EE Program Plan reduces LOLE 40% to 1.20, but at one-third of the cost of SCCT ($5 million per year). Table 21 shows similar results: SCCT provides a 65% LOLE reduction, but dispatchable DSM provides a 30% LOLE reduction, again at approximately one-third of the SCCT cost. Dispatchable DSM from the 2024-2030 DSM-EE Program Plan is therefore markedly more cost-effective than SCCT for enhancing the reliability of these portfolios.

- **Adding Brown BESS further enhances reliability, but its primary value is in providing operational experience for integrating future renewable generation.** Table 20 and Table 21 show that Brown BESS adds reliability in portfolios with and without solar. But based on its cost, it is not the most cost-effective means of enhancing reliability as modeled. Therefore, the primary benefit of Brown BESS would be to provide the Companies valuable operational experience with a technology at utility scale that will likely be vital to integrating large amounts of renewable generation reliably in the future.

It is notable that Brown BESS might provide quantifiable benefits the Companies have not attempted to quantify here. For example, battery energy storage systems can provide instantaneous load following and compensation for fluctuations in intermittent generation that might otherwise require rapid ramping from the Companies' SCCT and NGCC units, reducing wear (and related costs) on such units. The Brown BESS might also allow the Companies to carry lower amounts of spinning reserves, which could also provide savings. Table 22 summarizes the impact of the Brown BESS on PVRR.

Table 22: Impact of Brown BESS on PVRR ($M, 2022 dollars, $0/MWh CO_2 price)

	Fuel Price Scenario (Gas, CTG Price Ratio)	PVRR Impact
Expected CTG	Low Gas, Mid CTG	130
	Mid Gas, Mid CTG	127
	High Gas, Mid CTG	95
Atypical CTG	Low Gas, High CTG	130
	High Gas, Low CTG	78
	High Gas, Curr CTG	79

Based on this analysis and given the uncertainty facing the solar industry, the Companies believe it is appropriate to add to the optimal resource portfolio (1) the dispatchable DSM programs from the 2024-2030 DSM-EE Program Plan, which are a cost-effective means of improving reliability, and (2) the Brown BESS project.

4.6.3 Stage Three, Step Three: Analyzing OVEC Early Retirement Risk

In this final step of the Companies' analysis, they evaluated the impact of a possible early retirement of OVEC on the optimal resource portfolio of existing resources plus two NGCCs, 637 MW of solar PPAs, the least-cost solar asset purchase proposal (Marion County Solar Facility), the Companies' self-build solar project (Mercer County Solar Facility), dispatchable DSM from the Companies' 2024-2030 DSM-EE Program Plan, and the Brown BESS.

In particular, the Companies sought to determine if an early OVEC retirement had a reliability impact that would require adding any demand- or supply-side resources to the optimal portfolio.

Therefore, as a final scenario, the Companies used SERVM to evaluate the LOLE impact on the optimal resource portfolio (both with and without solar) if the OVEC units ceased operating in 2028 rather than 2040 as currently forecasted. Table 23 below contains the results of this analysis.

Table 23: Impact of 2028 OVEC Retirement on Optimal Resource Portfolio

Portfolio	LOLE (10 Years)		
	Summer (Jun, Jul, Aug)	Winter (Dec, Jan, Feb)	Total Year
MC5/BR12 + DSM + BESS	0.43	0.28	0.75
MC5/BR12 + DSM + BESS - OVEC	0.93	0.42	1.44
MC5/BR12 + Solar + DSM + BESS	0.02	0.22	0.24
MC5/BR12 + Solar + DSM + BESS - OVEC	0.05	0.39	0.45

These results show that the optimal resource portfolio would provide excellent reliability even if OVEC retired early. Therefore, there was no reason to adjust the optimal portfolio solely to address the possibility of early OVEC unit retirements.

5 Objective Met: A No-Regrets Resource Portfolio to Serve Customers' Needs

As discussed previously, the objective of this Resource Assessment is not to make every resource decision for the Companies and their customers for through 2050; rather, it is only to provide an optimal resource portfolio for the decisions that the Companies must make today due to the Good Neighbor Plan and the upcoming major capital investment at Brown 3. In other words, the objective is to provide an optimal resource portfolio for the resource decisions that must be made now concerning possible unit retirements in the 2026 to 2028 timeframe, and to do so in a way that ensures safe and reliable service at the lowest reasonable cost—ideally with a no-regrets resource portfolio.

Part of having no regrets is recognizing that, as the 2022 CPCN Load Forecast shows, customers will continue to have significant energy needs in all hours, seasons, and weather and daylight conditions. Thus, a no-regrets portfolio must be able to serve customers reliably 8,760 hours every year, not just for a handful of peak hours, not just when the sun is shining, and not just when customers are willing to voluntarily reduce their load in response to pricing signals.

The Companies' optimal resource portfolio is such a no-regrets portfolio. It economically retires three large coal units (1,194 MW total) that provide around-the-clock energy. It replaces those units with an optimal blend of resources offered in the Companies' competitive RFP process and cost-effective dispatchable DSM programs from the Companies' 2024-2030 DSM-EE Program Plan:

<u>The 2022 Resource Assessment's Optimal Resource Portfolio</u>

- Reliable, dispatchable, around-the-clock generation (1,242 MW total)
    - Mill Creek NGCC (621 MW)
    - Brown NGCC (621 MW)
- Clean renewable generation, hedging fuel price and CO_2 risk (877 MW total)
    - Mercer County Solar Facility (self-build; 120 MW)
    - Marion County Solar Facility (asset purchase; 120 MW)
    - Song Sparrow PPA (Clearway Energy; 104 MW)
    - Gage Solar PPA (BrightNight; 115 MW)
    - Nacke Pike PPA (ibV; 280 MW)
    - Grays Branch PPA (ibV; 138 MW)
- Cost-effective dispatchable DSM programs (192 MW summer; 102 MW winter)
- Additional reliability and valuable operational experience with Brown BESS (125 MW, 500 MWh)

The Companies' rigorous three-stage analysis ensured that the optimal portfolio appropriately balances economics, reliability, and risk; provides valuable experience with new technologies to accommodate greater renewable power generation in the future; and reduces CO_2 emissions considerably, more than other portfolios analyzed, which reduces future regulatory risk and potential cost related to CO_2 emissions. It is a no-regrets portfolio:

- **Low load or increased efficiencies, no regrets.** If actual load is materially lower than projected load for any reason, including if technological advances or economic changes result in additional energy and demand savings (through DSM-EE programs or otherwise), retiring additional aging coal capacity would likely be the most economical option, further reducing CO_2 emissions.

- **High load, no regrets.** If actual load is materially higher than projected load, nothing in the Companies' proposed portfolio precludes adding demand- or supply-side resources to address the need. If the increased load results from electric space heating or electric vehicle charging, the proposed NGCC units could prove to be particularly valuable given their ability to cost-effectively serve nighttime energy requirements.

- **Increased renewable generation or CO_2 constraints, no regrets.** The proposed portfolio's rapid-ramping NGCC units and Brown BESS well position the Companies to provide reliable service if renewable energy generation increases, and the lower CO_2 emissions of NGCCs and zero emissions of solar and DSM-EE all improve the Companies' positioning to address any CO_2 emissions pricing or regulations that might eventuate.

In sum, the optimal resource portfolio this Resource Assessment recommends will help ensure that customers receive safe, reliable, and lowest-reasonable-cost service for years to come.

6 Utility Ownership

6.1 Background

Since the merger of LG&E and KU, the Companies have commissioned thirteen 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, and Brown Solar. An ownership ratio for the jointly-owned SCCTs was determined so that each utility's projected reserve margin was equalized in the in-service year. Brown Solar's ownership was assigned by allocating its forecasted generation in each hour based on each company's forecasted share of native load energy requirements for the hour. Because Trimble County 2 and Cane Run 7 were expected to provide significant energy savings to customers, their ownership splits were based on the expected energy benefits to each company. To determine these benefits, the production costs associated with the Companies' existing generation portfolio and least-cost expansion plan were compared to the production costs associated with the Companies' generation portfolio and an expansion plan that included only SCCTs. This "all-SCCT" expansion plan represented the least-cost expansion plan when only considering capacity needs. The overall least-cost plan included the proposed unit (either Trimble County 2 or Cane Run 7) and was expected to result in significant energy savings over the "all-SCCT" plan. Because each company was expected to benefit differently from constructing the proposed unit due to each company's unique load profile and existing generation mix, the ownership split for the proposed unit was determined based on each company's share of the net present value of production cost savings.

6.2 Methodology

6.2.1 Solar Resources

The new solar resources were assigned to each company using a method similar to the method used for Brown Solar. This assignment was calculated by allocating the solar resources' forecasted generation in each hour based on each company's forecasted share of native load energy requirements for the hour. Each company's proposed assignment equals its allocated share of the total solar energy generated during the study period.

6.2.2 Mill Creek and Brown NGCC units

Depending on natural gas price levels and future CO_2 regulations, the Mill Creek and Brown NGCC units are expected to operate at a 60-85% capacity factor, generating significant amounts of energy. For this reason, the Companies calculated their ownership so that each company's ownership share matches its share of the anticipated energy benefits compared to an all-SCCT portfolio. This method is similar to the method used for TC2 and CR7 (see Section 6.1) as well as for the Green River NGCC unit proposed by the Companies in Case No. 2014-0002, which was later canceled.[24]

6.2.3 Battery Storage (Brown 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 Brown BESS's ownership was assigned using a method similar to the method used for the jointly-owned CTs by better balancing 2028 summer

[24] *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*.

reserve margins based on dispatchable and battery capacity, after assigning the NGCC units' ownership allocation.

6.3 Optimal Ownership

The optimal ownership allocations are shown in Table 24. For the Mill Creek and Brown NGCC units, the optimal ownership allocation is 69% for KU and 31% for LG&E. For the solar projects, the optimal allocation is 63% for KU and 37% for LG&E. Both of these ownership allocations are also close to the allocation of total energy between the Companies. KU's share of total energy is approximately 64%; LG&E's share is 36%. The Brown BESS is assigned 100% to LG&E to better balance the Companies' summer reserve margins.

Table 24: Optimal Ownership Allocations

	KU	LG&E
Solar Resources • 4 PPAs • Mercer County (self-build) • Marion County (asset purchase)	63%	37%
NGCC Units • Mill Creek NGCC • Brown NGCC	69%	31%
Brown BESS	0%	100%

7 Appendix A – Summary of Inputs

7.1 Load Forecast

Table 25 contains the Companies' load forecast, which was developed with the assumption that weather will be average or "normal" in every year.[25] The Companies' 2022 CPCN Load Forecast is Exhibit TAJ-1 to the testimony of Tim A. Jones.

Table 25: Load Forecast (Normal Weather)

Year	Annual Energy Requirements (GWh)	Peak Demand (MW)			Year	Annual Energy Requirements (GWh)	Peak Demand (MW)	
		Summer	Winter				Summer	Winter
2023	31,919	6,162	5,910		2037	33,207	6,275	6,108
2024	32,221	6,197	5,908		2038	33,254	6,271	6,110
2025	32,788	6,248	6,011		2039	33,258	6,266	6,111
2026	32,841	6,253	6,003		2040	33,382	6,262	6,113
2027	33,560	6,347	6,107		2041	33,302	6,257	6,114
2028	33,592	6,319	6,104		2042	33,321	6,253	6,116
2029	33,423	6,308	6,103		2043	33,330	6,249	6,117
2030	33,303	6,305	6,102		2044	33,439	6,244	6,118
2031	33,254	6,302	6,100		2045	33,375	6,240	6,120
2032	33,303	6,298	6,101		2046	33,411	6,235	6,121
2033	33,184	6,293	6,103		2047	33,451	6,231	6,123
2034	33,151	6,289	6,104		2048	33,576	6,226	6,124
2035	33,160	6,284	6,106		2049	33,506	6,222	6,125
2036	33,284	6,280	6,107		2050	33,547	6,218	6,127

7.2 Minimum Reserve Margin Target

The Companies' minimum reserve margin targets are 17% for summer and 24% for winter. A summary of the analysis for the Companies' minimum reserve margin targets is contained in Appendix D.

7.3 Capacity and Energy Need

Table 26 and Table 27 contain the Companies' summer and winter peak demand and resource summaries through 2050. These tables reflect the planned retirement of Mill Creek 1 at the end of 2024 and the assumed retirement of the small-frame SCCTs in 2025. Mill Creek 1 and 2 cannot be operated simultaneously during the ozone season due to NO_x limits, which results in a reduction of available summer capacity through 2024. Reserve margins are computed for 2028 with and without the retirements of Mill Creek 2, Ghent 2, and Brown 3.

[25] The Companies use 20 years of historical weather data to develop their normal weather forecast.

Table 26: Summer Peak Demand and Resource Summary (MW)

	2023	2024	2025	2026	2027	2028	2030	2040	2050
Peak Load	**6,162**	**6,197**	**6,248**	**6,253**	**6,347**	**6,319**	**6,305**	**6,262**	**6,218**
Dispatchable Generation Resources									
Existing Resources	7,583	7,612	7,612	7,612	7,612	7,612	7,612	7,612	7,612
Retirements/Additions									
Coal[26]	-300	-300	-300	-300	-300	-300	-300	-452	-452
Large-Frame SCCTs	0	0	0	0	0	0	0	0	0
Small-Frame SCCTs[27]	0	0	-47	-47	-47	-47	-47	-47	-47
Total	7,283	7,312	7,265	7,265	7,265	7,265	7,265	7,113	7,113
Reserve Margin	18.2%	18.0%	16.3%	16.2%	14.5%	15.0%	15.2%	13.6%	14.4%
Intermittent/Limited-Duration Resources									
Existing Resources	105	105	105	105	105	105	105	105	105
Existing CSR	128	128	128	128	128	128	128	128	128
Existing Disp. DSM[28]	62	60	56	52	49	46	42	28	24
Retirements/Additions									
Solar PPAs[29]	0	79	177	177	177	177	177	177	177
Total	294	371	466	462	459	456	451	438	434
Total Supply	**7,577**	**7,683**	**7,730**	**7,727**	**7,724**	**7,721**	**7,716**	**7,551**	**7,547**
Total Reserve Margin	**23.0%**	**24.0%**	**23.7%**	**23.6%**	**21.7%**	**22.2%**	**22.4%**	**20.6%**	**21.4%**
Dispatchable Generation Resources with Additional Coal Retirements									
Existing Resources	7,583	7,612	7,612	7,612	7,612	7,612	7,612	7,612	7,612
Retirements/Additions									
Coal[26,30]	-300	-300	-300	-300	-300	-1,494	-1,494	-1,646	-1,646
Large-Frame SCCTs	0	0	0	0	0	0	0	0	0
Small-Frame SCCTs	0	0	-47	-47	-47	-47	-47	-47	-47
Total	7,283	7,312	7,265	7,265	7,265	6,071	6,071	5,919	5,919
Reserve Margin	18.2%	18.0%	16.3%	16.2%	14.5%	-3.9%	-3.7%	-5.5%	-4.8%
Total Supply	**7,577**	**7,683**	**7,730**	**7,727**	**7,724**	**6,527**	**6,522**	**6,357**	**6,353**
Total Reserve Margin	**23.0%**	**24.0%**	**23.7%**	**23.6%**	**21.7%**	**3.3%**	**3.4%**	**1.5%**	**2.2%**

[26] Mill Creek 1 and 2 cannot be operated simultaneously during ozone season due to NO_x limits, which results in a reduction of available summer capacity through 2024. Mill Creek 1 will be retired by the end of 2024. OVEC's contract term ends in 2040.
[27] This analysis assumes Haefling 1-2 and Paddy's Run 12 are retired in 2025.
[28] Existing Dispatchable DSM reflects expected load reductions under normal peak weather conditions.
[29] This analysis assumes 100 MW of solar capacity is added in 2024 (Rhudes Creek), and an additional 125 MW of solar capacity is added in 2025 (Ragland). Capacity values reflect 78.6% expected contribution to summer peak capacity.
[30] Potential additional coal retirements include Mill Creek 2, Ghent 2, and Brown 3 in 2028.

