2024 Joint Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company

PPL companies

Case No. 2024-00326

Volume III

This Integrated Resource Plan represents a snapshot of an ongoing resource planning process using current business assumptions. The planning process is constantly evolving and may be revised as conditions change and as new information becomes available. Before embarking on any final strategic decisions or physical actions, the Companies will continue to evaluate alternatives for providing reliable energy while complying with all regulations in a least-cost manner. Such decisions or actions will be supported by specific analyses and will be subject to the appropriate regulatory approval processes.

STAFF RECOMMENDATIONS FOR LG&E/KU's 2024 IRP

1) **Load Forecasting**

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

The discussion in Volume I, Section 7 is responsive to this recommendation. Please note that additional documentation of the Companies' load forecasting process is available in Volume II "Electric Sales & Demand Forecast Process."

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

See Volume I, Section 7.(7).(b).4.

c) **LG&E/KU should expand its discussion of DERs to identify resources other than distributed solar that could potentially be adopted by customers and explain how and why those resources are expected to affect load, if at all.**

See Volume I, Section 7.(7).(b).7.

d) **LG&E/KU should expand its discussion of the projected adoption of distributed solar and its effect on load to include separate discussions of assumptions, methodology, and projections for residential, commercial, and industrial customers and separate discussions of assumptions, methodology, and projections for customers interconnected under LG&E/KU's net metering tariffs, qualifying facilities tariffs, and other similar tariffs.**

See Volume I, Section 7.(7).(b).7.

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

See Volume I, Section 7.(7).(b).7.

2) **Demand-Side Resource**

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

See Volume I, Section 8.(3).(e); Volume III, 2024 IRP Resource Assessment Section 3.1; Volume III, 2024 IRP Technology Update Section 3.3.1.

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

See Volume I, Section 8.(3).(e); Volume III, 2024 IRP Resource Assessment Section 3.1; Volume III, 2024 IRP Technology Update Section 3.3.1.

c) **LG&E/KU should describe and discuss all new demand-side resources that they considered, and if a resource was considered but ultimately not included in any model or formal assessment, LG&E/KU should explain each basis for excluding the resource.**

See Volume I, Section 8.(3).(e); Volume III, 2024 IRP Resource Assessment Section 3.1; Volume III, 2024 IRP Technology Update Section 3.3.1.

d) **LG&E/KU should continue the stakeholder process through the DSM Advisory Group and strive to include recommendations and inputs from the stakeholders in the demand-side resource assessment.**

See Volume I, Section 8.(3).(e). DSM Advisory Group minutes and slide presentations are available at https://lge-ku.com/dsm.

e) **LG&E/KU should consider making AMI usage data that is more closely aligned to real-time data available to customers and should consider peak time rebate programs, time-of-use rates, and prepay options for AMI customers.**

Customers can access their interval usage data via the MyMeter tool when they have an AMI meter installed. The usage data is populated in the portal within two to six hours.

The Companies will launch a Peak Time Rebates program in January 2025 as approved in Case No. 2022-00402. For a program overview, see Exhibit JB-1, Section 4.2 Peak Time Rebates.

f) **LG&E/KU should consider and model more aggressive options to increase use of the curtailable service rider and demand conservation program.**

See Volume I, Section 8.(3).(e); Volume III, 2024 IRP Resource Assessment Section 3.1; Volume III, 2024 IRP Technology Update Section 3.3.1.

The Companies received approval of programs enhancements to the Nonresidential Demand Response program in Case No. 2022-00402. The enhancements include a higher incentive paid to participating customers, year-round program availability up to a maximum of one hundred hours, and a target to achieve an enrolled capacity level of nearly 80 MW by the end of 2029. The Curtailable Service Rider (CSR) is a non-DSM rider that the Companies will continue to utilize in accordance with the published tariff.

The Residential and Small Nonresidential Demand Conservation program, as approved in Case No. 2022-00402, will continue to support load control events. This program uses one-way communication to a switch installed at the customer's property. While the technology is subject to failure over time, the Companies do not propose to purchase or capitalize new switches for the Residential and Small Nonresidential Demand Conservation subcomponent for the duration of the approved 7-year plan. However, there is an alternate program that is now available to customers which provides similar benefits to that of the Residential and Small Nonresidential Demand Conservation program; Bring Your Own Device was approved in Case No. 2022-00402.

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

The Companies launched an Optimized EV Charging program in January 2024 as part of Case No. 2022-00402. For details about the program, see Exhibit JB-1, Section 4.1 Connected Solutions. For details on how the program operates, refer to https://www.chargingrewards.com/lge-ku-ev/.

h) **Commission Staff notes the increased nonresidential participation in DSM-EE programs and the impact it has in reducing energy requirements and peak demand and recommends that LG&E/KU continue to identify energy efficiency opportunities for large customers and continue to offer incentives that encourage them to adopt or maintain energy-related technologies, sustainability plans, and long-range energy planning.**

In the most recently filed and approved DSM Filing, Case No. 2022-00402, the Companies included an expanded Business Solutions offering to assist non-residential customers in identifying and implementing energy efficient measures. For details about the program, see Exhibit JB-1, Section 3.4 Business Solutions. For details on how the program operates, as well as how to get started, please refer to https://lge-ku.com/bizrebates. Additionally, as part of the filing, the Companies reopened and expanded the Business Demand Response Program for large customers. For details about the program, see Exhibit JB-1, Section 4.3 Nonresidential Demand Response Program. For details on how the program operates, as well as how to get started, refer to https://lge-ku.com/business/demand-conservation-large.

i) **LG&E/KU should continue to define and improve procedures to evaluate, measure, and verify both actual costs and benefits of energy savings based on the actual dollar savings and energy savings.**

The Companies contracts with a third-party partner to perform independent Evaluation, Measurement, and Verification (EM&V) studies of its DSM/EE programs. The Companies EM&V third-party partner contract expired and a request for proposals is being conducted. The results of these evaluations provide helpful information to the Companies to confirm program processes and savings values or identify recommended areas of improvement in either or both areas, processes, or savings methodology.

j) **LG&E/KU should file to expand or revise current 2019-2025 DSM/EE Plan if ongoing resource assessments indicate that doing so is the least-cost option for meeting projected load.**

The Companies submitted a new DSM Plan in December 2022 for the program period of 2024 to 2030. This plan was filed alongside the CPCN and was part of Case No. 2022-00402. The DSM Plan was approved in November 2023 and currently being implemented in accordance with the outlined schedule.

3) **Supply-Side Resource**

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

See Volume III – 2024 IRP Technology Update, which includes a discussion of nuclear in Section 3.1 regarding fully dispatchable resources. The Companies modeled a small modular nuclear resource option, which was selected as part of a least-cost resource portfolio in some scenarios.

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

See Volume III – 2024 IRP Technology Update.

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

The Companies evaluated wind resources located in Indiana as an alternative to Kentucky-based wind and included associated transmission costs.

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

The 2024 IRP considers generic resources as future expansion alternatives, rather than resources located at specific sites. Generally, costs are assumed to include interconnection costs but do not consider transmission system upgrade costs. See Section 5.5 of Volume III – 2024 IRP Resource Assessment.

e) **LG&E/KU should include a more detailed and broader explanation of potential of potential and expected carbon regulation, given the significant effects such regulation could have on future resources, including a description of potential carbon regulation**

that would affect the useful life or cost of any resource, an explanation of the risk or likelihood and potential timing of such regulation, an explanation of how LG&E/KU accounted for the risk of each such regulation in its assessment of resources, e.g. modeling the cost of a resource using a shorter useful life or modeling a carbon cost, and an explanation of why LG&E/KU accounted for the risk in that manner. The potential regulations discussed should include at minimum the NSPS and carbon pricing or a carbon tax.

The 2024 IRP includes a scenario that assumes the existing Greenhouse Gas Rules survive court challenges and are implemented as finalized. See Section 4.1.3 in Volume III – 2024 IRP Resource Assessment.

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

See Section 5.6 of Volume III – 2024 IRP Resource Adequacy Analysis.

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

The 2024 IRP considers only generic resources as potential future resource options. Any opportunities to obtain specific third-party resources would be identified through an actual RFP. Any opportunities for resource partnerships would be addressed through a CPCN filing.

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

See the response to 3(g).

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

With the uncertainty regarding environmental regulations, the Companies have assumed that OVEC would operate economically through the end of the current agreement in 2040, except for the scenario with Greenhouse Gas regulations in which OVEC is assumed to retire by 2032.

4) **Integration**

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

Volume III – 2024 IRP Resource Assessment explains in detail the 2024 IRP's process for resource optimization throughout the planning period.

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

See Volume III – 2024 IRP Resource Assessment.

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

See Volume III – 2024 IRP Resource Assessment.

2024 IRP

Technology Update

PPL companies

Generation Planning & Analysis
October 2024

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1 Executive Summary

Table 1, Table 2, and Table 3 list the resources that were selected for evaluation in the Resource Assessment. Fully dispatchable resources are resources that can be dispatched any time and operated for days or months at a time. Fully dispatchable resources include large-frame simple-cycle combustion turbines ("SCCT"), natural gas combined cycle combustion turbines ("NGCC"), and small modular nuclear reactors ("SMR"). Renewable resource options include land-based wind resources located in Kentucky and Indiana as well as utility-scale solar resources located in Kentucky. Limited-duration resources can only be dispatched several hours at a time and in the case of the Companies' dispatchable demand-side management ("DSM") and Curtailable Service Rider ("CSR") programs and measures, have limited availability. Limited-duration resources include 4-hour and 8-hour battery energy storage systems ("BESS"), dispatchable DSM program measures, and an expansion of the Companies' CSR-2 tariff rider. Resource costs and assumptions are based on the "Moderate" scenario in National Renewable Energy Laboratory's 2024 Annual Technology Baseline ("NREL's 2024 ATB"), updated cost estimates for resources contemplated in the Companies' 2022 CPCN filing, and the Companies' own analysis.[1]

[1] See https://atb.nrel.gov/ for NREL's 2024 ATB.

Table 1: Fully Dispatchable Resources (2030 Installation; 2030 Dollars)

	SCCT	NGCC	SMR
Summer Capacity (MW)[2]	243	645	300
Winter Capacity (MW)	258	660	300
Heat Rate (MMBtu/MWh)[3]	9.5	6.3	9.2
Capital Cost ($/kW)[4]	1,636	2,121	9,765
Fixed O&M ($/kW-yr)[5]	6.9	7.8	166
Firm Gas Cost ($/kW-yr)[6]	19	15	N/A
Variable O&M ($/MWh)[7]	N/A	0.23	3.17
Start Cost ($/Start)[8]	[redacted]	N/A	N/A
Hourly Operating Cost ($/Hour)[9]	N/A	[redacted]	N/A
Fuel Cost ($/MWh)[10]	[redacted]	[redacted]	13.45
Investment Tax Credit[11]	N/A	N/A	40%
Earliest In-Service Year[12]	2030	2030	2039

[2] Capacity is the net installed capacity ("ICAP").

[3] Heat rate is the full load net heat rate.

[4] Capital cost is the overnight capital expenditure required to achieve commercial operation. Cost of financing is modeled through construction profiles for each resource type.

[5] Fixed operation and maintenance costs are operation and maintenance costs that do not vary with generation output. For SCCT and NGCC resources, fixed O&M includes fixed costs for a long-term service agreement ("LTSA").

[6] Firm gas transportation costs are costs associated with reserving firm gas-line capacity.

[7] Variable operation and maintenance costs are operation and maintenance costs incurred on a per-unit-energy basis.

[8] Start costs are starts-based variable LTSA costs for SCCT.

[9] Hourly operating costs are hours-based variable LTSA costs for NGCC.

[10] Fuel cost is the product of the unit's heat rate and the assumed cost of fuel.

[11] In accordance with the current tax credits, the Companies assumed nuclear SMR resources that are in-service by year 2039 would begin construction by year 2033 and receive the full credit; resources that are in-service in year 2040 would begin construction in 2034 and receive 75% of the credit; resources that are in-service in year 2041 would begin construction in 2035 and receive 50% of the credit; and resources that are in-service in year 2042 or later would begin construction in 2036 or later and not receive any tax credits. Further cost reductions may be possible by utilizing existing sites.

[12] Earliest in-service year is the first year the Companies expect a resource can be feasibly built based on permitting and construction timelines as well as lead times for electrical equipment such as generator step up transformers.

Table 2: Renewable Resources (2030 Installation; 2030 Dollars)

	KY Solar	KY Wind	IN Wind
Summer Capacity (MW)[2]	100+	100+	100+
Winter Capacity (MW)[2]	100+	100+	100+
Contribution to Summer Peak[13]	84%	0%	0%
Contribution to Winter Peak[13]	0%	0%	0%
Net Capacity Factor[14]	26.3%	36.3%	43.6%
Capital Cost ($/kW)[4]	1,902	2,460	2,238
Fixed O&M ($/kW-yr)[5]	17	33	36
Transmission Cost ($/kW-yr)[15]	N/A	N/A	67
Production Tax Credit ($/MWh)[16]	30.25	27.50	27.50
Earliest In-Service Year[12]	2028	2028	2028

[13] Contribution to peak is the assumed percentage of nameplate capacity that is available on average during the peak hour. For wind, zero percent contributions to peak were used to model wind as an energy-only resource. See section 3.2.3 for more details.

[14] Net capacity factor is the ratio of the unit's expected average hourly output over the course of the year to the unit's rated capacity.

[15] Transmission cost is based on current firm transmission costs to import power from an Indiana resource.

[16] In accordance with the current tax credits, the Companies assumed solar, wind, and BESS resources that are in-service by year 2036 would begin construction by year 2033 and receive the full credit; resources that are in-service in year 2037 would begin construction in 2034 and receive 75% of the credit; resources that are in-service in year 2038 would begin construction in 2035 and receive 50% of the credit; and resources that are in-service in year 2039 or later would begin construction in 2036 or later and not receive any tax credits. Production tax credits are included for the first 10 years of each solar or wind resource.

Table 3: Limited-Duration Resources (2030 Installation; 2030 Dollars)

	BESS		Dispatchable DSM[17]			
	4-Hour	**8-Hour**	**BYOD Energy Storage**	**BYOD Home Generators**	**BDR 50-200 kW**	**CSR[18]**
Summer Capacity (MW)[2]	100+	100+	0.89	0.85	1.45	100
Winter Capacity (MW)[2]	100+	100+	0.89	0.85	1.45	100
Capacity Contribution[19]	85%	93%	39%	39%	39%	39%
Round-Trip Efficiency	87%	87%	N/A	N/A	N/A	N/A
Capital Cost ($/kW)[4]	2,049	3,598	N/A	N/A	N/A	N/A
Fixed O&M ($/kW-yr)[5]	25	44	N/A	N/A	N/A	81
Investment Tax Credit[16]	50%	50%	N/A	N/A	N/A	N/A
Earliest In-Service Year[12]	2028	2028	2027	2027	2028	2028

Resource costs in NREL's 2024 ATB are provided in real 2022 dollars and must be converted to nominal dollars. In doing this, the Companies ensured that nominal capital costs for SCCT, NGCC, solar, and BESS aligned with recent capital cost estimates for an SCCT, the Brown 12 NGCC, Mercer County Solar, and Brown BESS, respectively. Assuming an annual inflation rate of 2.3 percent beyond 2024, this process produces implied inflation rates for each technology through 2024. In the absence of a recent capital cost estimate for wind, the Companies estimated the capital cost of wind by applying the implied inflation rate for solar to the "Moderate" capital cost estimate for wind in NREL's 2024 ATB. All costs for SMR were also based on the Moderate cost scenario and converted from real to nominal dollars assuming 2.3 percent inflation in all years.[20]

The earliest new NGCC or SCCT can likely be added is 2030 due to lead times for the generation equipment, transmission interconnection studies, and the resulting potential transmission upgrades, which could require long lead times for equipment such as transformers. The earliest a small modular nuclear reactor can be added is assumed to be 2039 due to the time required for permitting and construction. All other resources are assumed to be available in 2028.

Table 4 shows how capital costs ($/kW) and the sum of capital and non-fuel O&M ($/kW-yr) for selected resources have increased from the Companies' 2021 Integrated Resource Plan ("IRP") and their 2022 certificate of public convenience and necessity ("CPCN") filing.[21] Capital costs for SCCT and NGCC technologies have increased more than capital costs for solar and BESS. In addition, compared to the 2021

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

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

[19] The analysis to determine capacity contribution is summarized in IRP Volume III (2024 IRP Resource Adequacy Analysis).

[20] See Section 4 for further details.

[21] The sum of capital and non-fuel O&M ($/kW-yr) reflects the levelized cost of capacity including capital, fixed O&M, and firm gas transportation costs, as well as the effect of production and investment tax credits as applicable.

IRP, the impact of the Inflation Reduction Act's ("IRA's") tax incentives on solar and BESS costs is much greater (e.g., the IRA's production tax credit reduces the sum of capital and non-fuel O&M for solar by 27%, whereas the ITC previously available for solar reduced this sum by only 20%).[22] Finally, while the costs of SCCT and BESS are not directly comparable due to their different operating characteristics, this is the first time the sum of capital and non-fuel O&M for BESS (with tax incentives) is lower than SCCT.

Table 4: Capital Costs ($/kW) and Sum of Capital and Non-Fuel O&M ($/kW-yr) for Selected Resources

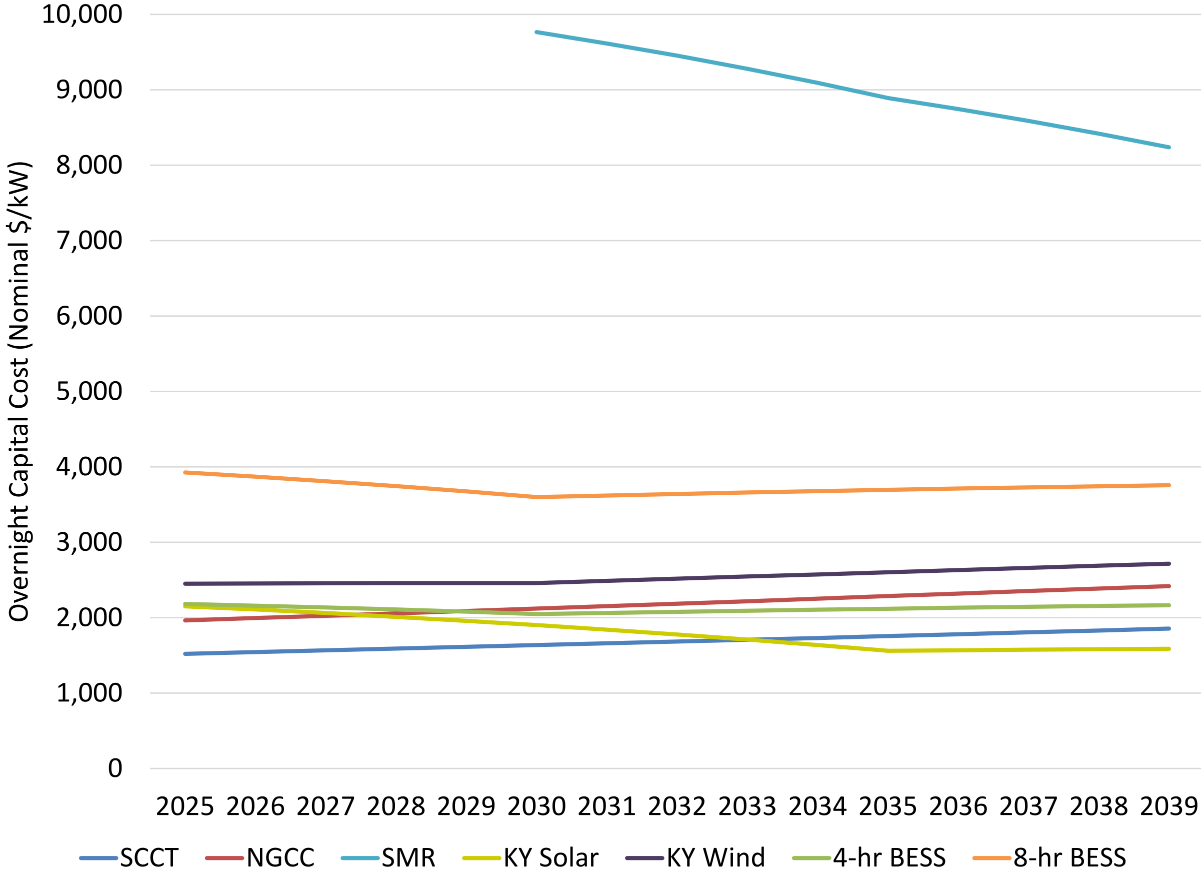
	2021 IRP 2022 $		**2022 CPCN[23] 2026/2027 $**		**2024 IRP 2030 $**	
Resource	**Capital ($/kW)**	**Capital + Non-Fuel O&M ($/kW-yr)**	**Capital ($/kW)**	**Capital + Non-Fuel O&M ($/kW-yr)**	**Capital ($/kW)**	**Capital + Non-Fuel O&M ($/kW-yr)**
SCCT	885	127	679	83	1,636	182
NGCC	1,008	140	1,048	117	2,121	222
Solar No ITC/PTC	1,305	126	1,462	136	1,902	183
Solar with ITC/PTC		101		90		133
4-hr BESS No ITC	1,274	172	2,159	300	2,049	265
4-hr BESS with ITC		N/A		138		138

Figure 1 contains the forecast of capital costs through the end of the IRP planning period for fully dispatchable, renewable, and BESS resources. Notably, not only are significant tax incentives available for renewables and BESS, but the capital costs for these technologies are forecast to decline in nominal terms for several years before escalating slowly through the end of the analysis period. As Figure 1 demonstrates, BESS capital costs decline nominally through 2030 and solar capital costs decline through 2035 before increasing slowly. Conversely, capital costs for SCCT and NGCC technologies are forecast to increase from the beginning of the analysis period and at higher rates than either renewables or battery storage in the latter parts of the analysis period.

[22] Tax incentives are available for solar and BESS via the IRA provided construction begins by 2035.

[23] 2022 CPCN values reflect costs as filed. The Companies provided an update to NGCC capital costs of $1,466/kW based on bids received in their response to the Joint Intervenors' post-hearing data request 4.1 in Case No. 2022-00402.

Figure 1: Generation Technology Cost Forecast (Nominal Dollars)



2 Introduction

The Companies' IRP objective is to create a resource portfolio that serves customers reliably at the lowest reasonable cost. In seeking to meet that objective, the Companies are agnostic regarding generating technologies, and they consider a range of supply options. The Companies seek to leverage the strengths of different supply options to create a generation portfolio that can reliably serve customers in all hours of the year, day and night, under a wide range of weather conditions.

Precisely because when and under what conditions a generator can operate are key to reliably serving customers, it is important to understand at the outset the limitations of a metric frequently used—and misused—to compare generation technologies, namely levelized cost of energy ("LCOE"). LCOE is an all-in measure of a generator's cost—capital, operating and maintenance, and fuel cost—spread over the energy the generator produces, resulting in a $/MWh value that communicates nothing about whether a generator can or will produce energy when customers need it. Thus, using LCOE alone to compare generating technologies with different production characteristics is both simplistic and inconsistent with the objective of creating a resource portfolio that *reliably* serves customers—in all hours of the year, day and night, under a wide range of weather conditions—at the lowest reasonable cost.

2.1 Different Generation Technologies Have Different Strengths and Limitations

The Companies' resource planning process must ensure their resource portfolio maintains the operational capabilities and attributes needed to serve customers in every moment. This process begins with an understanding of the way the Companies' customers use electricity. Summer peak demands typically occur in the afternoons, while winter peaks typically occur in the mornings or evenings during non-daylight hours. In 2023, approximately 41% of annual energy requirements and 53% of winter energy requirements were consumed at night. The Companies' hourly demands can vary by nearly 600 MW from one hour to the next and 3,000 MW in a single day. In addition, instantaneous demands can be almost as volatile.

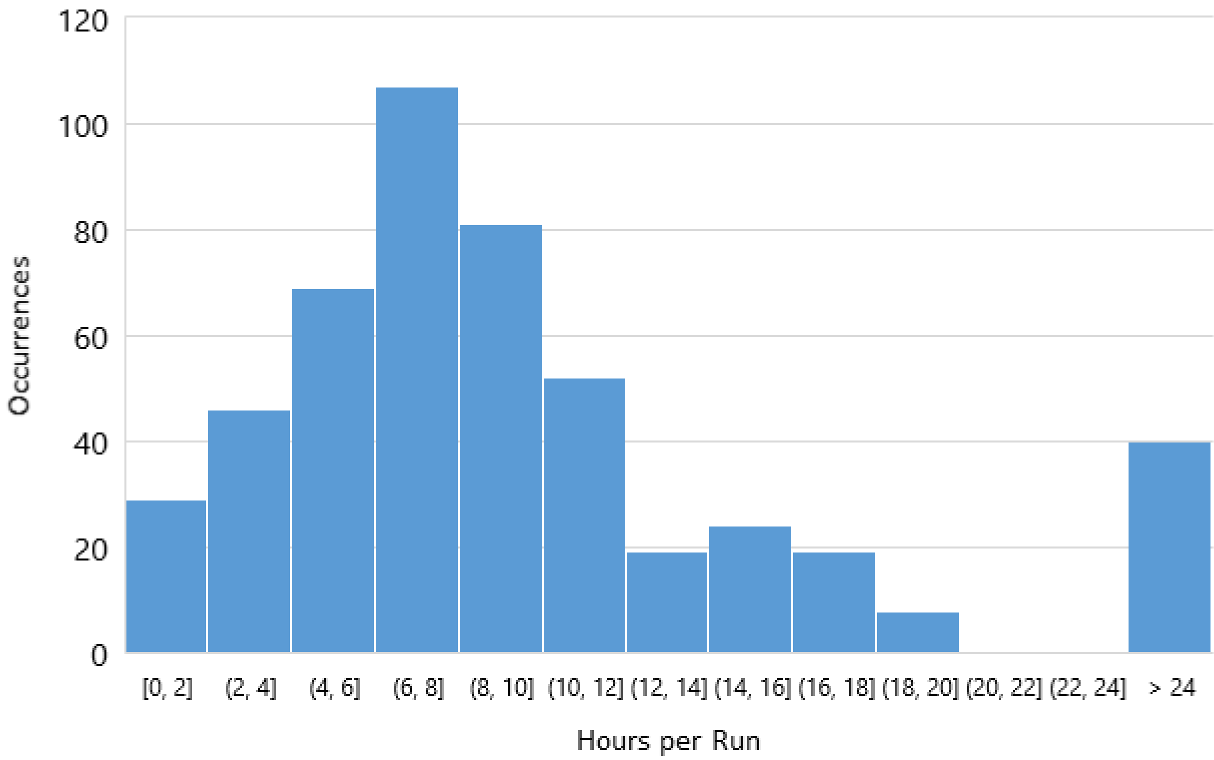
The Companies operate a resource portfolio comprising NGCC, coal, SCCT, hydro, and solar resources, and dispatchable demand-side management ("DSM") programs and measures, all of which have different characteristics and capabilities. For example, the Companies' NGCC and coal resources are capable of producing low-cost energy for weeks at a time. NGCC resources have higher capital costs but lower energy costs than SCCTs, though they have similar load following capabilities as SCCTs. SCCT resources have higher energy costs than coal or NGCC resources but are designed to start very quickly and operate for shorter periods and are needed to respond to unit outages and serve load during peak hours. One shared feature of coal, SCCT, and NGCC units is that they can produce power in all hours of the year. Hydro and solar resources hedge fuel cost and CO_2 regulation risk but can produce energy only when water or sunshine are available, making their production necessarily intermittent and variable. The Companies' Curtailable Service Rider ("CSR") and dispatchable DSM program measures improve reliability primarily during extreme weather events. Economically and reliably serving load at all moments and in all seasons and weather conditions typically requires a mixture of resources, blending their various performance and cost characteristics to offset the weaknesses of one with the strengths of another. In actual operation, as well as in modeling exercises, the Companies dispatch their resources subject to load, economic, and operating constraints.

In 2022, the Companies received approval to construct a 125 MW BESS at the Brown Station. BESS is not a generation source per se; rather, it allows previously generated energy to be used at other times, albeit a reduced amount of energy as discussed below. The cost of BESS is a function of its charging capacity (i.e., the maximum amount of electricity that can be charged or discharged at any given time) and its duration (i.e., the number of hours it can be charged or discharged at its charging capacity). A battery's storage capacity is the product of its charging capacity and duration. For example, a 1 MW, 4-hour battery can store up to 4 MWh. In addition to the cost of the batteries, the cost of BESS includes energy losses associated with charging and discharging the battery. The Companies assumed round-trip energy losses for BESS at approximately 13% (i.e., for every MWh charged, 0.87 MWh can be discharged).

Understanding these constraints on BESS performance helps explain why BESS cannot fully replace a like amount of SCCT capacity, and simply pairing solar with relatively small amounts of battery storage cannot produce the same generation profile as conventional, fossil-fueled resources.[24] To illustrate further, Figure 2 below shows the distribution of run times for the Trimble County SCCTs in 2023 (excluding test runs). When the Companies dispatched the Trimble County SCCTs economically to serve load in 2023, 81% of runs were greater than four hours and 35% of the runs were greater than eight hours. To achieve this kind of performance and operational flexibility with BESS would require greater amounts of batteries, as well as the resources to charge them so they could be available when needed. The Companies consider the strengths and limitations of resources when planning a generation portfolio that can reliably serve customers under a range of weather conditions.

[24] Pairing a BESS only with intermittent resources such as solar would reduce charging flexibility and capability, meaning that a greater quantity of batteries or intermittent resources would be required to be as dispatchable as SCCTs.

Figure 2: Distribution of Run Times for Trimble County SCCTs in 2023



2.2 Replacing Dispatchable Resources with Renewables and BESS Can Be Costly, Especially When Serving Nighttime Energy Requirements

Replacing fully dispatchable resources with renewables and battery storage is a common resource planning question, particularly as more tax incentives have become available for these technologies. Because solar resources can produce energy only during the day, serving load at night requires energy storage. The assumed LCOE of KY Solar installed in 2030 is $60.18/MWh. With the added cost of 8-hour BESS and 13% energy losses, a solar-plus-battery-storage system dedicated to serving nighttime energy would cost $200.10/MWh. Because in this example the BESS can be charged only by the solar array, its availability is limited on nights following cloudy days. The nameplate capacity of solar required to serve load around-the-clock is significantly greater than the load being served because solar is needed during the day to not only serve load but to charge the BESS for serving load during nighttime or cloudy hours.

Table 5 contains actual 2023 generation for the Companies' Mill Creek 3 coal unit. For this discussion, the Companies computed the cost of replacing Mill Creek 3's generation with renewables and BESS. This cost was computed for replacing Mill Creek 3's generation during daylight hours, during nighttime hours, and in total. To do this, the Companies used a simple Excel model to develop least-cost renewable portfolios for each of these load profiles. The first renewable portfolio includes KY solar and 8-hour BESS as resource options; the second renewable portfolio includes KY solar, KY wind, and 8-hour BESS as resource options. Table 2 and Table 3 in the Executive Summary contain the assumed costs for these resources.

Table 5: 2023 Mill Creek 3 Generation and Capacity Factor

Resource	Capacity (MW)[25]	2023 Capacity Factor	2023 Generation (GWh)		
			Total	Daylight Hours	Nighttime Hours
Mill Creek 3 Coal	391	68%	2,335	1,266	1,068

For this analysis, the Companies developed geographically diverse solar and wind generation profiles that reflect 1,000 MW systems comprising ten 100 MW systems located throughout the state. In 2023, solar would have had a 23% capacity factor. Wind would have operated at a 34% capacity factor, somewhat higher than solar and with generation in different hours.

Notably, these renewable portfolios would require numerous new generation sites and potentially significant transmission system upgrades. Because it is not practical to estimate transmission system upgrade costs for numerous generation sites that do not currently exist, this analysis assumes no cost for transmission system upgrades. In addition, this analysis does not consider potentially significant challenges with permitting and constructing these projects.

Table 6 below summarizes the results of this analysis. Kentucky's poor wind conditions generally and the prevalence of clouds in the winter when the availability of sunlight is already low due to fewer daylight hours exacerbate the cost of replacing coal generation with renewables and BESS. Indeed, 46 percent of the energy in the Mill Creek 3 generation profile is produced during nighttime hours. For a renewable portfolio, that energy must be concurrently produced by wind or by additional solar resources during daylight hours and stored in the BESS for nighttime use. Approximately 8.4 MW of solar and 6.6 MW of 8-hour BESS are needed to replace 1 MW of Mill Creek 3's generation profile. When wind is included as a resource option, 3.1 MW of solar, 2.0 MW of wind, and 2.3 MW of 8-hour BESS are needed. As the need for overnight generation decreases, the quantities of renewables and BESS needed to replace the generation profile decreases.

[25] Capacity reflects Mill Creek 3's net summer rating in 2023.

Table 6: Renewable Replacement Portfolios

Generation Resource	Coal (Mill Creek 3; 391 MW)	Daylight Only Coal (391 MW)	Nighttime Only Coal (391 MW)
	Generation Profile		
	Renewable Portfolio Needed to Replace Generation Profile		
Renewable Portfolio 1: Solar + BESS	3,300 MW Solar; 2,600 MW BESS	1,400 MW Solar; 1,000 MW BESS	2,000 MW Solar; 1,700 MW BESS
Renewable Portfolio 2: Solar + Wind + BESS	1,200 MW Solar; 800 MW Wind; 900 MW BESS	800 MW Solar; 200 MW Wind; 400 MW BESS	800 MW Solar; 500 MW Wind; 700 MW BESS
	Normalized Portfolio (per MW of Generation Replaced)		
Renewable Portfolio 1: Solar + BESS	8.4 MW Solar; 6.6 MW BESS	3.6 MW Solar; 2.6 MW BESS	5.1 MW Solar; 4.3 MW BESS
Renewable Portfolio 2: Solar + Wind + BESS	3.1 MW Solar; 2.0 MW Wind; 2.3 MW BESS	2.0 MW Solar; 0.5 MW Wind; 1.0 MW BESS	2.0 MW Solar; 1.3 MW Wind; 1.8 MW BESS

2.3 LCOE for a Technology Varies Greatly Depending on the Load Profile Being Served

Table 7 contains the LCOE for the renewable portfolios needed to replace the coal generation profiles as well as the LCOE for replacing the coal generation profiles with NGCC and SCCT units. The LCOE for replacing coal generation with renewables and BESS varies significantly depending on the type of generation profile needed to serve customers' load. A portfolio of solar, wind, and BESS is less expensive than just solar and BESS, but the cost of either renewable portfolio is significantly more expensive than new NGCC or SCCT resources.

Table 7: LCOE ($/MWh)

Generation Resource	Mill Creek 3 Coal 68% Capacity Factor	Daylight Only Coal 37% Capacity Factor	Nighttime Only Coal 31% Capacity Factor
	Generation Profile		
Renewable Portfolio 1	456	337	632
Renewable Portfolio 2	231	192	353
NGCC	65-104	98-137	112-151
SCCT	68-127	97-155	109-167

As seen in Table 7, NGCC is the least-cost resource for providing a dispatchable Mill Creek 3 coal generation profile ($65-104/MWh based on the range of natural gas prices assumed in the 2024 IRP).[26] The LCOE for the solar, wind, and BESS portfolio (i.e., Renewable Portfolio 2) needed to provide the same generation profile is $231/MWh, while the LCOE for the solar and BESS portfolio (i.e., Renewable Portfolio 1) is even higher at $456/MWh. This analysis demonstrates the high cost of serving nighttime energy

[26] Notably, if customer load requires it, an NGCC can operate at higher capacity factors and its LCOE at higher capacity factors is lower.

requirements with renewables and battery storage. The LCOE for both Renewable Portfolio 1 and Renewable Portfolio 2 are lower for the daylight only coal generation profile, and much higher for the nighttime only coal generation profile. Depending on the generation profile needed to serve load, a given technology can have varying LCOEs.

In any given year, the system load factor ranges between 56 and 69 percent, depending on weather, and approximately 43 percent of energy is consumed during nighttime hours. Like the cost of replacing fully dispatchable resources with renewables, the cost of serving total load exclusively with renewables is high.

When evaluating resources for the purpose of reliably serving load at the lowest cost, the analysis must consider the load being served and the operating characteristics of generation alternatives. As the discussion above shows, comparing LCOE alone for technologies with different operating characteristics is not appropriate because the technologies are not equally capable of serving the same load.

3 Generation Technology Options

The following sections include a discussion of the resource options considered in this analysis along with the rationale for selecting the resource options evaluated in the Resource Assessment.

3.1 Fully Dispatchable Resources

3.1.1 Natural Gas Simple-Cycle Combustion Turbines

Natural gas-fired SCCT options include traditional frame machines and aero-derivative combustion turbines. They are typically used for peaking power due to their fast ramp rates and relatively low capital costs. Aero-derivative machines are flexible, slightly more efficient than larger frame units, and can be installed with high temperature oxidation catalysts for carbon monoxide control and selective catalytic reduction ("SCR") for nitrogen oxides ("NO_x") control, which allows them to be located in areas with air emissions concerns. Additionally, utilities with significantly higher renewable penetration are building aero-derivatives for integration purposes.[27] While not quite as efficient or flexible, frame simple-cycle machines can also be installed with emission controls and are much less expensive to install and operate on a $/kW basis. In practice, once a need for fully dispatchable peaking capacity is identified, the Companies would conduct additional analysis to determine the optimal resource mix. The cost of SCCT in the 2024 ATB reflects the cost of frame simple-cycle machines. For these reasons, frame simple-cycle machines were evaluated in the Resource Assessment. The cost and assumptions for SCCT resources are based on the Companies' recent cost estimates and assumptions for SCCT. NREL's 2024 ATB was used for escalation assumptions.[28]

3.1.2 Natural Gas Combined-Cycle

NGCC units use both gas and steam turbines together to produce up to 50% more electricity than SCCT using the same amount of fuel. The steam turbine uses waste heat from the gas turbine to generate additional electricity. NGCC units are dispatchable in all weather conditions, can respond to significant load swings due to their high ramping capabilities, and can be cycled overnight. For these reasons, NGCC units were evaluated in the Resource Assessment.[29] The cost and assumptions for NGCC resources are based on the Companies' recent cost estimates and assumptions for Brown 12 NGCC. NREL's 2024 ATB was used for escalation assumptions.[28]

Another notable characteristic of NGCC units is their ability to use hydrogen instead of natural gas as an alternative fuel source. While the development of green hydrogen is uncertain and the U.S. Environmental Protection Agency ("EPA") removed hydrogen as a compliance option in the final Clean Air Act Section 111(b) greenhouse gas rules, the Companies recognize this potential advantage of NGCC technology.

3.1.3 Nuclear

Nuclear power refers to the generation of electricity using a fission reaction, where the nucleus of one atom is split into two or more nuclei, to produce heat which in turn drives a steam turbine to produce electricity. Nuclear generation emits no air pollution, including zero CO_2. The United States has 94

[27] https://www.powermag.com/srp-approves-arizona-expansion-with-16-gas-fired-turbines/

[28] See Section 4 for further details.

[29] The Companies evaluated NGCC units in a 1-on-1 configuration, consistent with their planned Mill Creek 5 unit.

operable reactors at just under 97 total GW of nuclear fission capacity in operation at this time, with the most recent additions of units 3 and 4 at the Vogtle plant in Georgia.[30] These units were originally expected to cost $14 billion and begin commercial operation in 2016 and 2017, but the project experienced significant construction delays and cost overruns. Ultimately, the units began commercial operation seven years later than expected in 2023 and 2024, and Georgia Power now estimates the total cost of the project to be more than $30 billion.[31]

Nuclear power faces several challenges including high capital costs, inability to ramp up or down quickly to follow load, economic competitiveness within energy markets, permitting, waste disposal, and public perception. At current nuclear capacity cost, which is greater than $7,000/kW, constructing a relatively small 600 MW nuclear plant is expected to cost approximately $4.2 billion. Environmental permitting and waste disposal is a challenge that was partially addressed by Kentucky 17RS SB 11. Kentucky 17RS SB 11 amended KRS 278.610 to require that nuclear power facilities have a plan for the storage of nuclear waste rather than a means of permanent disposal. Previously a federal permanent nuclear waste storage facility was required but with 17RS SB 11, construction of a new nuclear plant is allowed as long as there is a plan for storing the nuclear waste that is approved by the Nuclear Regulatory Commission ("NRC").

Small modular reactors ("SMR") and nuclear fusion are two nuclear technologies that are not commercially available but are actively being researched. SMR nuclear fission plants are smaller in capacity than modern fission plants and have the advantages of smaller footprints and reduced capital costs. The United States Department of Energy is working to make SMR technology commercially available by the late 2020s to early 2030s.[32] Nuclear fusion refers to the generation of energy by the combining of atoms rather than splitting. In 2022, an experiment at the National Ignition Facility achieved a key scientific milestone in nuclear fusion research, generating more energy than the amount of direct energy spent to start the reaction. However, the task of extracting energy from fusion to provide an economical source of electricity presents several complex systems engineering problems that have yet to be solved.[33]

In December 2019, the Tennessee Valley Authority ("TVA") became the first in the nation to obtain approval for an early site permit from the NRC to potentially construct and operate SMRs at its Clinch River Nuclear ("CRN") Site. In February 2022, the TVA Board of Directors approved an initial $200 million for the project, and in August 2024, another $150 million was approved, for a total of $350 million so far.[34] TVA announced in March 2023 that it is preparing a construction permit application for the project.[35] According to TVA, "[T]he decision to potentially build small modular reactors is an ongoing discussion as part of the asset strategy for TVA's future generation portfolio."[36]

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[30] See https://world-nuclear.org/information-library/country-profiles/countries-t-z/usa-nuclear-power.

[31] See https://www.eia.gov/todayinenergy/detail.php?id=61963.

[32] See https://www.energy.gov/ne/advanced-small-modular-reactors-smrs.

[33] See https://www.gao.gov/products/gao-23-105813.

[34] See https://www.tva.com/newsroom/press-releases/tva-board-approves-additional--150-million-in-advanced-nuclear-funding.

[35] See https://www.wbir.com/article/news/local/kingston-harriman-roane/tva-nuclear-energy-knoxville-clinch-river-roane-county/51-e79358d4-2c35-4402-bdb2-48a28b4b7292.

[36] See https://www.tva.com/energy/technology-innovation/advanced-nuclear-solutions.

Regarding SMR technology, there are significant challenges in estimating the cost for a technology that has not been built, especially when future cost estimates also depend on the widespread adoption of that technology in order to lower its "per unit" cost. In addition, the nuclear industry has a long history of actual project costs and construction times being significantly greater than original project estimates.[37] According to one media source, a 2014 academic study examined 180 nuclear power projects around the world and found 175 of them exceeded the initial budget by an average of 117% by the time they were completed, and they took, on average, 64% longer than projected.[38] While the successful development of SMRs would certainly aid in a future carbon-free generation world, numerous government policy, supply-chain, and technology hurdles will likely need to be overcome to move this technology forward.[39]

The nuclear SMR option was evaluated in the Resource Assessment with the assumption that it could be constructed as early as 2039. The cost of SMR considers the impact of the IRA and includes an investment tax credit of 40% with the energy community bonus for new SMR resources.[40] The cost and assumptions for SMR resources are based on the "Moderate" scenario in NREL's 2024 ATB.[41]

3.1.4 Carbon Capture and Sequestration Retrofits

Carbon capture and sequestration ("CCS") can be added to existing NGCC or coal-fired generation, or it can be included on a new NGCC. Retrofitting existing units results in a decrease in available capacity and an increase in heat rate, to account for the significant energy required to operate the CCS equipment. Table 8 shows cost and operating assumptions for coal and NGCC CCS retrofits from NREL's 2024 ATB, which does not include operating costs for CO_2 transportation and storage.[42]

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[37] See https://assets.jpmprivatebank.com/content/dam/jpm-pb-aem/global/en/documents/eotm/electravision.pdf at p. 24-25.