Table 27: Winter Peak Demand and Resource Summary (MW)

	2023	2024	2025	2026	2027	2028	2030	2040	2050
Peak Load	**5,910**	**5,908**	**6,011**	**6,003**	**6,107**	**6,104**	**6,102**	**6,113**	**6,127**
Dispatchable Generation Resources									
Existing Resources	7,901	7,909	7,909	7,909	7,909	7,909	7,909	7,909	7,909
Retirements/Additions									
Coal[26]	-300	-300	-300	-300	-300	-300	-300	-458	-458
Large-Frame SCCTs	0	0	0	0	0	0	0	0	0
Small-Frame SCCTs[27]	0	0	-55	-55	-55	-55	-55	-55	-55
Total	7,601	7,609	7,554	7,554	7,554	7,554	7,554	7,396	7,396
Reserve Margin	28.6%	28.8%	25.7%	25.8%	23.7%	23.7%	23.8%	21.0%	20.7%
Intermittent/Limited-Duration Resources									
Existing Resources	72	72	72	72	72	72	72	72	72
Existing CSR	128	128	128	128	128	128	128	128	128
Existing Disp. DSM[28]	22	22	22	22	22	22	22	22	22
Retirements/Additions									
Solar PPAs[31]	0	0	0	0	0	0	0	0	0
Total	221	221	221	221	221	221	221	221	221
Total Supply	**7,822**	**7,830**	**7,774**	**7,774**	**7,774**	**7,774**	**7,774**	**7,616**	**7,616**
Total Reserve Margin	**32.3%**	**32.5%**	**29.3%**	**29.5%**	**27.3%**	**27.4%**	**27.4%**	**24.6%**	**24.3%**
Dispatchable Generation Resources with Additional Coal Retirements									
Existing Resources	7,901	7,909	7,909	7,909	7,909	7,909	7,909	7,909	7,909
Retirements/Additions									
Coal[26,30]	-300	-300	-300	-300	-300	-1,499	-1,499	-1,657	-1,657
Large-Frame SCCTs	0	0	0	0	0	0	0	0	0
Small-Frame SCCTs[27]	0	0	-55	-55	-55	-55	-55	-55	-55
Total	7,601	7,609	7,554	7,554	7,554	6,355	6,355	6,197	6,197
Reserve Margin	28.6%	28.8%	25.7%	25.8%	23.7%	4.1%	4.1%	1.4%	1.1%
Total Supply	**7,822**	**7,830**	**7,774**	**7,774**	**7,774**	**6,575**	**6,575**	**6,417**	**6,417**
Total Reserve Margin	**32.3%**	**32.5%**	**29.3%**	**29.5%**	**27.3%**	**7.7%**	**7.8%**	**5.0%**	**4.7%**

Table 28 summarizes generation from Mill Creek 2, Ghent 2, and Brown 3 over the last 5 years. In addition to approximately 1,200 MW of dispatchable capacity, these units provided 15-18% of total energy requirements (4.5 to 6.2 TWh) from 2017 to 2021.[32] Slightly more than half of this energy was produced at night which is consistent with the proportion of total electricity consumed by customers at night. On average, these units produce between 700 and 850 MW in every hour of the year. Even if Mill Creek 2,

[31] This analysis assumes 100 MW of solar capacity is added in 2024, and an additional 125 MW of solar capacity is added in 2025. Capacity values reflect 0% expected contribution to winter peak capacity.

[32] The decrease in energy production from 2019 to 2020 (and continuing into 2021) is due to a reduction in generation at the Mill Creek station during the ozone season as a result of an agreement with the Louisville Metro Air Pollution Control District. The generation reduction could be accomplished by either idling Unit 1 or Unit 2. In practice, Unit 2 was often idled. Unit 1 will be retired by the end of 2024, so Unit 2 will be required to run more than was the case in 2020 and 2021.

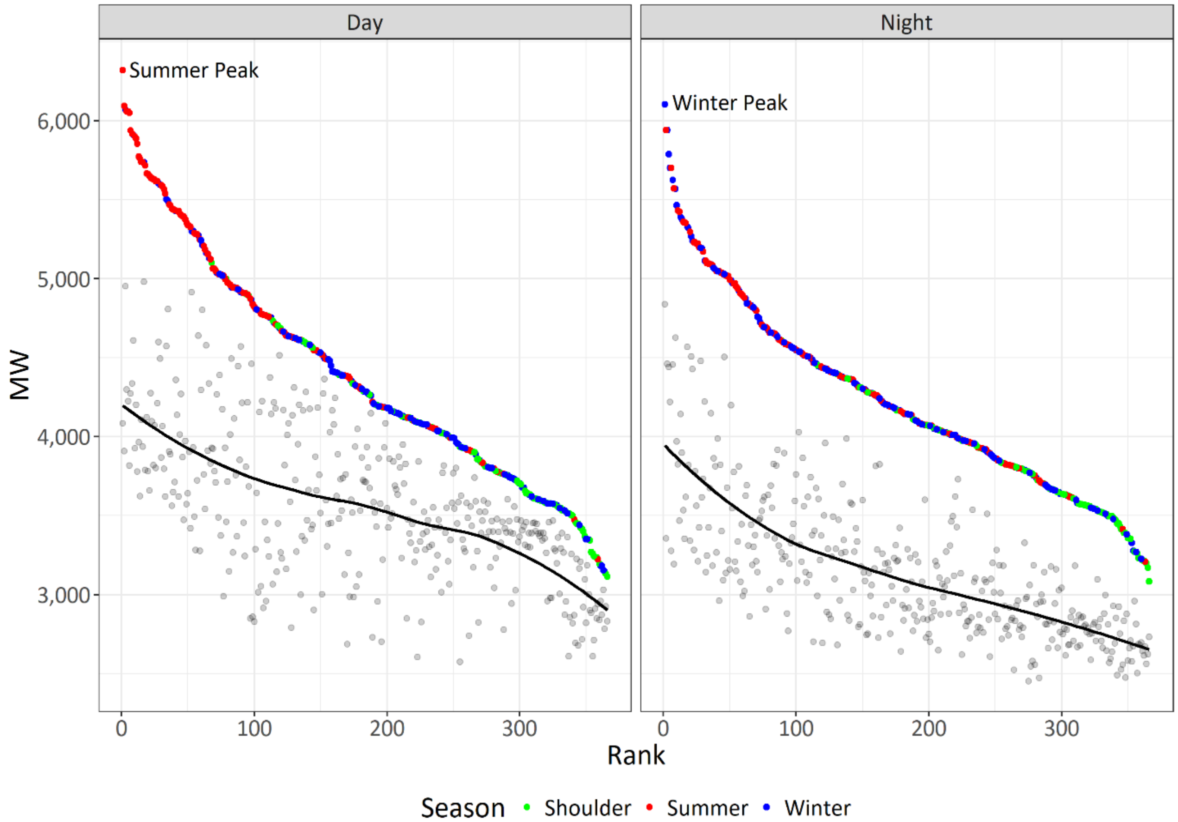
Ghent 2, and Brown 3 are not retired, the Companies' need for energy in 2028 will be exacerbated by the retirement of Mill Creek 1 and the addition of the BlueOval load.

Table 28: Mill Creek 2, Ghent 2, and Brown 3 Generation

Year	Total Energy (GWh)	% Night	% Day	Max Hourly Output (MW)	Average Hourly Output (MW)	% of Total Energy Requirements
2017	5,698	52%	48%	1,235	772	17%
2018	6,230	51%	49%	1,238	842	18%
2019	5,407	51%	49%	1,250	785	16%
2020	4,512	52%	48%	1,229	729	15%
2021	4,610	51%	49%	1,219	752	15%

Figure 8 shows the forecasted daily maximum and minimum loads during daytime and nighttime hours in 2028 under normal weather conditions. For each daytime and nighttime period, the daily maximum loads are sorted highest to lowest and are differentiated by season; the black lines are trend lines for the corresponding minimum daily loads. Notably, the generation capacity and load following capabilities needed to serve daytime and nighttime energy requirements are very similar. Under normal weather conditions, the forecasted winter peak demand (6,104 MW) occurs at night and is almost as high as the forecasted summer peak demand (6,319 MW), which occurs during the day. Importantly, the Companies' load is at least 2,450 MW in every hour of the year.

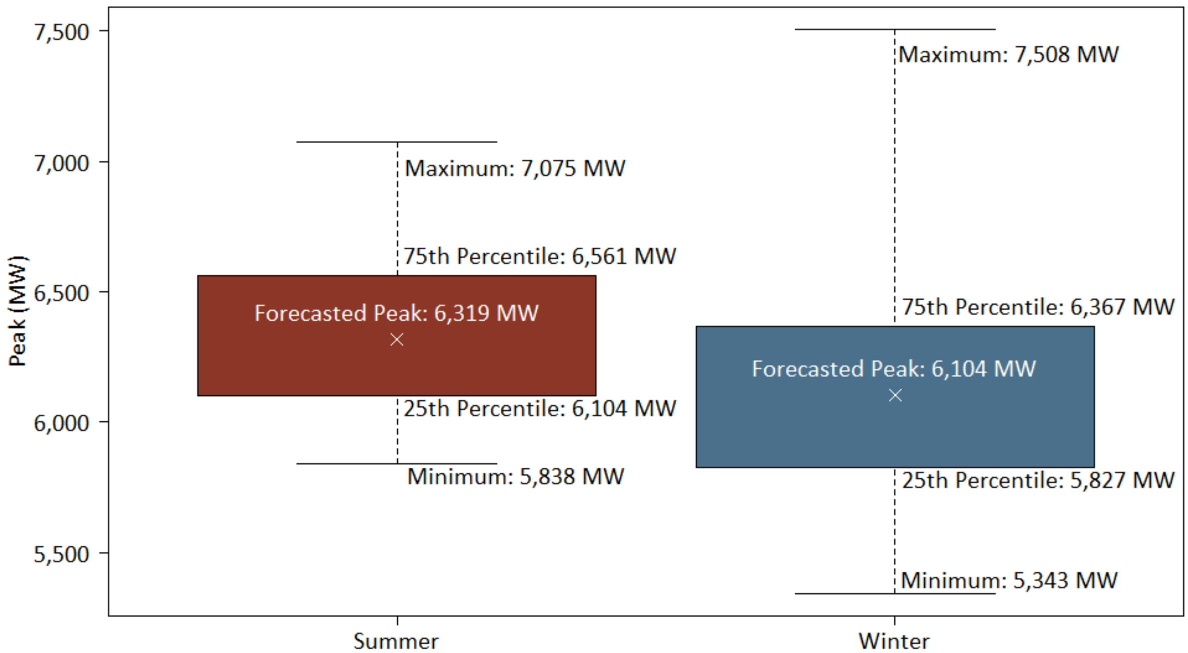
Figure 8: 2028 Daily Maximum and Minimum Loads during Daytime and Nighttime Hours[33]



Whereas Figure 8 shows the variability in load throughout the year under normal weather conditions, Figure 9 shows the variability in summer and winter peak demands based on the range of weather that can occur in the Companies' service territories.[34] Under normal weather conditions, the Companies' summer peak demand is higher than the winter peak demand but the variability in peak demand is highest in the winter. This variability is driven in part by electric space heating demands when backup resistance heating is triggered under extremely cold weather conditions. The Companies plan generation to reliably serve customers in all hours of the year and in all weather scenarios.

[33] Data points in color represent daily maximum values; those in light grey represent daily minimums. The solid black line is a smoothed curve fit through the daily minimums.
[34] To assess generation portfolio reliability over a wide range of weather scenarios, the Companies develop hourly load forecasts based on weather in each of the last 49 years. The distributions in Figure 9 are based on the summer and winter peak demands from these forecasts.

Figure 9: Distribution of 2028 Summer and Winter Peak Demands



7.4 Existing Resource Inputs

Table 29 lists the Companies' forecasted existing generating resources as of 1/1/2025. Consistent with Table 26 and Table 27, resources that are fully dispatchable are listed separately from intermittent resources and resources that can be dispatched for only several hours at a time. 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' solar and Ohio Falls hydro 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' dispatchable DSM and Curtailable Service Rider ("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 29: 2025 LG&E/KU Generating & DSM Portfolio[35]

Dispatchability	Resource Type	Resource Name	Net Max Summer Capacity (MW)	Net Max Winter Capacity (MW)
Fully Dispatchable[36]	Coal[37]	Brown 3	412	416
		Ghent 1	475	479
		Ghent 2	485	486
		Ghent 3	481	476
		Ghent 4	478	478
		Mill Creek 2	297	297
		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	691	691
	SCCT	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
Intermittent/ Limited-Duration	Hydro	Dix Dam 1-3	31.5	31.5
		Ohio Falls 1-8	64	40
	Interruptible	CSR	128	128
	Dispatchable DSM	DCP[38]	56	22
	Solar	Brown Solar	8	0
		Business Solar	0.18	0
		Solar Share	1.7	0
		Rhudes Creek Solar PPA[39]	79	0
		Ragland Solar PPA[39]	98	0

[35] The Resource Assessment assumes Mill Creek 1, Haefling 1-2, and Paddy's Run 12 are retired in 2025.

[36] 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.

[37] Except Mill Creek 2 and Ghent 2, all of the Companies' coal units are equipped with SCR, flue gas desulfurization ("FGD"), and baghouses.

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

As seen in Table 30, Mill Creek 2, Ghent 2, and Brown 3 are approximately 50 years old and approaching the end of their current book depreciation life. Although the units could theoretically operate beyond their depreciable book life, doing so would require a higher level of capital investments. 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 2050. 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 30: Age of Mill Creek 2, Ghent 2, and Brown 3

Unit	Age as of 1/1/2022	Age as of 1/1/2035	Age as of 1/1/2050	End of Book Depreciation Life
Mill Creek 2	47	60	75	2034
Ghent 2	44	57	72	2034
Brown 3	50	63	78	2035

Table 31 contains stay-open costs for Mill Creek 2, Ghent 2, and Brown 3. 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.[40] Stay-open costs include costs for routine 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. In the case of Mill Creek 2 and Ghent 2, stay-open costs include the costs of SCR for Good Neighbor Plan Compliance. Finally, Table 31 differentiates between "standard" major overhaul costs and the costs for projects that would be needed to operate the unit through 2050.[41] 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.

[39] The Rhudes Creek and Ragland solar projects have not received all of their necessary permits and are not yet under construction. Given current market conditions and interest rates, it is not clear whether these projects can be financed at the prices in their respective contracts.

[40] 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 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.

[41] 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.

Table 31: Total Stay-Open Costs ($M)

	Mill Creek 2				Ghent 2				Brown 3		
Year	Ongoing Costs	Overhaul Costs (Standard)	Overhaul Costs (Life Extension)	Environmental Compliance Costs (SCR)	Ongoing Costs	Overhaul Costs (Standard)	Overhaul Costs (Life Extension)	Environmental Compliance Costs (SCR)	Ongoing Costs	Overhaul Costs (Standard)	Overhaul Costs (Life Extension)
2023	11	0	0	2	12	0	0	3	27	0	0
2024	21	0	0	16	23	0	0	30	30	0	0
2025	15	0	0	47	12	0	0	76	31	0	0
2026	18	11	0	45	22	0	0	18	35	0	0
2027	14	0	0	1	17	36	0	1	32	26	0
2028	18	0	0	1	13	0	0	1	32	0	0
2029	14	0	37	1	14	0	0	1	35	0	32
2030	21	0	23	1	25	0	0	1	36	0	38
2031	17	0	22	1	19	0	0	1	36	0	22
2032	21	0	0	1	19	0	0	1	38	0	0
2033	17	0	2	1	20	0	25	1	38	0	2
2034	22	16	18	1	20	0	42	1	40	0	0
2035	18	0	0	1	21	24	23	1	40	30	0
2036	22	0	0	1	21	0	42	1	41	0	0
2037	19	0	0	1	22	0	8	1	42	0	0
2038	25	0	0	2	22	0	0	2	43	0	14
2039	20	0	0	2	22	0	14	2	44	0	0
2040	24	0	0	2	23	0	0	2	45	0	0
2041	21	0	15	2	23	0	0	2	46	0	0
2042	25	19	0	2	24	0	0	2	48	0	11
2043	21	0	0	2	24	28	0	2	48	35	0
2044	27	0	0	2	25	0	0	2	50	0	0
2045	22	0	12	2	26	0	0	2	50	0	0
2046	30	0	0	2	26	0	0	2	52	0	0
2047	23	0	0	2	27	0	0	2	52	0	0
2048	29	0	0	2	27	0	0	2	55	0	0
2049	24	0	0	2	28	0	0	2	55	0	0
2050	25	23	0	2	30	0	0	2	57	0	0

7.4.1 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 beneficial use of CCR materials is included in the Environmental Surcharge Mechanism as a credit to offset environmental compliance costs. In 2021, CCR sales revenues totaled over $15 million.

In recent years, as coal units have retired in the U.S., the market supply of CCR has decreased and the market price for CCR has increased. Table 32 lists the assumed sales prices for CCR in this analysis.[42] The 2022 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 two percent per year.

Table 32: Sales Prices for CCR Sales ($/ton)

	Mill Creek			Ghent		Trimble	
Year	**Fly Ash**	**Gypsum**	**Bottom Ash**	**Fly Ash**	**Gypsum**	**Fly Ash**	**Gypsum**
2022	[redacted]						
2023							
2024							
2025							
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 33 lists the percent of CCR produced at each station that is assumed to be sold to third parties. For Mill Creek, the values reflect current sales levels. For Ghent and Trimble County, the values are the assumed level of sales that will commence after current on-site pond closure projects are completed.[43] The Ghent station requires additional loading facilities to increase its fly ash sales after pond closure

[42] No sales prices for any CCR at Brown or for bottom ash at Ghent and Trimble are included because there is currently no market for these materials at these stations.
[43] Based on current progress of the active closure projects, completion is anticipated no later than December 2025.

projects are completed. 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 33: Percent of CCR Production Sold to Third Parties

Station	Fly Ash	Gypsum	Bottom Ash
Mill Creek	80%	97%	100%
Ghent	6%	70%	0%
Trimble County	80%	97%	0%
Brown	0%	0%	0%

7.5 Inflation Reduction Act Tax Incentives

As noted earlier, after the RFP proposals were received in August 2022, the Companies followed up with the respondents to ensure their proposals fully reflected the investment tax credits for renewables and battery storage in the Inflation Reduction Act. For PPAs, the impact of the IRA incentives is reflected in the PPA price. Table 34 summarizes the assumed tax incentives for solar and battery storage proposals that would require the Companies to own the assets. The solar projects that would require the Companies' ownership are expected to meet the IRA's prevailing wage and apprenticeship requirements. Additional incentives are available if construction materials (e.g., solar panels) are purchased from U.S. vendors or if the project is constructed on a coal mine or the site of a previously retired coal plant, but the proposed solar projects do not meet these requirements. The battery storage projects, on the other hand, do meet these requirements and are assumed to receive the maximum investment tax credit afforded by the IRA (50%).

Table 34: IRA Tax Incentives

	Production Tax Credit		
Resource Type	$/MWh	Term	Investment Tax Credit
Solar	27.50	10	N/A
Battery Storage	N/A	N/A	50%

7.6 Transmission System Upgrade Costs

In their analysis of the Mill Creek 2, Ghent 2, and Brown 3 retirements, the Companies are evaluating the addition of new generation at the Mill Creek and E.W. Brown generating stations. In a scenario where all three coal units are retired and new generation is added at both sites, the Companies would first add generation at Mill Creek (Mill Creek NGCC) in part to take advantage of existing emission permitting. Then, to serve customers reliably, Brown 3 would continue to operate until new generation at the Brown site is commissioned (Brown NGCC). In a scenario where Mill Creek 2 and Brown 3 are retired and SCR is added to Ghent 2, the Companies would still plan to add Mill Creek NGCC first. Then, to serve customers reliably, Brown 3 would continue to operate until SCR was added at Ghent 2. Because Brown 3 is needed in either case to maintain system reliability, new generation is always added first at the Mill Creek station.

The Companies have submitted Generator Interconnection Requests for the proposed self-build NGCC replacements in accordance with the LG&E/KU Open Access Transmission Tariff ("OATT"). Per the terms of the OATT, the Companies' Independent Transmission Organization ("ITO"), TranServ International, will perform studies to determine the proposed generators' impact to the transmission system. However, these studies are complex and time-consuming, and more importantly, cannot begin until all earlier queued Generator Interconnection Requests have been studied. Therefore, the results of the ITO's studies are not yet available.

Thus, for this Resource Assessment the Companies estimated costs for the identified transmission system upgrades that could be required to accommodate selected combinations of unit retirements and capacity replacements. Due to the volume of RFP responses, it was not practical to evaluate all proposals and potential retirements. The Companies initially developed least-cost resource plans considering transmission system upgrade costs for potential coal unit retirements and capacity replacements. Table 35 contains the transmission system upgrade cost estimates considered in this analysis.[44]

Table 35: Transmission System Upgrade Costs ($)[45]

Scenario	Cost (2022 Dollars)
Retirements: Mill Creek 1-2, Brown 3 Additions: SCCTs at Mill Creek	46,034,824
Retirements: Mill Creek 1-2, Brown 3 Additions: NGCC at Mill Creek	35,035,000
Retirements: Mill Creek 1-2, Brown 3, Ghent 2 Additions: NGCC or SCCTs at Mill Creek and Brown	3,420,000

7.7 Commodity Prices

7.7.1 Coal and Natural Gas Prices

Coal and natural gas 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 installing SCR on a coal unit versus replacing the unit with natural gas-fired generation. The fuel price scenarios for this analysis were developed over a range of low, mid, and high natural gas prices based on recent market quotes and the Energy Information Administration's 2022 Annual Energy Outlook ("EIA's 2022 AEO") (see Figure 10). Appendix E contains a more detailed discussion of the natural gas price forecasts and demonstrates that these forecasts are consistent with forecasts prepared by industry consultants.

[44] Due to the uncertainties involved in estimates of solar projects' transmission costs, the Companies have not included these costs in their analysis.

[45] Consistent with the Companies' prior filings, the study assumed the retirements of Mill Creek 2 and Brown 3 and considered the potential for Ghent 2's retirement. Replacement capacity was assumed to be either NGCC or sets of three SCCT units, with generic individual summer net capacities of 645 MW and 220 MW, respectively, consistent with the Companies' 2021 IRP.

Figure 10: Natural Gas Price Forecasts (Henry Hub; Nominal $/MMBtu)

[redacted]

The majority of the Companies' coal supply is sourced from the Illinois Basin. The Companies developed Illinois Basin coal prices for the 2022 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 available historical price data. Figure 11 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 2050.

Figure 11: Illinois Basin Coal and Henry Hub Gas Prices (2012-2022)

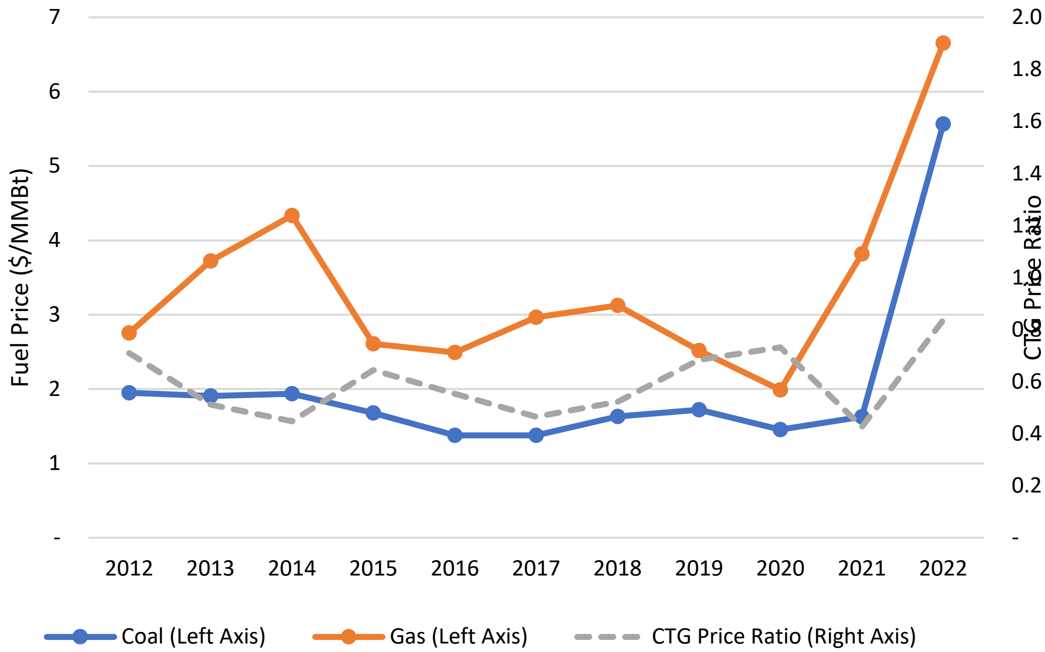


Table 36 summarizes the coal-to-gas price ratio in tabular form. Over the ten-year period from 2012 to 2021, the average coal-to-gas price ratio was 0.57. At this coal-to-gas price ratio, the cost of coal and NGCC energy is very similar, regardless of the level of gas prices. Furthermore, this average coal-to-gas price ratio is not surprising as 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 36 contains the 6-year average ratios. These 6-year averages were used to evaluate short-term variations in the coal-to-gas price ratio.[46]

Table 36: 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	0.84		

[46] 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 37 summarizes the six 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 2027 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 three 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 scenario 4 pairs low gas prices with a high coal-to-gas price ratio. Likewise, fuel 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 6-year average coal-to-gas ratios in Table 36. 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. Fuel scenario 6 was developed to evaluate the continuation of current fuel prices in an energy-constrained world (i.e., high gas and coal prices with an unusually high coal-to-gas price ratio). This fuel price scenario is particularly not expected to persist over a long analysis period.

Table 37: 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 (2022 AEO)	Mid (0.57)[47]	Low Gas, Mid CTG
	2	Mid (2022 AEO)	Mid (0.57)[47]	Mid Gas, Mid CTG
	3	High (2022 AEO)	Mid (0.57)[47]	High Gas, Mid CTG
Atypical CTG Price Ratios	4	Low (2022 AEO)	High (0.60)[48]	Low Gas, High CTG
	5	High (2022 AEO)	Low (0.52)[48]	High Gas, Low CTG
	6	High (2022 AEO)	Current (0.84)[49]	High Gas, Current CTG

Table 38 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 2023-2027 and a constant 0.57 CTG ratio thereafter. All other scenarios reflect constant CTG ratios in all years.

[47] 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.
[48] The High and Low coal-to-gas price ratios are the maximum and minimum, respectively, of the 6-year rolling average coal-to-gas ratio from 2012 to 2021. A six-year rolling average period was selected because the resource assessment contemplates retiring Mill Creek 2 and Ghent 2 six years before the end of their book deprecation lives (2034).
[49] The Current coal-to-gas price ratio is the coal-to-gas price ratio experienced in 2022 through mid-September.

Table 38 – 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		High Gas, Current CTG Ratio	
Year	Coal	Gas	Coal	Gas	Coal	Gas	Coal	Gas	Coal	Gas	Coal	Gas
2023	[redacted]											
2024												
2025												
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												

7.7.2 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 39 contains the ammonia price scenarios evaluated in this analysis. In the Mid Ammonia case, ammonia prices are assumed to increase by 5% from 2023 to 2024 and then escalate at 2% per year thereafter. “Current” Ammonia prices reflect recent high market ammonia prices corresponding to recent natural gas price spikes for 2023, increase by 5% from 2023 to 2024, and escalate at 2% 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 39 – Ammonia Prices (wholesale nominal $/ton)

	Low Ammonia		Mid Ammonia	High Ammonia		Current Ammonia
Year	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	High Gas, Current CTG Ratio
2023	[redacted]					
2024						
2025						
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						

7.7.3 CO_2 Prices

The Companies evaluated two non-zero CO_2 emissions price scenarios of $15 per short ton ("ton") and $25 per ton. These scenarios provide a reasonable range of future expectations of CO_2 prices based on the historical auction price trends of the two existing trading programs in North America: The Regional Greenhouse Gas Initiative ("RGGI") and the California-Quebec Cap-And-Trade Program.

RGGI, started in 2008, was the first CO_2 trading program in the U.S. and sets annual limits on CO_2 emissions by electric generation facilities in 11 states.[50] Though allowance pricing over the last five years (20 auctions) has averaged $7.38 per ton, prices have averaged $13.46 per ton over the last four quarterly auctions. The 3.5% annual emission cap decline, new state admittance to the program, and 7% annual escalation of the auction price ceiling and floor levels are expected to provide upward support to emission allowance prices going forward.

The California-Quebec Cap-And-Trade Program held the first joint auction in 2014.[51] The program seeks to reduce greenhouse gas emissions from the power, industrial, and fuel distribution sectors. Emission allowance prices have averaged $17.48 per ton over the last five years (20 auctions) and traded as high as $27.99 per ton in the May 2022 auction. The 2022 Auction Reserve Price (price floor) of $17.87 per ton is set to increase 12.75% in 2023 to $20.15 per ton due to annual escalation of 5% and inflation.[52]

7.7.4 Emission Allowance Prices

Table 40 summarizes the emission allowance price forecasts evaluated in this analysis. These forecasts were developed by IHS Markit/S&P Global in June 2022.

Table 40: Emission Allowance Prices (nominal $/ton)

Year	SO_2 Group 1	NO_x Seasonal Group 3	NO_x Annual		Year	SO_2 Group 1	NO_x Seasonal Group 3	NO_x Annual
2023	[redacted]				2037	[redacted]		
2024					2038			
2025					2039			
2026					2040			
2027					2041			
2028					2042			
2029					2043			
2030					2044			
2031					2045			
2032					2046			
2033					2047			
2034					2048			
2035					2049			
2036					2050			

7.8 Financial Inputs

Table 41 lists the financial inputs used to compute capital revenue requirements in this analysis.