[38] See https://www.utilitydive.com/news/nuscale-uamps-project-small-modular-reactor-ramanasmr-/705717/.

[39] See https://www.woodmac.com/horizons/making-new-nuclear-power-viable-in-the-energy-transition/ at section titled "What will it take to go nuclear?"

[40] In accordance with the current tax credits, the Companies assumed nuclear SMR resources that are in-service by year 2039 would begin construction by year 2033 and receive the full credit; resources that are in-service in year 2040 would begin construction in 2034 and receive 75% of the credit; resources that are in-service in year 2041 would begin construction in 2035 and receive 50% of the credit; and resources that are in-service in year 2042 or later would begin construction in 2036 or later and not receive any tax credits. Further cost reductions may be possible by utilizing existing sites.

[41] See Section 4 for further details.

[42] See https://atb.nrel.gov/. The Companies inflated NREL's cost forecasts, which were provided in real 2022 dollars, to nominal dollars. See Section 4.1 for further details.

Table 8: CCS Retrofit Assumptions (2030 Installation; 2030 Dollars)

	Coal CCS Retrofit		**NGCC CCS Retrofit**	
	90% CCS	**95% CCS**	**90% CCS**	**95% CCS**
Net Output Penalty (% change from pre-retrofit)	-22.2%	-23.3%	-11.6%	-12.2%
Heat Rate Penalty (% change from pre-retrofit)	+28.6%	+30.5%	+10.9%	+11.5%
Capital Cost ($/kW)	2,315	2,417	1,235	1,289
Fixed O&M ($/kW-yr)	183	187	74	76
Variable O&M ($/MWh)	20.42	20.87	5.49	5.63

CCS retrofit is specified as a compliance option in the EPA's Clean Air Act Section 111(b) and (d) greenhouse gas ("GHG") regulations, but various organizations have articulated concerns regarding its viability. For example, the Midcontinent Independent System Operator, Inc. ("MISO"), PJM Interconnection L.L.C. ("PJM"), Southwest Power Pool, Inc. ("SPP"), and Electric Reliability Council of Texas, Inc. ("ERCOT") recently stated:

> However, none of EPA's projected timeframes reflect historical rates of adoption of CCS technology for electrical generation purposes, nor does EPA adequately consider the risks that the technologies will not mature in time for EGU owners to deploy them. EPA's BSER determination is overly optimistic regarding the commercial viability of CCS today and downplays the cost and practicalities of developing entirely new supporting infrastructure within the timeframes and at the costs projected.
>
> Given the implausibility of CCS as a viable option for mitigating CO2 emissions and the resulting likelihood of premature retirements of fossil-fired generators, the Final Rule is likely to hamper *Amici* in their efforts to provide reliable power to the communities and consumers they and others serve.[43]

The capture, transportation, and injection of CO_2 underground has been employed for enhanced oil recovery in the US since the early 1980s. Therefore, the primary uncertainty for CCS involves the development of a robust regional and national CO_2 transportation and storage system for the volumes required in a carbon-free generation world that depends heavily on coal or natural gas generation. Recent geological assessments indicate the best locations in the US for long-term storage of large volumes of CO_2 are along the Gulf coast and in the Dakotas. These long distances will challenge CCS in Kentucky and are a major source of cost and execution uncertainty, particularly since the 111(d) GHG regulations require compliance with CCS by 2032. For these reasons, the Companies do not consider CCS a viable alternative in Kentucky and have not included it in their 2024 IRP.

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[43] Brief of Amici Curiae Midcontinent Independent System Operator, Inc., PJM Interconnection L.L.C., Southwest Power Pool, Inc., and Electric Reliability Council of Texas, Inc. at 7, *West Virginia et al. v. U.S. Environmental Protection Agency*, D.C. Cir. No. 24-1120 (filed Sept. 13, 2024), available at https://www.pjm.com/-/media/documents/other-fed-state/20240913-24-1120.ashx.

3.2 Renewable Resources

3.2.1 Solar

Photovoltaic ("PV") solar is a proven technology option for daylight energy and a viable option to pursue renewable goals and reduce emissions. In Kentucky, the summer peak contribution of solar resources is assumed to be 84 percent of total solar capacity. Because winter peaks typically occur in the mornings or evenings during non-daylight hours, the winter peak contribution of solar resources is assumed to be zero. The KY Solar option was further evaluated in the Resource Assessment, which considers the impact of the federal Inflation Reduction Act ("IRA") and includes a production tax credit of $30.25/MWh with the energy community bonus, for the first 10 years of new solar resources.[44] The cost and assumptions for solar resources are based on the Companies' recent cost estimates and assumptions for Mercer County Solar. NREL's 2024 ATB was used for escalation assumptions.[45]

Table 9 shows a comparison of residential and utility-scale solar resources.[46] Utility-scale solar has lower capital and fixed O&M costs, a higher capacity factor, and a lower weighted average cost of capital ("WACC") compared to Residential Solar. For this reason, the Companies evaluated only Utility-Scale Solar in the Resource Assessment.

Table 9: Comparison of Residential and Utility-Scale Solar (2030 Installation; 2030 Dollars)

Item	Residential Solar	Utility-Scale Solar
Capital Cost ($/kW)	3,847	1,902
Fixed O&M ($/kW-yr)	30	17
Capacity Factor	15.2%	26.3%
Weighted Average Cost of Capital ("WACC")	7.23%	6.56%
Tax Credit	30% ITC	$30.25/MWh PTC
Levelized Cost of Energy ($/MWh)	254.97	60.18

3.2.2 Wind

The viability of wind generation for a given region is dependent on wind speeds. Kentucky has average wind speeds that are less than 12.5 mph. Areas with wind speeds of at least 14.5 mph are better suited for wind generation. This is why there are currently no commercial-scale wind projects under development in Kentucky. In addition, the Companies received only one response to their 2022 RFP for out-of-state wind (143 MW). For this reason and the reasons discussed below, wind is modeled as an energy-only resource in PLEXOS, which is accomplished by setting its contributions to summer and winter peak to zero. Two land-based wind options were evaluated, one in Kentucky with a 36% capacity factor

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

[45] See Section 4 for further details.

[46] The Companies used "Class 6" solar from the 2024 ATB to represent a solar resource located in Kentucky.

and another in Indiana with a 44% capacity factor.[47] Both wind options were further evaluated in the Resource Assessment, which considers the impact of the federal IRA and includes a production tax credit of $27.50 for the first 10 years of new wind resources.[44] Unlike solar, the Companies do not have a current cost estimate for wind. Therefore, the Companies estimated the capital cost of wind by applying the implied inflation rate for solar to the "Moderate" capital cost estimate for wind in NREL's 2024 ATB.[48]

3.2.3 Contributions to Winter and Summer Peak Demands

For the Resource Assessment, the Companies have allowed for maximizing renewables penetration in the study period by limiting solar generation to 20% of total energy requirements and the sum of solar and wind generation to 25% of total energy requirements.[49] In the Mid load forecast scenario, a 20% limit equates to approximately 3,800 MW of solar. Despite receiving only one wind response to their 2022 RFP for 143 MW, a 25% limit equates to approximately 3,700 MW of Kentucky wind or 2,800 MW of Indiana wind, which has a higher expected capacity factor than Kentucky wind. The Companies are not proposing that these high levels of renewables could practically or economically be added all at once as these levels of renewables would require numerous new generation sites and potentially significant transmission system upgrades. In addition, because it is not practical to estimate transmission system upgrade costs for numerous generation sites that do not currently exist and the Companies are not seeking approval for new resources, the Resource Assessment conservatively assumes no cost for transmission system upgrades.

The intra-hour variability of renewables and their availability during peak periods are key considerations for integrating renewables. Whereas solar clearly cannot contribute to the Companies' winter peak, the potential contribution of wind resources during a winter peak is uncertain. While wind can potentially generate at high levels during winter peak hours, historical wind speeds indicate the potential for low wind generation output during winter peaks. Wind resources outside of the Companies' Kentucky footprint may likely be expected to generate more during winter peaks, but reliance on generation that must be exported from other transmission areas risks having even firm transmission cut during times of energy emergencies, which is when the Companies would need the resources most.[50]

In addition to the uncertainty associated with wind's availability during peak hours, the Companies do not have a current cost estimate for wind.[51] For all of these reasons (i.e., uncertainty in wind's availability during peak hours, limited responses in past RFPs, uncertainty in cost, inability to estimate transmission

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[47] The Companies used "Class 8" and "Class 6" wind from the 2024 ATB to represent wind resources located in Kentucky and Indiana, respectively.

[48] See Section 4 for further details.

[49] These limits are consistent with the Kentucky Regional Case Study conclusions reached in "Decarbonization Analysis for Thermal Generation and Regionally Integrated Large-Scale Renewables Based on Minutely Optimal Dispatch with a Kentucky Case Study," Lewis et al., 2023. See pp. 18-19 at https://www.engr.uky.edu/sites/default/files/PEIK/2023%20Energies%20UK%20SPARK%20Decarbonization%20Optimal%20Dispatch%20Regional%20Kentucky%20Author%27s%20Manuscript.pdf.

[50] The Companies are aware of this most recently occurring in August 2024 when MISO curtailed firm export schedules to OMU and KYMEA, who then purchased cost-based energy from the Companies to cover their loads.

[51] As noted above, in the absence of a recent cost estimate for wind, the Companies estimated the capital cost of wind by applying an implied inflation rate for solar to the "Moderate" capital cost estimate for wind in NREL's 2024 ATB.

system upgrade costs for wind sites that do not currently exist), the Companies modeled wind as an energy-only resource in PLEXOS by setting its contributions to summer and winter peak to zero.

For solar resources, the Companies calculated winter and summer capacity contributions of 0% and 83.7%, respectively, by evaluating historical solar generation during the Companies' historical peak load hours. The Companies first determined that winter peak loads occur most commonly in hour beginning 7 AM and summer peaks in hours beginning 2 PM or 3 PM, depending on the month. Using these peak load hours, the Companies determined the expected generation during peaks by calculating the median historical solar generation averaged across ten sites in Kentucky for both winter and summer seasons.

3.3 Limited-Duration Resources

3.3.1 Battery Energy Storage Systems

Energy storage options provide short-term peaking capacity and voltage frequency management. The Companies have been researching and testing lithium-ion batteries since 2016 for their potential to provide short-term energy storage on a utility scale. The basic composition of a lithium-ion battery includes an anode, a lithium-containing cathode, and an electrolyte solution. When the battery is in operation, lithium ions are moved between the negative anode and positive cathode. While discharging, the ions travel from the anode to the cathode and while charging they travel from the cathode to the anode.

Lithium-ion battery energy storage systems ("BESS") have virtually instantaneous response times, allowing flexibility in load management, and their scalability is an advantage over larger peaking options such as frame SCCTs. At higher levels of intermittent renewable penetration, lithium-ion batteries can be used to ameliorate solar intermittency by power smoothing, which discharges power instantaneously when solar output drops, and charges to absorb power when solar power rises suddenly. They can also serve to store excess solar generation from the day and discharge it at night, which can limit the need for solar curtailment. BESS are also capable of frequency and voltage regulation when installed at scale.

The Companies evaluated 4-hour and 8-hour BESS in the Resource Assessment, which considers the impact of the federal Inflation Reduction Act ("IRA") and includes an investment tax credit of 50% with the domestic content and energy community bonuses for new BESS resources.[44] The Companies assumed 85 and 93 percent capacity contribution for 4-hour and 8-hour BESS, respectively, as well round-trip efficiency of 87%.[52] The cost and assumptions for BESS resources are based on the Companies' recent cost estimates and assumptions for Brown BESS. NREL's 2024 ATB was used for escalation assumptions.[53]

3.3.2 Dispatchable Demand-Side Management

The Companies received approval in November 2023 from Case No. 2022-00402 for an DSM portfolio that covers the period of 2024-2030. This DSM portfolio represents the Companies' largest offering of

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[52] The analysis to determine capacity contributions for BESS is summarized in IRP Volume III (2024 IRP Resource Adequacy Analysis). In simple terms, with an 87% round-trip efficiency, 0.87 MWh can be discharged for every 1 MWh stored in the battery.

[53] See Section 4 for further details.

programs and budget to date with a variety of programs that allows for participation from every customer segment. Therefore, the Companies do not propose any new DSM programs at this time. There are, however, three potential program enhancements modeled in this IRP. These potential program enhancements are:

1. BYOD Energy Storage: a new measure within the existing Bring Your Own Device program for residential and small business customers to enroll customer-owned, dispatchable residential-style BESS.
2. BYOD Home Generators: a new measure within the existing Bring Your Own Device program for residential customers to enroll customer-owned, whole home dispatchable back-up generation units, and
3. BDR 50-200 kW: the allowance of small business customers, who have a measured base demand of 50 to 200 kW, to participate in the Business Demand Response program.[54]

Because these three potential program enhancements provide alternative means for customers to participate in existing programs, these programs have no incremental fixed costs and were included in all of the Companies' resource plans.

The Companies evaluated an extension of the existing CSR-2 program in the Resource Assessment, assuming the current rate of $5.90/kW-month.[55] Notably, the Companies' ability to require CSR-2 customers to curtal their usage without customer buy-through option is limited to 100 hours annually when all available units are dispatched or being dispatched. The Companies assumed 39 percent capacity contribution for DSM programs and CSR.[56]

3.4 Other Technologies

The following provides an update on other technologies not included in the Resource Assessment either because the Companies do not possess enough information to model the technology, the technology is not cost-effective, or the technology is not ideal for utility-scale applications in the Companies' service territories. With the exception of pumped hydro storage, none of these technologies have been proposed in any of the Companies' recent Requests for Proposals.

3.4.1 Integrated Gasification Combined-Cycle

Integrated Gasification Combined-Cycle ("IGCC") technology continues to be developed and is at various stages of commercialization. Only a limited number of IGCC plants have been built and operated around the world, and the cost of these plants have significantly exceeded expectations. For this reason, no IGCC options were evaluated in the Resource Assessment.

3.4.2 Coal-Fired Supercritical Boiler

Because of the high cost and environmental risk of new coal, no new coal-fired options were evaluated in the Resource Assessment.

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[54] See Section 8.(3).(e) in Volume I for further information.

[55] The Companies assumed an annual inflation rate of 2.3 percent per year for the CSR-2 rate.

[56] The analysis to determine capacity contributions for DSM is summarized in IRP Volume III (2024 IRP Resource Adequacy Analysis).

3.4.3 Hydro

The Companies recently upgraded the hydro units on Dix Dam and Ohio Falls, and are not aware of any viable alternatives near their service territories for expanding their portfolio of hydro generation further. For this reason, no new hydro option was evaluated in the Resource Assessment.

3.4.4 Pumped Hydro Storage

Pumped hydro storage facilities move water between two reservoirs. During off-peak periods, excess energy is stored by pumping water uphill. During on-peak periods, the water is released from the upper reservoir and flows through turbine generators to the lower reservoir, generating energy. Because the cost and characteristics of pumped hydro facilities can vary greatly from location to location, and because the Companies lack sufficient information to evaluate the potential costs of such a facility in any particular location, the Companies did not evaluate generic pumped hydro storage options in the Resource Assessment.

3.4.5 Compressed Air Energy Storage

Compressed air energy storage ("CAES") systems store off-peak power by compressing a gas, generally air, into a high pressure reservoir. The compressed air is expanded into a turbine to run an electrical generator during on-peak demand periods. However, the cost of CAES makes this storage technology unsuitable in the Companies' service territories; therefore, no CAES option was evaluated in the Resource Assessment.

3.4.6 Geothermal

Geothermal resources use steam from reservoirs of hot water below the earth's surface to rotate a turbine and produce electricity. The potential for geothermal resources is concentrated in the western United States. For this reason, no geothermal resources were evaluated in the Resource Assessment.

3.4.7 Biopower

Biopower resources convert renewable biomass fuels into heat and electricity with processes similar to those used in fossil fuel resources. Due to high capital and operating costs, no biopower options were evaluated in the Resource Assessment.

3.4.8 Reciprocating Engines, Microturbines, and Fuel Cell Technology

Reciprocating internal combustion engines, microturbines, and fuel cell technology are easily scalable and are well-suited for distributed generation and combined heat and power applications. Reciprocating engines can accommodate both natural gas and fuel oil, and have high efficiency across the ambient range. Reciprocating engines are more popular in areas with high penetrations of renewable generation due to their quick start times and operational flexibility. At present, high capital and maintenance costs, partly attributable to the lack of production capability and limited development, limit the potential for utility-scale applications of fuel cell technology.[57] For these reasons, these options were not evaluated in the Resource Assessment.

[57] Although fuel cell technology may seem comparable to BESS, the use of natural gas makes it more comparable to SCCT or NGCC.

3.4.9 Circulating Fluidized Bed

Circulating fluidized bed ("CFB") boilers are a mature coal technology option that is well-suited to burn fuels with a large variability in constituents. Large CFBs require more than one boiler, which increases capital costs but improves unit availability compared to PC technology options. Like PC technology options, CFB are also subject to NSPS for GHG regulations and would require the same CC technology. For these reasons, no CFB option was evaluated in the Resource Assessment.

3.4.10 Waste to Energy

Waste to energy ("WTE") generation can be a practical generation option if there is an existing source of waste that can be used as fuel. Waste fuel is a very diverse category that includes: municipal solid waste, refuse derived fuel, wood chips, landfill gas, sewage, and tire-derived fuel. Depending on the waste fuel, most traditional technologies can be employed, including stoker boilers, CFB boilers, and reciprocating engines. The greatest challenge to building large WTE plants or retrofitting a coal unit to a large biomass plant is the cost, availability, reliability, and homogeneity of a long-term fuel supply. The transport and handling logistics of large quantities of WTE fuel poses a significant challenge, depending on the size of the facility. Because of these considerations, no WTE options were evaluated in the Resource Assessment.

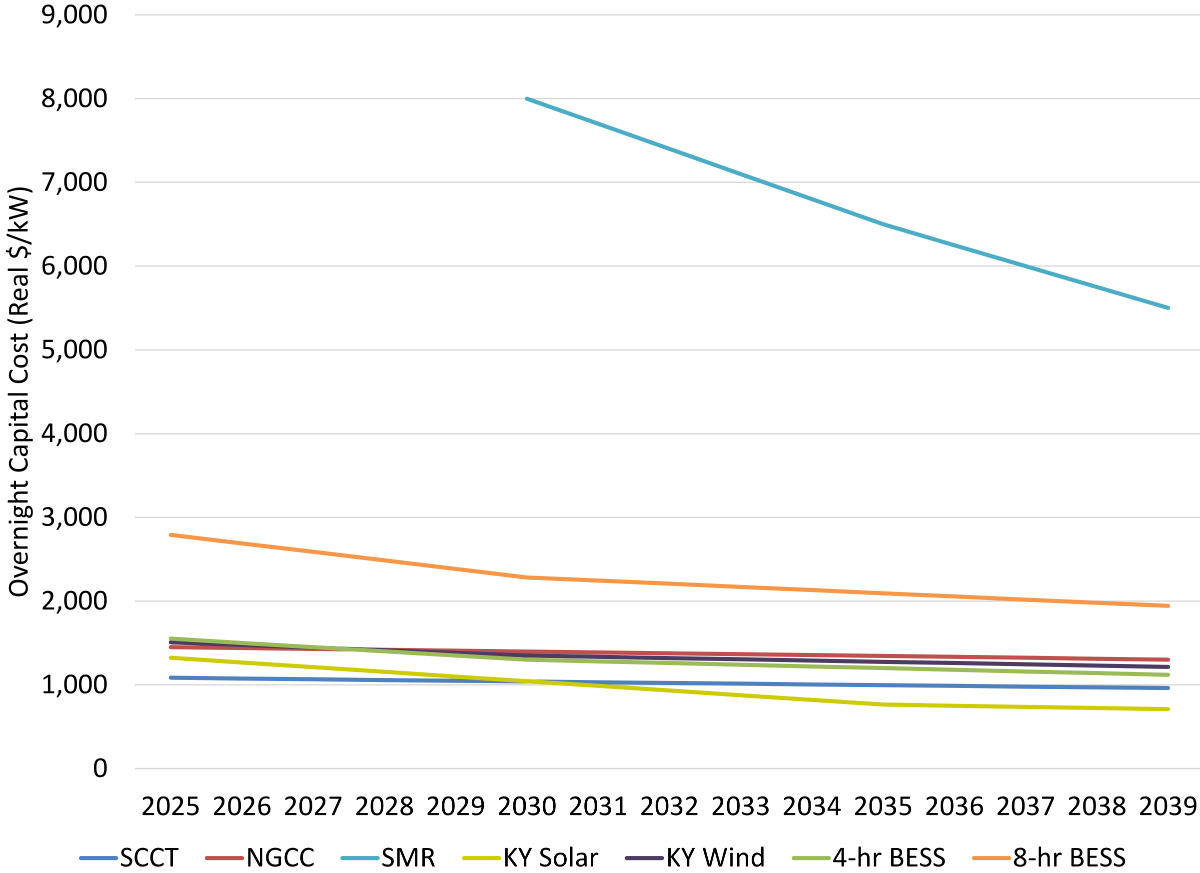
3.4.11 Concentrating Solar Power

A concentrating solar power ("CSP") option was not evaluated in the Resource Assessment because of its high capital costs and infeasibility in the Companies' service territories. The tower and heliostat technology CSP plants that have been built have had serious technical challenges and have performed far worse than expected. Parabolic trough CSP projects have performed better, but remain uneconomic. CSP options are better-suited for sunnier climates, and cost at least four times more than solar PV resources.

4 Converting NREL Costs from Real to Nominal Dollars

Figure 3 shows the generation technology cost forecast from NREL's 2024 ATB in real 2022 dollars.

Figure 3: Generation Technology Cost Forecast (Real Dollars)[58]



Resource costs in NREL's 2024 ATB must be converted to nominal dollars. In doing this, the Companies ensured that nominal capital costs for SCCT, NGCC, solar, and BESS aligned with recent capital cost estimates for an SCCT, the Brown 12 NGCC, Mercer County Solar, and Brown BESS, respectively. Table 10 shows the Companies' recent estimates for these units.

Table 10: Recent Capital Cost Estimates

Resource	Technology	Year $	Capital Cost ($/kW)
SCCT	SCCT	2024	1,500
Brown 12	NGCC	2030	2,121
Mercer Co Solar	Solar	2026	2,108
Brown BESS	BESS	2026	2,160

[58] See https://atb.nrel.gov/.

Assuming an annual inflation rate of 2.3 percent beyond 2024, this process to align NREL's 2024 ATB with recent capital cost estimates produces implied inflation rates for each technology through 2024. In the absence of a recent capital cost estimate for wind, the Companies estimated the capital cost of wind by applying the implied inflation rate for solar to the "Moderate" capital cost estimate for wind in NREL's 2024 ATB. All costs for SMR were also based on the Moderate cost scenario and converted from real to nominal dollars assuming actual consumer price index inflation in 2023 (4.1 percent) and 2.3 percent inflation thereafter. Table 11 shows resulting inflation assumptions for each technology, assuming implied inflation rates in 2023-2024, and 2.3 percent inflation for years 2025 forward.[59]

Table 11: Inflation Assumptions

	SCCT	NGCC	SMR	Solar	Wind	BESS
2023-2024	37.3%	32.4%	6.5%	59.0%	59.0%	37.5%
2025+	2.3%	2.3%	2.3%	2.3%	2.3%	2.3%

[59] See IRP Volume II (Inflation Assumptions) for further information regarding the 2.3 percent inflation assumption.

2024 IRP
Resource Adequacy Analysis

PPL companies

Generation Planning & Analysis

October 2024

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 carry a level of supply-side and demand-side resources that exceeds their forecasted peak demands under normal weather conditions. Reserve margin is the amount of resources carried in excess of forecasted peak demands and is expressed as a percentage of forecasted peak demand under normal weather conditions.

The Companies use PLEXOS, a resource planning model, to develop resource plans that minimize the cost of serving customers' load under normal weather conditions while meeting minimum summer and winter reserve margin constraints. The minimum reserve margin constraints generally enable the model to account for uncertainty associated with resource availability and weather. The Companies develop these constraints using the Strategic Energy & Risk Valuation Model ("SERVM"), a resource adequacy model, by assessing the adequacy of their resource portfolio over a wide range of weather and unit availability scenarios.

The 2021 Integrated Resource Plan ("IRP") established minimum reserve margins of 17 percent in the summer and 26 percent in the winter. In their 2022 CPCN filing (Case No. 2022-00402), the Companies updated their reserve margins to account for the addition of the BlueOval SK load (largely non-weather sensitive and summer peaking) and a lower cost of simple-cycle combustion turbine ("SCCT") capacity. The impacts of these changes were offsetting in the summer, but the minimum winter reserve margin decreased from 26 to 24 percent.

The 2021 IRP and 2022 CPCN reserve margins are "economic" reserve margins (i.e., the reserve margins where the cost of adding new generation is approximately equal to the benefits provided by the new generation). Other jurisdictions (e.g., PJM, MISO) assess resource adequacy based on a portfolio's loss-of-load expectation ("LOLE") and plan generation to limit LOLE to one day in 10 years. For this reason, in this and past IRPs, the Companies have computed both economic reserve margins and reserve margins that align with the one day in 10 years ("1-in-10") LOLE standard.

Table 1 contains economic and 1-in-10 LOLE reserve margins from the 2021 IRP, the 2022 CPCN filing, and the 2024 IRP. The determination of economic reserve margins is significantly focused on the costs and benefits of adding new simple-cycle combustion turbines ("SCCT"). Economic reserve margins have changed somewhat since the 2021 IRP due to changes in the cost of SCCT capacity as well as changes in load and equivalent forced outage rate ("EFOR") assumptions for the Companies' generating units.

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

Table 1: Economic and 1-in-10 LOLE Reserve Margins

Reserve Margin	2021 IRP			2022 CPCN			2024 IRP		
	Winter	Summer	Annual LOLE	Winter	Summer	Annual LOLE	Winter	Summer	Annual LOLE
Economic	26%	17%	4.8	24%	17%	4.8	22%	17%	4.7
1-in-10 LOLE	35%	24%	1.0	31%	23%	1.0	29%	23%	1.0

Notably, the LOLE for the 2024 IRP economic reserve margins is 4.7 days in 10 years and significantly higher than the 1-in-10 LOLE standard. Based on the events of Winter Storm Elliott and the ensuing investigation of its root cause, the Companies do not believe planning resources based on economic reserve margins is appropriate; as the Commission stated in its Final Order in the Companies' 2022 CPCN and DSM case:

> As it relates to measuring generation and demand for purposes of resource planning, given the uncertainty around financing, environmental regulations and the ability to timely construct energy infrastructure, all-else-equal the Commission would rather err on the side of having too much energy, as opposed to not enough. With surrounding regions concerned about being energy inadequate, the Commission would rather the Commonwealth standout as a state with enough power to meet customers' needs.[2]

Therefore, the Companies have developed this IRP using the 1-in-10 LOLE reserve margins, which are 29% in the winter and 23% in the summer. Importantly, like in prior reserve margin analyses, these reserve margins were developed with the assumption that the Companies can purchase power from TVA, PJM, or MISO when generation and transmission capacity are available. With no ability to purchase power from these neighboring markets, which was the case during the Winter Storm Elliott service curtailments, the Companies' 1-in-10 LOLE reserve margins are slightly higher.[3]

The Companies' reserve margins were developed based on a mix of fully dispatchable resources (i.e., resources that can be dispatched any time and operated for days at a time), renewable resources (e.g., Ohio Falls hydro units and Brown Solar) and limited-duration resources (i.e., resources like the Companies' dispatchable demand-side management ("DSM") programs that can only be dispatched for several hours at a time). Table 2 summarizes the contributions of these resources to the minimum reserve margins. Total reserve margin will become less meaningful as a reliability metric as the composition of fully dispatchable, renewable, and limited-duration resources change. When evaluating two portfolios with the same total reserve margin, the portfolio with a higher proportion of fully dispatchable resources will generally have higher reliability.

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[2] *Electronic Joint Application of Kentucky Utilities Company and Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity and Site Compatibility Certificates and Approval of a Demand Side Management Plan and Approval of Fossil Fuel-Fired Generation Unit Retirements*, Case No. 2022-00402, Order at 177-78 (Ky. PSC Nov. 6, 2023).

[3] During Winter Storm Elliott, the Companies were unable to purchase power due to a lack of generation; transmission capacity was available.

Table 2: Reserve Margin Constraints for Resource Planning Analyses

	Winter	Summer
Fully Dispatchable Resources	21%	15%
Renewable/Limited-Duration Resources	8%	8%
Total	29%	23%

In addition to minimum reserve margins, the Companies used SERVM to determine the capacity contribution of limited-duration resources such as battery storage and dispatchable DSM programs 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 ("ELCC") that PJM computes for their capacity accreditation process. 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 contribution for limited-duration resources depends on the composition of other resources in the portfolio and load levels. For the 2024 IRP, the capacity contributions for 4-hour battery storage, 8-hour battery storage, and dispatchable DSM are 85%, 93%, and 39%, respectively, of fully dispatchable resources.

2 Introduction

The reliable supply of electricity is vital to Kentucky's economy and public safety, and customers expect electricity 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. Figure 1 shows the distribution of annual high and low temperatures in Kentucky over the last 51 years.[4] Temperatures in Kentucky can vary from below zero degrees Fahrenheit to above 100 degrees Fahrenheit. From 1973 to 2023, the median annual high temperature was 96 degrees Fahrenheit and the median annual low temperature was 4 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: Annual High and Low Temperature Distributions (1973-2023)[5]

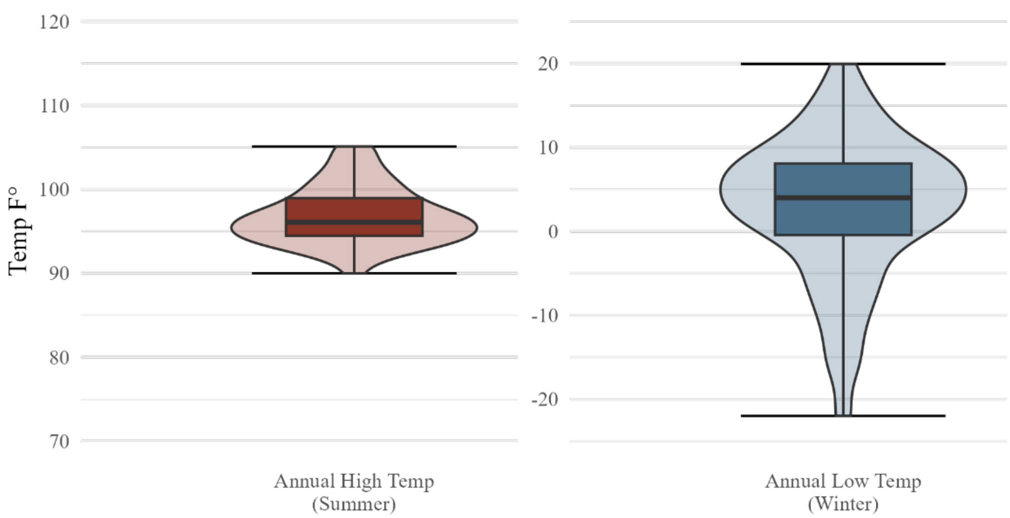

Figure 2 and Figure 3 plot annual high and low temperatures over time. Since 1973, annual high and low temperatures have fallen within a fairly consistent range. In addition, based on the 10- and 20-year rolling averages, the trends in annual high and low temperatures have been fairly flat over the last 20 or more years.

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[4] The Companies assess resource adequacy based on weather since 1973, the first year for which they have reliable hourly weather data.

[5] The limits of the box in the boxplots reflect the 25th and 75th percentiles while the "whiskers" represent the maximum and minimum. The shaded area behind the boxplot, called a violin plot, represents the distribution of points. The width of the violin represents the proportion of the data at that value.

Figure 2: Annual High Temperature Trends[6]

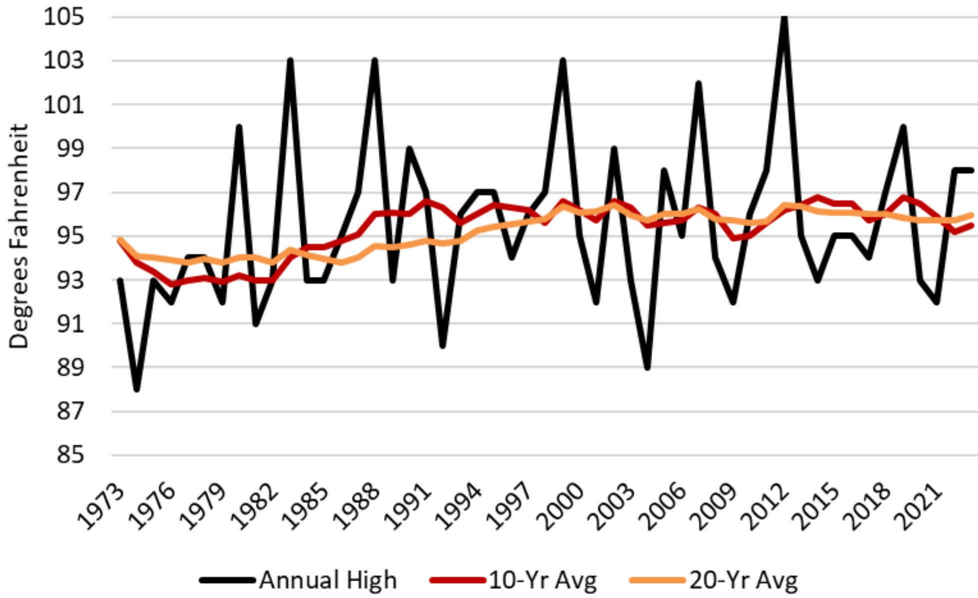
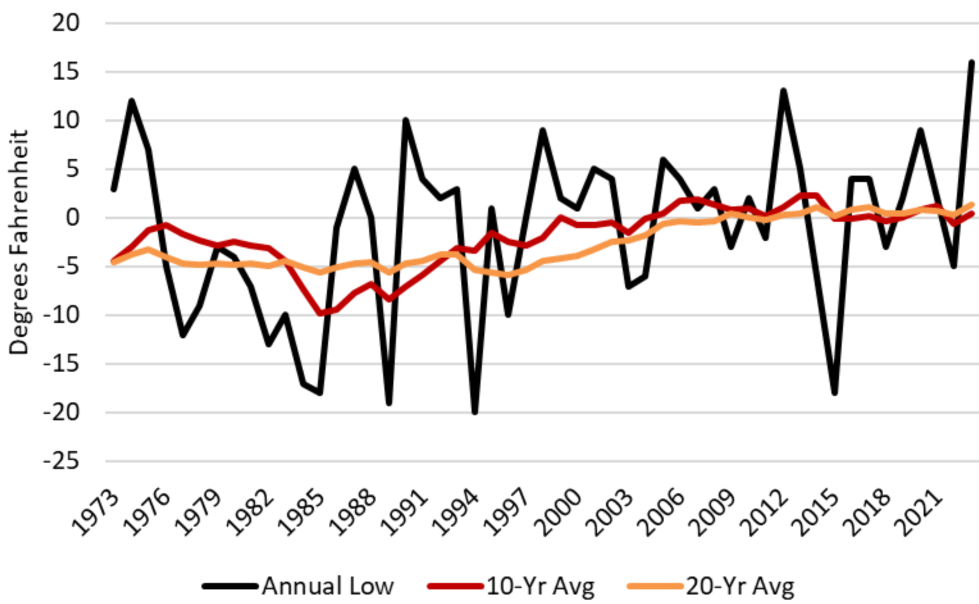


Figure 3: Annual Low Temperature Trends



[6] Temperature data is taken from the LEX weather station at the Blue Grass Airport in Lexington, Kentucky.

Because of the potential for cold winter temperatures and the increasing penetration of electric space heating, the Companies are somewhat unique in that annual peak demands can occur in summer and winter months. Summer peak demands typically occur in the afternoons, while winter peaks typically occur in the mornings or evenings during non-daylight hours. The Companies' resource adequacy considerations are primarily focused on the winter months given the potential for higher and more volatile peak demands in the winter months. The Companies' highest hourly demand occurred in August 2010, but since then, the Companies have experienced seven annual peak demands in excess of 6,400 MW, five of these occurred during the winter months, and the last summer peak exceeding 6,400 MW occurred in 2012.[7]

Customers consume electricity every hour of the year, but no resource can be available at all times and multiple resources can be unavailable at the same time. To account for the uncertainty in generating unit availability and the possibility of extreme weather events, the Companies carry a level of resources that exceeds their forecasted peak demand under normal or average weather conditions. Reserve margin is the amount of installed capacity ("ICAP") carried in excess of forecasted peak demands and is expressed as a percentage of forecasted peak demand under normal weather conditions.

The Companies use PLEXOS, a resource planning model, to develop resource plans that minimize the cost of serving customers' load while meeting minimum summer and winter reserve margin constraints. Because resource planning is a complex and time-consuming modeling exercise, the analysis is necessarily focused on a single normal weather scenario and utilizes somewhat simplified unit availability assumptions. Minimum reserve margin constraints generally enable the model to account for uncertainty associated with weather and resource availability.

The Companies develop these constraints using the Strategic Energy & Risk Valuation Model ("SERVM"), a resource adequacy model.[8] To properly capture the cost of high-impact, low-probability loss-of-load events, the Companies use SERVM to evaluate thousands of scenarios that encompass a wide range of load and unit availability scenarios. Specifically, the Companies assess resource adequacy over 51 load scenarios and 300 unit availability scenarios. Higher reserve margins are needed for portfolios with less reliable resources or for loads with greater variability.

In PLEXOS, each resource's ability to contribute to minimum summer and winter reserve margins is specified through capacity contribution inputs, which range from 0 to 100 percent for each season. The summer and winter capacity contribution for fully dispatchable resources is 100 percent. Limited-duration resources such as battery storage and dispatchable DSM programs 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 by comparing their impact on reliability to that of a SCCT.

[7] These statistics exclude municipal customers that departed in 2019.

[8] In past resource adequacy studies, the Companies also used the Equivalent Load Duration Curve Model ("ELDCM") to develop minimum reserve margin constraints. The ELDCM's simplified approach is able to consider a more complete range of unit availability scenarios than SERVM, but it is less capable of modeling limited-duration resources.

Sections 3 and 4 contain a summary of the Companies' analysis to determine minimum reserve margin constraints and capacity contributions for limited-duration resources. Section 5 contains a summary of key SERVM inputs and uncertainties.

3 Reserve Margin Constraints for Resource Planning

Figure 4 illustrates the costs and benefits of adding capacity to a generation portfolio.[9] 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 where the sum of (a) capacity costs and (b) reliability and generation production costs ("total cost") is minimized is the economic reserve margin. An economic reserve margin is computed for the summer and winter months as a function of the forecasted summer and winter peak, respectively, under normal weather conditions.

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

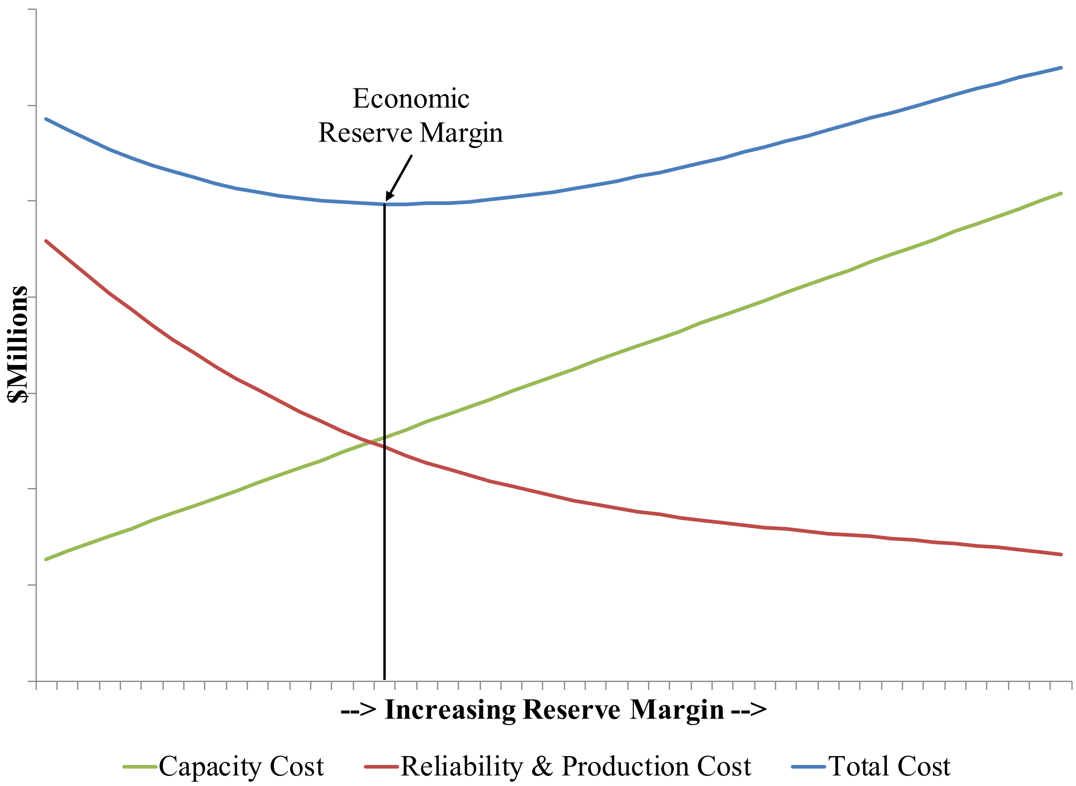


Figure 5 includes an alternative capacity cost scenario (dashed green line) for capacity with the same dispatch cost and reliability characteristics. The large dots mark the minimum of the range of reserve margins that is being evaluated. In this scenario, reliability and generation production costs are 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.[10]

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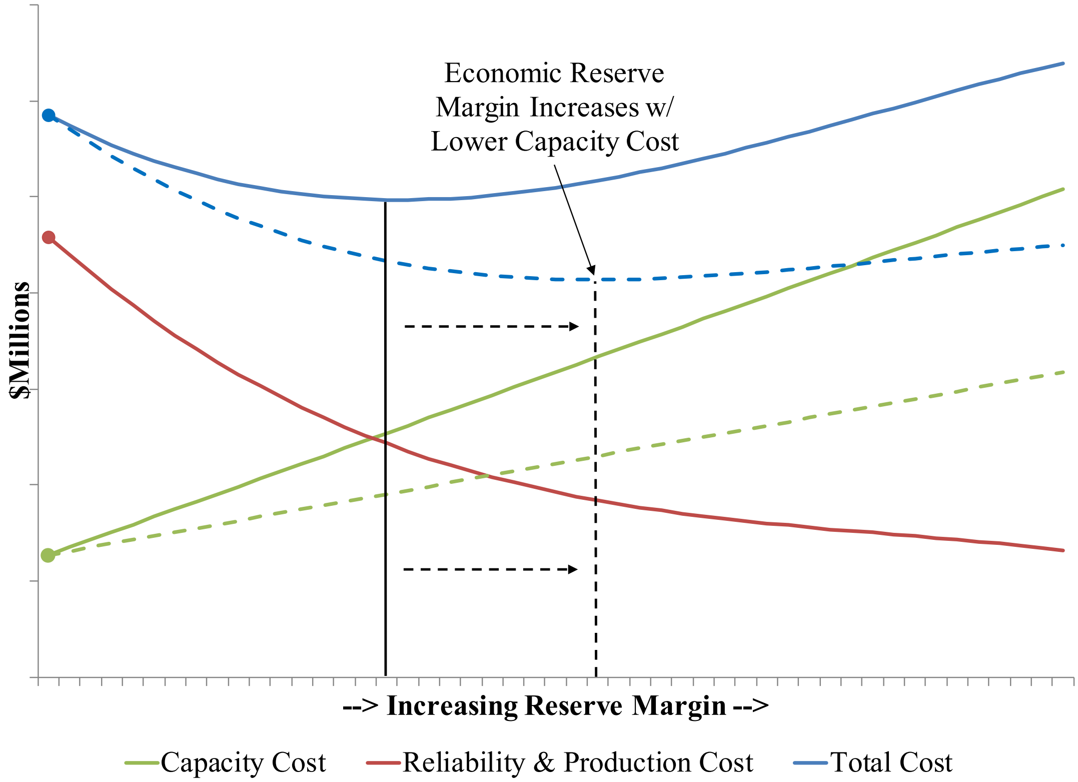
[9] As mentioned previously, different types of generation resources play different roles in serving customers; not all resources provide the same reliability and generation production cost benefit.

[10] 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).

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



In addition to an economic reserve margin, minimum reserve margin constraints can be established by targeting a desired LOLE. Other jurisdictions (e.g., PJM, MISO) assess resource adequacy based on a portfolio's LOLE and plan generation to limit LOLE to one day in 10 years. For this reason, in this and past IRPs, the Companies have computed economic reserve margins as well as reserve margins that achieve the one day in 10 years ("1-in-10") LOLE standard.

Table 3 contains the Companies' summer and winter reserve margins in the Mid load scenario for 2032 with CPCN-approved resource changes and solar PPAs as well as the assumed retirements of the small-frame SCCTs.[11] Specifically, Table 3 reflects the planned retirements of Mill Creek 1 (2024) and Mill Creek 2 (2027), the assumed retirements of the Companies' small-frame SCCTs (2025), and the planned additions of the Brown Battery Energy Storage System (2026), Mercer County Solar (2026), Mill Creek 5 (2027), Marion County Solar (2027), and dispatchable demand response programs from the Companies' 2024-2030 DSM-EE Program Plan.[12] Reserve margins are computed for fully dispatchable resources and in total, and total reserve margins are computed with no solar, with Company-owned solar, and with all solar (758 MW in total). With only the aforementioned resource changes, the winter reserve margin is

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[11] 2032 is the first full year in the Mid load forecast scenario with all economic development load additions. The Companies' fully dispatchable generation resources have a higher capacity in the winter primarily because natural gas units can produce more power at lower ambient air temperatures.

[12] Since 2019, the Companies have contracted – either in the context of Green Tariff Option #3 or their 2022 RFP – for six utility-scale PPAs. Of these PPAs, three have terminated and it is currently unclear whether the other three projects (Rhudes Creek, Gray's Branch, and Nacke Pike) will move forward.

only 18.3% due primarily to the addition of approximately 1,000 MW of economic development load by 2032 in the Mid load scenario.

Table 3: 2032 Resource Summary (MW, Existing Portfolio w/ CPCN-Approved Resources & Solar PPAs)

	Winter	**Summer**
Peak Load (Mid Load Forecast)	**7,135**	**7,201**
Fully Dispatchable Generation Resources		
Existing Resources	7,977	7,618
Retirements/Additions		
Coal (Mill Creek 1 and 2)[13]	-597	-597
NGCC (Mill Creek 5)[13]	660	645
Large-Frame SCCTs	0	0
Small-Frame SCCTs[14]	-55	-47
Total	7,985	7,619
Fully Dispatchable Reserve Margin (%)	11.9%	5.8%
Renewable & Limited-Duration Resources		
Existing Resources	72	107
Existing CSR	115	110
Existing and Approved Dispatchable DSM	145	190
Retirements/Additions		
Brown BESS	125	125
Company-Owned Solar[15]	0	201
Solar PPAs[15]	0	434
Total	456	1,167
Total Supply w/o Solar	**8,441**	**8,155**
Total Supply w/ Company-Owned Solar	**8,441**	**8,352**
Total Supply w/ All Solar	**8,441**	**8,786**
Total Reserve Margin w/o Solar (%)	**18.3%**	**13.2%**
Total Reserve Margin w/ Company-Owned Solar (%)	**18.3%**	**16.0%**
Total Reserve Margin w/ All Solar (%)	**18.3%**	**22.0%**

Like in past IRPs, the Companies first developed reserve margins assuming no solar in the portfolio. Table 4 contains summer and winter reserve margins, LOLE, and reliability and generation production costs for (1) the portfolio summarized in Table 3 ("2032 Portfolio") less solar and (2) the same portfolio with 70

[13] Mill Creek 1 will be retired at the end of 2024. Mill Creek 2 will be retired after Mill Creek 5 is commissioned in 2027.

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

[15] This summary includes 240 MW of Company-owned solar and 518 MW of solar PPAs. Whether the solar PPAs will be completed remains uncertain. Capacity values reflect 83.7% expected contribution to summer peak capacity.

MW of new SCCT capacity.[16] In SERVM, LOLE and reliability and generation production costs are evaluated over 51 weather scenarios and hundreds of unit availability scenarios.[17] Table 4 contains the annual LOLE and the average, 85th percentile, and 90th percentile of the reliability and generation production cost distribution. Consistent with past IRPs, the analysis of economic reserve margins 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.[18] As seen in the table, the new SCCT capacity increases annual costs by $11.4 million, but the reliability and generation production cost benefits from this capacity more than offset the capacity cost at these reserve margins. This result demonstrates that the economic and 1-in-10 LOLE reserve margins are higher than these reserve margins.

Table 4: Reliability & Generation Production Costs

Generation Portfolio	**Reserve Margin**		**Ann. LOLE**	**[A] New SCCT Capacity Cost[19] ($M/year)**	**Reliability & Generation Production Costs ($M/year)**			**Total Cost: Capacity Cost + Reliability & Generation Production Costs ($M/year)**		
	Win	**Sum**			**[B] Avg**	**[C] 85th %-ile**	**[D] 90th %-ile**	**[A]+[B] Avg**	**[A]+[C] 85th %-ile**	**[A]+[D] 90th %-ile**
2032 Portfolio less Solar	18.3%	13.2%	10.84	-	1,509	1,559	1,589	1,509	1,559	1,589
2032 Portfolio less Solar + New SCCT	19.4%	14.2%	8.41	11.4	1,501	1,533	1,559	1,512	1,544	1,570

To compute economic reserve margins for a given portfolio, the Companies evaluate the portfolio with and without new peaking capacity over a range of load levels to determine the load level at which the reliability and production cost benefits from the new peaking capacity offset its costs. 1-in-10 LOLE reserve margins can then be derived from the same analysis. Table 5 contains the reserve margin analysis results for the 2032 Portfolio less solar. The Companies evaluated load changes in increments of 70 MW; Table 5 contains selected results from this analysis.[16] Because near-term load forecast increases are driven by high load factor load additions, these load changes were assumed to be high load factor loads.

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[16] 70 MW is approximately equal to 1% of reserve margin in 2032.

[17] Sections 5.3 and 5.4.1 contain more information regarding load and unit availability scenarios, respectively.

[18] For example, without new SCCT capacity, reliability and generation production costs for the 2032 Portfolio less Solar are $80 million higher than average once in ten years (90th percentile of distribution). However, when SCCT capacity is added, these costs are only $58 million higher than average once in ten years.

[19] New SCCT capacity is modeled as 70 MW of SCCT capacity. SCCT capacity cost assumptions are summarized in Section 5.7.

Table 5: Economic Reserve Margin Analysis Results (2032 Portfolio without Solar)

	Reserve Margin & LOLE: 2032 Portfolio Less Solar			Total Cost w/ 85th %-ile Reliability and Production Costs ($M/year)			Total Cost w/ 90th %-ile Reliability and Production Costs ($M/year)		
Load Change	Winter Reserve Margin	Summer Reserve Margin	Annual LOLE	[A] 2032 Port Less Solar	[B] 2032 Port Less Solar + SCCT	[B]-[A] Diff	[A] 2032 Port Less Solar	[B] 2032 Port Less Solar + SCCT	[B]-[A] Diff
0	18.3%	13.2%	10.84	1,559	1,544	(15)	1,589	1,570	(19)
-140	20.7%	15.5%	6.19	1,498	1,495	(3)	1,513	1,503	(10)
-210	22.0%	16.7%	4.68	1,467	1,466	(1)	1,477	1,482	5
-280	23.2%	17.8%	3.39	1,436	1,443	7	1,452	1,461	9
…									
-560	28.5%	22.8%	1.00	1,354	1,365	11	1,360	1,373	13

As seen in Table 5, with no change in load and no solar, winter and summer reserve margins are 18.3% and 13.2%, respectively. If the Companies' load is decreased by 210 MW (i.e., winter reserve margin increases to 22.0 percent and summer reserve margin increases to 16.7 percent), the reliability and production cost benefits from adding new SCCT capacity approximately offsets the cost of the capacity (i.e., at these reserve margins, the total costs of the portfolios with and without SCCT are approximately equal). Thus, the economic reserve margins for the 2032 Portfolio less solar are 22 percent in the winter and 17 percent in the summer. If the Companies' load is decreased by 560 MW (i.e., winter reserve margin increases to 28.5 percent and summer reserve margin increases to 22.8 percent), the annual LOLE is 1. Thus, the 1-in-10 LOLE reserve margins for the 2032 Portfolio less solar are 29 percent in the winter and 23 percent in the summer.

Table 6 contains the reserve margin analysis results for the 2032 Portfolio with solar. With solar, the winter reserve margin for each load level evaluated is unchanged, but summer reserve margins are higher. In addition, with solar and a focus in this analysis on annual reliability and generation costs, the winter economic reserve margin is lower (i.e., the reliability and production cost benefits from adding new SCCT capacity approximately offset the cost of the capacity at a winter reserve margin of 18 percent and a summer reserve margin of 22 percent). Similarly, with 758 MW of solar, the annual LOLE is approximately 1 at a much lower winter reserve margin of 23 percent.

Table 6: Economic Reserve Margin Analysis Results (2032 Portfolio with Solar)

	Reserve Margin & LOLE: 2032 Portfolio			Total Cost w/ 85th %-ile Reliability and Production Costs ($M/year)			Total Cost w/ 90th %-ile Reliability and Production Costs ($M/year)		
				[A]	[B]	[B]-[A]	[A]	[B]	[B]-[A]
Load Change	Winter Reserve Margin	Summer Reserve Margin	Annual LOLE	2032 Port	2032 Port + SCCT	Diff	2032 Port	2032 Port + SCCT	Diff
140	16.1%	19.7%	5.62	1,588	1,571	(17)	1,593	1,588	(5)
70	17.2%	20.8%	4.26	1,554	1,547	(7)	1,564	1,554	(10)
0	18.3%	22.0%	3.30	1,523	1,526	3	1,533	1,532	(1)
…									
-280	23.2%	26.9%	1.02	1,428	1,438	10	1,434	1,442	8

Table 7 summarizes the results of this analysis and provides a comparison of seasonal LOLE values. As noted earlier, the Companies' resource adequacy considerations are primarily focused on the winter months given the potential for higher and more volatile peak demands in the winter months. With a focus in this analysis on annual costs, adding solar to the generation portfolio reduces the economic reserve margin but shifts reliability risk from the summer to winter months where the consequences of service curtailments are the greatest. As seen in Table 7, annual LOLE is one for both portfolios but winter LOLE is approximately two times higher for the 2032 Portfolio with solar. Importantly, the results of this analysis do not suggest that solar degrades winter reliability; it simply demonstrates the impact that solar has on a reserve margin analysis that is focused on annual costs. Depending on its cost, solar is a valuable resource for hedging natural gas price volatility and future CO_2 regulation risk, but the Companies have not proposed and would not propose to add solar for the purpose of accepting higher reliability risk in the winter. Therefore, the Companies used the 2032 Portfolio without solar to determine reserve margin constraints for resource planning.

Table 7: Impact of Solar on Economic Reserve Margins and LOLE

Portfolio	New Solar (MW)	1-in-10 Reserve Margin					Economic Reserve Margin				
		Reserve Margin		LOLE			Reserve Margin		LOLE		
		Win	Sum	Win	Sum	Ann	Win	Sum	Win	Sum	Ann
2032 Portfolio less Solar	-	29%	23%	0.32	0.68	1.0	22%	17%	1.2	3.5	4.7
2032 Portfolio	758	23%	27%	0.68	0.34	1.0	18%	22%	1.9	1.4	3.3

Table 8 contains economic and 1-in-10 LOLE reserve margins from the 2021 IRP, the 2022 CPCN filing, and the 2024 IRP. As seen above, the determination of economic reserve margins is significantly focused on the costs and benefits of adding new simple-cycle combustion turbines ("SCCT"). Economic reserve margins have changed somewhat since the 2021 IRP due to changes in the cost of SCCT capacity as well as changes in load and equivalent forced outage rate ("EFOR") assumptions for the Companies' generating units. Notably, the LOLE for the 2024 IRP economic reserve margins is 4.7 days in 10 years, which is significantly higher than the 1-in-10 LOLE standard. Based on the events of Winter Storm Elliott and the ensuing investigation of its root cause, the Companies do not believe planning resources based on economic reserve margins is appropriate. Therefore, the Companies have developed this IRP using 1-in-10 LOLE reserve margins, which are 29% in the winter and 23% in the summer.

Table 8: Economic and 1-in-10 LOLE Reserve Margins

Reserve Margin	2021 IRP			2022 CPCN			2024 IRP		
	Winter	Summer	Annual LOLE	Winter	Summer	Annual LOLE	Winter	Summer	Annual LOLE
Economic	26%	17%	4.8	24%	17%	4.8	22%	17%	4.7
1-in-10 LOLE	35%	24%	1.0	31%	23%	1.0	29%	23%	1.0

3.1 Sensitivity Analysis

As discussed earlier, the Companies assess resource adequacy over 51 load scenarios and 300 unit availability scenarios. In a given year, a unit's equivalent forced outage rate ("EFOR") can result from multiple shorter outages or relatively few longer outages. Therefore, unit availability scenarios are developed in SERVM to model the uncertainty in the timing and duration of forced outages. For each unit, the scenarios are developed to target the annual EFOR values in section 5.4.1 (Table 14), which are developed based on historical data.

In addition to load and the timing and duration of forced outages, these annual EFOR values and available transmission capacity ("ATC") are key inputs that impact LOLE. The Companies' sensitivity analysis is therefore focused on these two inputs. As shown in section 5.4.1 (Table 14), the base case inputs for EFOR range from 3.1% for coal units to 9.1% for the Brown SCCTs, and are based on historical EFOR values that vary from one year to the next. As discussed in section 5.6, assumed ATC during peak periods is also based on historical data.

The Companies' Long-Term Transfer Analysis shows that the Companies would not require any upgrades on the LG&E/KU transmission system for long-term winter-season imports of up to 500 MW and only a minor upgrade ($3.1 million) to accommodate up to 1,000 MW. The Companies similarly would not require transmission upgrades to accommodate long-term firm transfers to the Companies during the summer of up to 300 MW from PJM or MISO and up to 100 MW from TVA. Relatively small investments would be required to increase that import capacity to 500 MW for all three surrounding systems and to 1,000 MW for imports from MISO, but a fairly significant investment (almost $55 million) would be required to increase the capacity to 1,000 MW from TVA and PJM. But merely increasing import capability on the LG&E/KU system does not ensure there will be supply and transmission capacity on the neighboring system(s) adequate to serve the Companies, as they experienced during Winter Storm Elliott. In addition, the Companies would have to pay for firm transmission service and losses on the neighboring system(s) to secure access to this important capability.

Table 9 lists the results of the Companies' sensitivity analysis. For the annual EFOR sensitivities, the Companies increased and decreased EFOR by 1.5% and 1%, respectively. The Companies' generation performance has been excellent in recent years and the potential for higher EFORs is greater than the potential for lower EFORs. In the High EFOR case, EFORs range from 4.6% for coal baseload units to 10.6% for Brown SCCTs. The results of the EFOR cases highlights the importance of maintaining the Companies' generating units well. If all units' EFOR increases by 1.5 percent, LOLE more than doubles. If all units' EFOR decreases by 1 percent, LOLE halves.

Table 9: Sensitivity Analysis (Least-Cost Generation Portfolio)

Case	**LOLE**		
	Summer	**Winter**	**Annual**
Base Case	0.68	0.32	1.00
Unit Availability			
High EFOR: Increase EFOR by 1.5 Points	1.75	0.55	2.30
Low EFOR: Decrease EFOR by 1.0 Points	0.31	0.17	0.48
Available Transmission Capacity			
No Access to Neighboring Markets	0.76	0.32	1.10
High ATC (700 MW minimum)	0.02	0.13	0.15

For the ATC sensitivities, the Companies evaluated a case with no access to generation in neighboring regions and a "High ATC" case based on the Long-Term Transfer Analysis where the Companies pay approximately $101 million per year plus losses to have a minimum of 700 MW of ATC at all times. Because ATC is already limited in the base case, LOLE in the case with no access to neighboring markets is not significantly worse. The results of the High ATC case require an important caveat: when modeling resource adequacy, the Companies assume neighboring regions will have an LOLE of 1 day in 10 years, but based on the events of Winter Storm Elliott and the challenges that RTOs have articulated regarding resource adequacy and their markets generally, this assumption is uncertain. That said, if neighboring regions have an LOLE of 1 day in 10 years and the Companies secure 700 MW of firm transmission at a cost of $101 million per year plus losses, the Companies' LOLE would improve.

4 Capacity Contribution for Limited-Duration Resources

In addition to reserve margin constraints, the Companies use SERVM to determine the capacity contribution of limited-duration resources such as battery storage and dispatchable DSM programs by comparing their impact on LOLE to that of a SCCT. This concept is similar to the ELCC that PJM computes for their capacity accreditation process.[20] Capacity contribution enables PLEXOS to account for the fact that limited-duration resources do not contribute to reliability in the same way that fully dispatchable resources do.

As seen earlier in Table 3, the winter reserve margin for the 2032 Portfolio is only 18.3 percent. To complete this analysis, the Companies estimated LOLE for the generation portfolios in Table 10. The "Reference" portfolio (Portfolio 1) is the 2032 Portfolio in Table 3 less solar. Portfolios 2-5 add 300 MW of various technologies to the Reference portfolio to achieve summer and winter reserve margins close to the economic reserve margins.

Table 10: Generation Portfolios for Capacity Contribution Analysis

	Generation Portfolio	2032 Reserve Margin Winter / Summer
1	Reference: 2032 Portfolio Less Solar	18.3% / 13.2%
2	Reference + 300 MW of SCCT	22.6% / 17.4%
3	Reference + 300 MW of 4-hr BESS	
4	Reference + 300 MW of 8-hr BESS	
5	Reference + 300 MW of Dispatchable DSM	

Table 11 contains the results of this analysis. With summer and winter reserve margins significantly below the target minimums, the LOLE for the Reference portfolio is 10.84 days in 10 years, which is significantly higher than the reliability standard of 1 day in 10 years. When 300 MW of SCCT capacity is added to the Reference portfolio, LOLE decreases by 7.6 days. Alternatively, when 300 MW of 4-hour BESS is added to the Reference portfolio, LOLE decreases by 6.48 days. The capacity contribution for 4-hour BESS is computed as the ratio of the BESS LOLE impact to the SCCT LOLE impact (6.48/7.6 = 0.85). The capacity contributions for 4-hour BESS, 8-hour BESS, and dispatchable DSM are 85%, 93%, and 39%, respectively, of a SCCT or another fully dispatchable resource.

[20] 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 11: Capacity Contribution for Limited-Duration Resources

Generation Portfolio	Reserve Margin Winter/Summer	LOLE (Days in 10 Years)	LOLE Reduction (Days in 10 Years)	Capacity Contribution
1: Reference	18.3% / 13.2%	10.84	NA	NA
2: Reference + SCCT	22.6% / 17.4%	3.24	7.60	NA
3: Reference + 4-hr BESS		4.36	6.48	0.85
4: Reference + 8-hr BESS		3.77	7.07	0.93
5: Reference + Disp. DSM		7.89	2.95	0.39

5 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.

5.1 Study Year

The study year for this analysis is 2032. 2032 is the first full year in the Mid load forecast scenario with all economic development load additions. As explained in section 3, the Companies established minimum reserve margin constraints for resource planning by evaluating their existing resource portfolio with CPCN-approved resources over a range of load scenarios.

5.2 Neighboring Regions

While the Companies do not make a significant amount of off-system purchases, the vast majority of these 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. 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.
- 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, LOLEs in neighboring regions are assumed to be at their target levels of 1 day in 10 years.

5.3 Load Modeling

Table 12 summarizes the summer peak demand forecast for the Companies' service territories and neighboring regions in 2032 under normal weather conditions. 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 TVA's IRP.

Table 12: Peak Load Forecasts for 2032

	LG&E/KU	MISO-Indiana	PJM-West	TVA
Peak Load	7,201	16,433	72,920	31,101
Target LOLE (Days in 10 Years)	1	1	1	1

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 51 hourly demand forecasts for 2032 based on actual weather in each of the last 51 years.

Table 13 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 13: Summer and Winter Peak Demand Forecasts, 2032

	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	2012	7,980	16,002	80,754	32,482	1994	8,307	16,377	75,199	34,234
75th %-ile	2022	7,418	15,746	77,034	31,547	1979	7,409	15,016	66,530	29,848
Median	2021	7,090	14,942	64,787	28,326	1995	7,098	14,791	65,898	27,966
25th %-ile	1975	6,957	15,040	69,302	28,427	2006	6,848	14,025	59,518	27,338
Min	1974	6,551	14,912	64,979	23,945	2023	6,020	12,904	58,587	24,444

Figure 6 and Figure 7 contain graphical distributions of the Companies’ potential summer and winter peak demands for 2032 based on historical weather years. The values in Figure 6 labeled “Forecasted Peak” (i.e., 7,201 MW in the summer and 7,135 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. 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, 2032

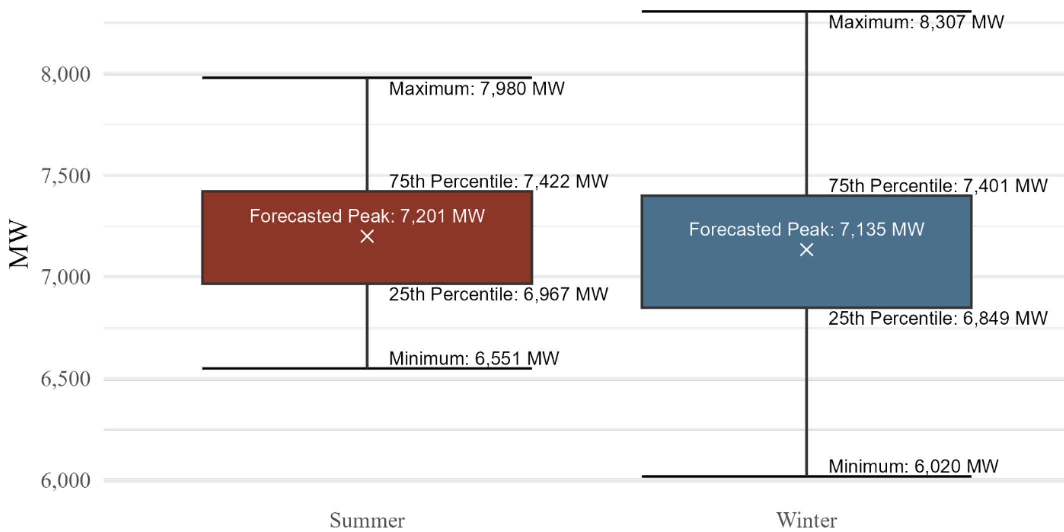
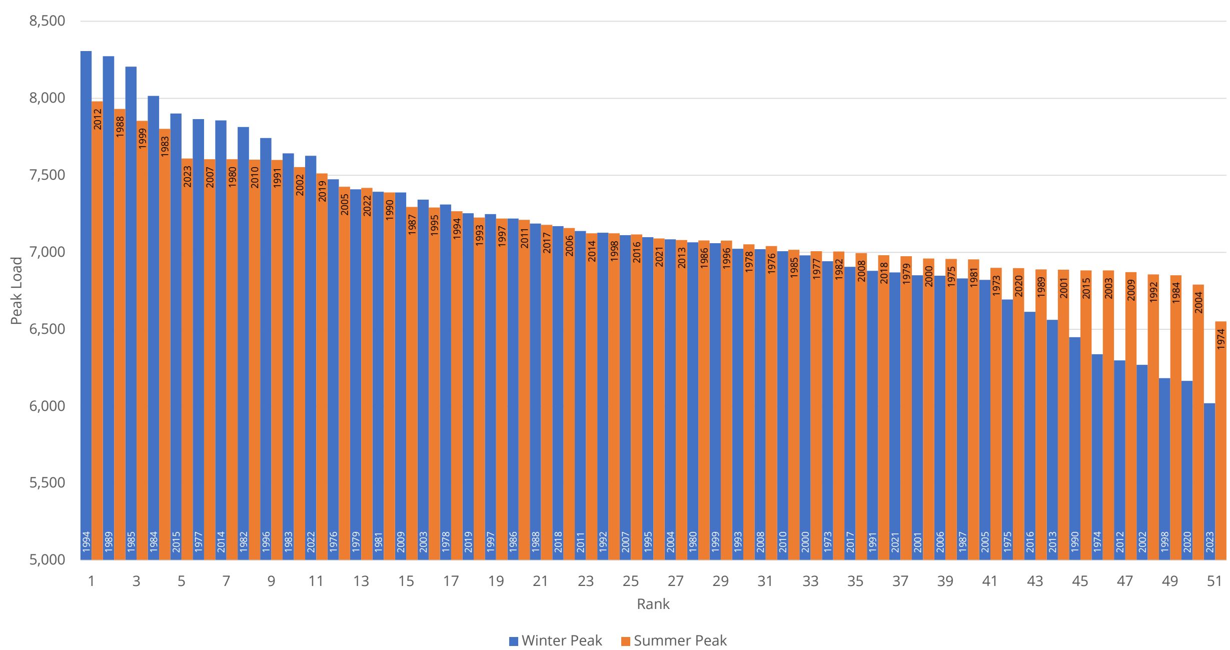


Figure 7: Distributions of Summer and Winter Peak Demands by Weather Year, 2032



5.4 Generation Resources

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

5.4.1 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. Therefore, unit availability scenarios are developed in SERVM to model the uncertainty in the timing and duration of forced outages. For each unit, the scenarios are developed to target the annual EFOR values in Table 14, which are based on the medians of historical EFORs from 2009 to 2024.

In developing these annual EFOR values, the Companies updated their analysis from the 2022 CPCN proceedings to compute the correlation between forced outages and temperature over this same time period (2009-2024).[21] The results are consistent with the 2022 CPCN analysis and show that there is almost no correlation, which is consistent with the way the Companies designed and maintain their generating units as well as the operating procedures the Companies follow during extreme weather events. Alternatively, modeling inputs for generating units in neighboring regions were developed by Astrape Consulting ("Astrape"), the licensor of SERVM. For each neighboring region, Astrape added a negative generating unit with higher output at lower temperatures to model the effects of correlated outages. Notably, with this resource, the neighboring regions were configured to have an LOLE of 1 day in 10 years.

[21] See the Companies' response to the Commission's Post-Hearing Data Request No. 25 in Case No. 2022-00402.

Table 14: 2032 LG&E/KU Generating & DSM Portfolio

Resource	Resource Type	Net Max Summer Capacity (MW)[22]	Net Max Winter Capacity (MW)	EFOR
Brown 3	Coal	412	416	8.0%
Brown 5	SCCT	130	130	9.1%
Brown 6	SCCT	146	171	7.4%
Brown 7	SCCT	146	171	7.4%
Brown 8	SCCT	121	128	9.1%
Brown 9	SCCT	121	138	9.1%
Brown 10	SCCT	121	138	9.1%
Brown 11	SCCT	121	128	9.1%
Brown Solar	Owned Solar	8	0	0%
Brown Battery	Battery	125	125	0%
Cane Run 7	NGCC	697	759	1.6%
Dix Dam 1-3	Hydro	32	32	N/A
Ghent 1	Coal	475	479	3.1%
Ghent 2	Coal	485	486	3.1%
Ghent 3	Coal	481	476	3.1%
Ghent 4	Coal	478	478	3.1%
Mill Creek 3	Coal	391	394	3.1%
Mill Creek 4	Coal	477	486	3.1%
Mill Creek 5	NGCC	645	660	1.6%
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	6.8%
Trimble County 1 (75%)	Coal	370	370	3.1%
Trimble County 2 (75%)	Coal	549	570	2.7%
Trimble County 5	SCCT	159	179	4.3%
Trimble County 6	SCCT	159	179	4.3%
Trimble County 7	SCCT	159	179	4.3%
Trimble County 8	SCCT	159	179	4.3%
Trimble County 9	SCCT	159	179	4.3%
Trimble County 10	SCCT	159	179	4.3%
Business Solar	Owned Solar	0.2	0	N/A
Solar Share	Owned Solar	1.7	0	N/A
Mercer Solar	Owned Solar	94	0	0%
Marion Solar	Owned Solar	94	0	0%
CSR	Interruptible	110	115	N/A
DCP[23]	DSM	190	145	N/A

[22] Projected net ratings as of 2032. 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.

[23] 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.

5.4.2 Fuel Prices

Fuel prices impact generation production costs and the determination of economic reserve margin. The forecasts of natural gas and coal prices for the Companies' generating units are summarized in Table 15 and Table 16. 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 15: 2032 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 16: 2032 Delivered Coal Prices (LG&E and KU; Nominal $/mmBtu)

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

5.4.3 Interruptible Contracts

Load reductions associated with the Companies' Curtailable Service Rider ("CSR") are modeled as generation resources. Table 17 lists the Companies' CSR customers and their assumed load reductions. The Companies can curtail each CSR customer up to 100 hours per year.[24] However, because the Companies can curtail CSR customers only in hours when more than ten 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

[24] 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.

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 110 MW.

Table 17: Interruptible Contracts

CSR Customers	Assumed Hourly Load Reduction (MW)
[redacted]	
Total	110

5.5 Solar Profile Modeling

The Companies developed solar generation profiles to align with the weather underlying each weather year load forecast. The Companies used NREL's PVWatts model to develop historical profiles for the years 1998 to 2022 based on historical solar irradiance data from NREL's National Solar Radiation Database ("NSRDB").[25] Then, solar generation profiles for the 1973-1997 and 2023 weather years were developed based on similar days in the 1998-2022 profiles. Specifically, each day in the 1973-1997 and 2023 profiles is based on a day in the 1998-2022 period with similar peak load and from the same time of year.

NREL's PVWatts model can be used to develop net generation profiles for different types of solar arrays (e.g., fixed-tilt and single-axis tracking). For specific projects (e.g., Mercer County Solar), generation profiles are based on historical solar irradiance from the NSRDB for the project site. For new solar, profiles were developed based on the average generation from ten sites located throughout the state. This was done to capture the benefits of a geographically diverse portfolio of solar projects.

Importantly, solar is modeled in SERVM as a fixed energy resource, and the Companies do not directly address its intra-hour intermittency (i.e., cloud risk). Although the solar profiles are reasonable and correlated with the weather and solar irradiance underlying the weather year forecasts, the models assume solar will reliably and consistently produce energy according to its profile.

5.6 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

[25] 1998 to 2022 is the period of history for which irradiance data is available.

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 18 summarizes the sum of daily ATC between the Companies' system and neighboring regions on weekdays during the summer and winter months of 2022, 2023, and 2024. Based on the daily ATC data, the Companies' ATC for importing power from neighboring regions is zero 55% of the time. ATC is modeled in SERVM based on this distribution.

Table 18: Daily ATC

Daily ATC Range	Count of Days	% of Total
0	221	55%
1 – 199	24	6%
200 - 399	20	5%
400 - 599	27	7%
600 - 799	16	4%
800 - 999	13	3%
>= 1,000	84	21%
Total	405	

5.7 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 taken from the 2024 IRP Technology Update and is summarized in Table 19 in 2032 dollars. Compared to the cost of SCCT capacity used in the 2022 CPCN filing, this cost is significantly higher.

Table 19: SCCT Cost (2032 Dollars)

Input Assumption	Value
Capital Cost ($/kW)	1,684
Fixed O&M ($/kW-yr)	7.3
Firm Gas Transport ($/kW-yr)	19.6
Escalation Rate	1.36%
Discount Rate	6.56%
Carrying Charge ($/kW-yr)	162.2

5.8 Cost of Unserved Energy (Value of Lost Load)

Cost of unserved energy is an input used in the determination of economic reserve margin. 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.[26] 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 2032 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 $26.9/kWh.

Table 20 shows how the numbers were derived. The range for residential customers varied from $1.9/kWh to $4.8/kWh. The range for commercial customers varied from $34.7/kWh to $51.3/kWh while industrial customers varied from $18.0/kWh to $41.7/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 $10.9/kWh.

[26] "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.

Table 20: Cost of Unserved Energy (2032 Dollars)

	Customer Class Mix	2003 DOE Study $/kWh	2009 DOE Study $/kWh	Christian Associates Study $/kWh	Billinton and Wacker Study $/kWh
Residential	31%	2.3	1.9	4.8	4.2
Commercial	39%	51.3	46.7	34.7	36.0
Industrial	30%	29.6	41.7	18.0	36.0
System Cost of Unserved Energy		29.6	31.3	20.4	26.2
	Customer Class Mix	**Min $/kWh**	**Mean $/kWh**	**Max $/kWh**	**Range $/kWh**
Residential	31%	1.9	3.3	4.8	2.9
Commercial	39%	34.7	42.2	51.3	16.7
Industrial	30%	18.0	31.3	41.7	23.8
Average System Cost of Unserved Energy			26.9		

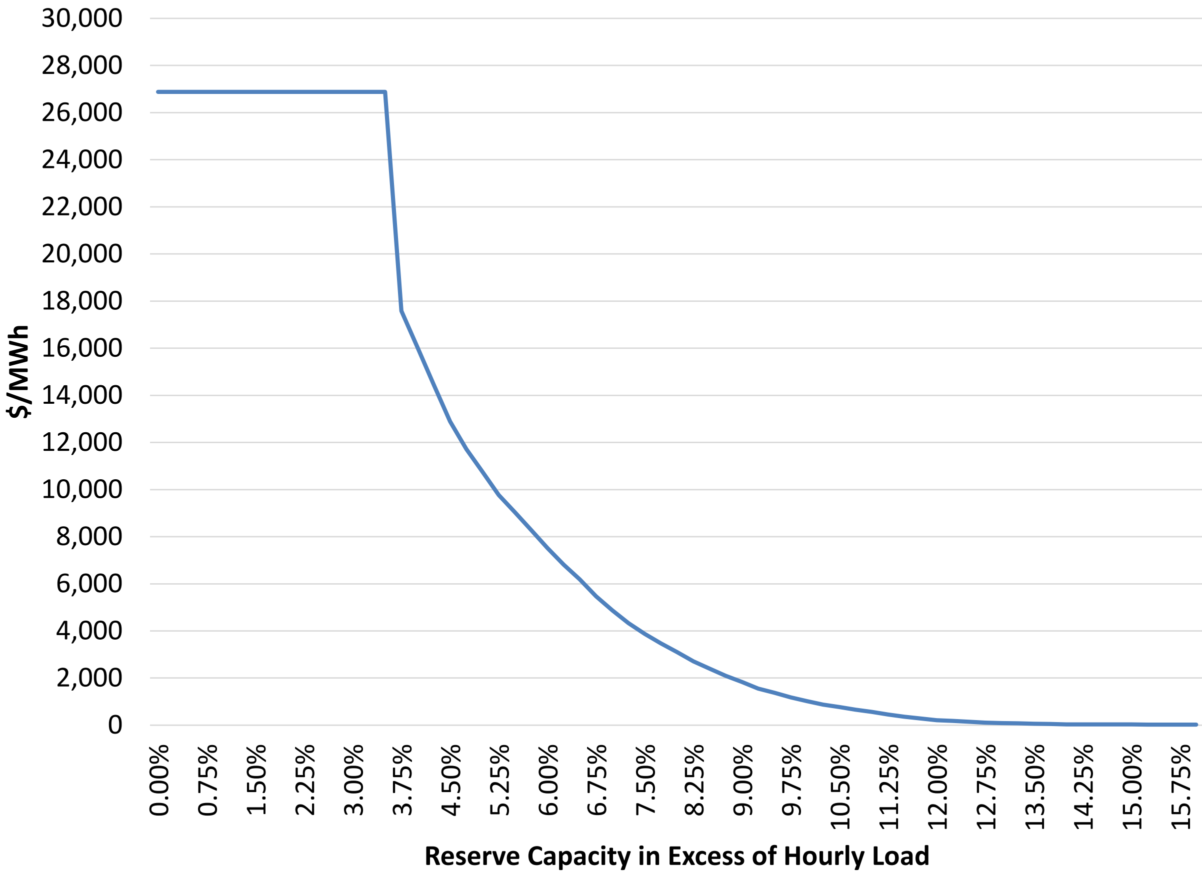
5.9 Spinning Reserves

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.

5.10 Scarcity Pricing

Scarcity pricing is an input used in the determination of economic reserve margin and impacts reliability and generation production costs only when generation reserves become scarce and market power is available. 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 3.4% of the forecasted summer peak demand in 2032 (7,201 MW). At reserve capacities less than 3.4% of the hourly load, the scarcity price is equal to the Companies' value of unserved energy ($26,900/MWh; see Section 5.8). The remainder of the curve is estimated based on market purchase data.

Figure 8: Scarcity Price Curve



5.11 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.

2024 IRP
Resource Assessment

PPL companies

Generation Planning & Analysis

October 2024

Table of Contents

1 Executive Summary

Louisville Gas & Electric Company ("LG&E") and Kentucky Utilities Company's ("KU") (collectively "Companies") Generation Planning & Analysis group conducted this 2024 Resource Assessment as part of the Companies' 2024 Integrated Resource Plan ("IRP"). The goal of the Companies' resource planning process is to provide safe, reliable, and low-cost service to their customers while complying with all laws and regulations. Unlike a Certificate of Public Convenience and Necessity ("CPCN") filing, an IRP contemplates a number of resource decisions over a 15-year planning horizon that do not require immediate action. Even though the IRP represents the Companies' analysis of the best options to meet customer needs at this point in time, the Companies' planning process is constantly evolving and resource plans may be revised as conditions change and as new information becomes available.

1.1 Supporting Load Growth Due to Economic Development Is Key IRP Focus

Kentucky's economic development progress has been historic for the last several years, and the state continues to invest heavily to ensure this progress continues. Therefore, as discussed in Volume I, Section 5, economic development drives significant increases in the Companies' load forecast, particularly increases related to projected new data center load. Data centers require significant amounts of electric power, low to moderate risk of adverse weather events and natural disasters, availability of telecommunications infrastructure and water for equipment cooling, and favorable tax incentives. Kentucky is well positioned with most if not all of these attributes. The Companies' Economic Development team is working with a growing number of data center projects that vary in stages of development, but which mostly have very large power requirements. Based on their interest and the projections of growth across the US, it is reasonable to assume that a portion of US growth in data center load will occur within the Companies' service territory. For these reasons, the Companies assign a low likelihood to the Low load forecast, which includes no economic development load growth, and focus on the Mid and High load forecasts, which include 1,050 MW and 1,750 MW of new data center load by 2032, respectively.

In addition to uncertainty in economic development load growth, these load forecast scenarios reflect the uncertainty in other factors such as the pace of energy efficiency improvements, electric vehicle growth, and the growth in distributed generation. The development of these scenarios is discussed in IRP Volume I, Section 5.(3) (Summary of Impact of Key Assumptions and Uncertainties on Load Forecast) and Section 7.(7).(e) (Sensitivity Analysis).

Importantly, each forecast also includes significant reductions by 2032 from customer-initiated energy efficiency improvements, AMI-related conservation load reduction and ePortal savings, distributed generation, and the energy efficiency effects of the Companies' proposed 2024-2030 Demand-Side Management and Energy Efficiency Program Plan ('DSM-EE") as well as new measures beyond 2030. The Mid load forecast, for example, includes nearly 1,500 GWh of these reductions. A summary of the Companies' load forecasting models and methods is included in Volume II (2024 IRP Electric Sales and Demand Forecast Process).

1.2 Resource Assessment Considers Wide Range of Environmental Scenarios

IRP Volume I, Section 6 summarizes significant changes in environmental regulations since the 2021 IRP. The Companies' Resource Assessment considers four environmental regulation ("environmental") scenarios:

- **No New Regulations**: This scenario assumes the Good Neighbor Plan (related to the National Ambient Air Quality Standards ("NAAQS") for ozone, "Ozone NAAQS"), 2024 Effluent Limit Guidelines ("ELG"), and recent Clean Air Act ("CAA") Section 111(b) and (d) Greenhouse Gas ("GHG") Rules or their equivalents do not take effect over the IRP planning period, and no new regulations are implemented through the end of the IRP planning period (2039) that require significant investment for environmental compliance.
- **Ozone NAAQS**: This scenario assumes the 2024 ELG and GHG Rules or their equivalents do not become effective during the IRP planning period, but the Good Neighbor Plan or its equivalent does become effective. In this case, because selective catalytic reduction ("SCR") is a Reasonably Achievable Control Technology for ozone NAAQS compliance, the Companies assume SCR will be needed to operate Ghent 2 in the ozone season (i.e., May through September) beyond 2030.
- **Ozone NAAQS + ELG**: This scenario builds on the Ozone NAAQS scenario and assumes the 2024 ELG or its equivalent will also become effective, but GHG Rules or their equivalents do not become effective during the IRP planning period. Based on Environmental Protection Agency ("EPA") obligation, EPA authority, and a pragmatic evaluation of compliance technology implementation, the Companies consider this environmental scenario to be most likely.
- **Ozone NAAQS + ELG + GHG**: This scenario assumes the Good Neighbor Plan (or a regulation with the same effect), 2024 ELG, and the GHG Rules or their equivalents all become effective during the IRP planning period. For the reasons discussed in Section 4.1.3, the Companies assign a low likelihood to this scenario.

1.3 Companies' Planning Process Is Comprehensive

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 resource plan development and screening, hourly dispatch, and reliability modeling software platforms.

In addition to the three load scenarios and the four environmental scenarios, the assessment began with:

- **Five fuel price scenarios**. The Companies developed these scenarios using the methodology that was used to develop fuel price scenarios for their 2022 CPCN Resource Assessment.
- **New supply-side resource options**. Costs and assumptions for new supply-side resources are based on the National Renewable Energy Laboratory's 2024 Annual Technology Baseline ("NREL's 2024 ATB"), updated cost estimates for resources contemplated in the Companies' 2022 CPCN filing, and the Companies' own analysis. These options are discussed in IRP Volume III (2024 IRP Technology Update).
- **New demand-side resource options**. New demand-side resources include new demand response measures and an expansion of the Companies' Curtailable Service Rider ("CSR"). These options are also discussed in IRP Volume III (2024 IRP Technology Update).
- **Existing resource retrofit options**. The Companies considered the option to add an SCR to Ghent 2 as well as the option to convert each of the coal units to co-fire or burn 100% natural gas.
- **Existing and CPCN-approved resources**. CPCN-approved resources include the Mill Creek 5 natural gas combined cycle ("NGCC") unit, the Brown Battery Energy Storage System ("BESS" or "battery storage"), Mercer County Solar, Marion County Solar, and demand response programs from the Companies' 2024-2030 DSM-EE Program Plan.