[50] https://www.rggi.org/sites/default/files/Uploads/Fact%20Sheets/RGGI_101_Factsheet.pdf
[51] https://ww2.arb.ca.gov/sites/default/files/cap-and-trade/guidance/cap_trade_overview.pdf
[52] https://ww2.arb.ca.gov/our-work/programs/cap-and-trade-program/cost-containment-information

Table 41: Financial Inputs

	Combined Companies
% Debt	47%
% Equity	53%
Cost of Debt	4.08%
Cost of Equity	9.43%
Tax Rate	24.95%
Property Tax Rate	0.15%
WACC (After-Tax)	6.43%

8 Appendix B – RFP Proposals and Dispatchable DSM Program Options

Table 42: RFP Proposals that Advanced to Modeling Analysis

Technology	No.	Resource ID and Respondent	Project Name	Location	Nameplate Capacity (MW)	Start Date	Term (Years)	Purchase Price ($/kW)	Capacity Price ($/kW-month)	Energy Price ($/MWh)
	1	[redacted]								
	3									
	7									
	12									
Solar	21									
	23									
	29									
	34									
	36									
	37									
	39									
	40									
	45									
Solar w/ 4-hr Battery Option	46									
	56									
	57									
	60									
	61									

CONFIDENTIAL INFORMATION REDACTED

Technology	No.	Resource ID and Respondent	Project Name	Location	Nameplate Capacity (MW)	Start Date	Term (Years)	Purchase Price ($/kW)	Capacity Price ($/kW-month)	Energy Price ($/MWh)
	70	[redacted]								
	71	[redacted]								
	74	[redacted]								
	75	[redacted]								
	78	[redacted]								
	79	[redacted]								
Solar + 4-hr Battery	80	[redacted]								
	81	[redacted]								
2-hr Battery	82	[redacted]								
	85	[redacted]								
4-hr Battery	86	[redacted]								
	87	[redacted]								
	88	[redacted]								
	91	[redacted]								
	92	[redacted]								
	93	[redacted]								
	94	[redacted]								
	95	[redacted]								

Technology	No.	Resource ID and Respondent	Project Name	Location	Nameplate Capacity (MW)	Start Date	Term (Years)	Purchase Price ($/kW)	Capacity Price ($/kW-month)	Energy Price ($/MWh)
	97	[redacted]								
Pumped Hydro	**98**									
Wind	**99**									
NGCC	**101**									
	103									
SCCT	**107**									
	108									

Table 43: All RFP Proposals

Technology	No.	Resource ID and Respondent	Project Name	Location	Nameplate Capacity (MW)	Start Date	Term (Years)	Purchase Price ($/kW)	Capacity Price ($/kW-month)	Energy Price ($/MWh)
Solar	**1**	[redacted]								
	2									
	3									
	4									
	5									
	6									
	7									
	8									
	9									
	10									
	11									

Technology	No.	Resource ID and Respondent	Project Name	Location	Nameplate Capacity (MW)	Start Date	Term (Years)	Purchase Price ($/kW)	Capacity Price ($/kW-month)	Energy Price ($/MWh)
	12	[redacted]								
	13									
	14									
	15									
	16									
	17									
	18									
	19									
	20									
	21									
	22									
	23									
	24									
	25									

Technology	No.	Resource ID and Respondent	Project Name	Location	Nameplate Capacity (MW)	Start Date	Term (Years)	Purchase Price ($/kW)	Capacity Price ($/kW-month)	Energy Price ($/MWh)
	26	[redacted]								
	27									
	28									
	29									
	30									
	31									
	32									
	33									
	34									
	35									
	36									
	37									
Solar w/ 4-hr Battery Option	38									
	39									
	40									
	41									
	42									
	43									
	44									

CONFIDENTIAL INFORMATION REDACTED

Technology	No.	Resource ID and Respondent	Project Name	Location	Nameplate Capacity (MW)	Start Date	Term (Years)	Purchase Price ($/kW)	Capacity Price ($/kW-month)	Energy Price ($/MWh)
	45	[redacted]								
	46	[redacted]								
	47	[redacted]								
	48	[redacted]								
	49	[redacted]								
	50	[redacted]								
	51	[redacted]								
	52	[redacted]								
	53	[redacted]								
	54	[redacted]								
	55	[redacted]								
	56	[redacted]								
	57	[redacted]								
	58	[redacted]								
	59	[redacted]								
	60	[redacted]								
	61	[redacted]								
	62	[redacted]								
	63	[redacted]								

CONFIDENTIAL INFORMATION REDACTED

Technology	No.	Resource ID and Respondent	Project Name	Location	Nameplate Capacity (MW)	Start Date	Term (Years)	Purchase Price ($/kW)	Capacity Price ($/kW-month)	Energy Price ($/MWh)
	64	[redacted]								
	65	[redacted]								
	66	[redacted]								
	67	[redacted]								
	68	[redacted]								
	69	[redacted]								
	70	[redacted]								
	71	[redacted]								
	72	[redacted]								
	73	[redacted]								
	74	[redacted]								
	75	[redacted]								
	76	[redacted]								
	77	[redacted]								
	78	[redacted]								
	79	[redacted]								
Solar + 4-hr Battery	**80**	[redacted]								
Solar + 4-hr Battery	**81**	[redacted]								
2-hr Battery	**82**	[redacted]								

Exhibit SAW-1

CONFIDENTIAL INFORMATION REDACTED

Technology	No.	Resource ID and Respondent	Project Name	Location	Nameplate Capacity (MW)	Start Date	Term (Years)	Purchase Price ($/kW)	Capacity Price ($/kW-month)	Energy Price ($/MWh)
	83	[redacted]								
	84	[redacted]								
	85	[redacted]								
4-hr Battery	**86**	[redacted]								
	87	[redacted]								
	88	[redacted]								
	89	[redacted]								
	90	[redacted]								
	91	[redacted]								
	92	[redacted]								
	93	[redacted]								
	94	[redacted]								
	95	[redacted]								
	96	[redacted]								
	97	[redacted]								
Pumped Hydro	**98**	[redacted]								
Wind	**99**	[redacted]								

Technology	No.	Resource ID and Respondent	Project Name	Location	Nameplate Capacity (MW)	Start Date	Term (Years)	Purchase Price ($/kW)	Capacity Price ($/kW-month)	Energy Price ($/MWh)
NGCC	100	[redacted]								
	101									
	102									
	103									
	104									
	105									
SCCT	106									
	107									
	108									
Solar Asset Development	109									
	110									

Table 44: Dispatchable DSM Program Options

No.	Program Name	Variable Cost $/kWh		Time-Dependent Characteristic	2024	2025	2026	2027	2028	2029	2030
		Winter	Summer								
1	Peak Time Rebates	2.00	2.00	Summer Capacity MW	-	4	9	17	31	31	31
				Winter Capacity MW	-	4	9	17	31	31	31
				Fixed Cost $/kW-Year	-	-	-	164	32	37	32
2	DLC-Water Heaters	2.50	2.50	Summer Capacity MW	3	3	3	2	2	2	2
				Winter Capacity MW	3	3	3	2	2	2	2
				Fixed Cost $/kW-Year	9	12	11	13	14	16	18
3	DLC-AC[53]	-	1.68	Summer Capacity MW	121	109	98	88	79	71	64
				Winter Capacity MW	-	-	-	-	-	-	-
				Fixed Cost $/kW-Year	9	12	11	13	14	16	18
4	BYOD-Smart Thermostats	4.17	4.93	Summer Capacity MW	1	3	6	10	17	23	29
				Winter Capacity MW	0.4	1	2	3	4	6	7
				Fixed Cost $/kW-Year	-	-	-	341	105	90	86
5	Non-residential Demand Response	7.55	7.55	Summer Capacity MW	29	36	45	56	67	79	79
				Winter Capacity MW	29	36	45	56	67	79	79
				Fixed Cost $/kW-Year	45	39	29	25	21	18	13

[53] Summer capacity values are design-day values. Expected load reductions are lower on an average peak day.

9 Appendix C – All-DSM Portfolio Analysis

To estimate the level of additional DSM programs required for Portfolio 10, the Companies modeled portfolio 10 in PROSYM and recorded the level of unserved energy in 2028.

Table 45: LOLE in 2028 with MC2, GH2, BR3 Retirements and Dispatchable DSM

	LOLE (10 Years)		
Portfolio	**Summer (Jun, Jul, Aug)**	**Winter (Dec, Jan, Feb)**	**Total Year**
Retire MC2, GH2, and BR3	98.65	14.58	130.20

2022 RFP

Minimum Reserve Margin Analysis

PPL companies

Generation Planning & Analysis

December 2022

Table of Contents

1 Executive Summary

The Companies' long-term load forecast is developed with the assumption that weather will be normal in every year.[1] 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 target a level of supply-side and demand-side resources that exceeds their forecasted peak demands. Reserve margin is the amount of resources carried in excess of forecasted peak demands and is typically expressed as a percentage of forecasted peak demands under normal weather conditions.

The Companies use PLEXOS, a generation portfolio optimization model, to develop least-cost resource plans over a range of scenarios. Minimum summer and winter reserve margins are key inputs to this analysis as these plans are developed to minimize the cost of serving customers' load while meeting minimum reserve margin targets. The Companies used the Equivalent Load Duration Curve Model ('ELDCM") and the Strategic Energy & Risk Valuation Model ("SERVM") to determine minimum reserve margin targets. SERVM is a licensed software from Astrape Consulting.

The 2021 IRP established minimum reserve margin targets of 17 percent in the summer and 26 percent in the winter. However, the 2021 IRP was finalized in October 2021, and the 2021 IRP load forecast did not contemplate the addition of the BlueOval SK Battery Park ("BlueOval SK") or the impacts of the Inflation Reduction Act ("IRA") and the Companies' proposed 2024-2030 Demand-Side Mangement and Energy Efficiency ("DSM-EE") Program Plan. Therefore, using the same methodology as the 2021 IRP, the Companies updated their minimum reserve margin targets based on an updated load forecast, which includes the BlueOval SK load as well as the impacts of the IRA and the 2024-2030 DSM-EE Program Plan.[2]

With the addition of the largely non-weather sensitive, summer peaking BlueOval SK load, the absolute level of reserve capacity needed for reliable service did not change materially, but the Companies' forecasted summer and winter peak demands increased, and the summer peak demand forecast increased more than the winter peak demand. The minimum reserve margin is the level of reserves below which the cost of adding additional generation capacity is economic. The cost of capacity for this analysis was based on a response to the Companies' June 2022 RFP for simple-cycle combustion turbine ("SCCT") capacity and was 34% lower than the cost of SCCT capacity used in the 2021 IRP Reserve Margin Analysis.

Based on the updated load forecast and after factoring in the updated cost of SCCT capacity, the minimum reserve margin target for the summer did not change from 17%, but the minimum winter reserve margin target decreased from 26% to 24%.

These reserve margin targets were developed based on a mix of (a) fully dispatchable resources (i.e., resources that can be dispatched any time and operated for days at a time) and (b) intermittent and limited-duration resources (i.e., resources like the Companies' dispatchable DSM programs that can only be dispatched for several hours at a time). Table 1 summarizes the portions of the minimum reserve margin targets that are made up of fully dispatchable and intermittent or limited-duration resources.

[1] The Companies use 20 years of historical weather data to develop their normal weather forecast.
[2] The Companies' 2022 CPCN Load Forecast is attached to the testimony of Tim A. Jones as Exhibit TAJ-1.

Total reserve margin will become less meaningful as a reliability metric as more intermittent and limited-duration resources are added to the generation portfolio.

Table 1 – Minimum Reserve Margin Targets

	Summer	Winter
Fully Dispatchable Resources	12%	21%
Intermittent/Limited-Duration Resources	5%	3%
Total	17%	24%

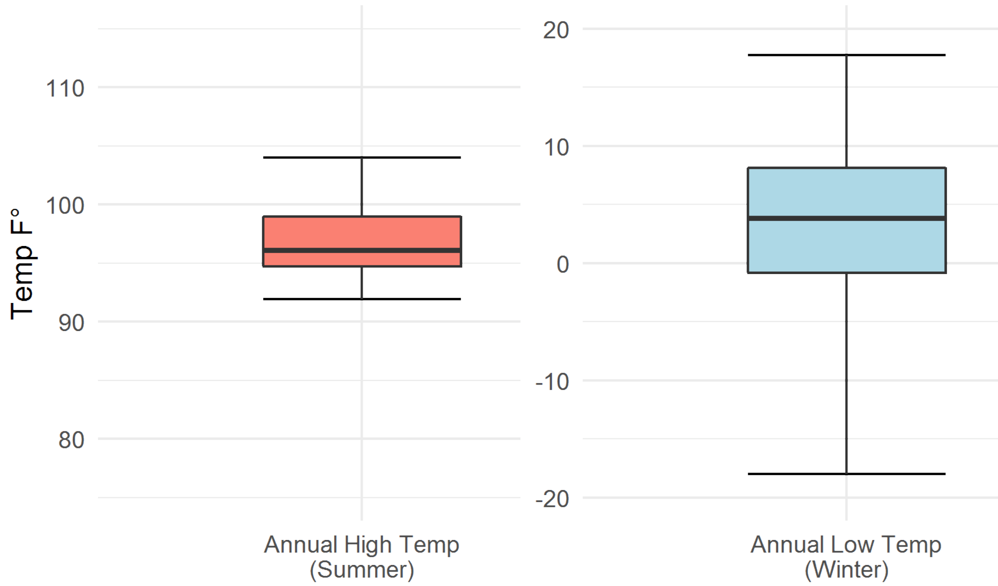
In addition to minimum reserve margins, the Companies used SERVM to determine the capacity contribution of limited-duration resources such as battery storage and the dispatchable DSM programs in the 2024-2030 DSM-EE Program Plan by comparing their impact on loss-of-load expectation ("LOLE") to that of a SCCT. This concept is similar to the effective load carrying capability that RTOs compute for limited-duration resources. PLEXOS uses these capacity contribution values to account for the fact that limited-duration resources do not contribute to reliability in the same way that fully dispatchable resources do. The capacity contributions for 4-hour battery storage, 8-hour battery storage, and dispatchable DSM are 85%, 94%, and 69%, respectively, of fully dispatchable resources.

2 Introduction

The reliable supply of electricity is vital to Kentucky's economy and public safety, and customers expect it to be available at all times and in all weather conditions. As a result, the Companies have developed a portfolio of demand- and supply-side resources with the operational capabilities and attributes needed to reliably serve customers' year-round energy needs at a reasonable cost. In addition to the ability to serve load during the annual system peak hour, the generation fleet must have the ability to produce low-cost baseload energy, the ability to respond to unit outages and follow load, and the ability to instantaneously produce power when customers want it.

An understanding of the way customers use electricity is critical for planning a generation, transmission, and distribution system that can reliably serve customers in every moment. Temperatures in Kentucky can range from below zero degrees Fahrenheit to above 100 degrees Fahrenheit. Figure 1 shows the distribution of annual high and low temperatures in Louisville over the last 49 years. From 1973 to 2021, the median annual high temperature was 96.1 degrees Fahrenheit and the median annual low temperature was 3.8 degrees Fahrenheit. Additionally, the variability of low temperatures in the winter is significantly greater than the variability of high temperatures in the summer.