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

1. Stage One: The Companies developed resource plans for all load and environmental scenarios subject to constraints due to reserve margins, legislative unit retirement restrictions, landfill storage capacity, and technology availability. The results of this analysis are impacted by the costs of new supply-side resources, which are significantly higher than two years ago and favor the extended operation of aging coal units.

   Result:

   - **No New Regulations**: New NGCC resources and battery storage charged by existing resources are added as needed to support economic development, and all coal units except Brown 3 operate through the end of the IRP period. The least-cost resource plan includes all new demand response measures but no additional CSR.
   - **Ozone NAAQS**: SCR is added to Ghent 2 in the Mid and High load scenarios. In the Low load scenario, Ghent 2 is not needed to meet the minimum summer reserve margin and operates only in the non-ozone season.
   - **Ozone NAAQS + ELG**: The Companies comply with the 2024 ELG rules at Ghent and Trimble County via zero liquid discharge, but not at Mill Creek due in part to landfill constraints. The Brown and Mill Creek coal units are replaced by NGCC and simple-cycle combustion turbine ("SCCT") capacity.
   - **Ozone NAAQS + ELG + GHG**: All coal units are replaced by a combination of NGCC with a 40% capacity factor limit, battery storage, and renewables by 2039. Some coal units are retrofitted to co-fire natural gas or fully converted to natural gas to manage the transition.

2. Stage Two: Considering load and environmental uncertainty, the Stage Two analysis provides the rationale for selecting a single resource plan ("Recommended Resource Plan") for IRP reporting. The Companies started with the resource plan that is least-cost in the Mid load, Ozone NAAQS + ELG scenario and modified it to (1) support the potential for high economic development load growth and CO_2 regulations and (2) have no regrets should high load or CO_2 regulations not come to fruition.

   Result:

   - Table 1 contains the Recommended Resource Plan as well as the least-cost resource plans across all fuel scenarios for the Mid load, Ozone NAAQS + ELG scenario and the High load, Ozone NAAQS + ELG scenario. The Mid load, Ozone NAAQS + ELG scenario includes retirements of Brown 3 and Mill Creek 3-4, ELG compliance at the Ghent and Trimble County stations via zero liquid discharge, and the additions of new dispatchable DSM measures, two NGCCs, 900 MW of battery storage, and a Ghent 2 SCR.[1] In the Recommended Resource Plan, to support the potential for high economic development load growth and CO_2 regulations, the additions of the Ghent 2 SCR and 400 MW of battery

[1] Unlike the High load scenario, the least-cost resource plan in the Mid load scenario does not initially include an SCR on Ghent 2. However, this is predicated upon the availability of almost 2,000 MW of solar at costs more than 30 percent lower than today, which is inconsistent with the Companies' recent market experience and potentially not possible to execute. When considering a sensitivity case where solar prices do not decline as predicted by NREL's 2024 ATB, the least-cost resource plan for the Mid load scenario includes an SCR on Ghent 2.

storage are accelerated to 2028, the addition of the second NGCC is accelerated to 2031, and the retirement of Brown 3 is deferred to 2035.[2] In addition, 500 MW of solar is added in 2035 after prices fall to hedge natural gas price volatility and future CO_2 regulation risk.

- The Recommended Resource Plan is a "no regrets" resource plan because the accelerated resources are needed by 2035 if high economic development load growth or CO_2 regulations do not come to fruition. Furthermore, the addition of 500 MW of solar reflects the likelihood that some level of solar will be least-cost even without CO_2 regulations.
- Finally, because growth in data center load is driven significantly by customers with aggressive carbon goals, more solar could be added by these customers in the context of the Companies' Green Tariff Option #3 or by the Companies in a scenario where solar prices fall faster than NREL projects. The Enhanced Solar Resource Plan reflects this possibility and includes 1,000 MW of additional solar in 2028 through 2032.

Table 1: Recommended Resource Plan and Enhanced Solar Resource Plan (only years in which changes occur are shown)

	Least-Cost Resource Plans Ozone NAAQS + ELG			
Year	**Mid Load, Solar Cost Sensitivity[1]**	**High Load**	**Recommended Resource Plan Ozone NAAQS + ELG Mid Load**	**Enhanced Solar Resource Plan Mid Load**
2028	+Dispatchable DSM	+Dispatchable DSM; +300 MW 4hr BESS	+Dispatchable DSM; +400 MW 4hr BESS; Add Ghent 2 SCR	+Dispatchable DSM; +400 MW 4hr BESS; Add Ghent 2 SCR +200 MW Solar
2029		+700 MW 4hr BESS		
2030	Retire Brown 3; Add Ghent 2 SCR; +1 NGCC; ELG @ Ghent, Trimble County; +100 MW 4hr BESS	Add Ghent 2 SCR; +1 NGCC; ELG @ Ghent, Trimble County	+1 NGCC; ELG @ Ghent, Trimble County	+1 NGCC; ELG @ Ghent, Trimble County; +200 MW Solar
2031	+400 MW 4hr BESS	Retire Brown 3; +1 NGCC; +200 MW 4hr BESS	+1 NGCC	+1 NGCC
2032	+200 MW 4hr BESS	+200 MW 4hr BESS		+600 MW Solar
2035	Retire Mill Creek 3-4; +1 NGCC; +200 MW 4hr BESS	Retire Mill Creek 3-4; +1 NGCC; +1 SCCT	Retire Mill Creek 3-4; Retire Brown 3; +500 MW 4hr BESS; +500 MW Solar	Retire Mill Creek 3-4; Retire Brown 3; +500 MW 4hr BESS;

[2] The 2030 need for SCR is based on the daily NO_x emission limit required by the Good Neighbor Plan beginning in 2030. However, SCR is added to Ghent 2 in 2028 to support compliance with limits for the ozone season beginning in 2028.

1.4 Despite Uncertainty, Next Steps Are Clear

As noted earlier, the IRP contemplates a number of resource decisions over a 15-year planning horizon that do not require immediate action. Moreover, due to the nature of the IRP planning exercise, the modeling of these decisions cannot fully reflect certain impactful real-world considerations, including the types and pricing of resources that would be made available to the Companies in response to a request for proposals, supply chain constraints, and specific siting and permitting expenses and timelines. Those issues notwithstanding and despite a considerable amount of uncertainty due to load and environmental regulations, the least-cost resource plans in this IRP indicate some potential resource changes that will require more immediate attention:

- **NGCC and battery storage are needed to support economic development load growth**. Additional resources are needed to support economic development load growth and a combination of NGCC and battery storage is the least-cost way to support this growth.
- **With higher costs for new resources and EPA's obligation to drive local NAAQS attainment, SCR is needed on Ghent 2 as early as 2028**. A Ghent 2 SCR in 2028 will drive self-compliance to NO_x reductions that support Kentucky's obligations to 2015 Ozone NAAQS attainment and provides assurance the unit will be available to support economic development load growth.

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

The objective of this Resource Assessment is to develop a 15-year resource plan that is the Companies' best estimate for providing safe and reliable service at the lowest reasonable cost. An optimal resource plan must be able to serve customers' needs reliably at all times and in all seasons, weather, and daylight conditions. Achieving that objective begins with an understanding of customers' projected needs, as well as the reserve margins necessary to provide reliable service.

2.1 Customers' Projected Needs: The 2024 IRP Load Forecasts

The Companies' load forecast projects customers' energy and demand requirements. Figure 1 shows the three forecasts of energy requirements considered in this Resource Assessment. Key load forecast uncertainties and the development of these scenarios are discussed in IRP Volume I, Section 5.(3) and Section 7.(7).(e).[3] Notably, each forecast includes significant reductions by 2032 from customer-initiated energy efficiency improvements, AMI-related conservation load reduction and ePortal savings, distributed generation, and the energy efficiency effects of the Companies' proposed 2024-2030 DSM-EE Program Plan as well as new programs beyond 2030.[4] Growth in the Mid and High load forecast scenarios is explained primarily by the addition of high load factor economic development loads. Kentucky's economic development progress has been historic for the last several years, and the state continues to invest heavily to ensure this progress continues. Data centers specifically require significant amounts of electric power, low to moderate risk of adverse weather events and natural disasters, availability of telecommunications infrastructure and water for equipment cooling, and favorable tax incentives. Kentucky is well positioned with most if not all of these attributes. The Companies' Economic Development team is working with a growing number of data center projects that vary in stages of development, but which mostly have very large power requirements. Based on their interest and the projections of growth across the US, it is reasonable to assume that a portion of US growth in data center load will occur within the Companies' service territory. As discussed in Section 5.(3) of Volume I, the Companies assign a low likelihood to the Low load forecast.

[3] A more detailed summary of the Companies' load forecasting models and methods is included in Volume II (2024 IRP Electric Sales and Demand Forecast Process).

[4] The Mid load forecast, for example, includes nearly 1,500 GWh of these reductions.

Figure 1: 2024 IRP Annual Energy Requirements (GWh)[5]

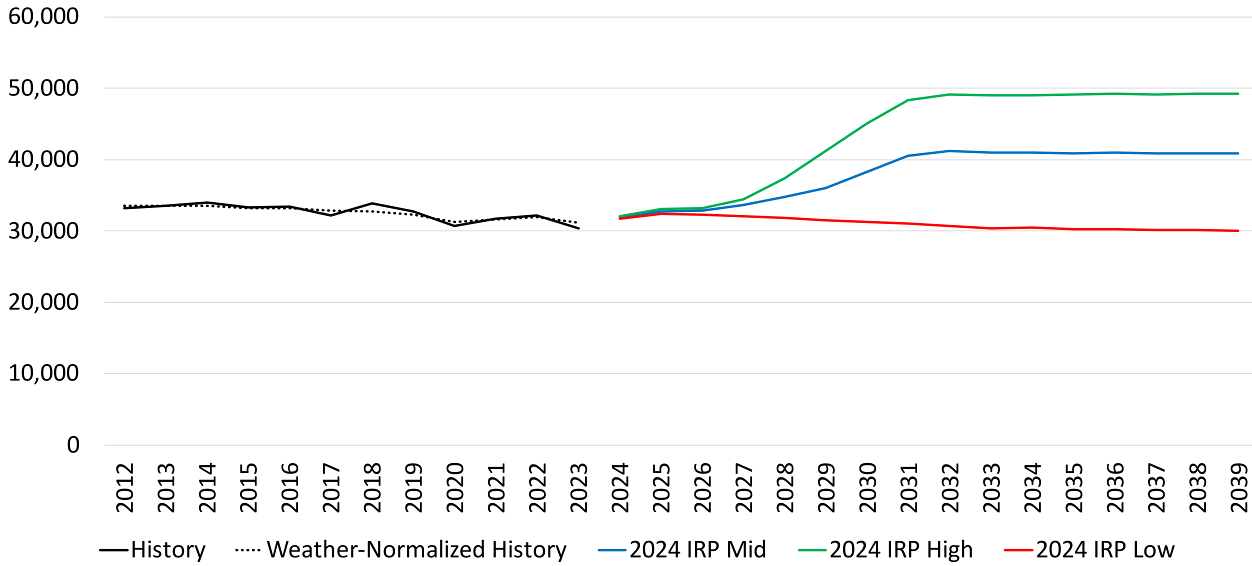


Figure 2 shows forecasts of winter and summer peak demands. Historically, winter peaks are much more volatile than summer peaks. Like energy requirements, near-term growth in peak demands is driven by the addition of large economic development loads. After 2031, peak demands are mostly flat as energy efficiency improvements offset the impact of new customer growth. Throughout the forecast period, the Companies' load continues to be dual peaking, which limits the opportunity for generating unit maintenance to the shoulder months.

[5] History excludes municipal customers that departed in 2019.

Figure 2: 2024 IRP Winter and Summer Peak Demands (MW)[6]

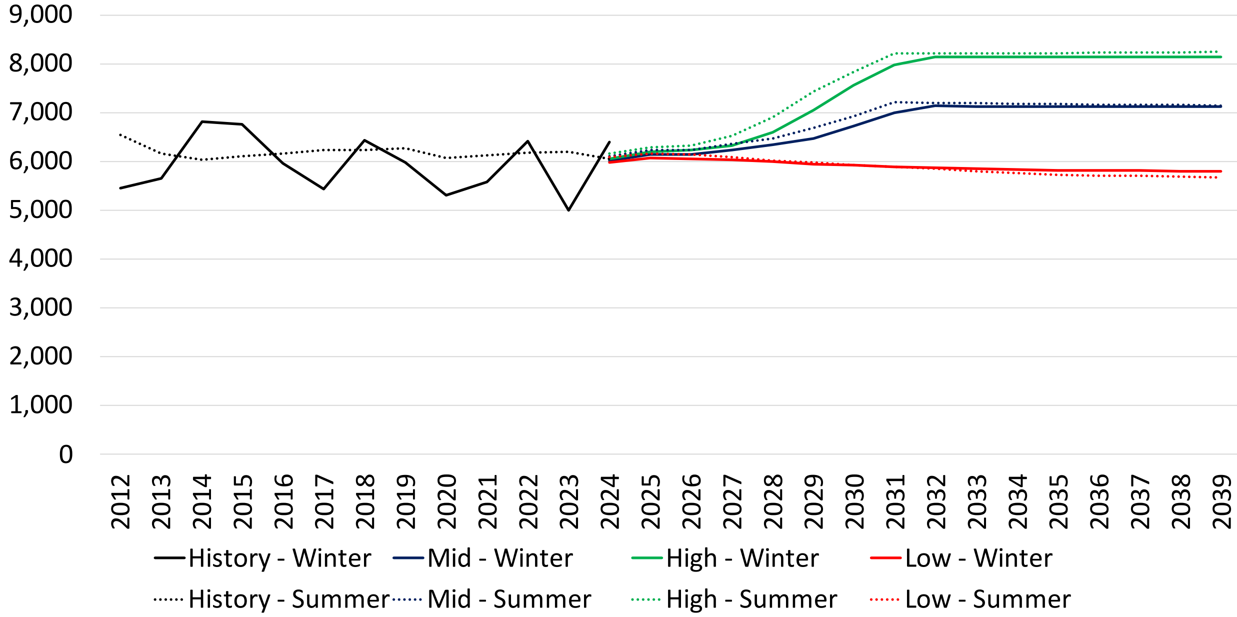


Figure 3 shows the proportion of energy consumed during daylight and non-daylight hours in 2032.[7] Approximately 43% of annual energy requirements and 53% of winter energy requirements is consumed at night.

[6] History excludes municipal customers that departed in 2019.

[7] 2032 is the first full year in the Mid load forecast scenario with all economic development load additions.

Figure 3: Proportion of Energy Consumed During Daylight and Non-Daylight Hours (Mid Load; 2032)

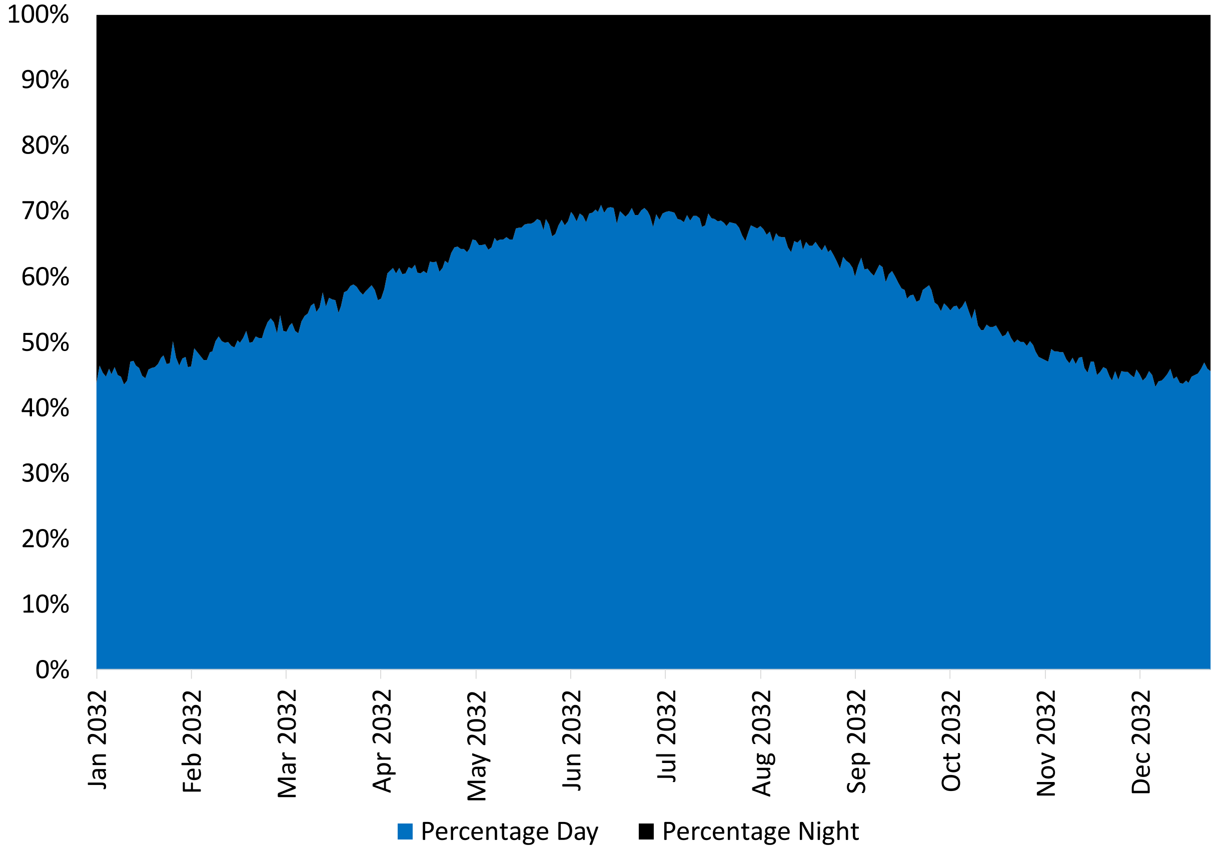


Figure 4 shows hourly energy requirements for 2032 chronologically and Figure 5 shows 2032 daily load duration curves for daylight and non-daylight hours. For Figure 5, each day in 2032 was broken into daylight and non-daylight periods. The left side of the figure (Daylight Hours) shows the maximum and minimum hourly loads for each day during daylight hours, and the right side of the figure (Nighttime Hours) shows the same data for nighttime hours. For both periods, the data is sorted by the maximum load in descending order, and the black solid line shows the trend in minimum loads. Notably, the generation capacity and load following capabilities needed to serve daylight and non-daylight energy requirements are very similar. Under normal weather conditions in the Mid load scenario, the forecasted winter peak demand (7,135 MW) occurs at night and is almost as high as the forecasted summer peak demand (7,201 MW), which occurs during the day. In addition, the Companies load is over 3,300 MW in every hour of the year.

Figure 4: 2032 Hourly Energy Requirements (Mid Load, MWh)

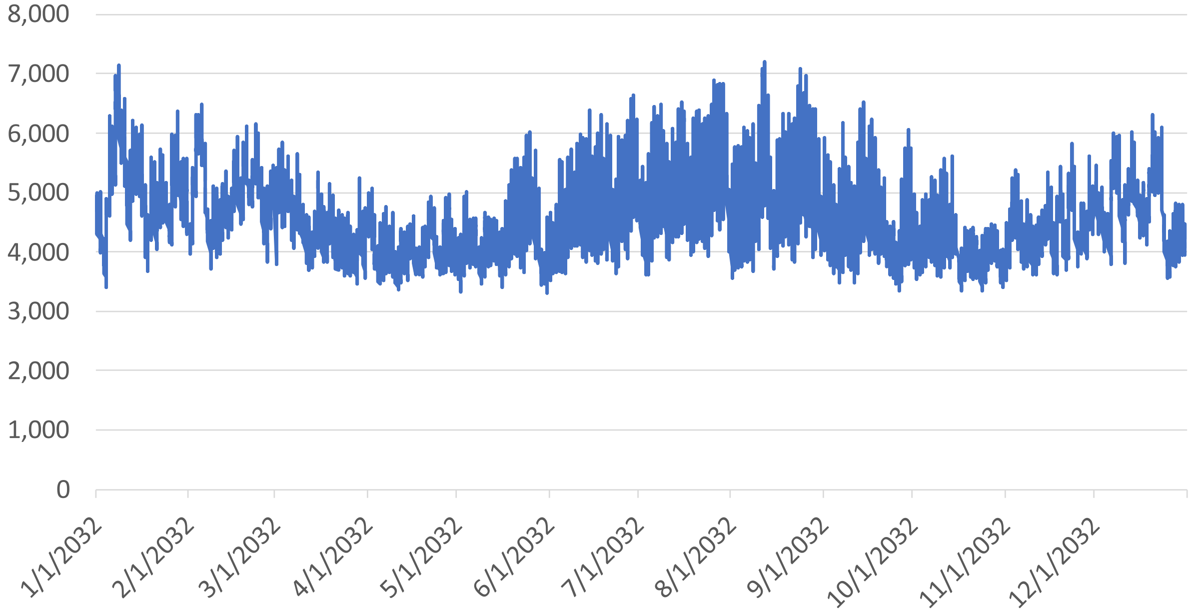
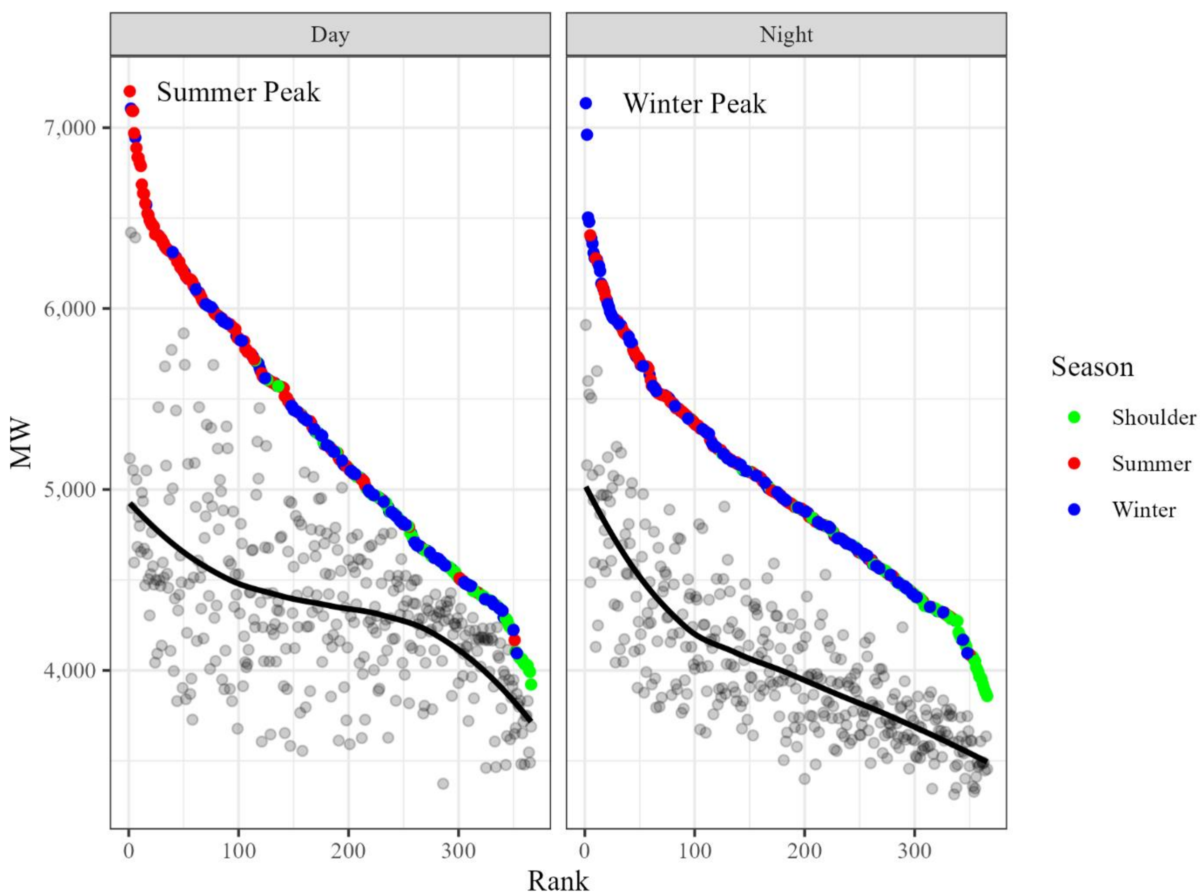


Figure 5: Daily Load Duration Curves; Daylight and Non-Daylight Hours

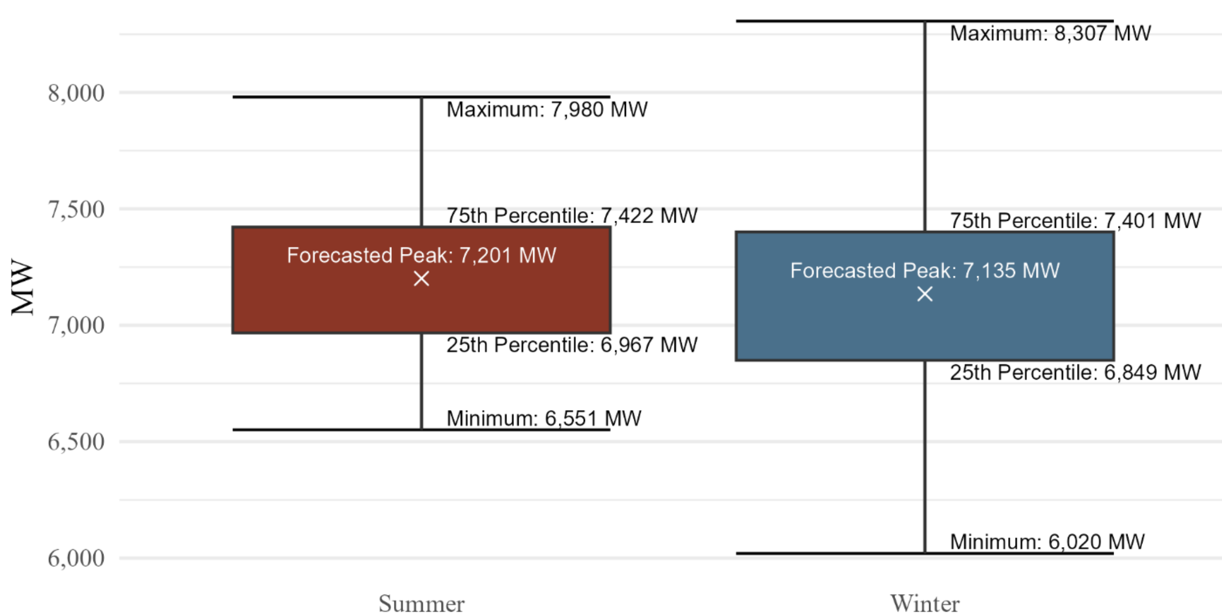


These figures show that a resource portfolio must be able to serve customers' considerable energy requirements in all hours, seasons, and weather and daylight conditions. Notably, the figures above reflect load under normal weather. Extreme weather conditions drive a need for additional reliability considerations.

2.2 Serving Customers Reliably: Minimum Reserve Margins

The Companies' long-term load forecast is developed with the assumption that weather will be normal in every year. While this is a reasonable assumption for long-term resource planning, weather from one year to the next is never the same. Therefore, to account for the possibility of extreme weather events and the uncertainty in generating unit availability, the Companies carry a level of supply-side and demand-side resources that exceeds their forecasted peak demands under normal weather conditions. Reserve margin is the amount of resources carried in excess of forecasted peak demands and is expressed as a percentage of forecasted peak demand under normal weather conditions. IRP Volume III (2024 IRP Resource Adequacy Study) summarizes the analysis used to determine minimum winter and summer reserve margin constraints for resource planning. The reserve margins needed to maintain a loss-of-load expectation ("LOLE") of one or fewer days in 10 years are 29% in the winter and 23% in the summer. This is consistent with the much greater variability of winter peak demands, as Figure 6 below shows:

Figure 6: Distributions of Winter and Summer Peak Demands, 2032



In addition to meeting minimum reserve margin constraints, the Companies developed resource plans that comply with KRS 278.264, which constrains retirements of fossil fuel-fired generation. Specifically, the Companies added constraints in PLEXOS to ensure (for cases where coal unit retirements are economic) that coal units are replaced over the analysis period by an equal or greater amount of fully dispatchable resources. This constraint did not limit the types of resources that could be added to serve load growth.

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

For the 2024 IRP, the Companies modeled new supply-side resources as well as new dispatchable DSM program measures and an expansion of the Companies' CSR program. As noted earlier, these resources are discussed in more detail in IRP Volume III (2024 IRP Technology Update).

3.1 New Supply-Side and Demand-Side Resources

Table 2 through Table 4 list the supply-side and demand-side resources considered in this Resource Assessment. Fully dispatchable resources are resources that can be dispatched any time and operated for days or months at a time. Fully dispatchable resources include large-frame SCCTs, NGCCs, and small modular nuclear reactors ("SMR"). Renewable resource options include land-based wind resources located in Kentucky and Indiana as well as utility-scale solar resources located in Kentucky. Limited-duration resources can only be dispatched several hours at a time and in the case of the Companies' dispatchable DSM and CSR programs, have limited availability. Limited-duration resources include 4-hour and 8-hour BESS, dispatchable DSM program measures, and an expansion of the Companies' CSR program. Resource costs and assumptions are based on the "Moderate" scenario in National Renewable Energy Laboratory's 2024 Annual Technology Baseline ("NREL's 2024 ATB"), updated cost estimates for resources contemplated in the Companies' 2022 CPCN filing, and the Companies' own analysis.[8]

[8] See https://atb.nrel.gov/ for NREL's 2024 ATB.

Table 2: Fully Dispatchable Resources (2030 Installation; 2030 Dollars)

	SCCT	NGCC	SMR
Summer Capacity (MW)[9]	243	645	300
Winter Capacity (MW)[9]	258	660	300
Heat Rate (MMBtu/MWh)[10]	9.5	6.3	9.2
Capital Cost ($/kW)[11]	1,636	2,121	9,765
Fixed O&M ($/kW-yr)[12]	6.9	7.8	166
Firm Gas Cost ($/kW-yr)[13]	19	15	N/A
Variable O&M ($/MWh)[14]	N/A	0.23	3.17
Start Cost ($/Start)[15]	27,398	N/A	N/A
Hourly Operating Cost ($/Hour)[16]	N/A	906	N/A
Fuel Cost ($/MWh)[17]	40.29	26.58	13.45
Investment Tax Credit[18]	N/A	N/A	40%
Earliest In-Service Year[19]	2030	2030	2039

[9] Capacity is the net installed capacity ("ICAP").

[10] Heat rate is the full load net heat rate.

[11] Capital cost is the overnight capital expenditure required to achieve commercial operation. Cost of financing is modeled through construction profiles for each resource type.

[12] Fixed operation and maintenance costs are operation and maintenance costs that do not vary with generation output. For SCCT and NGCC resources, fixed O&M includes fixed costs for a long-term service agreement ("LTSA").

[13] Firm gas transportation costs are costs associated with reserving firm gas-line capacity.

[14] Variable operation and maintenance costs are operation and maintenance costs incurred on a per-unit-energy basis.

[15] Start costs are starts-based variable LTSA costs for SCCT.

[16] Hourly operating costs are hours-based variable LTSA costs for NGCC.

[17] Fuel cost is the product of the unit's heat rate and the assumed cost of fuel.

[18] In accordance with the current tax credits, the Companies assumed nuclear SMR resources that are in-service by year 2039 would begin construction by year 2033 and receive the full credit; resources that are in-service in year 2040 would begin construction in 2034 and receive 75% of the credit; resources that are in-service in year 2041 would begin construction in 2035 and receive 50% of the credit; and resources that are in-service in year 2042 or later would begin construction in 2036 or later and not receive any tax credits. Further cost reductions may be possible by utilizing existing sites.

[19] Earliest in-service year is the first year the Companies expect a resource can be feasibly built based on permitting and construction timelines as well as lead times for electrical equipment such as generator step-up transformers.

Table 3: Renewable Resources (2030 Installation; 2030 Dollars)

	KY Solar	KY Wind	IN Wind
Summer Capacity (MW)[9]	100+	100+	100+
Winter Capacity (MW)[9]	100+	100+	100+
Contribution to Summer Peak[20]	84%	0%	0%
Contribution to Winter Peak[20]	0%	0%	0%
Net Capacity Factor[21]	26.3%	36.3%	43.6%
Capital Cost ($/kW)[11]	1,902	2,460	2,238
Fixed O&M ($/kW-yr)[12]	17	33	36
Transmission Cost ($/kW-yr)[22]	N/A	N/A	67
Production Tax Credit ($/MWh)[23]	30.25	27.50	27.50
Earliest In-Service Year[19]	2028	2028	2028

Table 4: Limited-Duration Resources (2030 Installation; 2030 Dollars)

	BESS		Dispatchable DSM[24]			
	4-Hour	8-Hour	BYOD Energy Storage	BYOD Home Generators	BDR 50-200 kW	CSR[25]
Summer Capacity (MW)[9]	100+	100+	0.89	0.85	1.45	100
Winter Capacity (MW)[9]	100+	100+	0.89	0.85	1.45	100
Capacity Contribution[26]	85%	93%	39%	39%	39%	39%
Round-Trip Efficiency	87%	87%	N/A	N/A	N/A	N/A
Capital Cost ($/kW)[11]	2,049	3,598	N/A	N/A	N/A	N/A
Fixed O&M ($/kW-yr)[12]	25	44	N/A	N/A	N/A	81
Investment Tax Credit[23]	50%	50%	N/A	N/A	N/A	N/A
Earliest In-Service Year[19]	2028	2028	2027	2027	2028	2028

Resource costs in NREL's 2024 ATB are provided in real 2022 dollars and must be converted to nominal dollars. In doing this, the Companies ensured that nominal capital costs for SCCT, NGCC, solar, and BESS

[20] Contribution to peak is the assumed percentage of nameplate capacity that is available on average during the peak hour. For wind, zero percent contributions to peak were used to model wind as an energy-only resource. See discussion below.

[21] Net capacity factor is the ratio of the unit's expected average hourly output over the course of the year to the unit's rated capacity.

[22] Transmission cost is based on current firm transmission costs to import power from an Indiana resource.

[23] In accordance with the current tax credits, the Companies assumed solar, wind, and BESS resources that are in-service by year 2036 would begin construction by year 2033 and receive the full credit; resources that are in-service in year 2037 would begin construction in 2034 and receive 75% of the credit; resources that are in-service in year 2038 would begin construction in 2035 and receive 50% of the credit; and resources that are in-service in year 2039 or later would begin construction in 2036 or later and not receive any tax credits. Production tax credits are included for the first 10 years of each solar or wind resource.

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

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

aligned with recent capital cost estimates for an SCCT, the Brown 12 NGCC, Mercer County Solar, and Brown BESS, respectively. Assuming an annual inflation rate of 2.3 percent beyond 2024, this process produces implied inflation rates for each technology through 2024. In the absence of a recent capital cost estimate for wind, the Companies estimated the capital cost of wind by applying the implied inflation rate for solar to the "Moderate" capital cost estimate for wind in NREL's 2024 ATB. All costs for SMR were also based on the Moderate cost scenario and converted from real to nominal dollars assuming 2.3 percent inflation in all years.

As noted in IRP Volume III (2024 IRP Technology Update), the costs of new NGCC and SCCT have increased more in recent years than renewables and BESS, and significant tax incentives are available for renewables and BESS. In addition, whereas the costs of NGCC and SCCT are projected to increase from the beginning of the analysis period, the costs of renewables and BESS are projected to decline for several years before escalating slowly through the end of the analysis period. This is particularly significant for the cost of solar, which is projected in nominal terms to decrease by more than 20% between 2028 and 2035.

The earliest that new NGCC or SCCT can likely be added is 2030 due to lead times for generation equipment, transmission interconnection studies, and resulting potential transmission upgrades, which could require long lead times for equipment such as transformers. The earliest a small modular nuclear reactor can be added is assumed to be 2039 due to the time required for permitting and construction. All other resources are assumed to be available beginning in 2028.

For this Resource Assessment, the Companies have allowed for maximizing renewables penetration in the study period by limiting solar generation to 20% of total energy requirements and the sum of solar and wind generation to 25% of total energy requirements.[27] In the Mid load forecast scenario, a 20% limit equates to approximately 3,800 MW of solar. Despite receiving only one wind response to their 2022 RFP for 143 MW, a 25% limit equates to approximately 3,700 MW of Kentucky wind or 2,800 MW of Indiana wind, which has a higher expected capacity factor than Kentucky wind. The Companies are not suggesting that these high levels of renewables could practically or economically be added all at once because these levels of renewables would require numerous new generation sites and potentially significant transmission system upgrades. In addition, because it is not practical to estimate transmission system upgrade costs for numerous generation sites that do not currently exist and the Companies are not seeking approval for new resources, the Resource Assessment conservatively assumes no cost for transmission system upgrades.

The intra-hour variability of renewables and their availability during peak periods are key considerations for integrating renewables. Whereas solar clearly cannot contribute to the Companies' winter peak, the potential contribution of wind resources during a winter peak is uncertain. While wind can potentially generate at high levels during winter peak hours, historical wind speeds indicate the potential for low wind generation output during winter peaks. Wind resources outside of the Companies' Kentucky

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

[27] These limits are consistent with the Kentucky Regional Case Study conclusions reached in "Decarbonization Analysis for Thermal Generation and Regionally Integrated Large-Scale Renewables Based on Minutely Optimal Dispatch with a Kentucky Case Study," Lewis et al., 2023. See pp. 18-19 at https://www.engr.uky.edu/sites/default/files/PEIK/2023%20Energies%20UK%20SPARK%20Decarbonization%20Optimal%20Dispatch%20Regional%20Kentucky%20Author%27s%20Manuscript.pdf.

footprint may likely be expected to generate more during winter peaks, but reliance on generation that must be exported from other transmission areas risks having even firm transmission cut during times of energy emergencies, which is when the Companies would need the resources most.[28]

In addition to the uncertainty associated with wind's availability during peak hours, the Companies do not have a current cost estimate for wind.[29] For all of these reasons (i.e., uncertainty in wind's availability during peak hours, limited responses in past RFPs, uncertainty in cost, inability to estimate transmission system upgrade costs for wind sites that don't currently exist), the Companies modeled wind as an energy-only resource in PLEXOS by setting its contributions to summer and winter peak to zero.

The Companies' IRP load forecasts fully account for the energy efficiency effects of the proposed 2024-2030 DSM-EE Program Plan as well as new programs beyond 2030; the combined impact of company-sponsored programs and customer-initiated energy efficiency improvements is assumed to grow throughout the 15-year planning horizon. The dispatchable DSM programs in the 2024-2030 DSM-EE Program Plan are modeled as existing resources and are assumed to grow throughout the 15-year planning horizon. In addition to these resources, the new dispatchable DSM program measures in Table 4 provide alternative means for customers to participate in existing programs. As such, these programs have no incremental fixed costs and were included in all of the Companies' resource plans. The CSR program in Table 2 is modeled as an expansion of the Companies' CSR-2 program. Notably, the Companies' ability to require CSR-2 customers to curtail their usage without a buy-through option is limited to 100 hours annually when all available units are dispatched or being dispatched.

[28] The Companies are aware of this most recently occurring in August 2024 when MISO curtailed firm export schedules to OMU and KYMEA, who then purchased cost-based energy from the Companies to cover their loads.

[29] As noted above, in the absence of a recent cost estimate for wind, the Companies estimated the capital cost of wind by applying an implied inflation rate for solar to the "Moderate" capital cost estimate for wind in NREL's 2024 ATB.

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

Table 5 and Table 6 summarize the Companies' winter and summer peak demand and resources with approved changes from the 2022 CPCN Order.[30] These tables reflect the planned retirements of Mill Creek 1 (2024) and Mill Creek 2 (2027), the assumed retirement of the small-frame SCCTs (2025), the planned additions of Brown BESS (2026), Mill Creek 5 (2027), two company-owned solar facilities in 2026 and 2027, and dispatchable demand response programs from the Companies' 2024-2030 DSM-EE Program Plan.[31] Reserve margins in the Mid load scenario indicate a need for new capacity beginning in 2030.[32] Table 7 summarizes the need for new capacity in all load scenarios.

[30] *Electronic Joint Application of Kentucky Utilities Company and Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity and Site Compatibility Certificates and Approval of a Demand Side Management Plan*, Case No. 2022-00402, Order (Ky. PSC Nov. 6, 2023).

[31] The Companies do not presently expect that the approved solar PPAs will advance under their approved terms, though both the 2024 IRP Recommended Resource Plan and the Enhanced Solar Resource Plan contain significant amounts of new solar. Of the six total solar PPAs into which the Companies have entered, including two prior to the 2022 CPCN and DSM-EE case, (a) one has been canceled by the developer due to interconnection issues, (b) one has been canceled by the developer due to a significant project price increase, and (c) one with a price reopener has been contractually terminated due to the Companies' unwillingness to proceed at a much higher price than in the original agreement. The remaining three PPAs appear unlikely to proceed under their approved terms. This IRP therefore does not include these PPAs. But again, the Companies' 2024 IRP Recommended Resource Plan and the Enhanced Solar Resource Plan both contain significant amounts of new solar in addition to hundreds of megawatts of new battery storage, which could help pave the way for additional new renewable resources in the future.

[32] Due to their age and relative inefficiency, the Companies do not perform major maintenance on their small-frame SCCTs, Paddy's Run Unit 12 and Haefling Units 1-2, but continue to operate them until they are uneconomic to repair. This analysis assumes that they will be retired in 2025 for planning purposes.

Table 5: Winter Peak Demand and Resource Summary (Mid Load Forecast, MW)

	2025	2028	2029	2030	2031	2032	2035	2037	2039
Peak Load	**6,146**	**6,347**	**6,471**	**6,733**	**7,003**	**7,135**	**7,118**	**7,118**	**7,117**
Fully Dispatchable Generation Resources									
Existing Resources	7,909	7,977	7,977	7,977	7,977	7,977	7,977	7,977	7,977
Retirements/Additions									
Coal[33]	-300	-597	-597	-597	-597	-597	-597	-597	-597
Small-Frame SCCTs[34]	-55	-55	-55	-55	-55	-55	-55	-55	-55
NGCC (Mill Creek 5)	0	660	660	660	660	660	660	660	660
Total	7,554	7,985	7,985	7,985	7,985	7,985	7,985	7,985	7,985
Reserve Margin	22.9%	25.8%	23.4%	18.6%	14.0%	11.9%	12.2%	12.2%	12.2%
Renewable/Limited-Duration Resources									
Existing Resources	72	72	72	72	72	72	72	72	72
Existing CSR	115	115	115	115	115	115	115	115	115
Existing Disp. DSM[35]	45	110	124	125	135	145	158	160	163
Retirements/Additions									
Solar[36]	0	0	0	0	0	0	0	0	0
BESS[37]	0	125	125	125	125	125	125	125	125
Total	231	421	435	437	446	456	469	471	475
Total Supply	**7,785**	**8,406**	**8,420**	**8,422**	**8,431**	**8,441**	**8,454**	**8,456**	**8,460**
Total Reserve Margin	**26.7%**	**32.5%**	**30.1%**	**25.1%**	**20.4%**	**18.3%**	**18.8%**	**18.8%**	**18.9%**
Capacity Need[38]	**143**	**-219**	**-73**	**264**	**602**	**764**	**728**	**726**	**722**

[33] Mill Creek 1 will be retired at the end of 2024. Mill Creek 2 will be retired after Mill Creek 5 is commissioned in 2027.

[34] Due to their age and relative inefficiency, the Companies do not perform major maintenance on their small-frame SCCTs, Paddy's Run Unit 12 and Haefling Units 1-2, but continue to operate them until they are uneconomic to repair. This analysis assumes that they will be retired in 2025 for planning purposes.

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

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

[37] Brown BESS is assumed in-service in 2026.

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

Table 6: Summer Peak Demand and Resource Summary (Mid Load Forecast, MW)

	2025	2028	2029	2030	2031	2032	2035	2037	2039
Peak Load	**6,228**	**6,474**	**6,686**	**6,931**	**7,216**	**7,201**	**7,171**	**7,160**	**7,149**
Fully Dispatchable Generation Resources									
Existing Resources	7,612	7,618	7,618	7,618	7,618	7,618	7,618	7,618	7,618
Retirements/Additions									
Coal[39]	-300	-597	-597	-597	-597	-597	-597	-597	-597
Small-Frame SCCTs[40]	-47	-47	-47	-47	-47	-47	-47	-47	-47
NGCC (Mill Creek 5)	0	645	645	645	645	645	645	645	645
Total	7,265	7,619	7,619	7,619	7,619	7,619	7,619	7,619	7,619
Reserve Margin	16.7%	17.7%	14.0%	9.9%	5.6%	5.8%	6.2%	6.4%	6.6%
Renewable/Limited-Duration Resources									
Existing Resources	106	107	107	107	107	107	107	107	107
Existing CSR	110	110	110	110	110	110	110	110	110
Existing Disp. DSM[41]	84	150	166	170	179	190	208	216	227
Retirements/Additions									
Solar[42]	0	201	201	201	201	201	201	201	201
BESS[43]	0	125	125	125	125	125	125	125	125
Total	300	692	709	713	722	733	751	759	769
Total Supply	**7,565**	**8,311**	**8,328**	**8,332**	**8,341**	**8,352**	**8,370**	**8,378**	**8,388**
Total Reserve Margin	**21.5%**	**28.4%**	**24.6%**	**20.2%**	**15.6%**	**16.0%**	**16.7%**	**17.0%**	**17.3%**
Capacity Need[44]	**95**	**-349**	**-104**	**193**	**534**	**506**	**451**	**429**	**404**

[39] Mill Creek 1 will be retired at the end of 2024. Mill Creek 2 will be retired after Mill Creek 5 is commissioned in 2027. These values do not reflect any potential reduction in Ghent 2's summer capacity due to Ozone NAAQS regulations.
[40] This analysis assumes Haefling 1-2 and Paddy's Run 12 are retired in 2025.
[41] Existing Dispatchable DSM reflects expected load reductions under normal peak weather conditions.
[42] This analysis assumes 120 MW of solar capacity is added in 2026, and an additional 120 MW of solar capacity is added in 2027. Capacity values reflect 83.7% expected contribution to summer peak capacity.
[43] Brown BESS is assumed in-service in 2026.
[44] The summer capacity need is based on a 23% summer minimum reserve margin target. Positive values reflect a capacity deficit.

Table 7: Reserve Margin Summary (All Load Scenarios, MW)

	2025	2028	2029	2030	2031	2032	2035	2037	2039
Winter									
Low Load									
Total Reserve Margin	28.1%	40.3%	41.5%	42.2%	43.0%	43.6%	45.4%	45.6%	45.8%
Capacity Need	55	-678	-742	-780	-825	-860	-951	-962	-974
Mid Load									
Total Reserve Margin	26.7%	32.5%	30.1%	25.1%	20.4%	18.3%	18.8%	18.8%	18.9%
Capacity Need	143	-219	-73	264	602	764	728	726	722
High Load									
Total Reserve Margin	25.5%	27.4%	19.3%	11.5%	5.6%	3.7%	3.9%	3.8%	3.8%
Capacity Need	216	108	687	1,319	1,868	2,062	2,047	2,054	2,051
Summer									
Low Load									
Total Reserve Margin	22.8%	38.0%	39.4%	40.5%	41.7%	42.9%	46.1%	47.0%	48.0%
Capacity Need	12	-904	-977	-1,038	-1,101	-1,163	-1,323	-1,368	-1,416
Mid Load									
Total Reserve Margin	21.5%	28.4%	24.6%	20.2%	15.6%	16.0%	16.7%	17.0%	17.4%
Capacity Need	94	-349	-105	192	533	505	450	428	404
High Load									
Total Reserve Margin	20.4%	20.2%	11.9%	6.4%	1.5%	1.6%	1.9%	1.7%	1.7%
Capacity Need	166	191	822	1,302	1,772	1,756	1,734	1,758	1,756

Section 5.3 in Appendix A contains a full discussion of existing resource assumptions including stay-open and life extension costs for existing coal units. In this Resource Assessment, PLEXOS was used to evaluate the continued operation of coal units by comparing these costs to the costs of replacement resources along with the costs of retrofitting alternatives such as natural gas co-firing or natural gas conversion.

4 Meeting the Objective: Comprehensive Planning Process

4.1 Key Constraints and Uncertainties of Analysis

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

4.1.1 Key Constraints

The Resource Assessment included the following constraints:

- Portfolios must maintain minimum reserve margins and comply with KRS 278.264.
- Brown 3 cannot operate as a coal-fired generating unit beyond 2034 due to landfill storage capacity limits.
- Mill Creek 3 and 4 cannot operate as coal-fired generating units beyond 2044 in the No New Regulations and Ozone NAAQS environmental scenarios due to landfill storage capacity limits. Due to additional landfill storage requirements, Mill Creek 3 and 4 cannot operate as coal-fired generating units beyond 2036 in the ELG environmental scenarios. These landfill constraints are discussed further in Section 5.3.4.
- The earliest new NGCC or SCCT can be added is 2030, and the earliest a small modular nuclear reactor can be added is assumed to be 2039. All other resources are assumed to be available in 2028 (see Section 3.1).
- Solar generation is limited to 20% of total energy requirements and the sum of solar and wind generation is limited to 25% of total energy requirements.

4.1.2 Key Uncertainty: Economic Development Load Growth

The level and timing of economic development load growth are key uncertainties in this Resource Assessment. The IRP considers three economic development load growth scenarios to address this uncertainty and opportunity. The Mid scenario assumes 1,050 MW of data center load by 2032 and another, relatively speaking, small economic development project. The High scenario assumes 1,750 MW of data center load in addition to the smaller project plus the second phase of the Blue Oval SK ("BOSK") electric vehicle battery production facility. The Low scenario includes only the one small project (and no data centers or BOSK phase 2) and assumes a couple of large customers leave the service territory later in the 2030s. The Companies assign a low likelihood to the Low scenario where load is assumed to decline from 2025 through the end of the analysis period.

4.1.3 Key Uncertainty: Environmental Regulations

This Resource Assessment considered four environmental regulation scenarios:

No New Regulations

This scenario assumes the Good Neighbor Plan, 2024 ELG, and GHG Rules or their equivalents do not take effect over the IRP planning period, and no new regulations are implemented through the end of the IRP planning period (2039) that require significant investment for environmental compliance.

Ozone NAAQS

This scenario assumes the 2024 ELG and GHG Rules or their equivalents do not become effective during the IRP planning period, but the Good Neighbor Plan or its equivalent does become effective. In this case, because SCR is a Reasonably Achievable Control Technology for ozone NAAQS compliance, the Companies assume SCR will be needed to operate Ghent 2 in the ozone season beyond 2030. The timing of the need for SCR is based on the Good Neighbor Plan's daily NO_x emission limit beginning in 2030. However, the

Good Neighbor Plan also limits NO_x emissions for the ozone season beginning in 2028. Based on EPA obligation, EPA authority, and a pragmatic evaluation of compliance technology implementation, the EPA is obligated by the CAA and ongoing litigations to drive local NAAQS attainment and to eliminate significant contribution of non-attainment by downwind states. Non-attainment of the Ozone standard is a function of NO_x and volatile organic compound ("VOC") emissions. SCR is a Reasonably Achievable Control Technology and a likely compliance requirement that results from the NAAQS process.

Ozone NAAQS + ELG

This scenario builds on the Ozone NAAQS scenario and assumes the 2024 ELG or its equivalent will also become effective, but GHG Rules or their equivalents do not become effective during the IRP planning period. Although the Companies have commented that the Best Available Control Technology determinations for the 2024 ELG are not adequately justified, the EPA has authority to implement the final rule, the technologies exist, and there are no particular impediments to implementation. The Companies believe the Ozone NAAQS + ELG scenario is the most likely environmental scenario.

Ozone NAAQS + ELG + GHG

This scenario assumes the Good Neighbor Plan (or a regulation with the same effect), 2024 ELG, and Greenhouse Gas Rules or their equivalents all become effective during the IRP planning period.[45] Although the EPA is obligated to set source performance standards, they must be achievable and adequately demonstrated. Among the standards are carbon capture transport and storage. There is no regulatory standard for storage wells or CO_2 pipelines in Kentucky, and implementing CO_2 transport or storage is not achievable on the GHG Rules' compliance timeline. Co-firing natural gas or full gas conversion are compliance alternatives for the GHG Rules; however, implementing additional natural gas transportation pipelines on the compliance timeline is questionable. Retiring generation is a compliance alternative for the GHG Rules, but retirements require reliable replacement capacity. Replacing generation at the scale necessary for compliance is not reasonable on the GHG Rules' timeline. Therefore, the Companies assign a low likelihood to this scenario.

4.1.4 Key Uncertainty: Fuel Prices

Fuel prices are an important uncertainty in any resource assessment. To address it, the Companies developed five fuel price scenarios using the methodology that was used in their 2022 CPCN Resource Assessment, which the Commission found to be credible and reasonable in its Final Order in that proceeding.[46] In these fuel price scenarios, natural gas prices are the primary price setting factor, with coal prices derived from gas prices beginning in 2025 based on different historical coal-to-gas ("CTG") price ratios.

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

[45] The Companies evaluated GHG Rules as a carbon constraint and did not separately model a carbon tax.

[46] *Electronic Joint Application of Kentucky Utilities Company and Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity and Site Compatibility Certificates and Approval of a Demand Side Management Plan*, Case No. 2022-00402, Order at 93-94 (Ky. PSC Nov. 6, 2023) ("The Commission finds that LG&E/KU's evidence regarding the relationship between coal and natural gas prices is credible. … [W]hether projected separately or together, the Commission believes that it is reasonable to assume a relationship between coal prices and natural gas prices. … [T]he Commission finds that LG&E/KU's fuel price scenarios were reasonable ….").

Gas Supply case (low gas price), Reference case (mid gas price), and Low Oil and Gas Supply case (high gas price).[47]

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 7 below shows these three fuel price cases in nominal dollars per MMBtu through 2039:

Figure 7: Coal and Natural Gas Price Scenarios with a Mid Coal-to-Gas Price Ratio

[redacted]

The other two fuel price scenarios involve relationships between gas and coal prices that would be atypical for an extended time horizon, essentially as sensitivity cases: (1) low gas prices with a historically high coal-to-gas ratio ("Low Gas, High CTG Ratio"); and (2) high gas prices with a historically low coal-to-gas

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

ratio ("High Gas, Low CTG Ratio"). Figure 8 below illustrates these three fuel price cases in nominal dollars per MMBtu through 2039:

Figure 8: Coal and Natural Gas Price Scenarios with Atypical Long-Term Coal-to-Gas Price Ratios

[redacted]

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

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

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

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

- **Resource Plan Development and Screening: PLEXOS.** The Companies used PLEXOS, a resource planning model, to develop least-cost resource plans over a range of fuel price scenarios. PLEXOS models and evaluates thousands of resource plans to determine which one minimizes the cost of serving customers' load while meeting reserve margin and other constraints. A resource planning model necessarily makes simplifying assumptions to reduce model run times, and a key consideration for any resource planning model is the level of granularity used to develop resource plans. Less granular analyses require more simplifying assumptions and have shorter run times, but too many simplifying assumptions may prevent the model from properly evaluating resources with limited availability or run times. Thus, it is important to evaluate resource plans with an appropriate level of granularity and then check the results with detailed production costs.[48]

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

- **Present Value of Revenue Requirements ("PVRR"): Excel Financial Model.** The Companies use a Financial Model developed in Excel to calculate and compare PVRR values for various resource plans. Inputs to the Financial Model include capital and fixed operating costs for new and existing resources as well as generation production costs. Table 8 below lists the primary costs included in the Financial Model. Production costs are developed in PROSYM; the costs for new and existing resources are the same costs modeled in PLEXOS and used to develop the least-cost resource plan.

Table 8: Financial Model Costs

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

4.3 Analytical Framework: Resource Assessment Completed in Two Stages

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

4.4 Stage One: Assessing Load and Environmental Regulation Uncertainty

The objective of the Companies' Stage One analysis is to assess the most economical way to serve customers in each load and environmental scenario (12 scenarios in total comprising three load scenarios

[48] The Companies develop resource plans in PLEXOS in six blocks of time per day across a series of six-year rolling horizons. With this level of granularity, each model run takes up to 75 hours to complete.

and four environmental scenarios). To do this, the Companies first used PLEXOS to develop resource plans for each of the 12 load and environmental scenarios across each of the five fuel price scenarios, resulting in 60 total resource plans. Then, the Companies evaluated each resource plan with detailed production costs over each of the fuel price scenarios to determine which resource plan for a given load and environmental scenario is lowest cost across all fuel price scenarios.

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

The first step of Stage One consisted of allowing PLEXOS to create least-cost resource plans subject to reserve margin and other constraints for each load and environmental scenarios and each of the five fuel price scenarios.

4.4.1.1 No New Regulations Environmental Scenario

The No New Regulations environmental scenario assumes the Good Neighbor Plan, 2024 ELG, and GHG Rules or their equivalents do not take effect over the IRP planning period, and no new regulations are implemented through the end of the IRP planning period (2039).

Important observations from this scenario:

- NGCC and battery storage charged by existing resources are added as needed to support economic development load growth. The level of fuel prices does not materially impact the need for resources that can economically produce large amounts of energy at night.
- With no ability to add NGCC prior to 2030, battery storage charged by existing resources is added to support economic development load additions prior to 2030 in the High load scenario.
- The desirability of renewables predictably correlates with fuel prices. More renewables are added in the High fuel price scenarios and beginning in 2035 after solar prices are forecast to decline.
- All coal units except Brown 3 operate through the end of the IRP period.

PLEXOS output:

Table 9 through Table 11 below provide the resource plans PLEXOS developed for the No New Regulations scenario.

Table 9: Resource Plan Screening Results (Mid Load, No New Regulations)[49]

	Expected CTG Ratio			Atypical CTG Ratio	
Year	**Low Gas, Mid CTG**	**Mid Gas, Mid CTG**	**High Gas, Mid CTG**	**Low Gas, High CTG**	**High Gas, Low CTG**
2028	+Disp DSM	+Disp DSM	+Disp DSM	+Disp DSM	+Disp DSM
2029					
2030	Retire BR3; +1 NGCC; +100 MW 4hr BESS	+1 NGCC	+1 NGCC	Retire BR3; +1 NGCC; +100 MW 4hr BESS	+1 SCCT; +100 MW 4hr BESS
2031	+400 MW 4hr BESS			+400 MW 4hr BESS	+400 MW 4hr BESS
2032	+200 MW 4hr BESS	+200 MW 4hr BESS	+200 MW 4hr BESS	+200 MW 4hr BESS	+200 MW 4hr BESS; +510 MW IN Wind
2033		Retire BR3; +400 MW 4hr BESS	Retire BR3; +400 MW 4hr BESS		
2034			+142 MW IN Wind		+53 MW IN Wind
2035			+1,509 MW Solar		Retire BR3; +1 SCCT; +100 MW 4hr BESS; +2,136 MW Solar
2036		+1,322 MW Solar	+2,001 MW Solar; +420 MW IN Wind		+1,375 MW Solar
2037					
2038					
2039					

Table 10: Resource Plan Screening Results (Low Load, No New Regulations)[49]

	Expected CTG Ratio			Atypical CTG Ratio	
Year	**Low Gas, Mid CTG**	**Mid Gas, Mid CTG**	**High Gas, Mid CTG**	**Low Gas, High CTG**	**High Gas, Low CTG**
2028	+Disp DSM	+Disp DSM	+Disp DSM	+Disp DSM	+Disp DSM
2029					
2030					
2031					
2032					
2033					
2034					
2035	Convert BR3	Convert BR3	Convert BR3	Convert BR3	Convert BR3
2036			+2,550 MW Solar		+2,550 MW Solar
2037					
2038					
2039					

[49] PLEXOS was configured to add NGCC (660 net winter MW) and SCCT (258 net winter MW) in one-unit increments and BESS in 100 MW increments. To reduce model run times, solar and wind could be added in 1 MW increments. "Convert" indicates that a generating unit is converted to burn 100% natural gas.

Table 11: Resource Plan Screening results (High Load, No New Regulations)[49]

	Expected CTG Ratio			Atypical CTG Ratio	
Year	Low Gas, Mid CTG	Mid Gas, Mid CTG	High Gas, Mid CTG	Low Gas, High CTG	High Gas, Low CTG
2028	+Disp DSM; +300 MW 4hr BESS	+Disp DSM; +300 MW 4hr BESS	+Disp DSM; +200 MW 4hr BESS; +49 MW Solar	+Disp DSM; +300 MW 4hr BESS	+Disp DSM; +200 MW 4hr BESS; +49 MW Solar
2029	+700 MW 4hr BESS	+700 MW 4hr BESS	+700 MW 4hr BESS; +42 MW Solar	+700 MW 4hr BESS	+700 MW 4hr BESS; +42 MW Solar
2030	+1 NGCC	+1 NGCC	+1 NGCC; +30 MW IN Wind	+1 NGCC	+1 NGCC
2031	Retire BR3; +1 NGCC; +200 MW 4hr BESS	Retire BR3; +1 NGCC; +200 MW 4hr BESS	+1 NGCC	Retire BR3; +1 NGCC; +200 MW 4hr BESS	+1 NGCC
2032	+200 MW 4hr BESS	+200 MW 4hr BESS	+187 MW IN Wind	+200 MW 4hr BESS	+47 MW IN Wind
2033					
2034			+149 MW IN Wind		+158 MW IN Wind
2035			Retire BR3; +500 MW 4hr BESS; +2,300 MW Solar; +209 MW IN Wind		Retire BR3; +500 MW 4hr BESS; +1,861 MW Solar; +338 MW IN Wind
2036		+2,652 MW Solar	+1,846 MW Solar; +96 MW IN Wind		+2,285 MW Solar; +128 MW IN Wind
2037					
2038					
2039					

4.4.1.2 Ozone NAAQS Environmental Scenario

This scenario assumes the 2024 ELG and GHG Rules or their equivalents do not become effective during the IRP planning period, but the Good Neighbor Plan or its equivalent does become effective. In this case, the Companies assume SCR at a capital cost of $137.8 million is needed to operate Ghent 2 in the ozone season beginning in 2030. The timing of the need for SCR is based on the Good Neighbor Plan's daily NO_x emission limit beginning in 2030. However, the Good Neighbor Plan also limits NO_x emissions for the ozone season beginning in 2028. With the addition of economic development load in a potentially strained NO_x emissions allowance market, SCR may be needed as soon as 2028 to comply with this limit and support operational flexibility. Additional impacts related to an SCR retrofit of Ghent 2 are summarized in Section 5.3.2.

Important observations from this scenario:

These observations build on the results of the No New Regulations scenario.

- SCR is added to Ghent 2 in three of five Mid load scenarios and three of five High load scenarios. In the Low load scenario, Ghent 2 is not needed to meet the minimum summer reserve margin and operates only in the non-ozone season.
- The results of the Mid and High load scenarios with High fuel prices are significantly influenced by NREL's forecast of declining solar costs. The impact of this forecast is discussed further in the context of the Ozone NAAQS + ELG environmental scenario.

PLEXOS output:

Table 12 through Table 14 below provide the resource plans PLEXOS developed for the Ozone NAAQS environmental scenario. With declining solar costs and no new environmental regulations (see Table 9 through Table 11), significant amounts of renewables are added beginning in 2035 in the Mid and High fuel price scenarios. To comply with Ozone NAAQS in the High fuel price scenarios, instead of adding SCR to Ghent 2, PLEXOS accelerates the addition of some solar and battery storage to minimally comply with summer reserve margin constraints and then adds the balance of solar beginning in 2035 when costs are lower. SCR is not needed in the Low load scenarios to meet the minimum summer reserve margin constraint.

Table 12: Resource Plan Screening Results (Mid Load, Ozone NAAQS)[50]

	Expected CTG Ratio			Atypical CTG Ratio	
Year	**Low Gas, Mid CTG**	**Mid Gas, Mid CTG**	**High Gas, Mid CTG**	**Low Gas, High CTG**	**High Gas, Low CTG**
2028	+Disp DSM	+Disp DSM	+Disp DSM	+Disp DSM	+Disp DSM
2029					
2030	Retire BR3; Add GH2 SCR; +1 NGCC; +100 MW 4hr BESS	Add GH2 SCR; +1 NGCC	GH2 Non-Ozone; +1 NGCC; +61 MW Solar	Retire BR3; Add GH2 SCR; +1 NGCC; +100 MW 4hr BESS	GH2 Non-Ozone; +1 NGCC; +61 MW Solar
2031	+400 MW 4hr BESS		+200 MW 4hr BESS; +203 MW Solar	+400 MW 4hr BESS	+200 MW 4hr BESS; +203 MW Solar
2032	+200 MW 4hr BESS	+200 MW 4hr BESS		+200 MW 4hr BESS	
2033		Retire BR3; +400 MW 4hr BESS	Retire BR3; +400 MW 4hr BESS; +34 MW Solar; +52 MW IN Wind		Retire BR3; +400 MW 4hr BESS; +34 MW Solar
2034			+124 MW IN Wind		+126 MW IN Wind
2035			+1,817 MW Solar		+1,268 MW Solar
2036		+1,681 MW Solar	+1,394 MW Solar; +386 MW IN Wind		+1,944 MW Solar; +436 MW IN Wind
2037					
2038					
2039					

[50] PLEXOS was configured to add NGCC (660 net winter MW) and SCCT (258 net winter MW) in one-unit increments and BESS in 100 MW increments. To reduce model run times, solar and wind could be added in 1 MW increments. "Convert" indicates that a generating unit is converted to burn 100% natural gas. "GH2 Non-Ozone" indicates that Ghent 2 is operated only in the non-ozone season.

Table 13: Resource Plan Screening Results (Low Load, Ozone NAAQS)[50]

	Expected CTG Ratio			Atypical CTG Ratio	
Year	Low Gas, Mid CTG	Mid Gas, Mid CTG	High Gas, Mid CTG	Low Gas, High CTG	High Gas, Low CTG
2028	+Disp DSM	+Disp DSM	+Disp DSM	+Disp DSM	+Disp DSM
2029					
2030	GH2 Non-Ozone	GH2 Non-Ozone	GH2 Non-Ozone	GH2 Non-Ozone	GH2 Non-Ozone
2031					
2032					
2033					
2034					
2035	Convert BR3	Convert BR3	Convert BR3; +548 MW Solar	Convert BR3	Convert BR3
2036		+510 MW Solar	+2,002 MW Solar; +54 MW IN Wind		+2,550 MW Solar
2037					
2038					
2039					

Table 14: Resource Plan Screening results (High Load, Ozone NAAQS)[50]

	Expected CTG Ratio			Atypical CTG Ratio	
Year	Low Gas, Mid CTG	Mid Gas, Mid CTG	High Gas, Mid CTG	Low Gas, High CTG	High Gas, Low CTG
2028	+Disp DSM; +300 MW 4hr BESS	+Disp DSM; +300 MW 4hr BESS	+Disp DSM; +200 MW 4hr BESS; +49 MW Solar	+Disp DSM; +300 MW 4hr BESS	+Disp DSM; +200 MW 4hr BESS; +49 MW Solar
2029	+700 MW 4hr BESS	+700 MW 4hr BESS	+700 MW 4hr BESS; +42 MW Solar	+700 MW 4hr BESS	+700 MW 4hr BESS; +42 MW Solar
2030	Add GH2 SCR; +1 NGCC	Add GH2 SCR; +1 NGCC	GH2 Non-Ozone; +2 NGCC	Add GH2 SCR; +1 NGCC	GH2 Non-Ozone; +2 NGCC
2031	Retire BR3; +1 NGCC; +200 MW 4hr BESS	Retire BR3; +1 NGCC; +200 MW 4hr BESS	+171 MW Solar	Retire BR3; +1 NGCC; +200 MW 4hr BESS	+171 MW Solar
2032	+200 MW 4hr BESS	+200 MW 4hr BESS	+442 MW IN Wind	+200 MW 4hr BESS	+211 MW IN Wind
2033					
2034			+53 MW IN Wind		+147 MW IN Wind
2035			Retire BR3; +500 MW 4hr BESS; +2,800 MW Solar		Retire BR3; +500 MW 4hr BESS; +2,214 MW Solar; +159 MW IN Wind
2036		+2,924 MW Solar	+1,175 MW Solar; +176 MW IN Wind		+1,761 MW Solar; +153 MW IN Wind
2037					
2038					
2039					

4.4.1.3 Ozone NAAQS + ELG Environmental Scenario

This scenario builds on the Ozone NAAQS scenario and assumes the 2024 ELG or its equivalent will also become effective, but GHG Rules or their equivalents do not become effective during the IRP planning period. The 2024 ELG requires modifications to the capture, handling, and disposal of coal combustion residuals at the Companies' coal stations for the purpose of achieving zero liquid discharge. The 2024 ELG impacts all coal stations except E.W. Brown, which already has zero liquid discharge.

At the Mill Creek, Ghent, and Trimble County stations, the required modifications will increase the need for landfill storage capacity, which has the greatest impact on the Mill Creek station where the ability to operate on coal is already limited to 2045 due to landfill storage constraints. If the Companies complied with the 2024 ELG at Mill Creek via zero liquid discharge, the units would only be able to operate until 2037 due to the increased need for landfill storage capacity. Landfill storage constraints are discussed in Section 5.3.4.

Compliance with the 2024 ELG via zero liquid discharge is required as soon as possible but no later than the end of 2029 unless the Companies declare by the end of 2025 to cease burning coal by the end of 2034. Thus, the Companies modeled the following ELG compliance options for the Mill Creek, Ghent, and Trimble County coal units: comply via zero liquid discharge by the end of 2029, retire by the end of 2034, or convert to burn 100% gas by the end of 2034. Table 15 contains ELG compliance costs for each of the affected stations. A summary of gas conversion costs is included in Section 5.3.2.

Table 15: ELG Station Compliance Costs ($M, 2030 Dollars)

Station	Capital Cost	Ongoing O&M
Ghent	$213.6	$10.4
Mill Creek	$156.4	$7.9
Trimble County[51]	$144.6	$6.6

The results of this and the Ozone NAAQS scenario are significantly influenced by NREL's forecast of declining solar costs. Whereas the costs of NGCC and SCCT are projected to increase from the beginning of the analysis period, the costs of solar is projected to decline by more than 30 percent through 2035 and then escalate at 0.2 percent through the end of the analysis period. Based on the significant increases in the costs of solar projects the Companies have observed over the past several years, these declines are particularly uncertain. Therefore, they evaluated the Mid load scenario under two solar escalation scenarios: one based on NREL's solar costs and a sensitivity where solar costs escalate from the beginning of the analysis period at 0.2 percent per year. In the latter sensitivity, the cost of solar escalates from the beginning of the analysis period at the rate it is assumed to escalate in the latter years of the analysis period (see Table 16). The escalation rates of solar are still favorable in this scenario compared to NGCC and SCCT, which are assumed to escalate at 1.4% per year from the beginning of the analysis period.

[51] Costs for Trimble County reflect the Companies' 75% ownership share of full station costs.

Table 16: Nominal Solar Escalation Rates

Year	NREL	No De-escalation Sensitivity (“Solar Cost Sensitivity”)
2027	-2.2%	0.2%
2028	-2.4%	0.2%
2029	-2.6%	0.2%
2030	-2.9%	0.2%
2031	-3.2%	0.2%
2032	-3.5%	0.2%
2033	-3.8%	0.2%
2034	-4.2%	0.2%
2035	-4.7%	0.2%
2036	0.2%	0.2%
2037	0.2%	0.2%
2038	0.2%	0.2%
2039	0.2%	0.2%

Important observations from these results:

These observations build on the results of the Ozone NAAQS scenario.

- The Companies comply with the 2024 ELG rules via zero liquid discharge at Ghent and Trimble County, but not at Mill Creek due in part to landfill constraints.
- The Mill Creek coal units are replaced by NGCC and SCCT capacity.
- When solar costs are assumed to decline by more than 30% through 2035 before escalating slowly through the end of the analysis period, SCR is added to Ghent 2 only in the Mid and High load scenarios with Low fuel prices. However, if solar is assumed to escalate slowly from the beginning of the analysis period, SCR is added to Ghent 2 in the Low and Mid fuel price scenarios.

PLEXOS output with NREL solar costs:

Table 17 through Table 19 below provide the resource plans PLEXOS developed for the Ozone NAAQS + ELG scenario using NREL solar costs. As in the Ozone NAAQS scenario, to comply with Ozone NAAQS in Mid and High fuel price scenarios, PLEXOS generally accelerates adding a portion of solar and battery storage to minimally comply with summer reserve margin constraints and then adds a significant amount of renewables beginning in 2035 when costs are lower. SCR is not needed in the Low load scenarios to meet the minimum summer reserve margin constraint.

Table 17: Resource Plan Screening Results (Mid Load, Ozone NAAQS + ELG, NREL Solar Costs)[52]

Year	Expected CTG Ratio			Atypical CTG Ratio	
	Low Gas, Mid CTG	**Mid Gas, Mid CTG**	**High Gas, Mid CTG**	**Low Gas, High CTG**	**High Gas, Low CTG**
2028	+Disp DSM	+Disp DSM	+Disp DSM	+Disp DSM	+Disp DSM
2029					
2030	Retire BR3; Add GH2 SCR; +1 NGCC; ELG @ GH, TC; +100 MW 4hr BESS	GH2 Non-Ozone; +1 NGCC; ELG @ GH, TC; +61 MW Solar	GH2 Non-Ozone; +1 NGCC; ELG @ GH, TC; +61 MW Solar	Retire BR3; Add GH2 SCR; +1 NGCC; ELG @ GH, TC; +100 MW 4hr BESS	GH2 Non-Ozone; +1 NGCC; ELG @ GH, TC; +61 MW Solar
2031	+400 MW 4hr BESS	Retire BR3; +1 NGCC; +100 MW 4hr BESS; +27 MW Solar	+200 MW 4hr BESS; +203 MW Solar	+400 MW 4hr BESS	+200 MW 4hr BESS; +203 MW Solar
2032	+200 MW 4hr BESS			+200 MW 4hr BESS	
2033					
2034					
2035	Retire MC3-4; +1 NGCC; +200 MW 4hr BESS	Retire MC3-4; +800 MW 4hr BESS; +121 MW Solar	Retire MC3-4; Convert BR3; +1 SCCT; +700 MW 4hr BESS; +3,246 MW Solar; +563 MW IN Wind	Retire MC3-4; +1 NGCC; +200 MW 4hr BESS	Retire MC3-4; Convert BR3; +1 SCCT; +700 MW 4hr BESS; +2,980 MW Solar; +563 MW IN Wind
2036		+2,099 MW Solar			+266 MW Solar
2037					
2038					
2039					

[52] PLEXOS was configured to add NGCC (660 net winter MW) and SCCT (258 net winter MW) in one-unit increments and BESS in 100 MW increments. To reduce model run times, solar and wind could be added in 1 MW increments. "Convert" indicates that a generating unit is converted to burn 100% natural gas. "GH2 Non-Ozone" indicates that Ghent 2 is operated only in the non-ozone season.

Table 18: Resource Plan Screening Results (Low Load, Ozone NAAQS + ELG, NREL Solar Costs)[52]

	Expected CTG Ratio			Atypical CTG Ratio	
Year	**Low Gas, Mid CTG**	**Mid Gas, Mid CTG**	**High Gas, Mid CTG**	**Low Gas, High CTG**	**High Gas, Low CTG**
2028	+Disp DSM	+Disp DSM	+Disp DSM	+Disp DSM	+Disp DSM
2029					
2030	GH2 Non-Ozone; ELG @ GH, TC	GH2 Non-Ozone; ELG @ GH, TC	GH2 Non-Ozone; ELG @ GH, TC;	GH2 Non-Ozone; ELG @ GH, TC;	GH2 Non-Ozone; ELG @ GH, TC;
2031					
2032					
2033					
2034					
2035	Convert MC3-4; Convert BR3;	Convert MC3-4; Convert BR3;	Convert MC3-4; Convert BR3; +2,046 MW Solar; +28 MW IN Wind	Retire MC3-4; Convert BR3; +1 NGCC; +1 SCCT	Convert MC3-4; Convert BR3; +1,678 MW Solar
2036		+1,509 MW Solar	+504 MW Solar; +305 MW IN Wind		+872 MW Solar
2037					
2038					
2039	Retire MC3-4; +1 NGCC; +1 SCCT				

Table 19: Resource Plan Screening Results (High Load, Ozone NAAQS + ELG, NREL Solar Costs)[52]

	Expected CTG Ratio			Atypical CTG Ratio	
Year	**Low Gas, Mid CTG**	**Mid Gas, Mid CTG**	**High Gas, Mid CTG**	**Low Gas, High CTG**	**High Gas, Low CTG**
2028	+Disp DSM; +300 MW 4hr BESS	+Disp DSM; +200 MW 4hr BESS; +49 MW Solar	+Disp DSM; +200 MW 4hr BESS; +49 MW Solar	+Disp DSM; +300 MW 4hr BESS	+Disp DSM; +200 MW 4hr BESS; +49 MW Solar
2029	+700 MW 4hr BESS	+700 MW 4hr BESS; +42 MW Solar	+700 MW 4hr BESS; +42 MW Solar	+700 MW 4hr BESS	+700 MW 4hr BESS; +42 MW Solar
2030	Add GH2 SCR; +1 NGCC; ELG @ GH, TC	GH2 Non-Ozone; +2 NGCC; ELG @ GH, TC	GH2 Non-Ozone; +2 NGCC; ELG @ GH, TC	Add GH2 SCR; +1 NGCC; ELG @ GH, TC	GH2 Non-Ozone; +2 NGCC; ELG @ GH, TC
2031	Retire BR3; +1 NGCC; +200 MW 4hr BESS	Retire BR3; +1 NGCC	+171 MW Solar	Retire BR3; +1 NGCC; +200 MW 4hr BESS	+171 MW Solar
2032	+200 MW 4hr BESS		+576 MW IN Wind	+200 MW 4hr BESS	+304 MW IN Wind
2033					
2034			+23 MW IN Wind		+53 MW IN Wind
2035	Retire MC3-4; +1 NGCC; +1 SCCT	Retire MC3-4; +800 MW 4hr BESS; +225 MW Solar	Retire MC3-4; Retire BR3; +1,500 MW 4hr BESS; +3,974 MW Solar; +71 MW IN Wind	Retire MC3-4; +1 NGCC; +1 SCCT	Retire MC3-4; Retire BR3; +1500 MW 4hr BESS; +3,974 MW Solar; +313 MW IN Wind
2036		+3,333 MW Solar			
2037					
2038					
2039					

PLEXOS output where solar costs are assumed to escalate from beginning of analysis period:

Table 20 below provides the resource plans PLEXOS developed for the Ozone NAAQS + ELG environmental scenario assuming solar costs escalate slowly from the beginning of the analysis period. If the cost of solar does not decline like NREL projects, SCR is added in the Low and Mid fuel price scenarios.

Table 20: Resource Plan Screening Results (Mid Load, Ozone NAAQS + ELG, Solar Cost Sensitivity)[52]

Year	Expected CTG Ratio			Atypical CTG Ratio	
	Low Gas, Mid CTG	**Mid Gas, Mid CTG**	**High Gas, Mid CTG**	**Low Gas, High CTG**	**High Gas, Low CTG**
2028	+Disp DSM	+Disp DSM	+Disp DSM	+Disp DSM	+Disp DSM
2029					
2030	Retire BR3; Add GH2 SCR; +1 NGCC; ELG @ GH, TC; +100 MW 4hr BESS	Retire BR3; Add GH2 SCR; +1 NGCC; ELG @ GH, TC; +100 MW 4hr BESS	GH2 Non-Ozone; +1 NGCC; ELG @ GH, TC; +61 MW Solar	Retire BR3; Add GH2 SCR; +1 NGCC; ELG @ GH, TC; +100 MW 4hr BESS	GH2 Non-Ozone; +1 NGCC; ELG @ GH, TC; +61 MW Solar
2031	+400 MW 4hr BESS	+400 MW 4hr BESS	Retire BR3; +1 NGCC; +128 MW Solar	+400 MW 4hr BESS	+100 MW 4hr BESS; +305 MW Solar
2032	+200 MW 4hr BESS	+200 MW 4hr BESS		+200 MW 4hr BESS	+100 MW 4hr BESS
2033					Retire BR3; +400 MW 4hr BESS
2034					+226 MW IN Wind
2035	Retire MC3-4; +1 NGCC; +200 MW 4hr BESS	Retire MC3-4; +1 NGCC; +200 MW 4hr BESS	Retire MC3-4; +900 MW 4hr BESS; +19 MW Solar; +563 MW IN Wind	Retire MC3-4; +1 NGCC; +200 MW 4hr BESS	Retire MC3-4; +1 NGCC; +300 MW 4hr BESS; +336 MW IN Wind
2036			+1,744 MW Solar		+910 MW Solar
2037					
2038					
2039					

4.4.1.4 Ozone NAAQS + ELG + GHG Environmental Scenario

This scenario assumes the Good Neighbor Plan, 2024 ELG, and Greenhouse Gas Rules or their equivalents all become effective during the IRP planning period. The GHG Rules impact new NGCC units and existing coal units. Table 21 summarizes the compliance options modeled for these resources. An additional compliance option for both resources is installing carbon capture and sequestration ("CCS") by 2032. However, as discussed in Section 3.1.4 of the Volume III (2024 IRP Technology Update), CCS is not considered a viable alternative in Kentucky because it would require hundreds of miles of a robust CO_2 transportation and storage system that almost certainly cannot be developed by 2032. A summary of gas conversion and gas co-firing costs is included in Section 5.3.2.

Table 21: Modeled GHG Rules Compliance Options

Resource	Compliance Options
NGCC	• Limit unit to 40% capacity factor beginning in 2032
Existing Coal	• Begin co-firing with 40% natural gas by 2030 and retire unit by 2039 • Convert unit to burn 100% natural gas by 2030 with no retirement obligation • Retire unit by 2032

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

- Existing coal units are typically retrofitted to co-fire natural gas (which requires retirement by 2039) or retired by 2032.
- At least five NGCCs are added to serve load in every scenario, even though NGCCs are limited to a 40% capacity factor starting in 2032.
- Solar is added in all fuel price scenarios. Wind and SMR are added in high gas fuel price scenarios.
- Battery storage is added in Mid and High load scenarios.

<u>PLEXOS output</u>:

Table 22 through Table 24 below provide the resource plans PLEXOS developed for the Ozone NAAQS + ELG + GHG scenario. While the Companies do not know how OVEC intends to comply with the GHG Rules, the IRP analysis assumes OVEC will retire by 2032 in this scenario as a simplifying assumption given the high costs of alternative compliance options.

Table 22: Resource Plan Screening Results (Mid Load, Ozone NAAQS + ELG + GHG)[53]

Year	Expected CTG Ratio			Atypical CTG Ratio	
	Low Gas, Mid CTG	**Mid Gas, Mid CTG**	**High Gas, Mid CTG**	**Low Gas, High CTG**	**High Gas, Low CTG**
2028	+Disp DSM	+Disp DSM	+Disp DSM	+Disp DSM	+Disp DSM
2029					
2030	Retire BR3; Co-fire MC3-4; Co-fire GH1-4; Add GH2 SCR; Convert TC1-2; +1 NGCC; ELG @ MC, GH; +100 MW 4hr BESS	Co-fire MC3-4; Co-fire GH1-4; GH2 Non-Ozone; Convert TC1-2; +1 NGCC; ELG @ MC, GH; +36 MW Solar	Co-fire MC3-4; Co-fire TC1-2; GH2 Non-Ozone; +1 NGCC; ELG @ MC, TC; +36 MW Solar	Co-fire MC3-4; Co-fire TC1-2; GH2 Non-Ozone; +2 NGCC; ELG @ MC, TC;	Co-fire BR3; Co-fire MC3-4; Co-fire TC1-2; GH2 Non-Ozone; +1 NGCC; ELG @ MC, TC; +36 MW Solar
2031	+400 MW 4hr BESS	Retire BR3; +1 NGCC; +128 MW Solar	Retire BR3; +1 NGCC; +128 MW Solar	Retire BR3; +1 NGCC	+1 NGCC
2032	+200 MW 4hr BESS		Retire GH1-4; +3 NGCC; +563 MW IN Wind	Retire GH1-4; +1 NGCC; +600 MW 4hr BESS; +9 MW Solar; +563 MW IN Wind	Retire GH1-4; +2 NGCC; +100 MW 4hr BESS; +563 MW IN Wind
2033					
2034					
2035	+100 MW 4hr BESS		+3,076 MW Solar	+14 MW Solar	Retire BR3; +500 MW 4hr BESS; +3,473 MW Solar
2036	+2,995 MW Solar	+3,346 MW Solar; +306 MW IN Wind	+270 MW Solar	+3,488 MW Solar	+1 MW Solar
2037					
2038					
2039	Retire GH1-4; Retire MC3-4; +4 NGCC	Retire GH1-4; Retire MC3-4; Retire TC1-2; +6 NGCC	Retire MC3-4; Retire TC1-2; +2 NGCC; +2 SMR	Retire MC3-4; Retire TC1-2; +4 NGCC	Retire MC3-4; Retire TC1-2; +2 NGCC; +3 SMR

53 PLEXOS was configured to add NGCC (660 net winter MW), SCCT (258 net winter MW), and SMR (300 net winter MW) in one-unit increments and BESS in 100 MW increments. To reduce run times, solar and wind could be added in 1 MW increments. “Convert” indicates that a generating unit is converted to burn 100% natural gas. “Co-fire” indicates that a generating unit is retrofitted to burn 40% natural gas. “GH2 Non-Ozone” indicates that Ghent 2 is operated only in the non-ozone season.