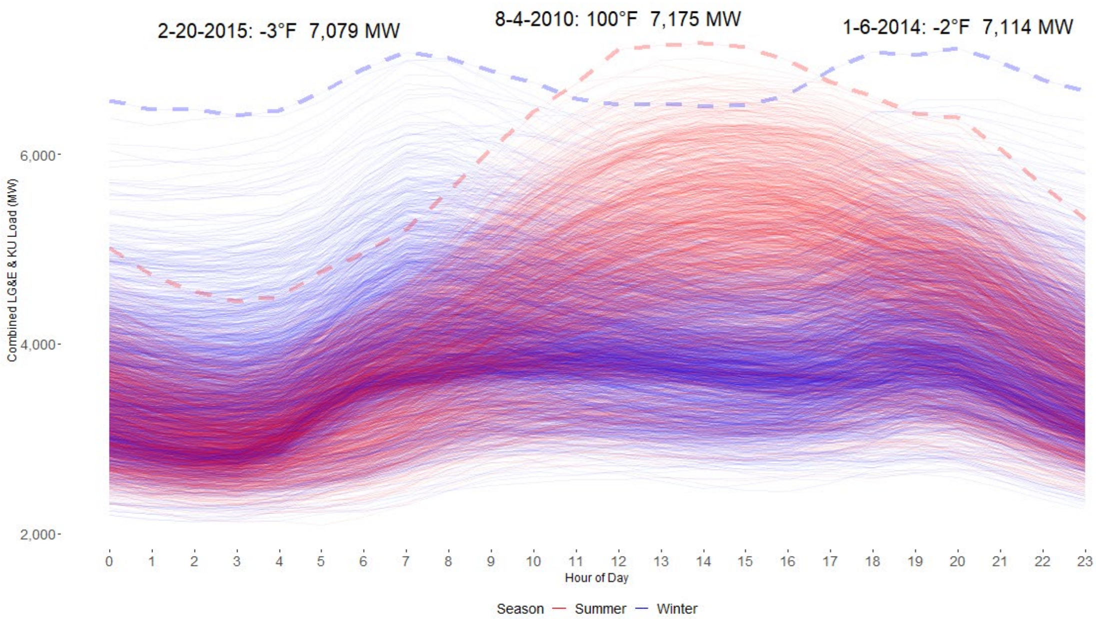
Figure 1: Louisville Annual High and Low Temperature Distributions (1973-2021)[3]



Because of the potential for cold winter temperatures and the increasing penetration of electric heating, the Companies are somewhat unique in that annual peak demands can occur in summer and winter months. The Companies' highest hourly demand occurred in the summer of 2010 (7,175 MW in August 2010). Since then, the Companies have experienced two annual peak demands in excess of 7,000 MW, both of which occurred during winter months (7,114 MW in January 2014 and 7,079 MW in February 2015). Figure 2 contains the Companies' hourly load profiles for every day from 2010 to 2020. Hourly demands can vary by as much as 600 MW from one hour to the next and by over 3,000 MW in a single day. Summer peak demands typically occur in the afternoons, while winter peaks typically occur in the mornings or evenings during nighttime hours.

[3] The limits of the box in the boxplots reflect the 25th and 75th percentiles while the "whiskers" represent the maximum and minimum.

Figure 2: Hourly Load Profiles, 2010-2020



System demands from one moment to the next can be almost as volatile as average demands from one hour to the next. Figure 3 contains a plot of four-second demands from 5:00 PM to 7:00 PM on January 6, 2014 during the polar vortex event. The average demand from 6:00 PM to 7:00 PM was 7,114 MW but the maximum 4-second demand was more than 150 MW higher.[4]

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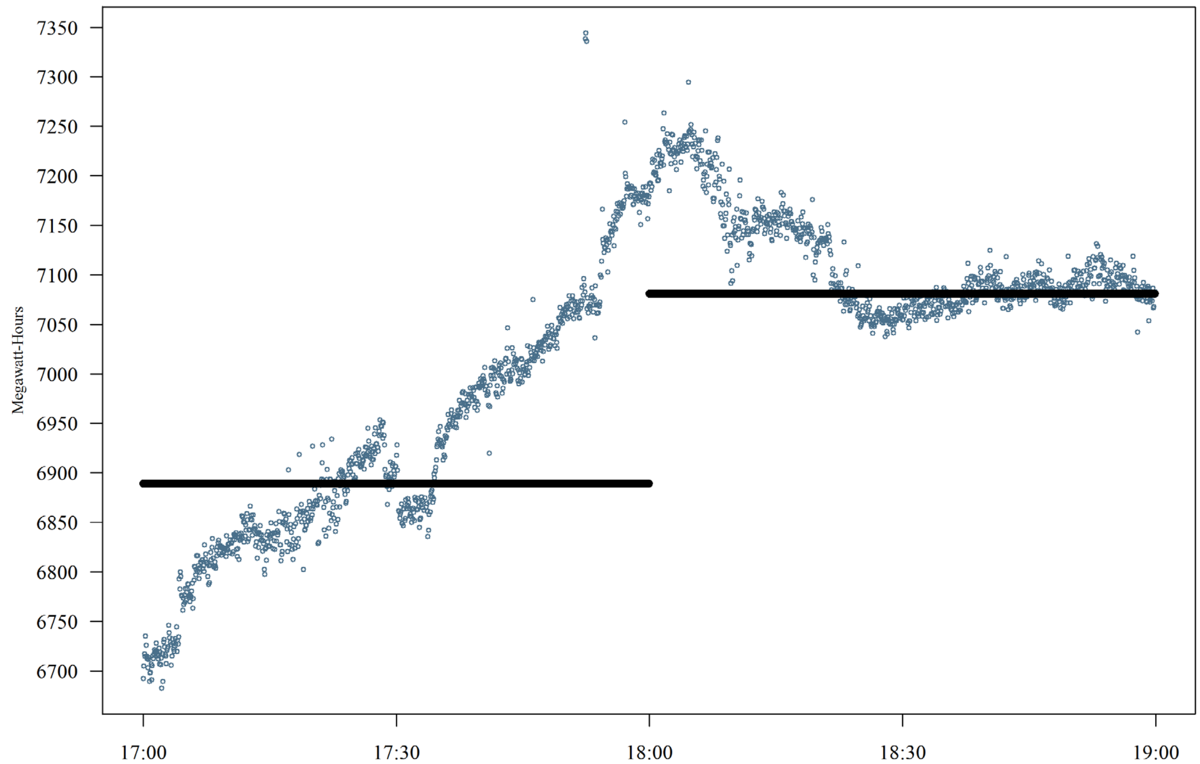
[4] 7,114 MW is an hourly demand and is computed as the average demand over the hour. A 4-second demand is an instantaneous measure of demand taken every 4 seconds.

Figure 3: Four-Second Demands, 5:00-7:00 PM on January 6, 2014



In addition to being reliable, a generation portfolio must possess numerous other attributes to produce power when customers want it. For example, a generation portfolio must possess the ramping capabilities to follow abrupt changes in customers' energy requirements. In addition, the Companies must be able to dispatch at least a significant portion of their generating units when they are needed. Peaking units can start quickly and are needed to respond to unit outages. Baseload units take longer to start, but because their start times are predictable, the Companies can bring them online when they are needed. The size of a resource is also important. If a unit is too big, taking the unit offline for maintenance can be problematic. If a unit is too small, its value in responding to unit outages is limited. The Companies' resource planning decisions must ensure their generation portfolio has the full range of operational capabilities and attributes needed to serve customers in every moment.

Customers consume electricity every hour of the year, but no generating resource can be available at all times. Considering the need for maintenance, the Companies' baseload units and large-frame SCCTs are available to be utilized up to 90 percent of hours in a year. The Companies' Curtailable Service Rider ("CSR") limits the ability to curtail participating customers to hours when all large-frame SCCTs have been dispatched. As a result, the ability to utilize this program is limited to, at most, a handful of hours each year.

As the Companies evaluate integrating more renewables into their generation portfolio, they must consider that renewables lack many of the characteristics required to serve customers in every moment. Compared to coal- and natural gas-fired resources, the availability of renewables is less predictable and their fuel supply (e.g., sunshine, wind, or water) is more intermittent. Furthermore, because annual peak demands can occur during the winter months and because winter peaks typically occur during non-daylight hours, solar generation has virtually no value in the Companies' service territories as a source of winter capacity.

The following sections summarize the Companies' reserve margin analysis. Section 3 discusses the analysis framework. Section 4 provides a summary of key inputs and uncertainties in the analysis. Finally, Section 5 provides a summary of the analysis results.

3 Analysis Framework

Figure 4 illustrates the costs and benefits of adding capacity to a generation portfolio.[5] As capacity is added, reliability and generation production costs decrease (i.e., the generation portfolio becomes more reliable), but fixed capacity costs increase. The reserve margin for the generation portfolio where the sum of (a) capacity costs and (b) reliability and generation production costs ("total cost") is minimized is the economic reserve margin.

Figure 4: Costs and Benefits of Generation Capacity (Illustrative)

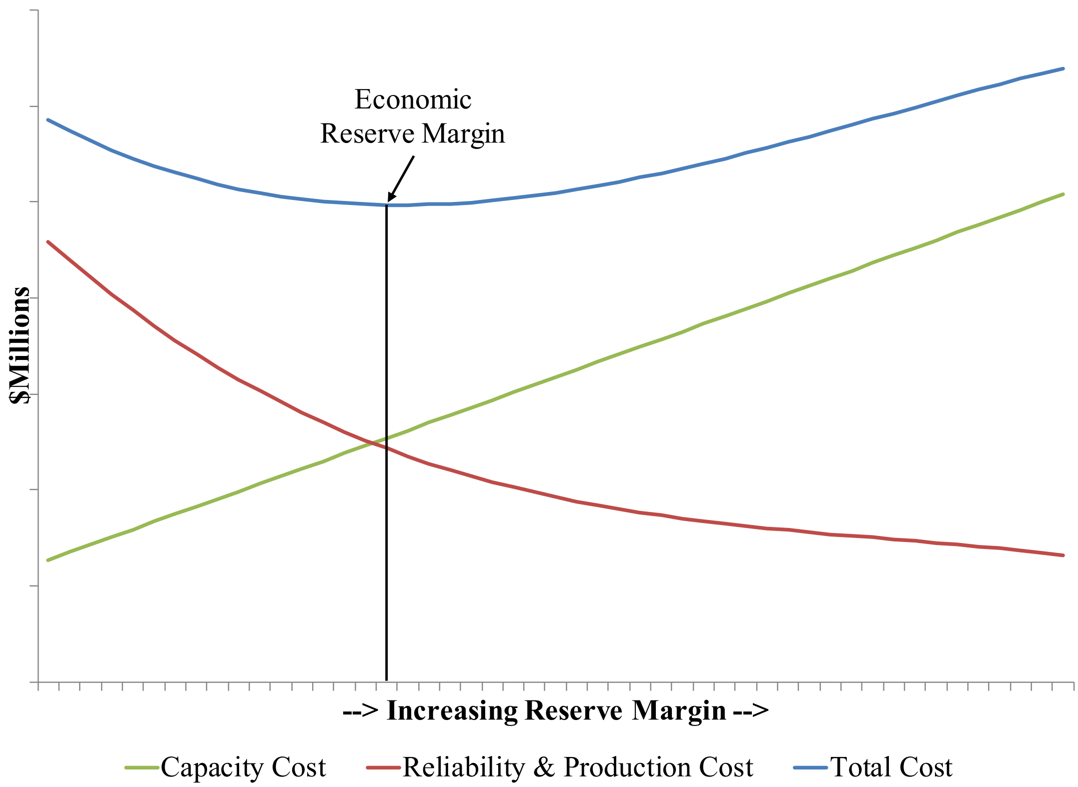


Figure 5 includes an alternative capacity cost scenario (dashed green line) for capacity with the same dispatch cost and reliability characteristics. The large dots mark the minimum of the range of reserve margins that is being evaluated. In this scenario, reliability and generation production costs are

[5] As mentioned previously, different types of generation resources play different roles in serving customers; not all resources provide the same reliability and generation production cost benefit.

unchanged but total costs (dashed blue line) are lower and the economic reserve margin is higher. This result is unsurprising; in an extreme case where the cost of capacity is zero, the Companies would add capacity until the value of adding capacity is reduced to zero.[6]

Figure 5: Economic Reserve Margin and Capacity Cost (Illustrative)

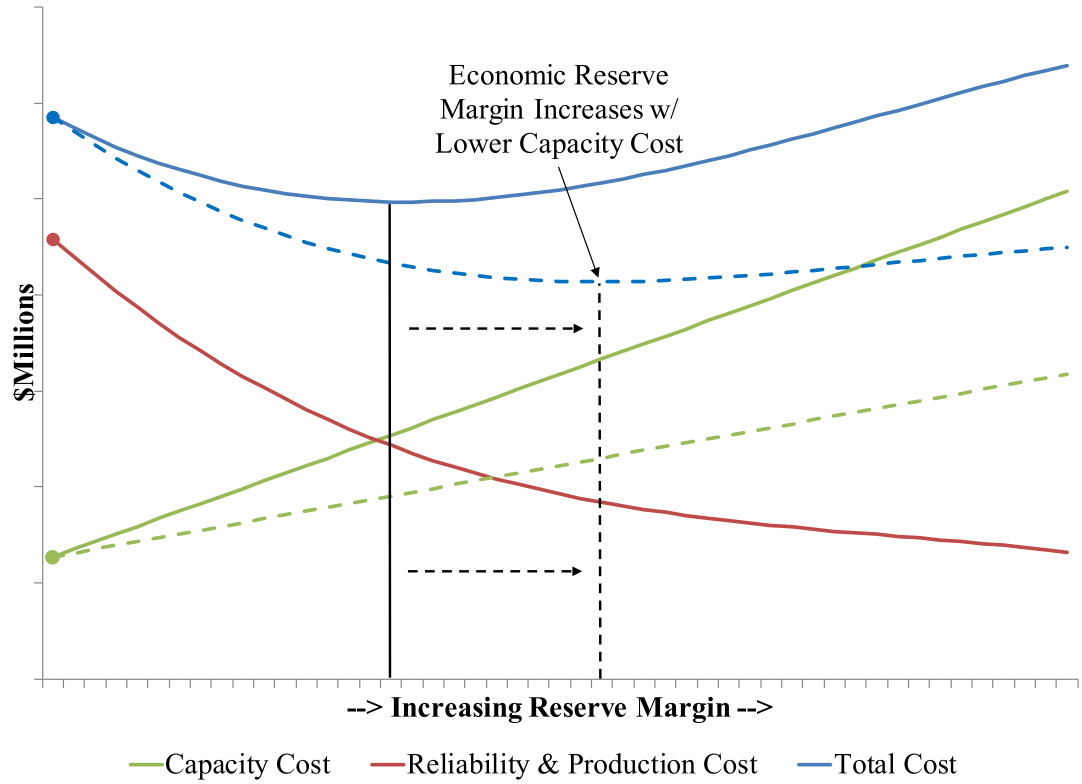


Table 2 contains the Companies' summer and winter reserve margin forecast for 2028. Generation resources have a higher capacity in the winter primarily because natural gas units can produce more power at lower ambient air temperatures. Mill Creek 1 and the Companies' small-frame SCCTs are assumed to be retired in 2025. Reserve margins are computed for 2028 with and without the Rhudes Creek and Ragland solar PPAs. These projects have not received all of their necessary permits and are not yet under construction. Given current market conditions and interest rates, it is not clear whether these projects can be financed at the prices originally proposed.

[6] In Figure 5, as more capacity is added to the generation portfolio, the value of adding the capacity decreases (i.e., the slope of the reliability and production cost line is flatter at higher reserve margins).