Table 23: Resource Plan Screening Results (Low Load, Ozone NAAQS + ELG + GHG)[53]

	Expected CTG Ratio			Atypical CTG Ratio	
Year	**Low Gas, Mid CTG**	**Mid Gas, Mid CTG**	**High Gas, Mid CTG**	**Low Gas, High CTG**	**High Gas, Low CTG**
2028	+Disp DSM	+Disp DSM	+Disp DSM	+Disp DSM	+Disp DSM
2029					
2030	Convert BR3; Convert MC3-4; Co-fire TC1-2; GH2 Non-Ozone; ELG @ TC	Co-fire TC1-2; GH2 Non-Ozone; ELG @ TC	Co-fire TC1-2; GH2 Non-Ozone; ELG @ TC	Convert BR3; Convert MC3-4; Co-fire TC1-2; GH2 Non-Ozone; ELG @ TC	Co-fire TC1-2; GH2 Non-Ozone; ELG @ TC;
2031					
2032	Retire GH1-4; +3 NGCC	Retire BR3; Retire MC3-4; Retire GH1-4; +5 NGCC	Retire BR3; Retire MC3-4; Retire GH1-4; +5 NGCC; +419 MW IN Wind	Retire GH1-4; +3 NGCC	Retire BR3; Retire MC3-4; Retire GH1-4; +5 NGCC; +342 MW IN Wind
2033					
2034					
2035			+1,606 MW Solar		+1,202 MW Solar
2036	+684 MW Solar	+2,527 MW Solar	+944 MW Solar	+684 MW Solar	+1,347 MW Solar; +77 MW IN Wind
2037					
2038					
2039	Retire MC3; Retire TC1-2; +2 NGCC	Retire TC1-2; +1 NGCC; +1 SCCT	Retire TC1-2; +1 NGCC; +1 SCCT	Retire MC3; Co-fire TC1-2; +2 NGCC	Retire TC1-2; +1 NGCC; +1 SCCT

Table 24: Resource Plan Screening results (High Load, Ozone NAAQS + ELG + GHG)[53]

Year	Expected CTG Ratio			Atypical CTG Ratio	
	Low Gas, Mid CTG	**Mid Gas, Mid CTG**	**High Gas, Mid CTG**	**Low Gas, High CTG**	**High Gas, Low CTG**
2028	+Disp DSM; +300 MW 4hr BESS	+Disp DSM; +200 MW 4hr BESS; +49 MW Solar	+Disp DSM; +200 MW 4hr BESS; +49 MW Solar	+Disp DSM; +300 MW 4hr BESS	+Disp DSM; +200 MW 4hr BESS; +49 MW Solar
2029	+700 MW 4hr BESS	+700 MW 4hr BESS; +42 MW Solar	+700 MW 4hr BESS; +42 MW Solar	+700 MW 4hr BESS	+700 MW 4hr BESS; +42 MW Solar
2030	Convert BR3; Co-fire GH1-4; Add GH2 SCR; Co-fire MC3-4; Convert TC1-2; +1 NGCC; ELG @ MC, GH	Co-fire GH1-4; GH2 Non-Ozone; Co-fire MC3-4; Convert TC1-2; +2 NGCC; ELG @ MC, GH	Retire BR3; Co-fire GH1-4; GH2 Non-Ozone; Co-fire TC1-2; +2 NGCC; ELG @ GH, TC +78 MW Solar; +138 MW IN Wind	Convert BR3; Co-fire GH1-4; Add GH2 SCR; Co-fire MC3-4; Convert TC1-2; +1 NGCC; ELG @ MC, GH	Retire BR3; Co-fire GH1-4; GH2 Non-Ozone; Co-fire TC1-2; +2 NGCC; ELG @ GH, TC; +78 MW Solar
2031	+1 NGCC	Retire BR3; +1 NGCC	+1 NGCC	+1 NGCC	+1 NGCC
2032			Retire MC3-4; +1 NGCC; +36 MW Solar; +533 MW IN Wind		Retire MC3-4; +1 NGCC; +36 MW Solar; +671 MW IN Wind
2033					
2034					
2035	+100 MW 4hr BESS		+4,032 MW Solar	+100 MW 4hr BESS	+4,032 MW Solar
2036	+4,237 MW Solar	+4,146 MW Solar; +671 MW IN Wind		+4,237 MW Solar	
2037					
2038					
2039	Retire GH1-4; Retire MC3-4; +5 NGCC	Retire GH1-4; Retire MC3-4; +4 NGCC	Retire GH1-4; Retire TC1-2; +2 NGCC; +5 SMR	Retire GH1-4; Retire MC3-4; +5 NGCC	Retire GH1-4; Retire TC1-2; +2 NGCC; +5 SMR

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

In the second step of Stage One, the Companies evaluated each resource plan with detailed production costs over each of the five fuel price scenarios to determine which resource plan for a given load and environmental scenario has the lowest PVRR on average across all fuel price scenarios. Whereas PLEXOS was configured to add solar and wind in 1 MW increments to reduce run times, solar and wind resources were modeled in the nearest 100 MW increments in PROSYM as a simplifying assumption and to align the modeling with the size of a more typical utility-scale solar project.

4.4.2.1 No New Regulations Environmental Scenario

Table 25 contains the least-cost resource plans for the No New Regulations scenario. In the Low load scenario, no new resources are needed to serve load, and Brown 3 is converted to 100% natural gas due to landfill constraints and diminished energy needs. In the Mid and High load scenarios, Brown 3 is replaced with NGCC due to landfill constraints, and load growth is accommodated with additional NGCC capacity and battery storage. All other coal units operate through the end of the analysis period. Notably, PLEXOS added zero solar in the Low fuel price scenarios, more than 1,000 MW of solar in the Mid fuel price scenario, and more than 3,000 MW of solar in the High fuel price scenarios. Among these values, zero solar was least-cost on average across all fuel price scenarios for all load scenarios. However, this is not to say that some amount of solar will not be least-cost if renewable costs fall as projected by NREL, and the Companies believe this is the least likely environmental scenario.

Table 25: Least-Cost Resource Plans (No New Regulations)

Year	Low Load	Mid Load	High Load
2028	+Disp DSM	+Disp DSM	+Disp DSM; +300 MW 4hr BESS
2029			+700 MW 4hr BESS
2030		Retire BR3; +1 NGCC; +100 MW 4hr BESS	+1 NGCC
2031		+400 MW 4hr BESS	Retire BR3; +1 NGCC; +200 MW 4hr BESS
2032		+200 MW 4hr BESS	+200 MW 4hr BESS
2033			
2034			
2035	Convert BR3		
2036			
2037			
2038			
2039			

4.4.2.2 Ozone NAAQS Environmental Scenario

Table 26 contains the least-cost resource plans for the Ozone NAAQS scenario. SCR is added to Ghent 2 in the Mid and High load scenarios. In the Low load scenario, Ghent 2 is not needed to meet the minimum summer reserve margin constraint and is operated in non-ozone season only beginning in 2030. The least-cost resource plans for this environmental scenario are similar to the least-cost resource plans for the No New Regulations scenario.

Table 26: Least-Cost Resource Plans (Ozone NAAQS)

Year	Low Load	Mid Load	High Load
2028	+Disp DSM	+Disp DSM	+Disp DSM; +300 MW 4hr BESS
2029			+700 MW 4hr BESS
2030	GH2 Non-Ozone	Retire BR3; Add GH2 SCR; +1 NGCC; +100 MW 4hr BESS	Add GH2 SCR; +1 NGCC
2031		+400 MW 4hr BESS	Retire BR3; +1 NGCC; +200 MW 4hr BESS
2032		+200 MW 4hr BESS	+200 MW 4hr BESS
2033			
2034			
2035	Convert BR3		
2036			
2037			
2038			
2039			

4.4.2.3 Ozone NAAQS + ELG Environmental Scenario

Table 27 contains the least-cost resource plans for the Ozone NAAQS + ELG scenario. ELG compliance via zero liquid discharge is least-cost in all load scenarios at the Ghent and Trimble County stations. Mill Creek 3 and 4 are retired at the end of 2034 and replaced by NGCC and SCCT capacity. Brown 3 is converted to 100% gas in 2035 in the Low load scenario but retired and replaced with NGCC in 2031 in the Mid and High load scenarios. When solar costs are assumed to decline by more than 30% through 2035 before escalating slowly through the end of the analysis period, adding SCR at Ghent 2 is least-cost in the High load scenario but not in the Mid load scenario. However, when solar costs are assumed to escalate at 0.2 percent per year from the beginning of the analysis period, the Ghent 2 SCR is also least-cost in the Mid load scenario.

In the Mid load scenario with declining solar costs, the modeling is willing to accept higher costs in the early 2030s based on the assumed availability of large quantities of solar in 2035 at significantly lower prices than today. In practice, this resource plan is potentially not possible to execute. Even if the Companies could contract for the low-cost solar resources required to avoid the Ghent 2 SCR and these resources required minimal transmission system upgrades as the analysis assumes, the ability to permit and construct more than 2,000 MW of solar resources appears unlikely based on the Companies' recent experience with solar PPAs.[54] For these reasons, the Companies have included the Ghent 2 SCR in the least-cost resource plan for the Mid load, Ozone NAAQS + ELG scenario.

[54] See footnote 31.

Table 27: Least-Cost Resource Plans (Ozone NAAQS + ELG)

Year	NREL Solar Costs: Solar Costs Decline by More than 30% through 2035; then Escalate by 0.2% per Year			Solar Cost Sensitivity: Solar Escalates at 0.2% Annually
	Low Load	**Mid Load**	**High Load**	**Mid Load**
2028	+Disp DSM	+Disp DSM	+Disp DSM; +300 MW 4hr BESS	+Disp DSM
2029			+700 MW 4hr BESS	
2030	GH2 Non-Ozone; ELG @ GH, TC;	GH2 Non-Ozone; +1 NGCC; ELG @ GH, TC; +61 MW Solar	Add GH2 SCR; +1 NGCC; ELG @ GH, TC;	Retire BR3; Add GH2 SCR; +1 NGCC; ELG @ GH, TC; +100 MW 4hr BESS
2031		Retire BR3; +1 NGCC; +100 MW 4hr BESS; +27 MW Solar	Retire BR3; +1 NGCC; +200 MW 4hr BESS	+400 MW 4hr BESS
2032			+200 MW 4hr BESS	+200 MW 4hr BESS
2033				
2034				
2035	Retire MC3-4; Convert BR3; +1 NGCC; +1 SCCT	Retire MC3-4; +800 MW 4hr BESS; +121 MW Solar	Retire MC3-4; +1 NGCC; +1 SCCT	Retire MC3-4; +1 NGCC; +200 MW 4hr BESS
2036		+2,099 MW Solar		
2037				
2038				
2039				

4.4.2.4 Ozone NAAQS + ELG + GHG Environmental Scenario

Table 28 contains the least-cost resource plans for the Ozone NAAQS + ELG + GHG scenario. In the Low load scenario, Trimble County 1-2 are retrofitted to co-fire 40% natural gas, and the remaining coal units are retired in 2032. In Mid and High load scenarios, Trimble County 1-2 are converted to 100% natural gas, Mill Creek 3-4 and Ghent 1-4 are retrofitted to co-fire 40% natural gas, and Brown 3 is retired in 2031. The predominant replacement technology is NGCC, despite the 40% capacity factor limit beginning in 2032. All load scenarios have high penetrations of solar, and Mid and High load scenarios have Indiana wind.

This scenario would result in significant cost increases for ratepayers. The incremental impact of the Ozone NAAQS and ELG regulations, as measured by comparing the average PVRR of the least-cost resource plans for the Mid load scenario to their comparative previous scenarios, is $261 million for Ozone NAAQS regulations and $637 million for ELG regulations. While these costs are not trivial, they are small in comparison to the cost of GHG regulations, which is estimated at $5.6 billion.

Furthermore, implementing any of these portfolios in such a short timeline would carry considerable risk across all technologies, conventional and renewable alike, and across all aspects of implementation, including labor supply, equipment availability, siting and permitting, and adequate fuel transportation. These challenges would be compounded because numerous other entities would be vying for the same resources at the same time to meet the same compliance requirements and deadlines. Thus, the projected PVRR impact of the GHG Rules likely *understates* the cost impact to customers of complying with the GHG Rules on the prescribed timeline.

Table 28: Least-Cost Resource Plans (Ozone NAAQS + ELG + GHG)

Year	Low Load	Mid Load	High Load
2028	+Disp DSM	+Disp DSM	+Disp DSM; +200 MW 4hr BESS; +49 MW Solar
2029			+700 MW 4hr BESS; +42 MW Solar
2030	Co-fire TC1-2; GH2 Non-Ozone; ELG @ TC;	Co-fire MC3-4; Co-fire GH1-4; GH2 Non-Ozone; Convert TC1-2; +1 NGCC; ELG @ GH, MC; +36 MW Solar	Co-fire GH1-4; GH2 Non-Ozone; Co-fire MC3-4; Convert TC1-2; +2 NGCC; ELG @ GH, MC;
2031		Retire BR3; +1 NGCC; +128 MW Solar	Retire BR3; +1 NGCC
2032	Retire BR3; Retire MC3-4; Retire GH1-4; +5 NGCC		
2033			
2034			
2035			
2036	+2,527 MW Solar	+3,346 MW Solar; +306 MW IN Wind	+4,146 MW Solar; +671 MW IN Wind
2037			
2038			
2039	Retire TC1-2; +1 NGCC; +1 SCCT	Retire GH1-4; Retire MC3-4; Retire TC1-2; +6 NGCC	Retire GH1-4; Retire MC3-4; +4 NGCC

4.5 Stage Two: Recommended Resource Plan for IRP Reporting

Table 29 contains the Recommended Resource Plan for IRP reporting as well as the least-cost resource plans across all fuel price scenarios for the Mid load, Ozone NAAQS + ELG scenario and the High load, Ozone NAAQS + ELG scenario.[55] For the reasons discussed in Section 4.1.3, the Companies believe the Ozone NAAQS + ELG environmental scenario is most likely. Moreover, as discussed in Section 5.(3) in

[55] As discussed in Section 4.4.2.3, unlike the High load scenario, the least-cost resource plan in the Mid load scenario does not initially include an SCR on Ghent 2. However, this is predicated upon the availability of almost 2,000 MW of solar at costs more than 30 percent lower than today, which is inconsistent with the Companies' recent market experience and potentially not possible to execute. When considering a sensitivity case where solar prices do not decline as predicted by NREL's 2024 ATB, the least-cost resource plan for the Mid load scenario includes an SCR on Ghent 2.

Volume I, the Companies assign a low likelihood to the Low load forecast. The Mid load, Ozone NAAQS + ELG resource plan includes the retirements of Brown 3 and Mill Creek 3-4, ELG compliance at the Ghent and Trimble County stations via zero liquid discharge, and the additions of new dispatchable DSM measures, two NGCCs, 900 MW of battery storage, and a Ghent 2 SCR. To develop the Recommended Resource Plan, the Companies started with this resource plan and modified it to (1) support the potential for high economic development load growth and CO_2 regulations and (2) have no regrets should high load or CO_2 regulations not come to fruition. In the Recommended Resource Plan, to support the potential for high economic development load growth and CO_2 regulations, the additions of the Ghent 2 SCR and 400 MW of battery storage are accelerated to 2028, the addition of the second NGCC is accelerated to 2031, and the retirement of Brown 3 is deferred to 2035. In addition, 500 MW of solar is added in 2035 after prices fall to hedge natural gas price volatility and future CO_2 regulation risk.

The Recommended Resource Plan is a "no regrets" resource plan because the accelerated resources are needed by 2035 if high economic load growth or CO_2 regulations do not come to fruition. Furthermore, the addition of 500 MW of solar reflects the high likelihood that some level of solar will be least-cost without CO_2 regulations.

Table 29: Recommended Resource Plan and Enhanced Solar Resource Plan (only years in which changes occur are shown)

Year	Least-Cost Resource Plans Ozone NAAQS + ELG		Recommended Resource Plan Ozone NAAQS + ELG Mid Load	Enhanced Solar Resource Plan Mid Load
	Mid Load, Solar Cost Sensitivity[55]	High Load		
2028	+Dispatchable DSM	+Dispatchable DSM; +300 MW 4hr BESS	+Dispatchable DSM; +400 MW 4hr BESS; Add Ghent 2 SCR	+Dispatchable DSM; +400 MW 4hr BESS; Add Ghent 2 SCR +200 MW Solar
2029		+700 MW 4hr BESS		
2030	Retire Brown 3; Add Ghent 2 SCR; +1 NGCC; ELG @ Ghent, Trimble County; +100 MW 4hr BESS	Add Ghent 2 SCR; +1 NGCC; ELG @ Ghent, Trimble County	+1 NGCC; ELG @ Ghent, Trimble County	+1 NGCC; ELG @ Ghent, Trimble County; +200 MW Solar
2031	+400 MW 4hr BESS	Retire Brown 3; +1 NGCC; +200 MW 4hr BESS	+1 NGCC	+1 NGCC
2032	+200 MW 4hr BESS	+200 MW 4hr BESS		+600 MW Solar
2035	Retire Mill Creek 3-4; +1 NGCC; +200 MW 4hr BESS	Retire Mill Creek 3-4; +1 NGCC; +1 SCCT	Retire Mill Creek 3-4; Retire Brown 3; +500 MW 4hr BESS; +500 MW Solar	Retire Mill Creek 3-4; Retire Brown 3; +500 MW 4hr BESS;

Table 29 further reflects that solar continues to play an important role in the Companies' resource planning. Although solar PPA pricing has risen significantly in recent years, resulting in the Companies' current expectation that the approved solar PPAs will not advance under their approved terms, current projections by NREL suggest that solar pricing may decrease over the IRP planning period, potentially allowing for additional solar development. Also, both existing and potential customers, such as data centers, may have an increasing interest in carbon-free energy and seek to have additional amounts of solar added through the Companies' Green Tariff Option #3. Thus, the Enhanced Solar Resource Plan includes 1,000 MW of solar to reflect the possibility of more solar being added sooner by customers in the context of the Companies' Green Tariff Option #3 or by the Companies in a scenario where solar prices fall faster than forecasted by NREL.

5 Appendix A – Summary of Inputs

5.1 Load Forecast

Section 2.1 summarizes the Companies' Low, Mid, and High load forecast scenarios. Additional information regarding the Companies' load forecasts is included in IRP Volume I (Sections 5-7) as well as IRP Volume II (Electric Sales and Demand Forecast Process).

5.2 Minimum Reserve Margin Target

The Companies' minimum reserve margin targets are 23% for summer and 29% for winter. IRP Volume III (2024 IRP Resource Adequacy Study) summarizes the analysis used to determine minimum winter and summer reserve margin constraints for resource planning.

5.3 Existing Resource Inputs

Table 30 lists the Companies' forecasted generating resources as of 2032. Resources that are fully dispatchable are listed separately from renewable and limited-duration resources. The Companies' coal, NGCC, and SCCT resources are fully dispatchable. For example, while SCCTs typically operate less than 24 hours each time they are started due to their higher fuel costs, they can operate for longer periods if necessary. The Companies' renewable resources are intermittent. For example, the ability to generate power at the Ohio Falls station is entirely a function of water availability, which is managed by the Corps of Engineers. Finally, the Companies' BESS, dispatchable DSM, and CSR resources can be dispatched when needed but only for limited durations. The operating characteristics of supply-side and demand-side resources are an important consideration in resource planning.

Table 30: 2032 LG&E/KU Generating & DSM Portfolio[56]

Category	Resource Type	Resource Name	Net Max Summer Capacity (MW)	Net Max Winter Capacity (MW)
Fully Dispatchable	Coal[57]	Brown 3	412	416
		Ghent 1	475	479
		Ghent 2	485	486
		Ghent 3	481	476
		Ghent 4	478	478
		Mill Creek 3	391	394
		Mill Creek 4	477	486
		Trimble County 1 (75%)	370	370
		Trimble County 2 (75%)	549	570
	Coal PPA	OVEC	152	158
	NGCC	Cane Run 7	697	759
		Mill Creek 5	645	660
	SCCT[58]	Brown 5	130	130
		Brown 6	146	171
		Brown 7	146	171
		Brown 8	121	128
		Brown 9	121	138
		Brown 10	121	138
		Brown 11	121	128
		Paddy's Run 13	147	175
		Trimble County 5	159	179
		Trimble County 6	159	179
		Trimble County 7	159	179
		Trimble County 8	159	179
		Trimble County 9	159	179
		Trimble County 10	159	179
Renewable[59]	Solar	Brown Solar	10	10
		Business Solar	0.34	0.34
		Solar Share	3.4	3.4
		Mercer County Solar	120	120
		Marion County Solar[60]	120	120
	Wind	Brown Wind	0.09	0.09
	Hydro	Dix Dam 1-3	33.6	33.6
		Ohio Falls 1-8	100.6	100.6
Limited-Duration	BESS	Brown BESS	125	125
	Interruptible	CSR	110	115
	Dispatchable DSM	DCP[61]	190	145

[56] The Resource Assessment assumes Mill Creek 1 is retired at the end of 2024, Haefling 1-2 and Paddy's Run 12 are retired in 2025, and Mill Creek 2 is retired in 2027.
[57] Except Ghent 2, all of the Companies' coal units are equipped with SCR, flue gas desulfurization ("FGD"), and baghouses.

5.3.1 Stay-Open Costs

As seen in Table 31, several of the Companies' coal units are over 45 years old and approaching the end of their current book depreciation life. Mill Creek 2 is 50 years old and is slated to retire in 2027 to allow for the commissioning of a new NGCC, Mill Creek 5. Although the other units could theoretically operate beyond their depreciable book life, doing so would require a higher level of capital investments.[62] To properly evaluate the economics of the existing fleet, the Companies identified the types of projects and associated costs that would be needed to extend the lives of units beyond their current depreciable book lives to at least the end of the analysis period. To be clear, the Companies are not proposing to extend these units' lives; rather, this analytical approach is necessary to properly evaluate the fleet's economics.

Table 31: Age of Existing Coal Units

Unit	Age as of 1/1/2025	Age as of 1/1/2040	End of Book Depreciation Life
Brown 3	53	68	2035
Ghent 1	50	65	2034
Ghent 2	47	72	2034
Ghent 3	43	58	2037
Ghent 4	40	55	2037
Mill Creek 2	50	75	2034
Mill Creek 3	46	61	2039
Mill Creek 4	42	57	2039
Trimble County 1	33	48	2045
Trimble County 2	13	28	2066

Stay-open costs for existing generating units include each unit's ongoing capital and fixed operating and maintenance ("O&M") costs. These costs are required to continue operating a unit and are avoided if a unit is retired. Costs that are shared by all units at a station (i.e., "common" costs) are allocated to units in proportion to how they would be reduced as units retire.[63] Stay-open costs include costs for routine

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[58] 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.

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

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

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

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

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

maintenance and major overhauls, and do not include carrying costs for prior investments or costs for projects that would not be affected by unit retirements in this analysis, such as ash pond closures. Stay-open costs differentiate between "standard" major overhaul costs and the costs for projects that would be needed to operate the unit through at least the end of the analysis period.[64] 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.

5.3.2 Retrofitting Alternatives

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

Adding an SCR to Ghent 2 would reduce its NO_x emissions and allow for year-round operation under Ozone NAAQS environmental regulations. The capital cost of an SCR for Ghent 2 is estimated at $137.8 million for a 2030 commissioning, with ongoing incremental capital and O&M costs of approximately $1.3 million in 2030 dollars. An SCR is assumed to decrease the net maximum available generation by 4 MW, reduce net unit efficiency (i.e., increase heat rates) by 1%, and increase the operating cost by approximately $0.42/MWh in 2030 dollars due to anhydrous ammonia needs for SCR operation. Under Ozone NAAQS environmental regulations scenarios, PLEXOS has the option to add an SCR (allowing for year-round operation), not to add an SCR and allow Ghent 2 to operate only during the non-ozone season (October through April), or to retire Ghent 2.

Co-firing at a ratio of 60% coal and 40% natural gas by 2030 is specified as a compliance option in the GHG Rules to allow continued operation through 12/31/2038, after which a co-fired unit must be retired. Estimates for capital costs of co-firing inclusive of pipeline modifications are summarized in Table 32. Co-firing is assumed to have no material impact to ongoing fixed O&M, net heat rates, and seasonal operating capacities. Fuel costs would be higher on a $/MMBtu basis as a function of coal-to-gas price ratios, and fuel transportation costs reflect the addition of firm gas transportation. Emissions and reagent costs related to emissions controls are assumed to be reduced in proportion to the natural gas co-firing percentage. Given the increased fuel costs, co-firing does not have any economic advantages and is considered solely as a GHG environmental compliance alternative.

Gas conversion by 2030 is specified as a compliance option in the GHG Rules, and gas conversion by 2035 is specified as a compliance option for new ELG regulations. Gas conversion also obviates the need for

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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.

[64] 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.

CCR landfill storage given the ceased combustion of coal. Estimates for capital costs of gas conversion inclusive of pipeline modifications are summarized in Table 32. Gas conversion is assumed to eliminate many mechanical components related to the combustion of coal and is assumed to reduce ongoing O&M by approximately 30%. Reductions in auxiliary load are offset by loss of boiler efficiency, resulting in a 2% loss in net seasonal maximum capacity and a reduction in net unit efficiency (i.e., increase in heat rates) of 13.6%. Minimum capacities are assumed to be reduced by 25% from current levels, providing increased operational capability for managing minimum generation issues. Fuel costs would be higher on a $/MMBtu basis as a function of coal-to-gas price ratios, and fuel transportation costs reflect the addition of firm gas transportation. SCRs are assumed to remain in service and maintain existing emissions levels, but anhydrous ammonia costs are assumed to be reduced by 50% given lower levels of NO_x in natural gas combustion compared to coal combustion. Other emissions controls, such as FGDs and baghouses, are assumed to be removed from service, associated emissions are assumed to be reduced consistent with the change from coal combustion to natural gas combustion, and reagent costs are assumed to be eliminated. Given the increased fuel costs and heat rates, gas conversion typically results in increased operating costs but may be warranted for a variety of compliance reasons. Therefore, it is considered as an alternative in all environmental regulations scenarios.

Table 32: Capital Costs of Retrofitting Alternatives, 2030 Commissioning ($M)[65]

Unit	Co-Firing Capital	Gas Conversion Capital
Brown 3	$39.4	$46.4
Ghent 1	$64.3	$72.3
Ghent 2	$64.9	$73.0
Ghent 3	$64.4	$72.4
Ghent 4	$64.3	$72.4
Mill Creek 3	$30.8	$36.5
Mill Creek 4	$33.4	$39.3
Trimble County 1[66]	$30.2	$36.1
Trimble County 2[66]	$42.7	$50.8

5.3.3 CCR Revenue Assumptions

Coal combustion residuals ("CCR") include fly ash, bottom ash, and gypsum. CCR is either used for onsite construction projects, sold to third parties for use in the production of products like cement and wallboard, or stored in onsite landfills. When sold to third parties, the 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 of CCR has increased. Table 33 lists the assumed CCR sales prices in this analysis.[67] The 2022 values are weighted average prices based on existing contracts. CCR sales prices are expected to approach

[65] Includes pipeline capital. Station costs for pipeline capital are allocated across units as a simplifying assumption, so costs may be understated if some units at a station are retrofitted and others are not.

[66] Costs for Trimble County reflect the Companies' 75% ownership share of full unit costs.

[67] 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.

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 33: 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							

Table 34 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.[68] The Ghent station requires additional loading facilities to increase its fly ash sales after pond closure 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 34: 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%

5.3.4 Landfill Storage Constraints

Table 35 shows the Companies' assumptions regarding landfill space at Brown and Mill Creek stations.[69] Because Brown 3 is a marginal unit, its generation and CCR production are more variable; therefore, the Companies assume a four-year buffer for planning purposes, compared to two years at the Mill Creek

[68] Based on current progress of the active closure projects, completion is anticipated no later than December 2025.
[69] Landfill space is not a concern at the Ghent and Trimble County stations.

station. As shown, the Companies assume the last year of landfill availability is 2035 for Brown station, 2045 for Mill Creek station in scenarios without 2024 ELG, and 2037 for Mill Creek station in scenarios with 2024 ELG.[70]

Table 35: Landfill Storage Constraints at Brown and Mill Creek Stations

		Mill Creek	
	Brown	**No ELG**	**With ELG**
Landfill Capacity Beg. 2024 (CY)	1,710,081	4,843,807	4,843,807
Average Annual Volumes Stored (CY)	110,000	200,000	300,000
Years of Remaining Capacity	15.5	24.2	16.1
Year Landfill is at Capacity	2039	2047	2039
Years of Buffer	4	2	2
Last Year of Landfill Availability	2035	2045	2037

5.4 Solar and Wind Generation Profiles

The Companies developed solar and wind generation profiles to align with the weather underlying the hourly load forecast. For solar profiles, the Companies used NREL's PVWatts model to develop historical profiles for the years 1998 to 2022 based on historical solar irradiance data from NREL's National Solar Radiation Database ("NSRDB").[71] Hourly loads in each month of the long-term load forecast are ordered based on the hourly loads in a historical month with the same weekday-weekend profile and approximately normal weather.[72] Therefore, the solar generation forecast for each month of the long-term forecast is based on the solar profile for the same historical month.

NREL's PVWatts model can be used to develop net generation profiles for different types of solar arrays (e.g., fixed-tilt and single-axis tracking). For specific projects (e.g., Mercer County Solar), generation profiles are based on historical solar irradiance from the NSRDB for the project site. For new solar, profiles were developed based on the average generation from ten sites located throughout the state. This was done to capture the benefits of a geographically diverse portfolio of solar projects.

The Companies developed wind generation profiles using NREL's System Advisor Model ("SAM") and modeled wind speed data from the NREL WIND Toolkit. Twenty sites (including ten each from Kentucky and Indiana) were selected as a representative sample from NREL's Limited Access Land Based Wind data set in the 2023 ATB based on criteria designed to produce the highest possible capacity factor while maintaining geographic diversity and avoiding access-restricted sites.

The NREL WIND Toolkit provides modeled wind data (including speed and direction) for a given location at various elevations from 2007 through 2013. This data was used as input for the SAM model to simulate generation output for a 108 MW wind farm comprising twenty-four Vestas V150 4.5 MW turbines with a hub height of 100 meters. This model utilized the Park WASP model to simulate wake effects and also factored in default operating and loss assumptions from NREL.

[70] Because Brown station is currently zero liquid discharge, it is unaffected by ELG rules.
[71] 1998 to 2022 is the period of history for which irradiance data is available.
[72] See IRP Volume II (Electric Sales & Demand Forecast Process) for a broader discussion of the long-term load forecast.

Like the solar profiles, the Companies developed historical wind profiles first and then used the historical profiles to develop forecasted profiles that align with the weather underlying the hourly load forecast. Separate profiles were created for Kentucky and Indiana wind as average profiles over ten sites in each state.

5.5 Transmission System Upgrade Costs

The Resource Assessment does not explicitly consider transmission system upgrade costs. These costs are typically low when replacing resources at existing stations and uncertain in scenarios that involve new generation sites. Because transmission system upgrade studies are time consuming and focused on specific generation scenarios, a detailed transmission system upgrade study is completed only for CPCN filings.

5.6 Commodity Prices

5.6.1 Natural Gas and Coal Price Forecasts

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

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

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

The Companies' range of three gas price forecasts, shown in Figure 9, is based on the U.S. Energy Information Administration's ("EIA") forecasts in its 2023 Annual Energy Outlook ("AEO2023").[73] These forecasts are consistent with forecasts prepared by industry consultants, as discussed in Section 5.6.2.4.

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

Figure 9: Natural Gas Price Forecasts (Henry Hub; Nominal $/MMBtu)

[redacted]

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

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

The majority of the Companies' coal supply is sourced from the Illinois Basin. The Companies developed Illinois Basin coal prices for the 2023 AEO natural gas prices based on the historical ratio of Illinois Basin coal and Henry Hub natural gas prices ("coal-to-gas price ratio" or "CTG price ratio") using publicly available historical price data. Figure 10 shows Illinois Basin coal prices and Henry Hub natural gas prices as well as the coal-to-gas price ratio since 2012. Coal and gas prices generally move together, but coal markets are slower to respond to changing market fundamentals than gas. As a result, periods of increasing gas prices are generally associated with lower coal-to-gas price ratios, and periods of decreasing gas prices are generally associated with higher coal-to-gas price ratios. In addition, the coal-to-gas price ratio is mean reverting (i.e., after hitting a high or low point, it reverts back toward the mean) and does not remain at high or low levels for long periods of time. In 2022, U.S. coal supply became tightly balanced with demand as export demand from Europe remained elevated due to reduction in the supply of Russian coal and gas. This resulted in the highest coal-to-gas ratio since before 2012, but this ratio is not expected to persist through the end of the IRP analysis period.

Figure 10: Illinois Basin Coal and Henry Hub Gas Prices (2012-2024)

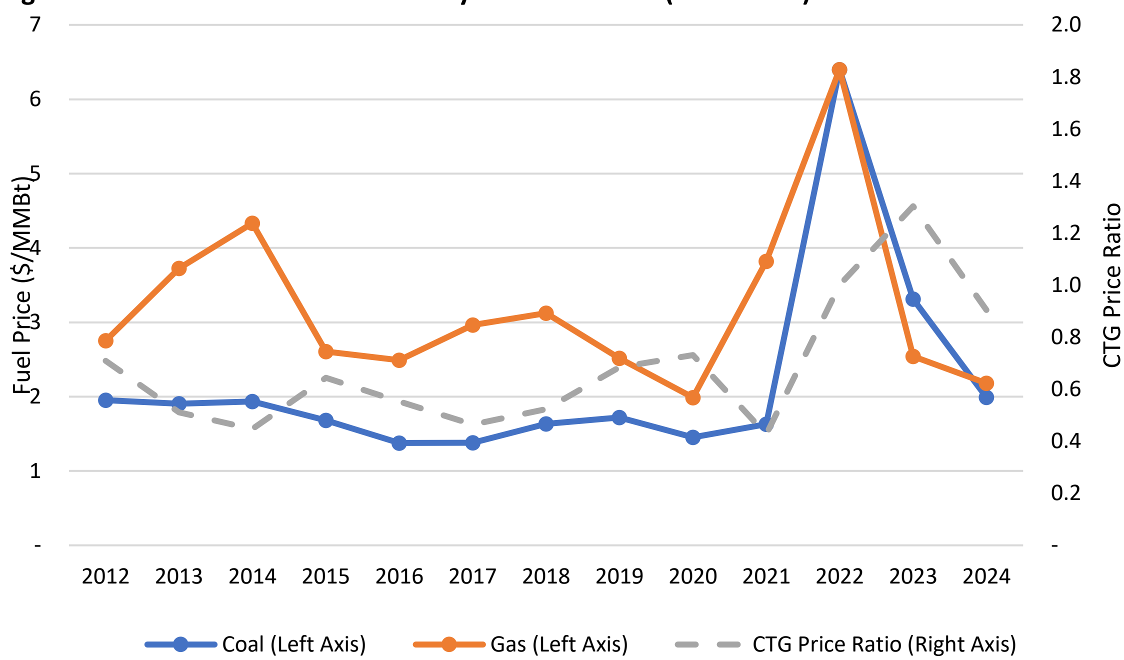


Table 36 summarizes the coal-to-gas price ratio in tabular form. The Companies' pricing analysis was focused on the period from 2012 through 2021 because the CTG price ratio resulting from spot market pricing between 2022 and 2024 reflects extreme and aberrant market conditions that would inappropriately skew long-term price forecasts. While spot market prices continue to show an above-average ratio through 2024, the Companies' Business Plan open position does show prices returning to the historical average ratio of 0.57 observed over the ten-year period from 2012 to 2021. At this coal-to-gas price ratio, the cost of coal and NGCC energy is very similar, regardless of the level of gas prices. Furthermore, this average coal-to-gas price ratio is unsurprising because coal and NGCC energy are economic substitutes, and a coal-to-gas price ratio of 0.57 approximates the ratio of NGCC and coal operating costs. Over a long analysis period, despite changing natural gas prices, the average coal-to-gas price ratio is expected to continue at this level. In addition to the 10-year average coal-to-gas price ratio, Table 36 contains the six-year average ratios. These six-year averages were used to evaluate short-term variations in the coal-to-gas price ratio.[74]

[74] 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 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	1.00		
2023	1.31		
2024	0.90		

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 2029 with the assumption that the coal-to-gas ratio would continue, on average, to approximate the average coal-to-gas price ratio from 2012 to 2021 (0.57). Again, note that the Mid coal-to-gas price ratio (0.57) approximates the ratio of NGCC and coal operating costs. Therefore, it is plausible to expect coal-to-gas price ratios to revert to this ratio over the long term, which is why the Companies refer to it as the "Expected CTG Price Ratio."

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

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 (2023 AEO)	Mid (0.57)[75]	Low Gas, Mid CTG
	2	Mid (2023 AEO)	Mid (0.57)[75]	Mid Gas, Mid CTG
	3	High (2023 AEO)	Mid (0.57)[75]	High Gas, Mid CTG
Atypical CTG Price Ratios	4	Low (2023 AEO)	High (0.60)[76]	Low Gas, High CTG
	5	High (2023 AEO)	Low (0.52)[76]	High Gas, Low 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 2025-2029 and a constant 0.57 CTG ratio thereafter. All other scenarios reflect constant CTG ratios in all years.

Table 38: Coal and Natural Gas Price Scenarios ($/mmBtu)

Year	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	
	Coal	Gas	Coal	Gas	Coal	Gas	Coal	Gas	Coal	Gas
2025	[redacted]									
2026										
2027										
2028										
2029										
2030										
2031										
2032										
2033										
2034										
2035										
2036										
2037										
2038										
2039										

[75] 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.

[76] The High and Low coal-to-gas price ratios are the maximum and minimum, respectively, of the six-year rolling average coal-to-gas ratio from 2012 to 2021.

5.6.2 Natural Gas Price Forecast Methodology

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

5.6.2.1 Gas Price Scenarios

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

5.6.2.2 Conversion of annual price curves to monthly

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

5.6.2.3 EIA AEO2023 Cases

5.6.2.3.1 EIA AEO2023 Reference case (Mid Gas Price Case)[77]

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

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

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

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

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

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

5.6.2.4 Gas Price Forecasts Reasonableness

The range of natural gas price forecasts compares reasonably to the market expectations of reputable industry consultants, as shown in Figure 11.[78] 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.

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

Figure 11: Comparison of Henry Hub Natural Gas Price History and Forecasts (Nominal $/MMBtu)

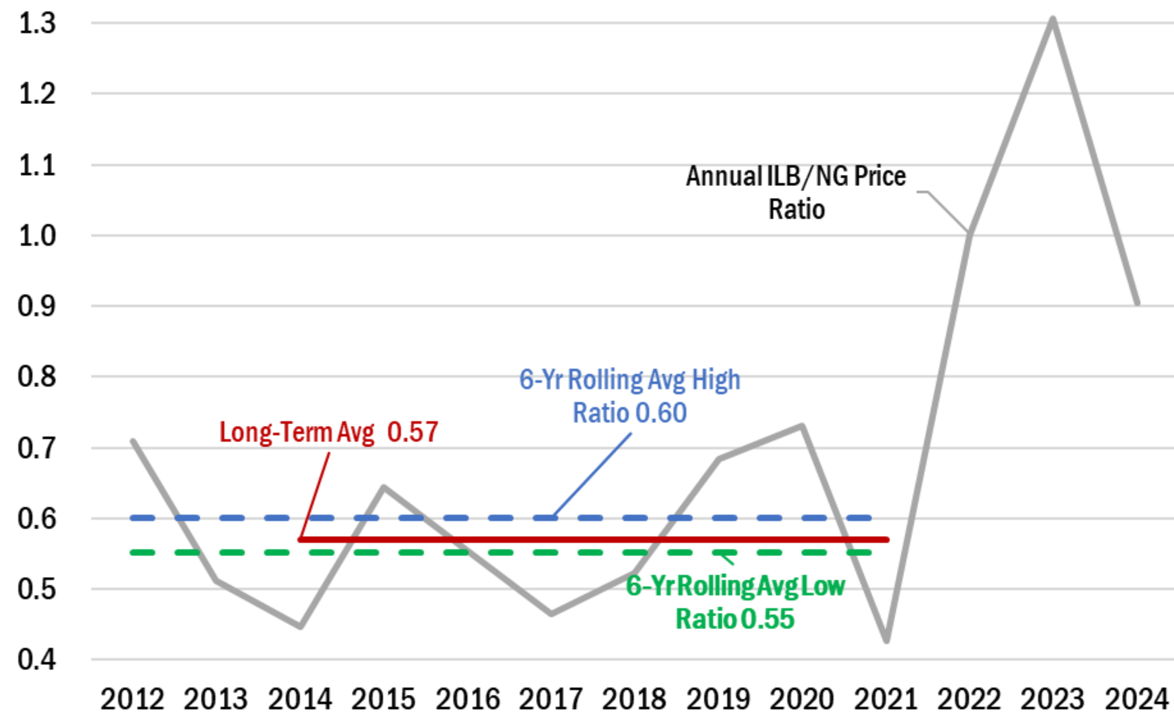
[redacted]

5.6.3 ILB Coal Price Forecast Methodology

The Illinois Basin ("ILB") coal open position price forecasts were created using bid prices solicited by LG&E-KU's Fuels group and historical ILB coal/gas price ratios. For the Mid Gas, Mid CTG coal price forecast, bid pricing sourced from LG&E-KU's Fuels group reflects minemouth quotations supplied by coal suppliers for delivery in each year through 2029. The fuels group received these quotations in response to a request for quotation (RFQ) issued in Q2 2024.

The long-term ILB price forecasts comprise five scenarios that were developed by applying historical relationships between ILB coal and natural gas prices to the natural gas price forecasts. Figure 12 shows that relationship over the past decade.

Figure 12: 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 12. This average is the basis for the Mid CTG coal price forecasts. As noted above, the Mid coal-to-gas price ratio (0.57) approximates the ratio of NGCC and coal energy costs. Therefore, it is plausible to expect coal-to-gas price ratios to revert to this ratio over the long term, which is why the Companies refer to it as the "Expected CTG Price Ratio" throughout the Resource Assessment.

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

5.6.3.1 ILB Coal Price Scenario Assumptions

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

Figure 13 shows the resulting near-term ILB price forecast and its components.

Figure 13: Mid ILB Coal Price Forecast, 2023-2027 (Nominal $/MMBtu)

[redacted]

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

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

5.6.4 Ammonia Prices

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

Table 39 contains the wholesale ammonia price scenarios evaluated in this analysis. In the Mid Ammonia case, ammonia prices are assumed to increase on average by 2.2% from 2025 to 2029 and then escalate at the Companies' inflation assumption of 2.3% per year thereafter. The Low and High Ammonia price cases reflect the relationship between the Mid Gas price forecast and the Low and High Gas Price forecasts, respectively.

Table 39: Ammonia Prices (wholesale nominal $/ton)

	Low Ammonia		Mid Ammonia	High 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
2025	[redacted]				
2026					
2027					
2028					
2029					
2030					
2031					
2032					
2033					
2034					
2035					
2036					
2037					
2038					
2039					

5.6.5 Emission Allowance Prices

Table 40 summarizes the emission allowance price forecasts used in this analysis. The SO_2 Group 1, NO_x Seasonal Group 3, and NO_x Annual forecasts were based on a consultant's December 2023 forecasts. For scenarios without Ozone NAAQS regulations, the Companies held current market NO_x Seasonal Group 2 emission allowance pricing constant through 2035 as the basis for the NO_x Seasonal emission allowance price forecast. For scenarios with Ozone NAAQS regulations, the Companies used the NO_x Seasonal Group 3 forecast.