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

	Summer	Winter
Peak Load	**6,319**	**6,104**
Dispatchable Generation Resources		
Existing Resources	7,612	7,909
Retirements/Additions		
Coal[7]	-300	-300
Large-Frame SCCTs	0	0
Small-Frame SCCTs[8]	-47	-55
Total	7,265	7,554
Reserve Margin (%)	15.0%	23.7%
Intermittent/Limited-Duration Resources		
Existing Resources	105	72
Existing CSR	128	128
Existing DLC	46	22
Retirements/Additions		
Solar PPAs[9]	177	0
Total	456	221
Total Supply w/ Solar	**7,721**	**7,774**
Total Reserve Margin w/ Solar (%)	**22.2%**	**27.4%**
Total Supply w/o Solar	**7,544**	**7,774**
Total Reserve Margin w/o Solar (%)	**19.4%**	**27.4%**

The Resource Assessment evaluates the retirement of dispatchable resources. Because reserve margin will become less meaningful as a reliability metric as more intermittent and limited-duration resources are added to the generation portfolio, reserve margins are computed in total as well as for fully dispatchable resources only. With no additional retirements beyond 2025 and with the Rhudes Creek and Ragland PPAs, the Companies' dispatchable reserve margin in 2028 is 15.0% in the summer and 23.7% in the winter; the Companies' total reserve margin in 2028 is 22.2% in the summer and 27.4% in the winter and stays above the minimum summer and winter reserve margin targets through 2040. Without the

[7] Mill Creek 1 and 2 cannot be operated simultaneously during ozone season due to NOx limits, which results in a reduction of available summer capacity through 2024. Mill Creek 1 will be retired at the end of 2024. OVEC's contract term ends in 2040.

[8] This analysis assumes Haefling 1-2 and Paddy's Run 12 are retired by 2025.

[9] This analysis assumes 100 MW of solar capacity is added in 2024 (Rhudes Creek), and an additional 125 MW of solar capacity is added in 2025 (Ragland). Capacity values reflect 78.6% expected contribution to summer peak capacity.

Rhudes Creek and Ragland PPAs, the Companies' dispatchable reserve margins are unchanged but the total reserve margins drop to 19.4% in the summer and 27.4% in the winter.

The Companies used the Equivalent Load Duration Curve Model ("ELDCM") and Strategic Energy Risk Valuation Model ("SERVM") to update the Companies' minimum reserve margin targets. SERVM was also used to compute capacity contributions for limited-duration resources based on their impact on loss of load expectation ("LOLE") in ten years. ELDCM estimates reliability and generation production costs based on an equivalent load duration curve.[10] SERVM is a simulation-based model and was used to complete the reserve margin studies for the 2011, 2014, 2018, and 2021 IRPs. SERVM models the availability of generating units in more detail than ELDCM, but ELDCM's simplified approach is able to consider a more complete range of unit availability scenarios. Given the differences between the models, their results should be consistent but not identical.

Key inputs to SERVM and ELDCM include load, unit availability, the ability to import power from neighboring regions, and other factors. SERVM separately models the ability to import power from each of the Companies' neighboring regions based on the availability of generation resources and transmission capacity in each region. In ELDCM, the Companies' ability to import power from neighboring regions is modeled as a single "market" resource where the availability of the resource is determined by the sum of available transmission capacity in all regions. Key analysis inputs and uncertainties are discussed in the following section.

4 Key Inputs and Uncertainties

Several factors beyond the Companies' control impact the Companies' planning reserve margin and their ability to reliably serve customers' energy needs. The key inputs and uncertainties considered in the Companies' reserve margin analysis are discussed in the following sections.

4.1 Study Year

The study year for this analysis is 2028. In the Resource Assessment, the Companies assumed they could comply with the Good Neighbor Plan if replacement generation was secured by 2028.

4.2 Neighboring Regions

The vast majority of the Companies' off-system purchase transactions are made with counterparties in MISO, PJM, or TVA. SERVM models load and the availability of excess capacity from the portions of the MISO, PJM, and TVA control areas that are adjacent to the Companies' service territory.[11] These portions of MISO, PJM, and TVA are referred to as "neighboring regions." The following neighboring regions are modeled:

- MISO-Indiana – includes service territories for all utilities in Indiana as well as Big Rivers Electric Corporation in Kentucky.

[10] See https://www-pub.iaea.org/MTCD/Publications/PDF/TRS1/TRS241_Web.pdf beginning at page 219 for the modeling framework employed by ELDCM.

[11] As discussed previously, the ability to import power from neighboring regions is modeled as a single "market" resource in ELDCM.

- PJM-West – refers to the portion of the PJM-West market region including American Electric Power ("AEP"), Dayton Power & Light, Duke Ohio/Kentucky, and East Kentucky Power Cooperative service territories.
- TVA – TVA service territory.

Moving forward, uncertainty exists regarding the Companies' ability to rely on neighboring regions' markets to serve load. Approximately 20 GW of capacity was retired over the past five years in PJM and an additional 3 GW of retirements have been announced for the next five years. For the purpose of developing a minimum reserve margin for long-term resource planning, reserve margins in neighboring regions are assumed to be at their target levels of 18% (MISO[12]), 14.8% (PJM), and 17% (TVA[13]).[14]

4.3 Generation Resources

The unit availability and economic dispatch characteristics of the Companies' generating units are modeled in SERVM and ELDCM. SERVM also models the generating units in neighboring regions.

4.3.1 Unit Availability Inputs

Uncertainty related to the performance and availability of generating units is a key consideration in resource planning. From one year to the next, the average availability of generating units is fairly consistent. However, the timing and duration of unplanned outage events in a given year can vary significantly. A key aspect in developing a target reserve margin is properly considering the likelihood of unit outages during extreme weather events. Table 3 contains a summary of the Companies' generating resources along with their assumed equivalent forced outage rates ("EFORs"). The availability of units in neighboring regions was assumed to be consistent with the availability of units in the Companies' generating portfolio and not materially different from the availability of neighboring regions' units today.

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[12] See NERC's "2020 Long-Term Reliability Assessment" at https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2020.pdf.

[13] See TVA's "2019 Integrated Resource Plan" at https://www.tva.com/environment/environmental-stewardship/integrated-resource-plan.

[14] In the reserve margin analysis, adjustments were made to the neighboring regions' generating portfolios as needed to reflect planned retirements and meet the neighboring regions' target reserve margins.

Table 3: 2028 LG&E/KU Generating & DSM Portfolio

Resource	Resource Type	Net Max Summer Capacity (MW)[15]	Net Max Winter Capacity (MW)	EFOR
Brown 3	Coal	412	416	5.8%
Brown 5	SCCT	130	130	8.1%
Brown 6	SCCT	146	171	8.1%
Brown 7	SCCT	146	171	8.1%
Brown 8	SCCT	121	128	8.1%
Brown 9	SCCT	121	138	8.1%
Brown 10	SCCT	121	138	8.1%
Brown 11	SCCT	121	128	8.1%
Brown Solar	Solar	8	0	2.5%
Cane Run 7	NGCC	691	691	2.2%
Dix Dam 1-3	Hydro	32	32	N/A
Ghent 1	Coal	475	479	3.2%
Ghent 2	Coal	485	486	3.2%
Ghent 3	Coal	481	476	3.2%
Ghent 4	Coal	478	478	3.2%
Mill Creek 2	Coal	297	297	3.2%
Mill Creek 3	Coal	391	394	3.2%
Mill Creek 4	Coal	477	486	3.2%
Ohio Falls 1-8	Hydro	64	40	N/A
OVEC-KU	Power Purchase	47	49	N/A
OVEC-LG&E	Power Purchase	105	109	N/A
Paddy's Run 13	SCCT	147	175	8.1%
Trimble County 1 (75%)	Coal	370	370	3.2%
Trimble County 2 (75%)	Coal	549	570	5.1%
Trimble County 5	SCCT	159	179	4.9%
Trimble County 6	SCCT	159	179	4.9%
Trimble County 7	SCCT	159	179	4.9%
Trimble County 8	SCCT	159	179	4.9%
Trimble County 9	SCCT	159	179	4.9%
Trimble County 10	SCCT	159	179	4.9%
Business Solar	Solar	0.2	0	2.5%
Solar Share	Solar	1.7	0	2.5%
Rhudes Creek Solar	Solar	79	0	2.5%
Additional GT Option 3 Solar	Solar	98	0	2.5%
CSR	Interruptible	128	128	N/A
DCP[16]	DSM	46	22	N/A

[15] Projected net ratings as of 2022. OVEC's capacity reflects the capacity that is expected to be available to the Companies at the time of the summer and winter peaks. The ratings for Brown Solar, Business Solar, Solar Share, Dix Dam 1-3, and Ohio Falls 1-8 reflect the assumed output for these facilities during the summer and winter peak demand. Cane Run 7 reflects the estimated impact of evaporative cooling under average summer ambient conditions.

[16] The Demand Conservation Programs include the Residential and Non-Residential Demand Conservation Programs. These programs are the Companies' only dispatchable demand-side management programs. The Companies did not evaluate the Curtailable Service Rider because the elimination of this rider would have no impact on total revenue requirements.

4.3.2 Fuel Prices

The forecasts of natural gas and coal prices for the Companies' generating units are summarized in Table 4 and Table 5. Those prices represent the Mid Gas, Mid Coal-To-Gas Ratio scenario. Fuel prices in neighboring regions were assumed to be consistent with the Companies' fuel prices. The natural gas price forecast reflects forecasted Henry Hub market prices plus variable costs for pipeline losses and transportation, excluding any fixed firm gas transportation costs.

Table 4: 2028 Delivered Natural Gas Prices (LG&E and KU; Nominal $/mmBtu)

Month	Value
1	[redacted]
2	
3	
4	
5	
6	
7	
8	
9	
10	
11	
12	

Table 5: 2028 Delivered Coal Prices (LG&E and KU; Nominal $/mmBtu)

Station	Value
Brown	[redacted]
Ghent	
Mill Creek	
Trimble County – High Sulfur	
Trimble County – PRB	

4.3.3 Interruptible Contracts

Load reductions associated with the Companies' Curtailable Service Rider ("CSR") are modeled as generation resources. Table 6 lists the Companies' CSR customers and their assumed load reductions. The Companies can curtail each CSR customer up to 100 hours per year.[17] However, because the Companies can curtail CSR customers only in hours when more than 10 of the Companies' large-frame SCCTs are being dispatched, the ability to utilize this program is limited to at most a handful of hours each year, and then the magnitude of load reductions depends on participating customers' load during the hours when they are called upon. The total assumed capacity of the CSR program is 128 MW.

[17] See KU's Electric Service Tariff at https://psc.ky.gov/tariffs/Electric/Kentucky%20Utilities%20Company/Tariff.pdf and LG&E's at https://psc.ky.gov/tariffs/Electric/Louisville%20Gas%20and%20Electric%20Company/Tariff.pdf.

Table 6: Interruptible Contracts

CSR Customers	Assumed Hourly Load Reduction (MW)
[redacted]	

4.4 Available Transmission Capacity

Available transmission capacity ("ATC") determines the amount of power that can be imported from neighboring regions to serve the Companies' load and is a function of the import capability of the Companies' transmission system and the export capability of the system from which the power is purchased. For example, to purchase 50 MW from PJM, the Companies' transmission system must have at least 50 MW of available import capability and PJM must have at least 50 MW of available export capability. If PJM only has 25 MW of export capability, total ATC is 25 MW.

The Companies' import capability is assumed to be negatively correlated with load. Furthermore, because weather systems impact the Companies' service territories and neighboring regions similarly, the export capability from neighboring regions is oftentimes also limited when the Companies' load is high. Table 7 summarizes the sum of daily ATC between the Companies' system and neighboring regions on weekdays during the summer months of 2019 and 2020 and the winter months of 2020 and 2021. Based on the daily ATC data, the Companies' ATC for importing power from neighboring regions is zero 42% of the time. ATC is modeled in SERVM based on this distribution.

Table 7: Daily ATC

Daily ATC Range	Count of Days	% of Total
0	98	42%
1 – 199	2	1%
200 - 399	10	4%
400 - 599	17	7%
600 - 799	11	5%
800 - 999	21	9%
>= 1,000	73	31%
Total	232	

During peak hours when ATC is most likely needed to ensure reliable supply, ATC in ELDCM is assumed to be approximately 500 MW two-thirds of the time and zero MW one-third of the time.

4.5 Load Modeling

Uncertainty in the amount and timing of customers' utilization of electricity is a key consideration in resource planning. Uncertainty in the Companies' load is modeled in SERVM and ELDCM. SERVM also models load uncertainty in neighboring regions. Table 8 summarizes the summer peak demand forecast for the Companies' service territories and neighboring regions in 2028. The Companies' peak demand is taken from the base energy requirements forecast scenario and reflects the impact of the Companies' DSM programs. The forecasts of peak demands for MISO-Indiana, PJM-West, and TVA were taken from RTO forecasts and NERC Electricity Supply and Demand data.

Table 8: Peak Load Forecasts for 2028

	LG&E/KU	MISO-Indiana	PJM-West	TVA
Peak Load	6,319	20,809	34,677	30,442
Target Reserve Margin	N/A	18.0%	14.8%	17%

The Companies develop their long-term energy requirements forecast with the assumption that weather will be average or "normal" in each month of every year. In a given month, weather on the peak day is assumed to be the average of weather on the peak day over the past 20 years. While this is a reasonable assumption for long-term resource planning, weather from one month and year to the next is never the same. The frequency and duration of severe weather events within a year have a significant impact on load shape and reliability and generation production costs. For this reason, the Companies produced 49 hourly demand forecasts for 2028 based on actual weather in each of the last 49 years.

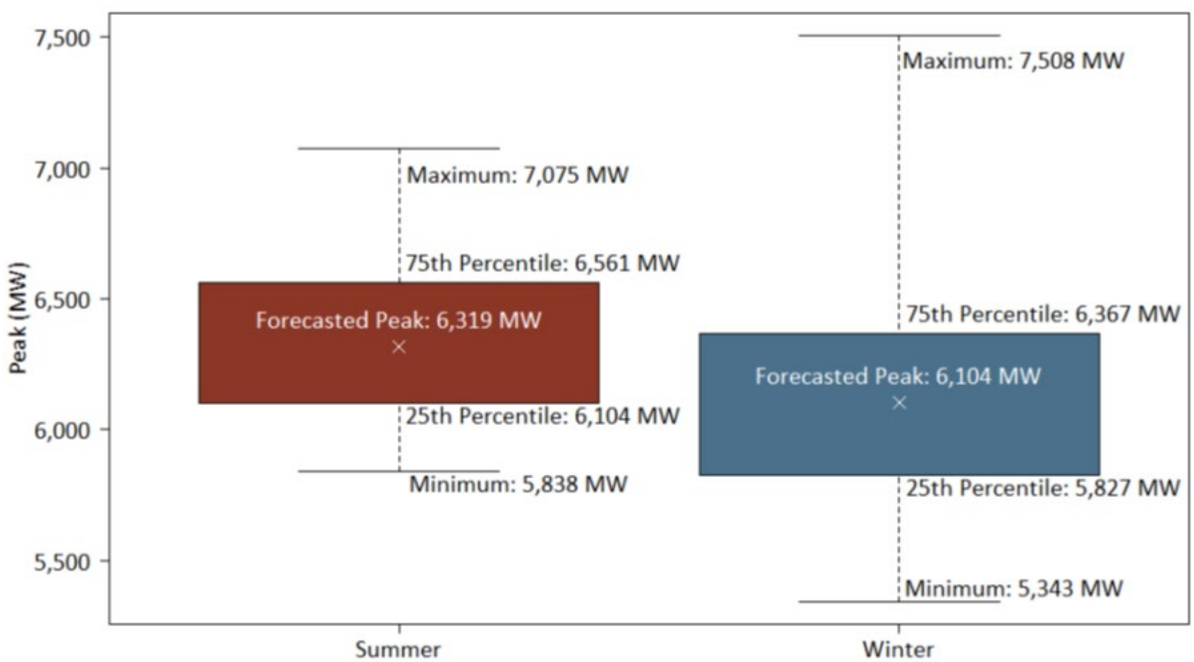
Table 9 summarizes the distributions of summer and winter peak demands for the Companies' service territory and coincident demands in the neighboring regions based on these "weather year" forecasts. Because each set of coincident peak demands is based on weather from the same weather year, SERVM captures weather-driven covariation in loads between the Companies' service territories and neighboring regions to the extent weather is correlated. Because the ability to purchase power from neighboring regions often depends entirely on the availability of transmission capacity, load uncertainty in the Companies' service territories has a much larger impact on resource planning decisions than load uncertainty in neighboring regions.