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

Year	SO_2 Group 1	NO_x Seasonal Group 2	NO_x Seasonal Group 3	NO_x Annual
2025	[redacted]			
2026				
2027				
2028				
2029				
2030				
2031				
2032				
2033				
2034				
2035				
2036				
2037				
2038				
2039				

5.7 Financial Inputs

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

Table 41: Financial Inputs

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

2024 RTO Membership Analysis

Section 1: Overview and Summary

Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (collectively "Companies") are required by the Kentucky Public Service Commission ("KPSC" or "Commission") to annually file a report evaluating whether joining a regional transmission organization ("RTO") would be in the best interest of customers.[1] This 2024 RTO Membership Analysis builds on work performed in the previous RTO reports and extensive information related to RTOs that was filed in Case No. 2022-00402. The primary conclusions of this year's analysis are:

1. Midcontinent Independent System Operator, Inc. ("MISO") and PJM Interconnection, L.L.C. ("PJM") continue to modify their market rules to address concerns about resource adequacy. In particular, the PJM Base Residual Auction ("BRA") results announced on July 30, 2024, showed a significant increase in capacity prices for delivery year 2025/2026. Until such time as MISO and PJM consistently demonstrate that their markets are capable of attracting new generation resources to maintain reliability, the Companies do not support initiating detailed discussions with MISO or PJM regarding membership.
2. Due to uncertainty regarding RTO reliability and related capacity market reforms in MISO and PJM and each RTO's concerns about the reliability impact of the U.S. Environmental Protection Agency's ("EPA") Clean Air Act Section 111(b) and (d) greenhouse gas regulations ("Greenhouse Gas Rules"), attempting to model the Companies' membership in either RTO is not practical to the degree necessary to confidently make a decision to join one of them.
3. Retail choice is one of the primary reasons that RTOs can struggle to ensure resource adequacy because retail providers do not have a long-term obligation to serve. In PJM, eight of the thirteen states and District of Columbia allow retail choice, whereas in MISO only three of the fifteen states allow retail choice. Therefore, the Companies are likely to focus more attention on MISO developments in the future because their membership may better align with the Companies' obligation to serve.[2]
4. In its final order in Case No. 2022-00402, the Commission stated, "This Commission has no interest in allowing our regulated, vertically-integrated utilities to effectively depend on the market for generation or capacity for any sustained period of time."[3] This requirement, along with recent PJM capacity accreditation rating reforms, would increase the Companies' capacity needs in PJM and would eliminate the potential for capacity and energy savings that were a primary source of potential RTO savings.

---

[1] *See Electronic Application of Kentucky Utilities Company for an Adjustment of Its Electric Rates*, Case No. 2018-00294, Order (Ky. PSC Apr. 30, 2019); *Electronic Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Rates*, Case No. 2018-00295, Order (Ky. PSC Apr. 30, 2019).
[2] Retail choice states in PJM are Delaware, Illinois, Maryland, Michigan, New Jersey, Ohio, Pennsylvania, and the District of Columbia. Retail choice states that have load in MISO are Illinois, Michigan, and Texas.
[3] *Electronic Joint Application of Kentucky Utilities Company and Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity and Site Compatibility Certificates and Approval of a Demand Side Management Plan*, Case No. 2022-00402, Order at 177 (Ky. PSC Nov. 6, 2023).

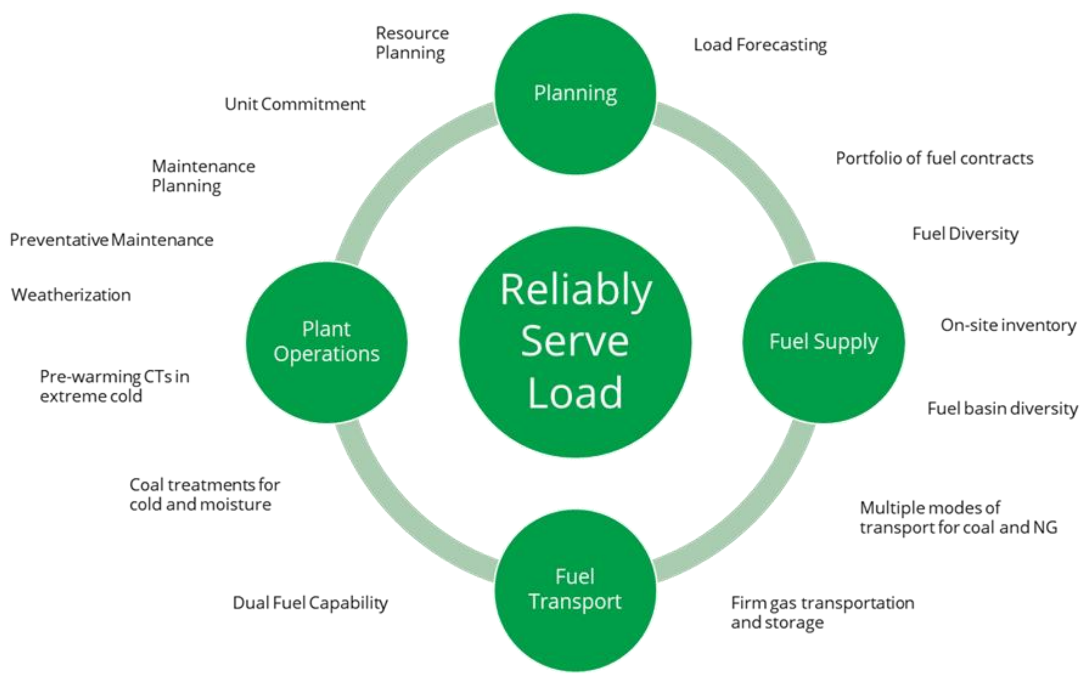
For the reasons stated above, this report focuses on the reliability and market issues that are ongoing in both MISO and PJM and the challenges each RTO faces in addressing its future capacity and energy needs. It also describes the fundamental differences between operating as a standalone utility and operating inside an RTO (e.g., capacity planning, fuel planning and procurement, unit commitment and dispatch).

The Companies remain open to the possibility of future RTO membership, and they believe that continuing to study it, albeit perhaps less frequently than the current annual requirements (e.g., only in conjunction with the triennial IRP filing), is entirely appropriate. Less frequent study would allow more time between studies for RTOs to address the numerous issues related to resource adequacy and EPA regulations and to demonstrate some degree of stability. Stability and certainty are important in a decision to join an RTO because it is likely to be challenging and costly to undo such a decision. Therefore, prudence requires that the benefits be clear and durable before making such a decision and commitment on behalf of the Companies' customers.

Section 2: Key Difference in Operating as a Standalone Utility versus in an RTO

A decision to join an RTO must include a thorough consideration of the vast operational differences relative to being an independent vertically integrated utility (as the Companies currently operate), as well as the operational differences between the RTOs themselves.

As a standalone, vertically integrated utility, the Companies are solely responsible for all aspects of planning and operating to reliably serve their customers' energy needs 8,760 hours a year across a broad range of possible future conditions. The Companies are also responsible for ensuring that their generation fleet is compliant with all current EPA regulations and for making changes to that fleet to comply with future EPA regulations. The following figure illustrates, at a high level, the continuous cycle of long-term and short-term generation-related planning and operational activities in which the Companies engage to ensure reliable service to customers.



In an RTO, there are numerous parties that can (and do) perform these functions in response to, and to comply with, various RTO markets, tariffs, and rules. RTO markets are highly structured mechanisms whose rules are set through processes approved by the Federal Energy Regulatory Commission ("FERC"). It is via these markets that the RTO is to ensure that the grid has adequate generation and energy to reliably serve customers. However, both MISO and PJM in recent years have indicated a growing concern that their markets may, or are, not adequately procuring generation for the future.

Concerns about whether RTO markets, as they have historically operated, can be modified to address future reliability have been expressed by many industry observers. For example, current FERC Commissioner Mark Christie published a detailed discussion of the challenges facing RTO markets in 2023 in the Energy Law Journal entitled, "It's Time to Reconsider Single-Clearing Price Mechanisms in U.S. Energy Markets," in which he stated:

> [L]et's not pretend capacity markets, with their administratively set demand curves and scarcity prices, are true markets that are more efficient at predicting the future because of the Hayekian collective intelligence of the marketplace. They are just another way to transfer money from consumers to generation investors to try to ensure sufficient power supply in the future. Not that there's anything wrong with that in concept. If Americans are not willing to live with regular power supply shortages – and we are not – then it is necessary to pay in advance for resources to make sure they are there whenever needed, just like buying an insurance policy that may never be used. Just don't pretend, however, that what's at work in capacity markets is Adam Smith's invisible hand efficiently allocating capital through a single-clearing price mechanism.
>
> And that raises the following question: How can this administrative pricing mechanism used in capacity markets -- with the complexities and subjectivity of an administratively set demand curve, administratively set local deliverability areas used to calculate zonal prices to load, administrative determination of CONE, administrative judgments about effective load carrying capabilities, offer caps, etc.-- possibly be described as the "market" alternative to the "regulated" construct of paying for needed generation through rate base, or purchasing needed power through bilateral contracts? To the honest observer RTO capacity markets and state IRP processes are both planning constructs, just in different forms. This article suggests that most state IRP processes may be far better suited to plan comprehensively, to manage the risks associated with different types of generation, to incorporate demand-side resources, and to balance state policies promoting renewables with the core goals of delivering reliability and controlling consumer costs than RTO capacity markets are.[4]

It is important to keep in mind that, functionally, MISO and PJM do not own generation resources nor transmission lines, but coordinate the flow of electricity across their respective geographical footprints over the high-voltage transmission system. They are both responsible for maintaining a fair and competitive wholesale market for electricity, where buyers and sellers can have equal access to the grid. They, however, are not responsible for the distribution of electricity to end consumers, as this is handled

[4] Mark C. Christie, "It's Time to Reconsider Single-Clearing Price Mechanisms in U.S. Energy Markets," Energy Law Journal Vol. 41.1 at 15-16 (May 2, 2023), available at https://www.eba-net.org/wp-content/uploads/2023/05/3-Commr-Christie1-30-1.pdf.

by local distribution companies or utilities. They have extensive stakeholder committee processes for designing and revising complex market and reliability rules to ensure the price of wholesale electricity transparently reflects supply and demand fundamentals and that the supply of electricity meets demand every hour of the year. The various stakeholder groups include generation resource owners, independent power providers, power marketers, Independent Market Monitors, consumer advocacy groups, state regulators, utilities, and others.

PJM and MISO use the four markets described below to balance wholesale electricity supply and demand in every hour of every year. In these markets, load pays market prices and generation receives market prices. Thus, an important activity for a load-serving entity ("LSE") in an RTO is to financially balance and hedge load's market price risk with generation revenues.

Capacity Market

PJM's capacity market provides financial signals to generation owners to make investments in existing generation resources, build new generation resources, and retire generation resources that have reached the end of their useful life while meeting long-term reliability objectives. Each capacity auction, known as a Base Residual Auction ("BRA"), is held three years in advance of the delivery year, using BRA-specific peak load forecast and expected resource mix. Capacity owners economically bid into the capacity auction, taking into consideration, among other things, long-term fixed costs, operations and maintenance costs, fuel costs, environmental regulation compliance costs, and profitability margin. The bidders that clear the auction receive capacity revenue based on their location for every MW of capacity they commit to be available to supply energy when needed by PJM.

MISO's capacity market provides financial signals to market participants representing LSEs to make investments in existing generation resources, build new generation resources, and retire generation resources that have reached the end of their useful life while meeting resource adequacy objectives. Known as the Planning Resource Auction ("PRA"), it is a seasonal resource adequacy construct that was originally approved by FERC in August 2022 and implemented by MISO beginning the 2023/2024 Planning Year. The new seasonal approach was adopted to provide better clarity into the seasonal resource adequacy needs in each Local Resource Zone and match that more precisely to the seasonal performance attributes of generation resources. It is conducted in April every year to establish a separate auction price for each season (summer, fall, winter, and spring) of the next planning year, which begins June 1.

Day-Ahead Energy Market

Generation owners bid their electricity supply into the day-ahead market to meet forecast demand for the following day, providing enough time for resources that clear the market to make the necessary preparations to generate electricity. Individual generators are incentivized to minimize costs and maximize profitability. Among other costs, depending on the generation resource, bid considerations include the cost of fuel, fixed and variable operations and maintenance, natural gas pipeline transportation, transmission, emission allowances, and profit margin. Note that the Day-Ahead Energy Market is just a financial settlement because no actual load is served on a day-ahead basis; actual load is only served in real-time.

Real-Time Energy Market

Differences between forecast and actual demand during the operating day and as cleared in the Day-Ahead market are resolved in the real-time market by PJM. PJM remedies supply shortages by procuring the lowest cost supply from generators that are synchronized to the grid and able to immediately supply energy. Just as in the day-ahead market, generators are incentivized to minimize costs and maximize the profitability of their units when bidding into the real-time market. Essentially, load and generation pay or receive differences in the volumes that cleared the Day-Ahead market at the real-time LMP.

Ancillary Services Market

PJM and MISO have other specialized products and services that they procure to control the critical balance of supply and demand on their respective grids (such services are "ancillary services"). Ancillary services markets help "ensure that there are adequate electric reserves to maintain reliability and sufficient voltage to enable the grid to operate."[5]

Conclusion

The primary difference between the Companies' planning and operating as a standalone utility versus planning and operating in an RTO can be summarized in one word: control. As a standalone utility, the Companies are a one-stop shop for planning and operating their generation fleet. The Companies interact with regional energy markets to optimize energy costs and off-system sales benefits for customers, but they do not depend on regional markets. Customers pay the prudently incurred costs for the Companies' generation fleet, and the Commission has clear oversight and authority over those costs. Conversely, because RTOs have many stakeholders, as RTO members the Companies would have limited influence over the RTO's market tariffs and rules that may or may not be beneficial to the Companies' customers.

Section 3: Markets in Transition: Resource Adequacy Concerns in PJM and MISO as They Modify Market Rules to Accommodate Increasing Load and Adapt to a Changing Resource Mix

Growing concerns regarding resource adequacy in PJM and MISO are receiving increasing attention by the RTOs themselves, industry observers, and regulators. With different stakeholder groups and different existing market tariffs, MISO and PJM are taking somewhat different approaches to their market redesigns to attempt to address future capacity and energy reliability concerns. It is interesting to observe that one of the consequences of each RTO's efforts is that capacity prices have risen dramatically from recent levels. This is as should be expected because each RTO is trying to send a price signal via each capacity market that existing generation should consider remaining operational and that new generation (particularly non-intermittent technology) is urgently needed. However, because load always pays market price, the increase in prices has not been well received by many, despite the need for future generation capacity and energy.

[5] FERC, "Participation in Midcontinent Independent System Operator (MISO) Processes: An Introductory Guide to Participation in Midcontinent Independent System Operator (MISO) Processes," available at https://www.ferc.gov/participation-midcontinent-independent-system-operator-miso-processes (accessed Oct. 12, 2024).

PJM

Key events in recent months include:

- December 19, 2023 - FERC approves settlement to reduce non-performance charges incurred during Winter Storm Elliott by 32%.[6]
- January 30, 2024 - FERC approves Critical Issue Fast Path ("CIFP") capacity market reforms.[7]
- July 2024 - PJM's 2025/2026 Base Residual Auction held, implementing new FERC-approved CIFP market reforms.
    - RTO capacity prices increased to $269.92/MW-day for 2025/2026 compared to $28.92/MW-day for the 2024/2025 BRA.[8]

2025/2026 BRA Complaints

The dramatic increase in capacity prices from $28.92/MW-day to $269.92/MW-day in the recent 2025/2026 BRA produced a flurry of comments and complaints from stakeholders. This was the first auction to incorporate the CIFP market reforms approved by FERC in January 2024.[9] However, the exclusion of Reliability Must Run ("RMR") units from the capacity auction supply pool became a central theme in many stakeholder concerns. When a generation plant owner notifies PJM of their intent to retire generation capacity, Transmission Owners will conduct a Reliability Analysis. If that Reliability Analysis shows reliability violations, PJM may formally request that a plant continue operating under a Reliability Must Run agreement until the transmission system can be upgraded to allow the unit to retire without reliability violations.

- On September 27, 2024, several Public Interest Organizations ("PIOs") filed a complaint with FERC about the exclusion of RMR units from the capacity auction supply pool, arguing that doing so artificially inflated capacity prices and that the upcoming 2026/2027 BRA should be delayed until the RMR issues are resolved.[10]

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[6] *PJM Interconnection L.L.C.*, FERC Docket No. ER23-2975-000, Order (FERC Dec. 19, 2023), available at https://elibrary.ferc.gov/eLibrary/docketsheet?docket_number=er23-2975&sub_docket=all&dt_from=1960-01-01&dt_to=2023-12-31 (accessed Oct. 12, 2024).

[7] *PJM Interconnection L.L.C.*, FERC Docket No. ER24-99-000, Order (FERC Jan. 30, 2024), available at https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20240130-3113&optimized=false (accessed Oct. 12, 2024).

[8] PJM, "2025/2026 Base Residual Auction Results" at 5 (Aug. 21, 2024), available at: https://pjm.com/-/media/committees-groups/committees/mrc/2024/20240821/20240821-item-08---2025-2026-base-residual-auction---presentation.ashx (accessed Oct. 12, 2024).

[9] *PJM Interconnection L.L.C.*, FERC Docket No. ER24-99-000, Order (FERC Jan. 30, 2024), available at https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20240130-3113&optimized=false (accessed Oct. 12, 2024).

[10] *Sierra Club et al. v. PJM Interconnection, L.L.C.*, FERC Docket No. EL24-148-000, Complaint of Sierra Club, Natural Resources Defense Council, Sustainable FERC Project, and Union of Concerned Scientists (Sept. 27, 2024), available at: https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20240927-5073&optimized=false (accessed Oct. 12, 2024).

- Governmental consumer advocates for Maryland, Delaware, the District of Columbia, Illinois, New Jersey, and Ohio previously raised similar RMR agreement concerns to the PJM Board on August 30, 2024.[11]
- Monitoring Analytics' (PJM's Independent Market Monitor, "IMM") analysis of the 2025/2026 BRA found many flawed market rules. Though the IMM did not take issue with excluding RMR units from the supply stack per se, it concluded that doing so increased capacity prices by roughly $4.3 billion.[12]
- On September 27, 2024, the Organization of PJM States Inc. ("OPSI"), which represents state utility commissions, raised six market flaws that PJM urgently needed to address. Of the six, four high-priority items (the first of which was RMR units) needed resolution prior to the next capacity auction (2026/2027), currently slated for December 2024. They argued temporarily delaying the next auction to provide enough time to resolve them should also be considered.[13]
- On October 8, 2024, OPSI filed comments agreeing with the complaint filed at FERC by several PIOs on September 27, 2024, but added that they believed the cost of excluding RMR units from generation supply in the upcoming 2026/2027 BRA alone could cost rate payers as much as $14.5 billion.[14]
- PJM has defended the exclusion of RMR units from auction supply, stating that the ongoing trend of dispatchable generation retirement, slow new entry of dispatchable generation, long interconnection queues, and load growth necessitated a strong price signal to provide incentives for new dispatchable generation to be built.[15]

New Capacity Concerns

In addition to the discussions around the 2025/2026 auction results, serious concerns remain with respect to building new dispatchable generation. The 2025/2026 BRA procured only 110.3 MW of new

[11] David S. Lapp, People's Counsel, Maryland Office of People's Counsel; Ruth Ann Price, Acting Public Advocate, Delaware Division of the Public Advocate; Sandra Mattavous-Frye, People's Counsel, Office of the People's Counsel for the District of Columbia; Sarah Moskowitz, Executive Director, Citizens Utility Board of Illinois; Brian O. Lipman, Director, New Jersey Division of Rate Counsel; Maureen R. Willis, Consumers' Counsel, Office of the Ohio Consumers' Counsel, "Urgent Reforms to the PJM Capacity Market Regarding Reliability Must Run Units" (Aug. 30, 2024), available at: https://www.pjm.com/-/media/about-pjm/who-we-are/public-disclosures/2024/20240903-consumer-advocate-letter-on-capacity-markets.ashx (accessed Oct. 12, 2024).

[12] Monitoring Analytics, "Analysis of the 2025/2026 RPM Base Residual Auction, Part A" at 2 (Sept. 20, 2024), available at: https://www.monitoringanalytics.com/reports/Reports/2024/IMM_Analysis_of_the_20252026_RPM_Base_Residual_Auction_Part_A_20240920.pdf (accessed Oct. 12, 2024).

[13] OPSI, Letter (Sept. 27, 2024), available at: https://pjm.com/-/media/about-pjm/who-we-are/public-disclosures/2024/20240927-opsi-letter-re-results-of-the-2025-2026-bra.ashx (accessed Oct. 12, 2024).

[14] *Sierra Club et al. v. PJM Interconnection, L.L.C.*, FERC Docket No. EL24-148-000, Comments and Motion to Lodge of the Organization of PJM States, Inc. at 3 (Oct. 8, 2024), available at: https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20241008-5114&optimized=false (accessed Oct. 12, 2024).

[15] PJM, Letter at 1-2 (Sept. 19, 2024), available at; https://www.pjm.com/-/media/about-pjm/who-we-are/public-disclosures/2024/20240919-pjm-board-response-consumer-advocates-letter-re-urgent-reforms-pjm-capacity-market-re-reliability-must-run-units.ashx (accessed Oct. 12, 2024).

generation.[16] As of September 13, 2024, only 2,000 MW of new generation had been put into service in PJM in 2024, nearly all solar.[17] According to PJM Inside Lines, PJM's official company news source, "That pace is trending below the lowest annual number of megawatts of new generation added to the grid in PJM's history."[18] Similarly, a PJM official stated in a recent Markets and Reliability Committee meeting, "While PJM continues to execute against the [interconnection] transition plan, concerns are growing that the construction build-out from the volume of applications has not yet materialized."[19] Some 38,000 MW of new generation have cleared the PJM interconnection queue but have yet to be built due to various issues ranging from financing, supply chain, and siting and permitting challenges.[20]

Not only is it challenging to build new dispatchable generation capacity, but it remains challenging to permit and build the supporting pipeline infrastructure to support specifically dispatchable natural gas-fired generation.

On July 30, 2024, the United States Court of Appeals for the District of Columbia Circuit vacated and remanded FERC's authorization of Transcontinental Gas Pipe Line Company, LLC's ("Transco") 0.8 Bcf/day Regional Energy Access ("REA") pipeline expansion project serving customers in Pennsylvania, New Jersey, and Maryland.[21] Environmental groups challenged FERC's approval of the project, questioning the need for the expansion project as well as FERC's assessment of the project's greenhouse gas emissions.

According to PJM's recent comments to FERC supporting a temporary emergency certificate for the REA project, shutting down the REA project, which also would involve replacing existing system facilities supporting 1.2 Bcf/day of existing firm contracts, would threaten over 2 Bcf/day of gas supply and "could have potentially adverse impacts on PJM's ability to maintain reliability over the upcoming 2024-2025 winter and beyond…."[22] PJM further stated, "The electric reliability impacts from the approximately 22.6

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[16] PJM, "2025/2026 Base Residual Auction Report" at 7 (June 30, 2024) ("[T]he 2025/2026 BRA procured 110.3 MW of capacity from new generation and 753.8 MW from uprates to existing or planned generation. The quantity of new generation is down from the previous BRA where there was 328.5 MW of new generation."), available at: https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2025-2026/2025-2026-base-residual-auction-report.ashx (accessed Oct. 12, 2024).

[17] PJM, "Commercial Deployment of New Generation" at 8 (Sept. 25, 2024), available at: https://pjm.com/-/media/committees-groups/committees/mrc/2024/20240925/20240925-item-09---pjm-interconnection-queue---presentation.ashx (accessed Oct. 12, 2024).

[18] PJM Inside Lines, "As Interconnection Reform Sees Success, PJM Focuses on Post-Study Obstacles" (Sept. 25, 2024), available at: https://insidelines.pjm.com/as-interconnection-reform-sees-success-pjm-focuses-on-post-study-obstacles/ (accessed Oct. 12, 2024).

[19] Ethan Howland, "PJM says 'concerns are growing' after less than 2 GW added this year," Utility Dive (Sept. 26, 2024), available at: https://www.utilitydive.com/news/pjm-interconnection-capacity-online-construction-shortfall-vc-renewables/728145/ (accessed Oct. 12, 2024).

[20] PJM, "PJM Capacity Auction Procures Sufficient Resources To Meet RTO Reliability Requirement: Tighter Supply/Demand Balance Drives Higher Pricing Across the Region" (July 30, 2024), available at: https://www.pjm.com/-/media/about-pjm/newsroom/2024-releases/20240730-pjm-capacity-auction-procures-sufficient-resources-to-meet-rto-reliability-requirement.ashx (accessed Oct. 12, 2024).

[21] *N.J. Conservation Found. v. FERC*, 111 F.4th 42 (D.C. Cir. July 30, 2024), available at https://www.ferc.gov/media/new-jersey-conservation-foundation-et-al-v-ferc-2 (accessed Oct. 12, 2024).

[22] *Transcontinental Gas Pipe Line Company, LLC*, FERC Docket No. CP21-94-004, PJM Interconnection, L.L.C.'s Comments in Support of Transcontinental Gas Pipe Line Company, LLC for a Temporary Emergency Certificate at 2-3 (Oct. 7, 2024), available at https://www.pjm.com/-/media/documents/ferc/filings/2024/20241007-cp21-94-004.ashx (accessed Oct. 12, 2024).

percent reduction of Transco's delivery capacity into the region would … affect the availability of almost 10 percent of the electric capacity (unforced) needed to meet one of PJM's electric subregion's reliability requirement. Such loss of necessary fuel supply— without any opportunity to obtain replacements before the upcoming winter—could prove severely problematic."[23]

The IMM filed comments with FERC supporting Transco's application for a temporary certificate to allow it to continue operating the REA project and underlining the urgent need for the expansion project and additional pipeline capacity in general, citing its 2023 State of the Market report published on March 14, 2024.[24] The IMM estimated that between 1.9 Bcf/day and 4.8 Bcf/day of additional firm natural gas pipeline capacity would need to be built in PJM's footprint to replace retiring dispatchable base load generation over the coming years.[25] According to the IMM, this would facilitate system reliability while complementing the growing intermittent generation resource fleet.[26]

2026/2027 BRA

New build issues also loom for the 2026/2027 BRA because it is uncertain whether new generation can be built in time to participate in that delivery year. Additionally, the auction parameters used in the 2026/2027 BRA could result in capacity prices jumping again from $269.92/MW-day to as high as $695/MW-day.[27] The peak load forecast for the 2026/2027 delivery year is 2.2% higher than the 2025/2026 BRA, increasing the Reliability Requirement, reflecting the target reserve level to procure in the auction, by 1.9%.[28] The reference resource used in the 2026/2027 BRA is also changing to a natural gas combined cycle (CC) from a natural gas combustion turbine (CT) used in the 2025/2026 BRA.[29] This has significant capacity auction implications as the auction demand curve is developed in part by the Gross Cost of New Entry (CONE) of the reference resource, and the Gross CONE of a CC is much higher than that of a CT.[30]

[23] *Id.* at 3.
[24] *Transcontinental Gas Pipe Line Company, LLC*, FERC Docket No. CP21-94-004, Comments of the Independent Market Monitor for PJM at 2-3 (Oct. 8, 2024), available at: https://www.monitoringanalytics.com/filings/2024/IMM_Comments_Docket_No_CP21-94-004_20241008.pdf (accessed Oct. 12, 2024).
[25] Monitoring Analytics, LLC, "State of the Market Report for PJM, Volume 2, Section 7: Net Revenue" at 392 (Mar. 14, 2024), available at: https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2023/2023-som-pjm-sec7.pdf (accessed Oct. 12, 2024).
[26] *Transcontinental Gas Pipe Line Company, LLC*, FERC Docket No. CP21-94-004, Comments of the Independent Market Monitor for PJM at 3 (Oct. 8, 2024), available at: https://www.monitoringanalytics.com/filings/2024/IMM_Comments_Docket_No_CP21-94-004_20241008.pdf (accessed Oct. 12, 2024).
[27] "The Variable Resource Requirement (VRR) Curve defines the maximum price for a given level of Capacity Resource commitment relative to the applicable reliability requirement". The RTO Gross CONE of $695.83 / MW-Day is designated as point "A" and the highest price point on the 2026/2027 BRA VRR Curve, per the auction Planning Parameters. Thus, the price cap for the 2026/2027 BRA is $695.83 / MW-Day. https://www.pjm.com/-/media/documents/manuals/m18.ashx, pgs. 143, 144, 245.
[28] PJM Interconnection, LLC, "2026/2027 RPM Base Residual Auction Planning Period Parameters" at 1 (Aug. 26, 2024), available at https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2026-2027/2026-2027-planning-period-parameters-for-base-residual-auction-pdf.ashx (accessed Oct. 12, 2024).
[29] *Id.* at 5.
[30] *Id.*

Also, due to the complaint case opened at FERC concerning the 2025/2026 BRA discussed in the *2025/2026 BRA Complaints* section above, PJM announced on October 11, 2024, its intent to request a six-month delay in the 2026/2027 BRA to resolve the issues raised in the complaint before conducting the next auction.[31] PJM's statement suggested that further market reforms could be forthcoming:

> PJM will be supporting a delay of the PJM 2026/2027 Base Residual Auction for approximately six months. PJM does not take auction delay lightly, as the schedule for these auctions has already been compressed due to previous reform efforts. … Further, this delay will allow PJM to discuss with its Members, stakeholders and the PJM Board of Managers the possibility of other capacity market reforms that could occur through a Federal Power Act section 205 filing.[32]

This highlights the difficulty of attempting to analyze RTO membership quantitatively with any meaningful degree of certainty. Putting aside other significant uncertainties, the potential costs and benefits can shift considerably across capacity auctions as the rules of the auctions continue to change.

MISO

Key events in recent months include:

- March 28, 2024 - In an attempt to address the challenges presented by a changing resource mix with higher levels of intermittent generation, MISO filed tariff changes with FERC to implement a new capacity accreditation method to be in place for the 2028/2029 planning year.[33] This filing is still pending.
    - This new method "measures a resource's availability when reliability risk is the greatest."[34] It "first measures a resource's expected marginal contribution to reliability using Resource Class-level performance during the loss of load expectation ("LOLE") analysis."[35] It then uses historical resource-specific performance during reliability risk hours to arrive at the resource level capacity accreditation.[36]

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[31] PJM, "Stakeholder," available at https://go.pjm.com/webmail/678183/1180215207/b19206215435bd981f743fe618c0c1f4d66b0ccc7e4fb079703a5731fa709c91 (accessed Oct. 14, 2024); Ethan Howland, "PJM plans to delay upcoming capacity auction by six months," Utility Dive (Oct. 11, 2024), available at https://www.utilitydive.com/news/pjm-interconnection-delay-capacity-auction-ferc-opsi-sierra-club/729580/ (accessed Oct. 14, 2024).

[32] PJM, "Stakeholder," available at https://go.pjm.com/webmail/678183/1180215207/b19206215435bd981f743fe618c0c1f4d66b0ccc7e4fb079703a5731fa709c91 (accessed Oct. 14, 2024).

[33] MISO, "Fact Sheet: MISO filed accreditation approach with FERC as next phase of Resource Adequacy reform," available at https://cdn.misoenergy.org/Fact%20Sheet%20FERC%20Resource%20Accreditation%20Filing632372.pdf (accessed Oct. 12, 2024).

[34] *Midcontinent Independent System Operator, Inc.'s Filing to Reform MISO's Resource Accreditation Requirements*, FERC Docket No. ER24-1638-000, MISO Filing at 3 (Mar. 28, 2024), available at https://cdn.misoenergy.org/2024-03-28%20Docket%20No.%20ER24-1638-000632361.pdf (accessed Oct. 12, 2024).

[35] *Id.*

[36] *Id.* at 3-4.

- June 27, 2024 - FERC approves sloped demand curves to begin use in the 2025 Planning Resource Auction.[37]
    - Since the 2009/2010 Planning Year auction, MISO used a vertical demand curve that represented the Zonal Reserve Requirement.
    - Auction clearing prices were set where the supply curve intersected the vertical demand curve.
    - Under a vertical demand curve construct, supply beyond the Reserve Requirement did not clear the Auction.
    - MISO argues a downward sloping demand curve will better reflect the reliability value of incremental capacity.
- 2024/2025 Planning Reserve Auction (PRA) – Second seasonal capacity auction held in March 2024.
    - Compared to 2023/2024 (PRA):
        - Summer season capacity prices tripled to $30/MW-day.
        - Fall season capacity prices were steady at $15/MW-day.
        - Winter season capacity prices fell from $2.00/MW-day to $0.75/MW-day
        - Spring season capacity prices more than tripled to $34.10/MW-day.
        - Zone 5 fell short of its local clearing requirement in the fall and spring, capacity prices increased to $719.81/MW-day.[38]

2024/2025 Seasonal Capacity Auction

MISO is similarly challenged by the simultaneous retirement of dispatchable generation and the slow entry of new dispatchable generation to balance intermittent renewable generation. MISO held its second seasonal capacity auction, the 2024/2025 PRA, in March 2024 and highlighted these concerns. All zones except Zone 5 cleared with sufficient capacity, but capacity prices in summer and spring still increased significantly in all zones. Zone 5 failed to clear enough capacity to meet its local clearing requirement in the fall and spring by 872.4 MW and 196.4 MW, respectively. According to MISO's IMM, the shortage was "primarily attributable to the retirement of two large coal-fired resources at the end of the summer and long-duration planned outages in those shoulder seasons."[39] This resulted in capacity prices for those seasons to rise to the CONE of $719.81/MW-day.[40] The IMM went on to note that "winter prices dropped in the 2024–25 PRA to just $0.75 per MW-day, despite the high reliability risk from recent

[37] *Midcontinent Independent System Operator, Inc.*, Docket Nos. ER23-2977-000, ER23-2977-001, and ER23-2977-002, Order Accepting Tariff Revisions (FERC June 27, 2024), available at: https://elibrary.ferc.gov/eLibrary/filelist?accession_num=20240627-3010 (accessed Oct. 12, 2024).
[38] *See, e.g.,* MISO, "Planning Resource Auction: Results for Planning Year 2024-25" at 2 (Apr. 25, 2024, corrections posted Apr. 26, 2024), available at https://cdn.misoenergy.org/2024%20PRA%20Results%20Posting%2020240425632665.pdf (accessed Oct. 12, 2024).
[39] Potomac Economics, "2023 State of the Market Report for the MISO Electricity Markets" at 73 (June 2024), available at https://www.potomaceconomics.com/wp-content/uploads/2024/06/2023-MISO-SOM_Report_Body-Final.pdf (accessed Oct. 12, 2024).
[40] *Id.*

winter storms. This has largely been due to the growth in wind resources, even though having high levels of wind output during winter storms is not guaranteed."[41]

Overall, MISO noted concerning the 2024/2025 PRA results, "Capacity surplus across MISO eroded 30% in summer, primarily in the North/Central region,"[42] and, "Retirements, reduced imports and higher requirements are insufficiently offset by new capacity."[43] MISO went on to note, "Receding surplus, coupled with emerging risks due to fleet transition and new load additions, continue to pressure resource adequacy."[44]

Resource Adequacy Concerns

The North American Electric Reliability Corporation's ("NERC") 2023 Long-Term Reliability Assessment identified MISO identified as one of several grids that could see power supply shortfalls during normal peak operations.[45]

Later, in June 2024, an annual survey conducted by the Organization of MISO States ("OMS") and MISO indicated a growing capacity deficit beginning in the 2025/26 planning year.[46] OMS and MISO stated concerning the survey results, "Resource Adequacy risks could grow over time across all seasons, absent increased new capacity additions and actions to delay capacity retirements."[47]

Market Reforms

MISO and its IMM have stated capacity market reforms are urgently needed to address future resource adequacy concerns. The IMM has noted the vertical demand curve distorts economic signals and recommended a sloped demand curve instead:

> Unfortunately, MISO's capacity market has not been designed to send efficient price signals to spur the development of new dispatchable resources. Addressing this inefficiency requires MISO to correct the representation of demand by adopting a

[41] *Id.* at 74.
[42] MISO, "Planning Resource Auction Results for Planning Year 2024-25" at 2 (Apr. 25, 2024; corrections posted Apr. 26, 2024), available at https://cdn.misoenergy.org/2024%20PRA%20Results%20Posting%2020240425632665.pdf (accessed Oct. 12, 2024).
[43] *Id.*
[44] *Id.*
[45] NERC, "2023 Long-Term Reliability Assessment" at 6-7 (Dec. 2023), available at https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2023.pdf (accessed Oct. 12, 2024).
[46] MISO, "OMS-MISO survey results indicate tight resource capacity in the upcoming planning year" (June 20, 2024), available at https://www.misoenergy.org/meet-miso/media-center/2024/oms-miso-survey-results-indicate-tight-resource-capacity-in-the-upcoming-planning-year/ (accessed Oct. 12, 2024).
[47] OMS and MISO, "2024 OMS-MISO Survey Results" (June 20, 2024, corrections posted June 20, 2024), available at https://cdn.misoenergy.org/20240620%20OMS%20MISO%20Survey%20Results%20Workshop%20Presentation635585.pdf (accessed Oct. 12, 2024).

reliability-based demand curve (RBDC). MISO has proposed an RBDC that would have raised summer capacity prices by five-fold to more than $50 per MW-day.[48]

MISO is set to replace the vertical demand curve with a new sloped demand curve in the 2025 planning year auction following a FERC approval in June 2024. MISO also has pending market reform proposals before FERC to adopt a new capacity accreditation methodology. A future FERC filing is also planned to propose reforms that will address the lengthy interconnection queue.

Conclusion

From the Companies' perspective, the continuing market reforms and redesigns, combined with the recent volatility in capacity prices, make it challenging at best to evaluate the implications of RTO membership for its customers. The Companies continuously monitor developments in both MISO and PJM in order to stay current on their issues in order to inform possible future actions that could impact the Companies' operations, even outside of RTO membership.

Section 4: CIFP Market Reform Impacts to Accredited Capacity

MISO is in the midst of filing for its own marginal capacity accreditation reforms. Due to the uncertainty around the final form of these tariff changes, the Companies focused on PJM's CIFP reforms, which FERC approved in January 2024. One of PJM's major reforms was implementing a capacity accreditation methodology known as marginal Effective Load Carrying Capability ("ELCC") to all generation resources. This methodology determines a resource class's marginal contribution to system reliability during historical loss-of-load hours when system reliability was strained.[49] If reliability declines during those hours as more capacity of a particular resource class is added to the system, the marginal ELCC class rating will be lower, and vice versa. Additionally, historical performance of a resource class during reliability-strained hours will also factor into the capacity rating. In other words, if a resource class experienced high forced outage rates during those loss-of-load hours, its ELCC ratings would be negatively impacted. The high level of correlated outages in PJM during Winter Storm Elliott in December 2022 was one of the driving motivations for thermal resource capacity accreditation reforms in the CIFP.

The adoption of this new capacity accreditation methodology had a sizable impact on the results of the 2025/2026 BRA because it was a significant departure from the previous accreditation methodology. Previously, only intermittent renewable resources were subject to a class average ELCC rating, not a marginal rating, to calculate their accredited capacity. Accredited capacity for thermal resources was different as well and calculated in the following way:

Installed Capacity (ICAP) * (1-Equivalent Demand Forced Outage Rate or EFORd)

[48] Potomac Economics, "2023 State of the Market Report for the MISO Electricity Markets" at 73 (June 2024), available at https://www.potomaceconomics.com/wp-content/uploads/2024/06/2023-MISO-SOM_Report_Body-Final.pdf (accessed Oct. 12, 2024).

[49] *See, e.g.,* PJM, "ELCC Education" at 25 (Feb. 16, 2024), available at: https://pjm.com/-/media/committees-groups/committees/pc/2024/20240216-special/elcc-education.ashx (accessed Oct. 12, 2024).

PJM defines EFORd as, "A measure of the probability that generating unit will not be available due to a forced outages or forced deratings when there is a demand on the unit to generate."[50] For context, PJM's pool-wide EFORd for the 2024/2025 delivery year was 5.02%.[51] For example, a proxy natural gas combined cycle unit with an installed capacity of 691 MW would be accredited with 656 MW of unforced capacity ("UCAP"), or approximately 95% of the unit's installed capacity, using the previous accreditation methodology.

The new marginal ELCC class ratings implemented for the first time in the 2025/2026 BRA saw broad reductions of capacity accreditation across most resource classes relative to the pre-CIFP accreditation methodology used in the 2024/2025 BRA, as shown for select resource classes in the table below.

PJM Capacity Accreditation Ratings Changes			
Resource Class	**2024/2025 BRA[52]**	**2025/2026 BRA[53]**	**Change**
Onshore Wind	21%	35%	14%
Offshore Wind	47%	60%	13%
Fixed-Tilt Solar	33%	9%	-24%
Tracking Solar	50%	14%	-36%
4-hr Storage	92%	59%	-33%
6-hr Storage	100%	67%	-33%
8-hr Storage	100%	68%	-32%
Nuclear	95%*	95%	0%
Coal	95%*	84%	-11%
Gas Combined Cycle	95%*	79%	-16%
Gas Combustion Turbine	95%*	62%	-33%
Gas Combustion Turbine Dual Fuel	95%*	79%	-16%
*Assuming pool-wide EFORd for the 2024/2025 delivery year of 5.02%			

The capacity accreditation reductions for natural gas and coal units specifically have an outsized effect due to their proportion of total generation supply in PJM. They have represented, on average, 46% and 23%, respectively, of cleared capacity in the five BRAs prior to the 2025/2026 auction.[54]

With respect to the 2025/2026 auction results, the impact of the new ELCC accreditation methodology was substantial. PJM estimated that approximately 28,064 MW of additional supply would have been

[50] PJM Glossary, available at: https://www.pjm.com/Glossary#:~:text=Equivalent%20Demand%20Forced%20Outage%20Rate,on%20the%20unit%20to%20generate (accessed Oct. 16, 2024).

[51] PJM, "2025/2026 RPM Base Residual Auction Planning Period Parameters" at 2, available at: https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2025-2026/2025-2026-planning-period-parameters-for-base-residual-auction-pdf.ashx (accessed Oct. 12, 2024).

[52] PJM, "ELCC Class Ratings for 2024/2025," available at https://www.pjm.com/-/media/planning/res-adeq/elcc/elcc-class-ratings-for-2024-2025.ashx (accessed Oct. 12, 2024).

[53] PJM, "ELCC Class Ratings for the 2025/2026 Base Residual Auction," available at: https://www.pjm.com/-/media/planning/res-adeq/elcc/2025-26-bra-elcc-class-ratings.ashx (accessed Oct. 12, 2024).

[54] *See* PJM spreadsheet available at: https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/rpm-commitment-by-fuel-type-by-dy.ashx (accessed Oct. 16, 2024).

accredited in the 2025/2026 auction using the pre-CIFP capacity accreditation rules.[55] PJM's IMM estimated that the new ELCC approach increased total auction capacity costs by 49.1%, or $4.4 billion compared to the pre-CIFP accreditation methodology.[56] S&P Commodity Insights forecasts PJM's reserve margin will fall to as low as 6.8% in 2025 due to the capacity accreditation reforms and slow build-out of new generation.[57]

New RTO Capacity Accreditation Methods Significantly Impair any Capacity "Benefit" the Companies Might Have Realized

Past RTO studies have generally shown that the Companies could reduce their need for capacity by RTO membership due to the way in which RTOs calculate members' capacity responsibility relative to their load. Furthermore, the reduced capacity need often created a near-term revenue opportunity until the "excess" capacity (from an RTO perspective) was retired. However, the recent changes in market rules and capacity accreditation have flipped the analysis. Using the new tariff, the Companies would actually have less accredited capacity in PJM and MISO than they do as a standalone utility outside an RTO.

PJM

To demonstrate this, the Companies assessed the impact of the new PJM capacity accreditation methodology on two versions of their capacity position: a backward look at the most recent excess capacity analysis in the 2022 RTO Analysis and a forward-looking analysis including an updated load forecast and future resource mix.

The 2022 RTO Analysis showed favorability in the early years of the analysis for capacity sales in an environment with low capacity auction prices. This analysis used PJM's pre-CIFP capacity accreditation methodology, which provided higher UCAP accreditation and resulted in ample room for near-term capacity sales. But applying the 2026/2027 BRA capacity accreditation methodology and holding all else constant from the 2022 RTO analysis produces a very different result: UCAP levels fall markedly and the excess capacity available to sell disappears, as indicated in the table below for capacity year 2024/2025 as a proxy.