Table 9: Summer and Winter Peak Demand Forecasts, 2028

	Summer					Winter				
			Coincident Peak Demand in Neighboring Regions					Coincident Peak Demand in Neighboring Regions		
LG&E/ KU Load	Weather Year	LG&E/KU	MISO-Indiana	PJM-West	TVA	Weather Year	LG&E/KU	MISO-Indiana	PJM-West	TVA
Max	2007	7,075	20,045	32,361	32,639	1994	7,508	21,305	37,717	31,274
75th %-ile	1995	6,466	19,401	30,643	27,017	2003	6,367	17,718	32,037	24,089
Median	1998	6,208	19,569	30,729	28,624	2016	5,963	18,819	33,226	29,893
25th %-ile	1985	6,098	21,085	30,672	27,620	2011	5,827	16,905	33,525	26,061
Min	2004	5,838	17,591	28,155	22,179	1998	5,343	14,906	26,772	21,662

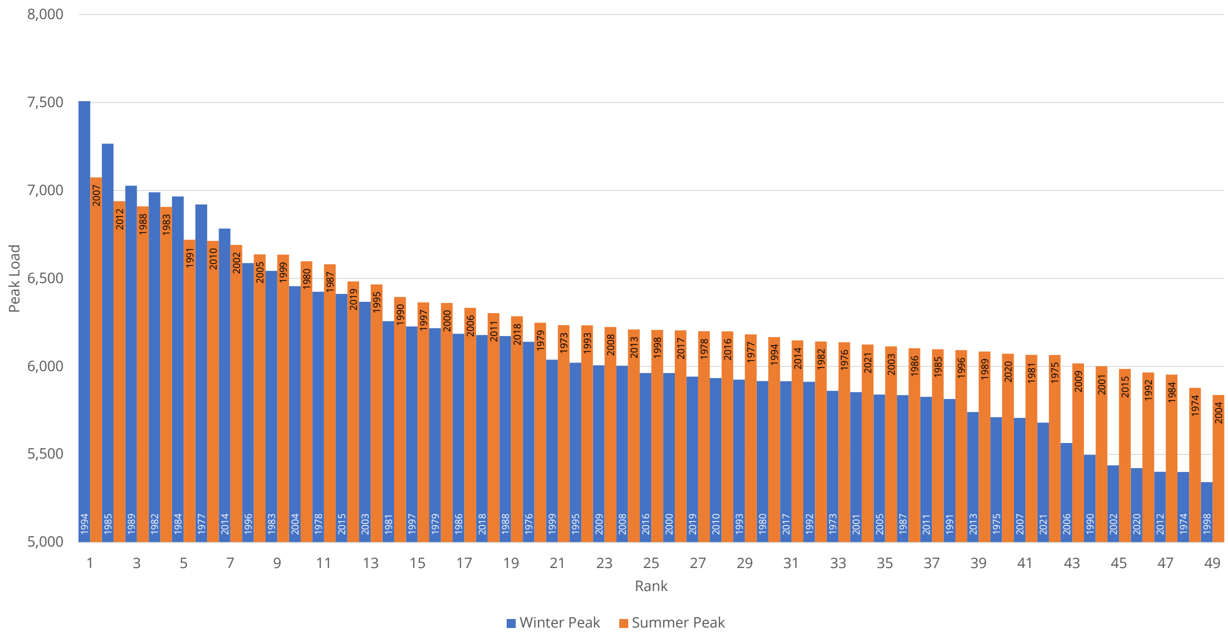
Figure 6 and Figure 7 contain graphical distributions of the Companies' summer and winter peak demands for 2028. The values in Figure 6 labeled "Forecasted Peak" (i.e., 6,319 MW in the summer and 6,104 MW in the winter) are the Companies' forecasts of summer and winter peak based on average peak weather conditions over the past 20 years. In Figure 7, the year labels indicate the weather years on which the seasonal peaks are based. The Companies' Forecasted Peak is higher in the summer, but the variability in peak demands is much higher in the winter.[18] This is largely due to the wider range of low temperatures that can be experienced in the winter and the fact that electric heating systems with heat pumps consume significantly more energy during extreme cold weather when the need for backup resistance heating is triggered.

Figure 6: Distributions of Summer and Winter Peak Demands, 2028



[18] The distributions in Table 9 do not reflect load reductions associated with the Companies' Curtailable Service Rider ("CSR") because this program is modeled as a generation resource; CSR load reductions are forecast to be 128 MW in 2028. The maximum winter peak demand (7,508 MW) is forecasted based on the weather from January 19, 1994 when the average temperature was -9 degrees Fahrenheit and the low temperature was -22 degrees Fahrenheit. For comparison, the Companies' peak demand on January 6, 2014 during the polar vortex event was 7,114 MW and the average temperature was 8 degrees Fahrenheit and the low temperature was -3 degrees Fahrenheit. CSR customers were curtailed during this hour and the departing municipals' load was 285 MW.

Figure 7: Distributions of Summer and Winter Peak Demands, 2028



4.6 Capacity Costs

For minimum reserve margin, the Companies estimated the change in load that would require the addition of generation resources. Specifically, the Companies estimated the load increase that would cause adding new SCCT to the portfolio to be less costly than the Existing portfolio. The cost of new SCCT capacity is based on a response to the Companies' June 2022 RFP and is summarized in Table 10 in 2028 dollars. Compared to the cost of SCCT capacity used in the 2021 IRP Reserve Margin Analysis, this cost is 34% lower.

Table 10: SCCT Cost (2028 Dollars)

Input Assumption	Value
Capital Cost ($/kW)	700
Fixed O&M ($/kW-yr)	3.6
Firm Gas Transport ($/kW-yr)	15.6
Escalation Rate	1.47%
Discount Rate	6.43%
Carrying Charge ($/kW-yr)	73.9

4.7 Cost of Unserved Energy (Value of Lost Load)

The impacts of unserved energy on business and residential customers include the loss of productivity, interruption of a manufacturing process, lost product, potential damage to electrical services, and inconvenience or discomfort due to loss of cooling, heating, or lighting.

For this study, unserved energy costs were derived based on information from four publicly available studies.[19] All studies split customers into residential, commercial, and industrial classes, which is a typical breakdown of customers in the electric industry. After escalating the costs from each study to 2028 dollars and weighting the cost based on LG&E and KU customer class weightings across all four studies, the cost of unserved energy was calculated to be $21.0/kWh.

Table 11 shows how the numbers were derived. The range for residential customers varied from $1.6/kWh to $4.0/kWh. The range for commercial customers varied from $28.4/kWh to $42.1/kWh while industrial customers varied from $14.7/kWh to $34.1/kWh. Not surprisingly, commercial and industrial customers place a much higher value on reliability given the impact of lost production and/or product. The range of system cost across the four studies is approximately $8.6/kWh.

Table 11: Cost of Unserved Energy (2028 Dollars)

	Customer Class Mix	2003 DOE Study $/kWh	2009 DOE Study $/kWh	Christian Associates Study $/kWh	Billinton and Wacker Study $/kWh
Residential	34%	1.8	1.6	4.0	3.4
Commercial	36%	42.1	38.3	28.4	29.5
Industrial	30%	24.3	34.1	14.7	29.5
System Cost of Unserved Energy		23.0	24.6	16.0	20.6
	Customer Class Mix	**Min $/kWh**	**Mean $/kWh**	**Max $/kWh**	**Range $/kWh**
Residential	34%	1.6	2.7	4.0	2.4
Commercial	36%	28.4	34.6	42.1	13.7
Industrial	30%	14.7	25.7	34.1	19.4
Average System Cost of Unserved Energy			21.0		

4.8 Spinning Reserves

Based on the Companies' existing resources, they are assumed to carry 243 MW of spinning reserves to meet their reserve sharing obligation and comply with NERC standards. The reserve margin analysis assumes the Companies would shed firm load in order to maintain their spinning reserve requirements.

[19] "Estimated Value of Service Reliability for Electric Utility Customers in the Unites States," Ernest Orlando Lawrence Berkeley National Laboratory, June 2009;
"Assessment of Other Factors: Benefit-Cost Analysis of Transmission Expansion Plans," Christensen Associates Energy Consulting, August 15, 2005;
"A Framework and Review of Customer Outage Costs: Integration and Analysis of Electric Utility Outage Cost Surveys," Ernest Orlando Lawrence Berkeley National Laboratory, November 2003;
"Value of Lost Load," University of Maryland, February 14, 2000.

4.9 Reserve Margin Accounting

The following formula is used to compute reserve margin:

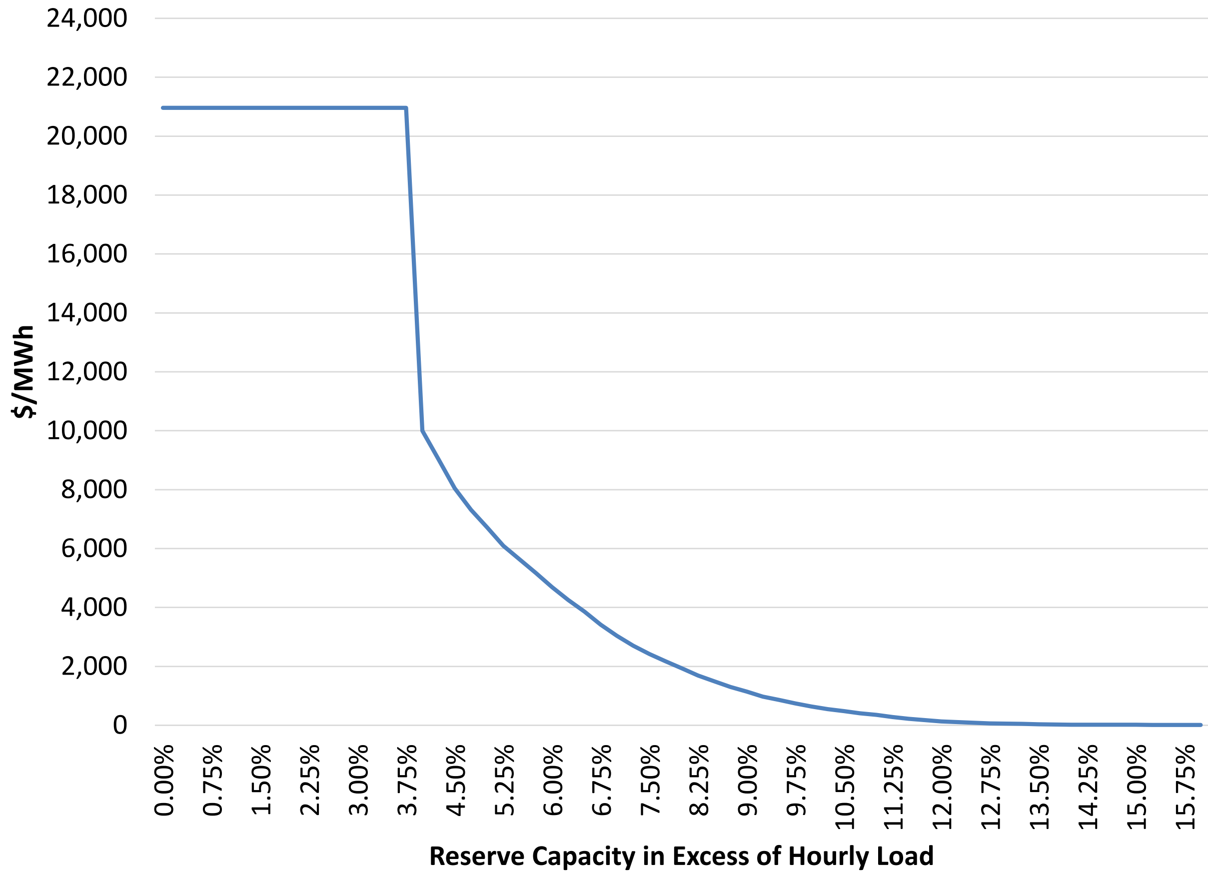
Reserve Margin = Total Supply/Peak Demand Forecast – 1

Total supply includes the Companies' generating resources and interruptible contracts. The peak demand forecast is the forecast of peak demand under normal weather conditions. The impact of the Companies' DSM programs is reflected in the Companies' peak demand forecast. While the Companies are assumed to carry 243 MW of spinning reserves to meet their reserve sharing obligation, this obligation is not included in the peak demand forecast nor as a reduction in generation resources for the purpose of computing reserve margin.

4.10 Scarcity Pricing

As resources become scarce, the price for market power begins to exceed the marginal cost of supply. The scarcity price is the difference between market power prices and the marginal cost of supply. Figure 8 plots the scarcity pricing assumptions in SERVM. The scarcity price is a function of reserve capacity in a given hour and is added to the marginal cost of supply to determine the price of purchased power. The Companies' assumed spinning reserve requirement (243 MW) is approximately 3.8% of the forecasted summer peak demand in 2028 (6,319 MW). At reserve capacities less than 3.8% of the hourly load, the scarcity price is equal to the Companies' value of unserved energy ($21,000/MWh; see Section 4.7). The remainder of the curve is estimated based on market purchase data.

Figure 8: Scarcity Price Curve



The scarcity price impacts reliability and generation production costs only when generation reserves become scarce and market power is available. In ELDCM, the scarcity price is specified as a single value ($100/MWh).

4.11 Summary of Scenarios

Reliability costs and loss-of-load events occur when loads are high or when supply is limited. To properly capture the cost of high-impact, low-probability events, the Companies evaluate thousands of scenarios that encompass a wide range of load and unit availability scenarios. Specifically, the Companies evaluated each generation portfolio over 49 load scenarios and 300 unit availability scenarios.

5 Analysis Results

5.1 Minimum Reserve Margin

To determine minimum summer and winter reserve margin targets, the Companies estimated the change in load that would cause the addition of generation capacity to be economic. To do this, the Companies modeled two generation portfolios:

- Existing: Existing portfolio except Mill Creek 1 (planned retirement in 2024) and the small-frame SCCTs (assumed retirement in 2025); Rhudes Creek and Ragland solar PPAs are not completed.
- Add SCCT: Existing portfolio plus 60 MW of SCCT.[20]

Specifically, the Companies estimated the load increase that would cause the total cost of the Add SCCT and Existing portfolios to be approximately equal. Total costs include generation capacity costs as well as reliability and generation production costs. The summer and winter reserve margins associated with this load increase are the minimum summer and winter reserve margin targets. Below this range, the Companies should seek to acquire additional resources to avoid reliability falling to levels that would likely be unacceptable to customers.

Because significant near-term load increases are most likely to be the result of the addition of one or more large industrial customers, the analysis evaluated the addition of large, high load factor loads. The results of this analysis from ELDCM and SERVM are summarized in Table 12 and Table 13, respectively. Consistent with the 2021 IRP reserve margin analysis, this analysis is focused on total costs that are estimated based on the 85th and 90th percentiles of the reliability and generation production cost distribution for the purpose of reducing volatility for customers. Based on ELDCM and assuming all other things equal, if the Companies' load increases by 150 MW (i.e., summer reserve margin decreases to 17 percent and winter reserve margin decreases to 24 percent), the reliability and production cost benefits from adding new SCCT capacity would more than offset the cost of the capacity. The results from SERVM are very similar.

Table 12: Minimum Reserve Margin Target (ELDCM)

Load Change	Summer Reserve Margin for Existing Portfolio	Winter Reserve Margin for Existing Portfolio	Total Cost w/ 85th %-ile Reliability and Production Costs ($M/year)			Total Cost w/ 90th %-ile Reliability and Production Costs ($M/year)		
			Existing	Add SCCT	Diff: Add SCCT less Existing	Existing	Add SCCT	Diff: Add SCCT less Existing
0	19.4%	27.4%	1,277	1,280	3	1,283	1,285	2
50	18.4%	26.4%	1,295	1,298	3	1,302	1,304	2
100	17.5%	25.3%	1,315	1,317	2	1,321	1,323	2
150	16.6%	24.3%	1,337	1,335	(2)	1,342	1,342	0
200	15.7%	23.4%	1,361	1,358	(3)	1,366	1,363	(3)

[20] 60 MW of capacity is approximately equal to 1% of reserve margin.

Table 13: Minimum Reserve Margin Target (SERVM)

Load Change	Summer Reserve Margin for Existing Portfolio	Winter Reserve Margin for Existing Portfolio	Total Cost w/ 85th %-ile Reliability and Production Costs ($M/year)			Total Cost w/ 90th %-ile Reliability and Production Costs ($M/year)		
			Existing	Add SCCT	Diff: Add SCCT less Existing	Existing	Add SCCT	Diff: Add SCCT less Existing
0	19.4%	27.4%	1,272	1,273	1	1,277	1,280	3
100	17.5%	25.3%	1,310	1,311	1	1,321	1,316	(5)
150	16.6%	24.3%	1,334	1,333	(1)	1,337	1,337	0
200	15.7%	23.4%	1,355	1,353	(2)	1,362	1,361	(1)

5.2 Capacity Contribution of Limited-Duration Resources

In the previous section, the Companies determined the minimum summer and winter reserve margin targets as 17% and 24%, respectively. For portfolio development and screening in PLEXOS, the Companies evaluate potential supply- and demand-side resources as generation replacement alternatives. Some supply- and demand-side resources such as battery storage and dispatchable DSM programs are limited-duration dispatchable resources which do not contribute to reliability in the same way that fully-dispatchable resources do. Therefore, the Companies use SERVM to determine the capacity contribution of limited-duration resources such as battery storage and the proposed new DSM programs by comparing their impact on LOLE to that of a SCCT. This concept is similar to the effective load carrying capability that RTOs compute for limited-duration resources.[21]

To complete this analysis, the Companies estimated LOLE for the generation portfolios in Table 14. The "Reference" portfolio (Portfolio 1) replaces Mill Creek 2, Ghent 2, and Brown 3 with one 621 MW NGCC and has reserve margins that are significantly lower than the minimum reserve margin targets. Portfolios 2-5 add 480 MW of various technologies to the Reference portfolio to achieve summer and winter reserve margins close to the minimum reserve margin targets.

Table 14: Generation Portfolios for Capacity Contribution Analysis

	Generation Portfolio	**2028 Reserve Margin Summer / Winter**
1	Reference: Replace Mill Creek 2, Ghent 2, and Brown 3 with 1 621 MW NGCC	10.3% / 17.6%
2	Reference + 480 MW of SCCT	17.9% / 26.0%
3	Reference + 480 MW of 4-hr BESS	
4	Reference + 480 MW of 8-hr BESS	
5	Reference + 480 MW of Dispatchable DSM	

[21] See PJM's Effective Load Carrying Capability (ELCC) at https://www.pjm.com/-/media/committees-groups/task-forces/ccstf/2020/20200407/20200407-item-04-effective-load-carrying-capability.ashx

Table 15 contains the results of this analysis. With summer and winter reserve margins significantly below the target minimums, the LOLE for the Reference portfolio is 25.13 days in 10 years, which is significantly higher than the reliability standard of 1 day in 10 years. When 480 MW of SCCT capacity is added to the Reference portfolio, LOLE decreases by 21.26 days. Alternatively, when 480 MW of 4-hour BESS is added to the Reference portfolio, LOLE decreases by 18.15 days. The capacity contribution for 4-hour BESS is computed as the ratio of the BESS LOLE impact to the SCCT LOLE impact (18.15/21.26 = 0.85). The capacity contributions for 4-hour BESS, 8-hour BESS, and dispatchable DSM are 85%, 94%, and 69%, respectively, of a SCCT or another fully dispatchable resource.

Table 15: Capacity Contribution for Limited-Duration Resources

Generation Portfolio	Reserve Margin Summer/Winter	LOLE (Days in 10 Years)	LOLE Reduction (Days in 10 Years)	Capacity Contribution
1: Reference	10.3% / 17.6%	25.13	NA	NA
2: Reference + SCCT	17.9% / 26.0%	3.87	21.26	NA
3: Reference + 4-hr BESS		6.98	18.15	0.85
4: Reference + 8-hr BESS		5.13	20.00	0.94
5: Reference + Disp. DSM		10.49	14.64	0.69

2022 Resource Assessment Fuel Price Forecasts

1 Summary

The 2022 Resource Assessment fuel price forecasts for Henry Hub natural gas and Ilinois Basin ("ILB") coal were developed in mid-2022. Using several combinations of these forecasts, the Companies developed the following six 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
- Atypcial CTG Ratios
    - Low Gas, High CTG Ratio
    - High Gas, Low CTG Ratio
    - High Gas, Current CTG Ratio

The Companies' range of three gas price forecasts is based on the Energy Information Administration's ("EIA") forecasts in its 2022 Annual Energy Outlook ("AEO2022")[1] and is consistent with forecasts prepared by industry consultants, as discussed in Section 2.1. The gas price forecasts and the coal price forecasts with high gas paired with mid and current CTG ratios generally assume that some level of elevated demand in the international fuel markets will remain intact through the long-term period. The High Gas, Current CTG Ratio coal price forecast assumes a continuation of demand outstripping supply in global fuel markets. 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 ILB coal and gas prices experienced between 2012 and 2021, compared to the corresponding gas prices, as discussed in Section 2.2. 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, Current CTG coal price forecast assumes a continuation of the more recent ILB coal/gas price ratios experienced in 2022, as the coal and gas markets became extremely tight. 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.

2 Forecast Methodology

2.1 Natural Gas

The Henry Hub natural gas price forecasts were developed as combinations of short-term and long-term forecasts. The first three years (2023-2025) of the gas price forecasts reflect monthly forward market prices from NYMEX at various quote dates between March and July 2022. In the subsequent years, the market prices were interpolated to the endpoints of the AEO2022 forecasts (see Section 2.1.3).

[1] EIA released the AEO2022 in March 2022. See https://www.eia.gov/outlooks/aeo/.

2.1.1 Gas Price Scenario Assumptions

The first three years of each gas price forecast reflect market forward pricing as of three quote dates between March and July 2022, when the forecasts were being developed and as the forward gas market experienced high volatility.

- **Mid Gas**
  - **2023-2025**: Henry Hub Natural Gas forwards, 7/7/22 market quote date, reflecting the most recent forward market prices when the Companies' 2023 Business Plan forecasts were being finalized.
  - **2026+**: Interpolation to the endpoint in 2050 of the EIA's AEO2022 Reference case.
- **High Gas**
  - **2023-2025**: 6/9/22 quote date, reflecting the peak of forward gas prices during the forecast development period.
  - **2026+**: Interpolation to the endpoint in 2050 of the EIA's AEO2022 Low Oil and Gas Supply case.
- **Low Gas**
  - **2023-2025**: 3/21/22 quote date, reflecting a period of relatively low forward market prices as the current international market factors were still taking shape.
  - **2026+:** Interpolation to the endpoint in 2050 of the EIA's AEO2022 High Oil and Gas Supply case.

2.1.2 Conversion of annual price curves to monthly

Monthly/annual pricing ratios were calculated using NYMEX Henry Hub forwards for the respective market date in each case. These monthly average "factors" were then applied to the annual prices of each gas price case to derive a monthly price curve for years 2026 through 2050.

2.1.3 EIA AEO2022 Cases

2.1.3.1 EIA AEO2022 Reference case (Mid Gas Price Case)[2]

- **Supply.** Natural gas production grows by almost 24%, approximately twice as fast as consumption. U.S. natural gas production increases in all cases except in the Low Oil and Gas Supply case. More than half of the growth in natural gas production is associated with natural gas from tight oil plays with the remaining growth in production attributed to shale resources. Crude oil production returns to pre-pandemic levels in 2023 and peaks in the late 2020s. Production then remains relatively flat through 2050.
- **Demand.**
  - Projected U.S. 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 U.S. natural gas exports. LNG capacity expansions, coupled with high demand for natural gas abroad, result in an increase in LNG exports to 5.86 trillion cubic feet (16.1 Bcf/d) by 2033.
  - Natural gas consumption for space heating, which is the largest single contributor to both U.S. commercial and residential delivered energy consumption throughout the Reference case projection period, declines through 2050.
- **Electricity consumption.** U.S. annual average electricity growth rate remains below 1% over the projection period (2021-2050). Electricity is the fastest-growing fuel used for transportation, growing from less than 0.5% of total consumption in 2019 to nearly 2% in 2050.

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[2] https://www.eia.gov/outlooks/aeo/pdf/AEO2022_Narrative.pdf

- **Generation mix.** In all Cases, the EIA projects that renewable energy will be the fastest-growing U.S. energy source through 2050, more than doubling the current renewable electricity generation mix. Renewable electric generating technologies account for over 57% of the approximately 1,000 gigawatts (GW) of cumulative capacity additions. Solar capacity accounts for 47% of electric generating capacity additions, and wind accounts for about 10%. Solar's share of total U.S. capacity increases from 7% in 2020 to 29% in 2050. Natural gas generation makes up 39% of new capacity additions from 2021-2050. Significant projected coal and nuclear generating unit retirements cause the shares from those sources to drop by half.

2.1.3.2 EIA AEO2022 Low Oil and Gas Supply Case (High gas price case)

- Compared with 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 United States; 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 United States.
- The Low Oil and Gas Supply case assumes higher costs and less resource availability, which increases natural gas prices, so LNG exports begin to decline in the mid-2030s.
- In 2050, the projected natural gas price is almost twice as high in the Low Oil and Gas Supply case as in the Reference case.

2.1.3.3 EIA AEO2022 High Oil and Gas Supply Case (Low gas price case)

- Compared with 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 United States; the undiscovered resources in Alaska and the offshore lower 48 states; the rates of technological improvement.
- Shale gas and associated natural gas from tight oil plays are the primary contributors to the long-term growth of U.S. natural gas production through 2050.
- In 2050, the price is approximately 29% lower than in the Reference case.

2.1.4 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 2.[3] 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.

[3] The constultant's forecasts were published in June and August 2022.

Figure 1 - Comparison of Henry Hub Natural Gas Price History and Forecasts (Nominal $/MMBtu)

[redacted]

2.2 ILB Coal

The Illinois Basin ("ILB") coal open position price forecasts were created using the following inputs.

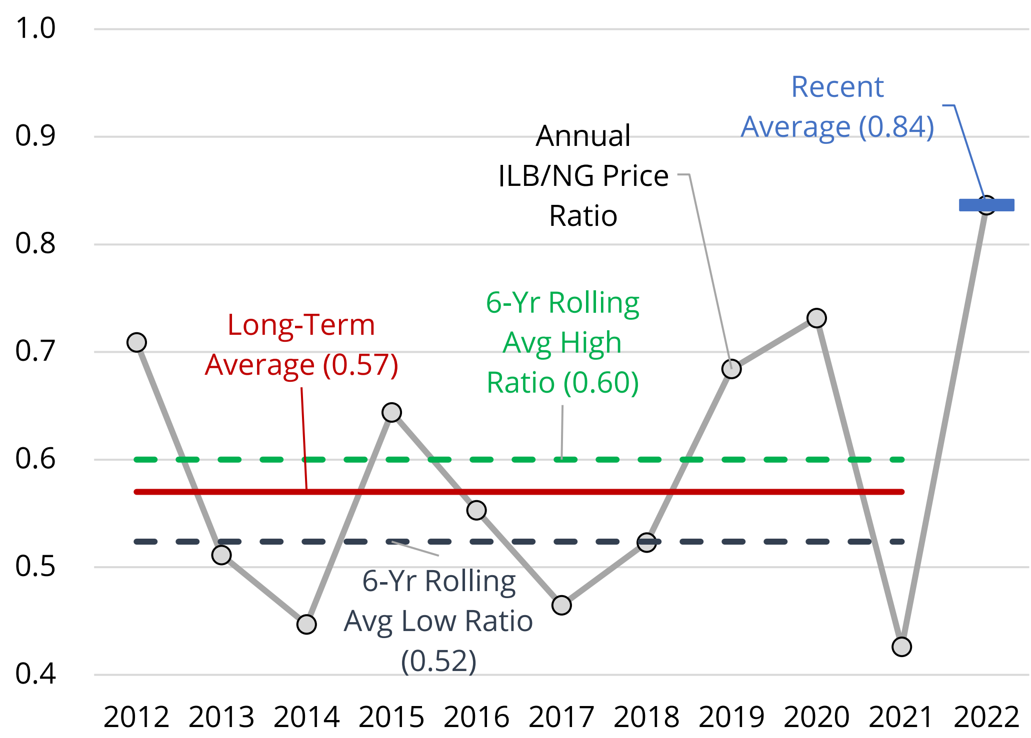
- Bid prices solicited by LG&E/KU's Fuels group
- S&P Global's ("SPG") price forecast
- Historical ILB coal/gas price ratios

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 2027. The fuels group received these quotations in response to a request for quotation (RFQ) issued in Q2 2022. Bid pricing for 2027 was estimated by inflating 2026's price by 2%, due to low bid 2027 volume.

SPG was contracted to produce a coal price forecast to complement the Companies' bid pricing. SPG produced this forecast in Q1 2022 just before a steep increase in commodity prices, so the forecast was adjusted in July 2022 to reflect current natural gas futures prices, which had increased by 25%-30% due to production being tightly balanced with demand as export demand from Europe remained elevated as the supply of Russian coal and gas was reduced.

The long-term ILB price forecasts comprise 6 scenarios that were developed by applying historical relationships between ILB coal and natural gas prices to the natural gas price forecasts. Figure 3 shows that relationship over the past decade.

Figure 2 - 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 vs. demand as depicted by the red line on Figure 3. 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 remaining CTG ratios are atypical. The first such atypical CTG ratio is the recent average ratio (referred to as the "Current CTG"), at 0.84, is the 2022 January through mid September average CTG. This ratio reflects a volatile market and is the basis for the High Gas, Current CTG coal price forecast, which assumes that strong demand for ILB coal continues in both domestic and export markets and that the coal industry constrains supply increases by maintaining low capital expenditures.

The High and Low rolling 6-yr average ratios (referred to as the "High CTG" and "Low CTG") depicted on the graph at 0.60 and 0.52, respectively, are also atypical. They are the maximum and minimum rolling 6-year average ILB coal/Henry Hub gas price ratio over the past 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.

2.2.1 ILB Coal Price Scenario Assumptions

- **Mid Gas, Mid CTG**
  - **2023-2027**: blend of bid prices and the adjusted SPG forecast using the following weightings.
    - 2023: 100% bid pricing
    - 2024: 75% bid pricing/25% adjusted SPG forecast
    - 2025-2027: 50% bid pricing/50% adjusted SPG forecast

Figure 4 shows the resulting near-term ILB price forecast and its components.

Figure 3 - 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, Current CTG** was developed by multiplying the High gas price forecast by the Recent CTG, which is 0.84.
- **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.