2024/2025 Capacity Year					
Pre-CIFP Accreditation (2022 RTO Study)			**Post-CIFP 2026/2027 BRA Accreditation**		
ICAP	**UCAP**	**Long/(Short)**	**ICAP**	**UCAP**	**Long/(Short)**
7,924 MW	7,154 MW	127 MW	7,924 MW	5,938 MW	(973 MW)

[55] PJM, "2025/2026 Base Residual Auction Results" at 26 (Aug. 21, 2024), available at: https://www.pjm.com/-/media/committees-groups/committees/mrc/2024/20240821/20240821-item-08---2025-2026-base-residual-auction---presentation.ashx (accessed Oct. 12, 2024).

[56] Monitoring Analytics, "Analysis of the 2025/2026 RPM Base Residual Auction, Part A" at 1 (Sept. 20, 2024), available at: https://www.monitoringanalytics.com/reports/Reports/2024/IMM_Analysis_of_the_20252026_RPM_Base_Residual_Auction_Part_A_20240920.pdf (accessed Oct. 12, 2024).

[57] https://www.capitaliq.spglobal.com/apisv3/spg-webplatform-core/news/article?id=83514230&KeyProductLinkType=58&utm_source=MIAlerts&utm_medium=scheduled-news&utm_campaign=Alert_Email

With respect to the forward assessment, the Companies' current load forecast was incorporated with the expected resource mix for 2028. In that year, the Companies assume their fleet installed capacity will be 8,256 MW, resulting in unforced capacity of 6,243 MW after applying PJM's post-CIFP accreditation ratings for the 2026/2027 BRA. Assuming all resources clear 100% of their capacity as seen in the 2025/2026 BRA, the UCAP position results in a capacity deficit of 787 MW relative to the 2028 peak load forecast of 7,030 MW. However, if the Companies were to consider the Fixed Resource Requirement ("FRR") Alternative, the unforced capacity obligation is estimated to be 6,585 MW, still leaving the Companies' UCAP position at a deficit of approximately 342 MW. This seemingly removes the FRR Alternative from consideration and would require the Companies to resolve any capacity deficit as a full Reliability Pricing Model ("RPM") market participant:

> Failure to commit the required resources would result in FRR Commitment Insufficiency Charge and ineligibility to continue the FRR Alternative. An FRR Capacity Plan is the long-term plan for the commitment of Capacity Resources to satisfy the daily zonal unforced capacity obligations of an LSE that has elected the FRR Alternative in an FRR Service Area….[58]

MISO

Given the uncertainty around the final form of MISO's marginal capacity accreditation reform proposal currently before FERC, MISO's 2024/2025 PRA Seasonal Accredited Capacity ("SAC") methodology was used to provide an indicative estimation of the Companies' capacity position in 2028 from MISO's perspective. The SAC methodology was approved by FERC on August 31, 2022. Under this market reform, class average capacity accreditation and ELCC continued to apply to solar and wind resources, respectively, but on a seasonal basis instead of an annual basis following MISO's shift to a seasonal capacity auction construct.[59] Additionally, thermal resources were subject to a new seasonal availability-based accreditation that sought to account more accurately for correlated outages.[60]

Applying these accreditation factors to the Companies' assumed 2028 generating fleet produces a UCAP of 6,565 MW. This results in a 465 MW annual deficit to the Companies' 2028 peak load forecast of 7,030 MW for the 2028 base year. The Companies' total obligation would also include a seasonal Reserve Margin and transmission losses on top of the peak demand.[61] The annual deficit value also does not contemplate the seasonal allocation of this deficit, which may have capacity procurement cost implications involved with remedying any shortfall to the seasonal Reserve Requirements.

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[58] PJM, "PJM Manual 18: PJM Capacity Market, Revision 59" at 215 (June 27, 2024), available at: https://www.pjm.com/-/media/documents/manuals/m18.ashx (accessed Oct. 16, 2024).

[59] MISO, "Planning Year 2024-2025: Wind and Solar Capacity Credit Report" (Mar. 2024), available at: https://cdn.misoenergy.org/Wind%20and%20Solar%20Capacity%20Credit%20Report%20PY%202024-2025632351.pdf (accessed Oct. 12, 2024).

[60] MISO, "Planning Year 2024-2025: Schedule 53 Class Averages" (Feb. 20, 2024), available at: https://cdn.misoenergy.org/PY%202024-2025%20Schedule%2053%20Class%20Average631181.pdf (accessed Oct. 12, 2024).

[61] MISO Resource Adequacy Subcommittee, "Planning Reserve Margin Requirement (PRMR) Allocation" at 4-5 (Oct. 9, 2024), available at: https://cdn.misoenergy.org/20241009%20RASC%20Item%2009%20PRMR%20Allocation651953.pdf (accessed Oct. 12, 2024).

<u>Section 5: PJM and MISO Express Reliability Concerns Regarding EPA's Recent Greenhouse Gas Rules</u>

One concern among many that electric utilities have expressed regarding the EPA's recent final Greenhouse Gas Rules is that the regulations will jeopardize grid reliability. PJM and MISO are so concerned that they joined with ERCOT and SPP to file a joint *Amicus* brief opposing the regulations. In it, the grid operators stated:

> The Final Rule unreasonably discounts that existing fossil power generators will need to decide whether to commit to installing untested technology or retire the generating unit years before the compliance deadline, given the economic cost and risk of compliance. As a result, decisions to retire units before the end of their useful life may be accelerated because of the Final Rule. The Joint ISOs/RTOs are concerned that premature retirements of generating units that provide critical reliability attributes can have significant, negative consequences on reliability.[62]

In support of their position, the grid operators made the follow arguments:

- "EPA did not adequately analyze or adopt proposed adjustments to the Rule to mitigate potential reliability impacts."[63]
  - "EPA has not adequately analyzed resource adequacy and reliability impacts in the Final Rule. Congress explicitly required consideration of resource adequacy and reliability impacts by providing in Section 111 that EPA consider 'energy requirements' in establishing its regulatory program under this section. 42 U.S.C. § 7411(a). By including that requirement, Congress clearly required EPA to do more than simply look at environmental issues in a vacuum without considering the larger energy requirements of the grid."[64]
- "EPA has not adequately considered resource adequacy and reliability impacts as part of its responsibility to consider "energy requirements" in conjunction with other proposed, pending, or existing regulations."[65]
  - "The impact of the Final Rule must also be considered in conjunction with the numerous other proposed, pending, or existing environmental regulations that impact grid reliability and resource adequacy—all of which are resulting in a decline in reserve margin and premature retirement of dispatchable 'baseload' resources (i.e., resources most currently in the form of coal and natural gas)."[66]
- "The Final Rule doesn't allow enough compliance flexibility to mitigate short-term grid emergencies."[67]

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[62] *West Virginia v. EPA*, D.C. Cir. Docket No. 24-1120, Brief of Midcontinent Independent System Operator, Inc., PJM Interconnection L.L.C., Southwest Power Pool, Inc., and Electric Reliability Council of Texas, Inc., as *Amici Curiae* in Support of Petitioners at 1 (Sept. 13, 2024), available at: https://www.pjm.com/-/media/documents/other-fed-state/20240913-24-1120.ashx (accessed Oct. 12, 2024).
[63] *Id.* at 10.
[64] *Id.*
[65] *Id.* at 17.
[66] *Id.* at 17-18.
[67] *Id.* at 24.

- "The Final Rule is too constraining to address reliability impacts resulting from the compliance strictures of the Rule by making the declaration of an EEA2 emergency a condition precedent to a unit owner availing itself of short-term compliance relief from the Rule's requirements."[68]

Regarding the viability of complying with the Greenhouse Gas Rules through carbon capture and sequestration ("CCS") technology, the grid operators stated: "None of EPA's projected timeframes reflect historical rates of adoption of CCS technology for electrical generation purposes, nor does EPA adequately consider the risks that the technologies will not mature in time for [electric generating unit] owners to deploy them."[69]

Section 6: Continued uncertainty and cost attributable to transmission expansion cost within the RTOs

Transmission planning and the allocation of transmission expansion cost are major activities for each RTO. Under current PJM policy, the cost of new high voltage transmission projects approved under its annual Regional Transmission Expansion Planning ("RTEP") process is allocated based on a combination of zonal load ratio share and flow-based calculations. These charges are recovered under Schedule 12 of the PJM tariff. In MISO, these type of high voltage projects are currently recovered via Schedule 26A of the MISO tariff, which are allocated to all withdrawals of energy from the market on a per-MWh basis. MISO's Board of Directors has already approved $10.3 billion in projects in "Tranche 1" and is expected to approve nearly $22 billion in additional projects in "Tranche 2" later this year. These projects alone could add hundreds of millions of dollars of cost to the Companies if they joined MISO.

Section 7: Continued uncertainty and reliability concerns in RTOs impair ability for modeling to inform Companies' RTO decision.

The current state of flux in MISO and PJM market designs, rules, and tariffs make it difficult to reliably and confidently model the financial implications of future RTO membership. At the time the 2024 RTO Membership Analysis was prepared, it was hoped that the RTOs would make significant progress in addressing their resource adequacy issues, thus enabling a comprehensive modelling exercise of the Companies' generation and load as members of both MISO and PJM. However, the market rules in each RTO continue to evolve, and when combined with the large uncertainty created by EPA's final Greenhouse Gas Rules, it is not practical to perform any meaningful modelling of MISO and PJM that would provide definitive insights to inform a decision to join either RTO.

Nonetheless, the Companies continue to monitor the market design activity of each RTO, the results of their capacity auctions, and their various reports regarding future resource adequacy. As the Companies have stated on numerous occasions, they are not opposed to RTO membership, but because it is likely a one-way option, exercising that option should only be done when it is clearly in the best long-term interest of customers.

[68] *Id.* at 26-27.
[69] *Id.* at 7.

Section 8: Update on SEEM Activities

The Southeast Energy Exchange Market ("SEEM") has been operational for almost two years, and it has been beneficial for the Companies' customers.[70] From January 2023 through June 2024, the Companies have sold 38,641 MWh at an average price of $44.20/MWh and purchased 51,045 MWh at an average price of $12.62/MWh. The Companies have been active SEEM participants, accounting for 7.5% of total SEEM transactions over this period. The resulting off-system sales margins and power purchase savings have benefited customers through the Companies' Fuel Adjustment Clause mechanisms. Indeed, the Companies estimate that customers have benefited by approximately $1,075,000 from sales and purchases in 2023 and the first two quarters of 2024, which is over *eight times* the estimated cost of SEEM participation during that period ($127,000).[71]

The Companies seek to participate in every 15-minute market and have a systematic process that determines the Companies' incremental costs and volume available for sale and the decremental costs and volumes for purchase. This process is similar to that used for making "over-the counter" off-system sales and purchases from MISO, PJM, and TVA. See Appendix 8 for a detailed description of the Companies' SEEM bid and offer process.

Finally, it is important to note that while SEEM continues to operate, the U.S. Court of Appeals for the District of Columbia ("D.C. Circuit") remanded orders approving SEEM back to FERC. Only FERC can change open access transmission tariff rates related to SEEM's operations. Thus, the D.C. Circuit's decision did not immediately affect SEEM's operations. The intervening entities who challenged SEEM have filed an additional appeal based on the passage of time on remand without an order from FERC. At present, the parties are actively litigating at the D.C. Circuit but have also briefed the issues associated with the SEEM remand proceedings at FERC. Due to the status of the ongoing litigation on SEEM in both venues, it is not possible to identify the potential impacts to the ongoing operation of SEEM. However, the Companies will continue to monitor SEEM developments and seek to use their SEEM membership to customers' benefit whenever and as long as possible.

Section 9: De-pancaking Litigation Update

The Companies currently provide merger mitigation de-pancaking ("MMD") credits to certain entities importing from MISO under Rate Schedule 525 currently on file with FERC. The Companies had been crediting MISO transmission charges for imports from MISO for certain customers pursuant to a FERC filed agreement, LG&E/KU FERC First Revised Rate Schedule No. 402, relating to the Companies' 1998 merger and 2006 exit from MISO.[72] The Companies received FERC approval to eliminate MMD subject to the implementation of a transition mechanism for certain power supply arrangements.[73] A decision from the D.C. Circuit Court of Appeals largely affirmed FERC's analysis in the 2019 Removal Order, but it ultimately

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[70] See [Southeast Energy Exchange Market (southeastenergymarket.com)](southeastenergymarket.com) for more information on SEEM and Appendix 7 for August 2024 audit report.

[71] See Appendix 7 for the most recent SEEM Independent Market Monitor monthly report, which provides various SEEM market data.

[72] *See E.ON U.S., LLC, et al.*, FERC Docket No. ER06-1279-000.

[73] *Louisville Gas & Elec. Co.*, 166 FERC ¶ 61,206 ("2019 Removal Order"), *order on reh'g & clarification*, 168 FERC ¶ 61,152 (2019), *aff'd sub nom. Ky. Mun. Energy Agency v. FERC*, 45 F.4th 162 (D.C. Cir. 2022) ("KYMEA").

vacated the decision and remanded the matter back to FERC.[74] In its order on remand, FERC reversed its decision allowing for the termination of MMD and required the Companies to reinstitute the MMD provisions of Rate Schedule 402.[75] The Companies complied with this directive by filing Rate Schedule 525. The Companies appealed FERC's orders on remand and the compliance filing to the D.C. Circuit Court of Appeals. Due to the status of the ongoing litigation on MMD, it is not possible to identify how the Companies' MMD obligation might be impacted by RTO membership or to quantify such hypothetical impact. The Companies will revisit the potential impact of and to MMD in performing the next RTO analysis.

Section 10: Conclusion

The Companies continue to be open to possible future RTO membership. The Companies are actively monitoring market developments in MISO and PJM to help inform their analysis and future decisions. However, given the uncertainty in RTO market design, resource adequacy, and EPA's Greenhouse Gas Rules, it is clear that RTO membership at this time would introduce significant unquantifiable risks for the Companies' customers without a clear quantification of possible benefits.

[74] The D.C. Circuit stated, "In short, the Commission's conclusion that sufficient competition would continue after [MMD] was based on substantial evidence from which it drew sensible inferences employing its expert knowledge of electricity markets. That is the 'kind of reasonable agency prediction to which we ordinarily defer.'" However, the D.C. Circuit faulted FERC for failing to evaluate the impact of the removal of MMD on rates and vacated the decision. *KYMEA,* 45 F.4th at 177.

[75] *Louisville Gas & Elec. Co.*, 183 FERC ¶ 61,122 (2023).

APPENDICES

Appendix 1 – PJM Regional Transmission Expansion Plan, March 7, 2024

Appendix 2 - Energy Transition in PJM: Flexibility for the Future, June 24, 2024

Appendix 3 – MISO's Response to the Reliability Imperative, February 2024

Appendix 4 – Attributes Roadmap – MISO, December 2023

Appendix 5 – 2024 OMS-MISO Survey Results, June 20, 2024

Appendix 6 – Queued Up: 2024 Edition - Lawrence Berkeley National Laboratory, April 2024

Appendix 7 - SEEM Audit Report prepared by Potomac Economics, August 2024

Appendix 8 - Companies' SEEM Bid/Offer Process, July 2023

Appendix 9 – DC Circuit Court of Appeals Case No. 24-1120 – PJM, MISO, SPP, ERCOT Amicus Curiae Brief

Appendix 10 - It's Time to Reconsider Single-Clearing Price Mechanisms in U.S. Energy Markets - Energy Law Review, May 2, 2023

Appendix 11 - Resource Accreditation White Paper V 2.1 – MISO, March 2024

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Natural Gas Fuel Security Analysis

PPL companies

Generation Planning & Analysis
October 2024

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1 Background

On December 23, 2022, LG&E and KU Energy ("the Companies") curtailed firm customer load for the first time, due primarily to low gas pressure on the Texas Gas Transmission ("TGT") pipeline during Winter Storm Elliott ("WS Elliott"). As a result of this event, TGT installed additional weatherization equipment and altered its operating procedures to reduce the likelihood of low-pressure issues during future extreme weather events. Also, the Companies have implemented software upgrades on the Trimble County combustion turbines ("CTs") and will have gas compression for the new natural gas combined cycle unit ("NGCC") at Mill Creek ("Mill Creek 5") that will enable these units to operate if the same low-pressure event were to occur again despite the changes that TGT has implemented.

Fuel assurance was a key point of emphasis in the 2022 CPCN proceedings. After Mill Creek 5 is commissioned, the TGT pipeline system will deliver primary fuel to nine gas-fired units (Mill Creek 5, Cane Run 7, Paddy's Run 13, and Trimble County 5-10) as well as startup and stabilization fuel to two coal-fired units (Trimble County 1-2).[1] It will also be able to deliver backup startup and stabilization fuel for two additional coal-fired units, Mill Creek 3-4. In addition, the Companies have seven CTs at their E.W. Brown site ("Brown") that are currently connected to two interstate pipelines – Texas Eastern Transmission ("TETCO") and Tennessee Gas Pipeline ("TGP") – and could add an additional NGCC at Brown ("Brown 12") as soon as 2030.[2]

The Companies have compression at the Cane Run and Brown sites, and they plan to install compression at Mill Creek to support operation of Mill Creek 5. In addition, four of the seven CTs at Brown have fuel oil backup. The purpose of this study is to assess whether any alternatives – such as additional compression, on-site fuel oil or liquefied natural gas ("LNG") backup, or underground natural gas storage – could cost-effectively improve the reliability of natural gas fuel security at TGT sites (Trimble County, Cane Run, Paddy's Run, Mill Creek) and the TETCO/TGP site (Brown). Broader alternatives, such as new battery storage or demand-side management resources, are not considered here but will be considered as part of portfolio-level analysis in an Integrated Resource Plan ("IRP").

[1] For purposes of this study, the Companies are excluding the small-frame CT at Paddy's Run ("Paddy's Run 12"). While it is currently served by TGT, its fuel consumption is small given its relative size (28 MW gross winter capacity), and the Companies anticipate the unit will be retired in the upcoming years as the need for major maintenance renders the unit uneconomic to repair.

[2] *Electronic Joint Application of Kentucky Utilities Company and Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity and Site Compatibility Certificates and Approval of a Demand Side Management Plan and Approval of Fossil Fuel-Fired Generation Unit Retirements*, Case No. 2022-00402, Order at 137 (Ky. PSC Nov. 6, 2023) ("[C]onstruction of Brown 12 should be deferred with the construction beginning on a date that provides for an in-service date of 2030.").

2 Potential Natural Gas Reliability Risks

Natural gas pipeline risks largely fall into one of two categories – transportation risks and supply risks.

2.1 Transportation

In a transportation event, natural gas supply is available, but pipeline infrastructure is unable to deliver it to a given receipt point within contractual specifications, including adequate pressure. Therefore, the low gas pressure event during WS Elliott is an example of a transportation event. The Companies believe that the winterization and operational improvements made by TGT have mitigated these risks on their pipeline, making the probability of a recurrence of such an event very low.[3]

Another potential transportation event would be pipeline maintenance for the sections of the pipelines owned by the Companies, whether planned or unplanned. Pipeline maintenance may limit available gas to specific sites, and in some circumstances it may cut off all gas delivery to a site.[4] In most circumstances, planned maintenance can be coordinated with unit outages, and on-site backup fuel sources for certain units can mitigate the amount of capacity that would be unavailable at a specific site during a pipeline maintenance outage.

2.2 Supply

In a supply event, natural gas production is curtailed at its source, making gas unavailable to pressurize or transport. Production curtailments can occur due to wellhead freeze-offs during winter storms (e.g., during WS Uri and in the northeast during WS Elliott) and due to hurricane activity in the Gulf of Mexico in warmer weather.[5] While natural gas production can be curtailed due to inclement weather, storage supports reliability during such events. Natural gas is injected into storage during lower demand periods in the warmer summer months and withdrawn from storage to accommodate higher demand during colder winter months. Interstate pipelines maintain storage fields across their geographic footprints, allowing for more direct access during a weather event. Thus, the industry plans for the possibility of production curtailments in its routine winter operations of natural gas pipelines.[6] The Companies procure natural gas commodity purchases on a firm basis (as opposed to an interruptible basis), which mitigates much of the risk of supply curtailments; however, the risk of curtailment is not zero, and the Companies could further mitigate this risk through localized (i.e., in-state) underground natural gas storage or on-site backup fuel such as fuel oil or LNG.

To reiterate, the expected probability of any fuel disruption – via transportation or via supply – is very low in any given year. In fact, the Companies have only experienced one such event in over 20 years of service with TGT and only one such event with TETCO/TGP, the latter of which the Companies were able to

[3] TGT did not experience issues during similar cold weather events, including the Polar Vortex events in January 2014 and February 2015, Winter Storm Uri in February 2022, and most notably, Winter Storm Heather in January 2024 (after winterization and operational changes were implemented by TGT).

[4] Current gas regulations require the Companies to perform line pigging and inspection of their new pipelines after ten years of service, and every seven years thereafter. Repairs for anomalies identified in these inspections must begin within as little as five days and repairs may render gas service to be unavailable for days or weeks depending upon the length of pipeline and the scope of repairs.

[5] Hurricane activity is not as significant of a production driver since the advent of shale gas, but this risk still affects natural gas production.

[6] Natural gas forward markets are largely driven by the quantity of natural gas in storage compared to historical norms, and potential shortfalls create price signals that incentivize incremental production.

mitigate with existing infrastructure.[7] Because such disruptions are rare and the cost of risk mitigation measures (e.g., fuel oil backup) can be high, prudence requires ensuring that the risk-weighted cost of interruptions is greater than the cost of a mitigation measure before investing in that measure. Furthermore, the Companies note that the fuel security risk is not all or nothing (i.e., fuel disruptions may partially but not fully reduce fuel availability, as experienced with partial curtailments with TGT during WS Elliott), and 100% redundancies are not required to resolve these unlikely scenarios.

[7] The Companies experienced some supply cuts by marketers on TGT during Winter Storm Uri that were later deemed improper, and the Companies were awarded liquidated damages due to the firm nature of the underlying natural gas contracts. Replacement natural gas was available and purchased by the Companies on the open market. The Companies also opted to displace some gas-fired generation with additional coal-fired generation given fuel price spreads during the event.

3 Evaluation of Alternatives

3.1 TGT System

The TGT pipeline system currently delivers primary fuel to eight gas-fired units (Cane Run 7, Paddy's Run 13, and Trimble County 5-10) and startup and stabilization fuel to two coal-fired units (Trimble County 1-2). By 2027, the Companies will expand TGT deliveries to include primary fuel for Mill Creek 5 and will have the option to utilize TGT for startup and stabilization fuel for Mill Creek 3-4.

The Companies procure a portfolio of firm gas transportation services from TGT that provides firm hourly and daily scheduling and delivery priority, as well as pipeline imbalance services that can act as storage. Table 1 provides a summary of current and expected firm gas transportation contract volumes.

Table 1: Existing and Future Firm Gas Transportation Services on TGT[8]

Service	Months	Primary Delivery Point[9]	Daily Volume (MMBtu)	Hourly Rights (MMBtu)
Summer No Notice	Apr-Oct	Trimble County	100,000	1/16 of daily volume
Enhanced Short Term Firm	Apr-Oct	Trimble County	50,000	1/16 of daily volume
Winter No Notice	Dec-Feb	Trimble County	229,000	1/16 of daily volume
Winter No Notice	Mar & Nov	Trimble County	114,500	1/16 of daily volume
Summer No Notice	Apr-Oct	Cane Run	72,000	1/16 of daily volume
Short Term Firm	Apr-Oct	Cane Run	44,000	1/24 of daily volume
Winter No Notice	Nov-Mar	Cane Run	107,000	1/16 of daily volume
Firm Transport	Jan-Dec	Mill Creek	110,000	1/24 of daily volume

Potential alternatives considered to enhance fuel security for the TGT system include compression, fuel oil backup, LNG backup, and underground natural gas storage.

3.1.1 Compression

TGT has contractual minimum delivery pressures of 550 psig for Cane Run and 530 psig for Trimble County, but typically operates at levels over 600 psig.[10] The Companies have on-site compression at Cane Run that is designed to compress gas at incoming compressor suction pressures as low as 460 psig to an outlet pressure of 595 psig to ensure pipeline pressure sufficient for turbine operation.[11] The compression at Cane Run was designed using the historical operating characteristics of TGT at the time of Cane Run 7's development but was not sufficient to allow full load operation during the events of WS Elliott where the

[8] See the Texas Gas Transmission tariff for descriptions of these services (DisplayPostingDocumentPage.aspx (bwpipelines.com)).

[9] Deliveries may be redirected to other delivery points (e.g., from Cane Run to Trimble County) in accordance with transport agreement provisions. The transport agreements also allow volumes for all three specific delivery points to be reallocated during the renewal process for the Trimble County and Cane Run agreements in 2028.

[10] While these contractual minimum delivery pressures are in the agreements, TGT is not required to maintain these pressures if they have operational issues, as observed during WS Elliott.

[11] While Paddy's Run is served behind the same gas meter as Cane Run, Cane Run's compression does not provide any benefit to the Paddy's Run station as the compression is located several miles downstream of the pipeline branch connection which feeds Paddy's Run. However, as shown in Table 2, Paddy's Run 13 is capable of full load operation at pressures of 432 psig, lower than the 489 psig required for full load operation of Cane Run 7.

pressure on the TGT line takeoff point dropped to approximately 455 psig, and the suction of the compressor fell as low as 387 psig during the event. The Companies are designing compression at Mill Creek to be able to maintain full load at pressures observed on TGT during WS Elliott.

The Companies do not have compression at the Trimble County station; however, the aforementioned software upgrades for the Trimble County CTs will allow full load operation once the units are started at pressures seen on TGT during WS Elliott, even without compression. Table 2 provides a summary of minimum delivery pressures and fuel flows (measured in millions of standard cubic feet, or MMSCF, per day) needed to maintain full load on gas-fired units and startup for coal-fired units.[12]

Table 2: Gas Pressures and Volumes Needed on TGT for Full Load Operation

Unit	Minimum Delivery Pressure (psig)[13]	Total Flow Requirements (MMSCF per day)[14]
Cane Run 7	489	116.9
Paddy's Run 13	432	41.3
Mill Creek 5	430	98.0
Trimble County 5-10	423	43.2 per CT
Trimble County 1	100	10.8
Trimble County 2	100	14.0

The Companies performed a preliminary assessment of compression options at the Cane Run and Trimble County stations and expect the costs of implementing compression would range between $30-$40 million for each site. While any specific event will have a unique set of pipeline conditions, generally, the TGT pipeline system is an interconnected system and if it were to begin experiencing pressure issues, those issues would likely cause restrictions for Cane Run 7 first, implying that incremental compression would be a more logical fit at Cane Run before Trimble County. However, when the TGT pipeline system is running at a deficit like it was during WS Elliott – that is, the number of molecules being added to the system is less than that being consumed due to the unavailability of the TGT compressor station – adding compression at one station would accelerate the consumption of line pack and run the risk of creating pressure drawdowns at other facilities. In short, the Companies' existing and planned compression assets are sufficient to meet expected historical operational scenarios, but in the unlikely scenario of a repeated event like that experienced during WS Elliott, it is uncertain whether additional investment in compression at Cane Run or Trimble County would materially improve reliability for the Companies' TGT-connected system as a whole.

[12] Regarding startup and stabilization gas for coal units, the majority of gas needs are driven by unit startup, and to a lesser extent, managing operational changes like accommodating a coal mill swap. Other stabilization gas needs are typically low.

[13] Minimum delivery pressures reflect gas compression being online at Mill Creek and Cane Run and reflect installation of software upgrades for Trimble County CTs.

[14] Fuel flows are typically reflected in volumetric measurements, such as MMSCF, whereas firm gas transportation volumes are reflected in energy measurements, such as MMBtu. Conversion factors vary depending upon the heat content of natural gas, but according to the EIA, the average heat content of natural gas delivered to end-use sectors in 2023 averaged about 1,038 Btu per cubic foot. Therefore, 1,000 MMSCF is approximately equal to 1.038 MMBtu. See https://www.eia.gov/tools/faqs/faq.php?id=45&t=8.

3.1.2 Fuel Oil Backup

The Companies do not have fuel oil backup on any of the units served by the TGT pipeline. Among the gas-fired units on the TGT pipeline, the best candidates for adding fuel oil backup are the Trimble County 5-10 CTs. GE 7FA turbines (make and model of the Trimble County CTs) are commonly operated on fuel oil and have conversion kits and parts readily available. Also, as shown in Table 3, the Trimble County site has the highest concentration of MW served by a single TGT delivery point, so adding fuel oil provides a benefit of having some MW available during planned or unplanned maintenance to pipeline sections owned by the Companies. In addition, the Trimble County delivery point is further away from the TGT compressor stations at Slaughters and Midland and is served by two pipes compared to three pipes feeding Mill Creek. Thus, adding fuel oil backup at the Trimble County station would provide marginally higher benefit of risk mitigation.

Table 3: Gross Winter MW By TGT Delivery Point

Delivery Point	Gas Units Served (Primary Fuel)	Coal Units Served (Startup and Stabilization)	Gross Winter MW
Trimble County	Trimble County 5-10	Trimble County 1-2[15]	2,065[16]
Cane Run	Cane Run 7, Paddy's Run 13	N/A	949[17]
Mill Creek	Mill Creek 5	Mill Creek 3-4	679[18]

The next best candidate for fuel oil backup would be Paddy's Run 13, though the cost of fuel oil retrofitting is expected to be more expensive for Paddy's Run 13 than for a Trimble County CT. Cane Run 7 is not considered a good candidate for fuel oil given a lack of industry experience with fuel oil performance on this particular F-class machine design and the risks of renegotiating Cane Run 7's Long Term Program Contract with Siemens.[19] Mill Creek 5 is not considered a good candidate for fuel oil given a lack of operational data and post-operation component analysis related to fuel oil operation for H-class machines. In addition, the NGCCs were not optimized to operate on fuel oil; data from GE Vernova suggests that Mill Creek 5 would experience a significant loss of available capacity (or "derate") of approximately 92 MW when operating on fuel oil, whereas Trimble County CTs and Paddy's Run 13 are not expected to experience any such derate. Fuel oil installation at any site would require environmental permitting modifications. The costs of fuel oil backup are summarized in Table 4.

[15] Trimble County 1-2 startup and stabilization was originally supported using fuel oil but was converted to natural gas in 2017 due to the expense of fuel oil and lack of a reliable delivery method for the volume of fuel oil needed for a unit start.

[16] Reflects the Companies' 75% ownership of Trimble County 1-2.

[17] Reflects an expected increase in Cane Run 7's Network Integration Transmission Service ("NITS") limit from 691 MW to 775 MW.

[18] Reflects Mill Creek 5 capacity only. The Companies expect to maintain startup and stabilization for Mill Creek 3-4 with the LG&E local distribution company as well as add the option to use TGT to preserve diversity in fuel supply.

[19] While Trimble County CTs are also F-class machines, those models have a better track record performing on fuel oil and GE Vernova has been willing to share lessons learned regarding fuel oil operations of their F-class units.

Table 4: Fuel Oil Backup Capital and Operating Cost Assumptions

Cost Item	Mill Creek 5	Trimble County CT (Per CT)	Paddy's Run 13
Capital (Tanks, Infrastructure) for 48 Hours of Inventory	$25,312,000	$12,000,000[20]	$22,000,000
Initial Fuel Oil Inventory[21]	$4,300,000	$2,150,000	$2,150,000
Effect of Testing/Operations on Long Term Services Agreement	$100,000/Yr	N/A	N/A
Tank/Turbine Maintenance & Inspections	$250,000/Yr	$260,000/Yr	$260,000/Yr
Annual Fuel Oil for Testing	$3,000,000-$4,000,000/Yr	$200,000-$250,000/Yr	$200,000-$250,000/Yr
Derate Associated with Fuel Oil Operation (Gross MW)	92 MW	0 MW	0 MW
Available Capacity at Full Load, Extreme Winter Conditions (Gross MW)	587 MW	180 MW	176 MW

Regarding firm gas transportation, installing fuel oil backup at Trimble County may allow the Companies to redeploy some firm gas transportation contract volumes from Trimble County to other stations. This would potentially be valuable during December through February, when the Companies contract for additional firm gas transportation volumes to allow for 24-hour operation of the Trimble County CTs during extreme weather.

3.1.3 LNG Backup

The Companies do not have LNG backup on any of the units served by the TGT pipeline. The advantage of LNG relative to fuel oil backup is that there is no change in the underlying fuel, so the risks of limited performance data and unit derates for NGCCs on fuel oil are not applicable. If the Companies were to install LNG at one of the TGT delivery points, Cane Run would be the most likely candidate, given its central geographic location among the Companies' delivery points on the TGT pipeline, and, as stated in section 3.1.1, Cane Run 7 would likely be the first unit affected during a future pressure drop event like that experienced during WS Elliott. Preliminary cost estimates for 48 to 72 hours of LNG storage at the Cane Run station range are approximately $225 million. The scale of these costs relative to fuel oil backup for Trimble County CTs is considered cost prohibitive, but this technology is evolving quickly and has experienced significant cost reductions over the past five years. The Companies will continue to monitor LNG as an alternative and will evaluate in further detail if LNG becomes more cost competitive.

[20] Trimble County 8 and 10 have fast-start capability (i.e., can be brought to 100 MW from an offline state within 15 minutes, compared to 30 minutes for a normal CT start) and would require additional capital of approximately $1 million for each unit to retain this option alongside dual fuel capability.

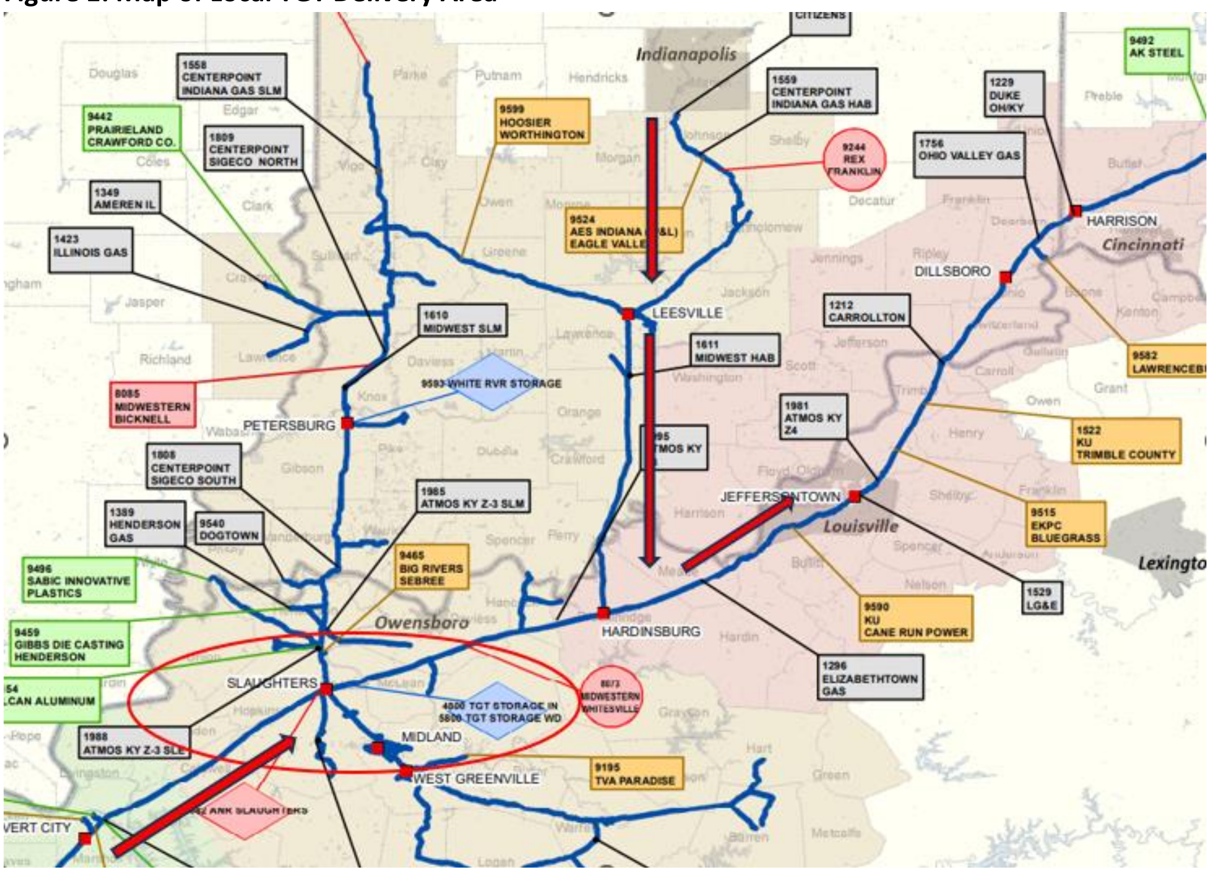
[21] Values reflect costs associated with 48 hours of inventory, approximately 1.3 million gallons for Mill Creek 5 and 0.65 million gallons per Trimble County CT or for Paddy's Run 13. Fully replenishing 1.3 million gallons of fuel oil inventory would require approximately 173 fuel oil tanker trucks and would take several weeks to complete, depending upon the availability of trucks and road conditions. Barge deliveries may be viable for larger storage installations (i.e., over three million gallons) but were not considered for this analysis.

3.1.4 Underground Natural Gas Storage

Underground natural gas storage would serve two primary purposes: price arbitrage (from injecting natural gas during low price periods and withdrawing natural gas during high price periods) and shoring up reliability during a disruption in supply. While price arbitrage isn't necessarily location-dependent (aside from potential zonal price differences), the ability to shore up supply during a disruption is highly dependent upon whether the storage is within the available supply paths. As such, the Companies' preferred TGT storage locations would be those nearest the Companies' delivery points.

In February 2024, TGT offered 5.79 Bcf of storage in an open season from an expansion at the Midland Storage facility near Slaughters on the mainline of the pipeline in western Kentucky. Figure 1 shows the location of the storage facility (within the red oval) and typical gas delivery paths (represented by red arrows).[22] Withdrawal rights from this storage asset were for 113 days at up to approximately 51,000 MMBtu per day, with the ability to inject natural gas for 252 days at up to approximately 75,000 MMBtu per day. The full fixed cost of this storage was approximately $3.1 million per year, with an additional variable cost of approximately $0.3 million based on expected injection and withdrawal volumes.

Figure 1: Map of Local TGT Delivery Area



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22 The Companies' delivery points are 9590 KU Cane Run Power and 1522 KU Trimble County. The Mill Creek delivery point will be located southwest of Cane Run within Jefferson County. The proposed storage would not have addressed the transportation issues experienced during WS Elliott because it is located on the other side of the compressor station at Slaughters.

The Companies analyzed the value of historical injection/withdrawal price spreads in both the spot and forward markets to assess the price arbitrage value of this storage asset. Spot market spreads from 2019 to 2023 provided a margin of approximately $0.6 million per year, which was not sufficient to cover the fixed demand or variable costs of the storage (i.e., evaluating spot pricing only, the storage did not pay for itself). An additional analysis reviewed actual prior forward purchases over the same timeframe and assumed a reduction in fixed winter purchases offset by incremental summer purchases at summer market prices. The average annual net savings of $2.6 million was less than the annual demand and variable costs, so again, the storage did not pay for itself over this historical period.

Because the Companies could not demonstrate that the available underground natural gas storage would result in a net reduction in fuel procurement costs for customers, the Companies did not place a bid on the storage during the open season.[23] However, it is possible that injections and withdrawals could be better optimized in a way to increase the probability of gas storage resulting in a net reduction in costs for customers. Regarding the reliability benefit, the Companies procure all supply on a firm basis, so any supply disruptions would be considered low risk, but having in-state gas storage would reduce the risk of any curtailments in such a scenario.

3.2 TETCO/TGP Systems

The Brown site currently has seven simple-cycle CTs fueled by an eleven-mile gas pipeline owned and operated by the Companies that connects to two interstate pipeline providers, TETCO and TGP. Four of these seven CTs have fuel oil backup. The Companies have the capability to manually switch between TETCO and TGP, but predominantly use TETCO given higher operating pressures. Broadly, the access to two interstate pipelines at Brown provides an additional layer of protection that reduces fuel security risk.

As previously noted, the Companies are planning to construct Brown 12 as early as 2030. This additional generating unit would result in a significant increase in fuel flows on the natural gas pipeline that feeds the Brown station. The Companies do not currently procure firm gas transportation on either TETCO or TGP but are able to secure firm deliveries through purchases on the spot market from suppliers who hold firm transportation. However, the Companies would expect to procure firm gas transportation to support Brown 12 given more consistent flows and the plan to purchase forward gas contracts to mitigate gas price volatility.

Potential alternatives considered to enhance fuel security for the Brown station include installing additional compression, adding fuel oil capabilities to additional units, and improving fuel controls to automate interstate pipeline switching and allow gas procurement from both interstate pipelines simultaneously. The Companies are not considering LNG at Brown at this time but may consider adding it in the future if it becomes more cost competitive (see section 3.1.3 regarding LNG cost estimates at Cane Run). Similarly, the Companies are not considering pipeline storage on TETCO or TGP at this time but will consider adding it in the future using evaluation criteria comparable to that used for TGT storage.

[23] The winning bid was for 108 years and for the full volume, so any bid from the Companies for this product would have been insufficient to procure the available storage.

3.2.1 Compression

TETCO and TGP have minimum delivery pressures of 550 psig, but typically operate at levels above 600 psig. The minimum delivery pressures for the Brown CTs and the future NGCC Brown 12 are summarized in Table 5.

Table 5: Gas Pressures and Volumes Needed on TETCO/TGP for Full Load Operation

Unit	Minimum Delivery Pressure (psig)[24]	Total Flow Requirements (MMSCF per day)
Brown 6-7	575	40.8 per CT
Brown 8-11[25]	350	33.5 per CT
Brown 5	350	38.0
Brown 12	675	91.0

The Companies currently operate a natural gas compressor located at the purchase points of the TETCO and TGP interstate pipelines. Unlike the compressor described at Cane Run and those proposed at Trimble County, the Brown compressor is a high-pressure low-flow unit. Because the minimum pressure needed at the existing simple-cycle CTs is lower than the typical operating pressure of the pipelines, compression is not needed. The Brown compressor was designed to create line pack providing additional volume in the Companies' eleven-mile pipeline, essentially acting as localized natural gas storage. This line pack provides valuable flexibility for the Brown CTs – allowing the Companies to dispatch the units as needed for several hours instead of having to wait to purchase gas on the spot market, and later for replenishing line pack from the spot market in advance of the next operational need. This flexibility offers yet another layer of protection, ensuring generation during a gas line shortage (transportation or supply).

While the existing infrastructure works today, it will be insufficient in meeting the additional needs of Brown 12. The Companies performed a compression Front-End Engineering Design ("FEED") study in September 2023 that estimated the cost of compression necessary to accommodate the increased flows from Brown 12 at approximately $53 million. The Companies have included this cost in the construction estimate for Brown 12. This additional compression includes compressors designed to operate at higher flow rates to continuously supply natural gas with boosted pressure to Brown 6, 7, and 12 as well as meet the pressure requirements of all the CTs in the event of pressure drop even greater than that seen during WS Elliott.

The Companies have not experienced a pressure drop event at Brown like the one experienced on TGT during WS Elliott, but the existing compression (before Brown 12 comes online) and planned compression (after Brown 12 comes online) would be expected to mitigate fuel security risks of such an event.

3.2.2 Fuel Oil Backup

The seven CTs at Brown are of three different models: four are GE/Alstom GT11N2s (Units 8-11), one is a GE/Alstom GT11N2+ (Unit 5), and two are GE/Alstom GT24s (Units 6 and 7). Four of the seven CTs at Brown (Units 8-11) are currently capable of operating on both natural gas and fuel oil. The site has two million gallons of fuel oil storage, which is sufficient to operate all four CTs at max load for approximately

[24] Minimum delivery pressures reflect unit needs after gas compression.
[25] Brown 8-11 are also capable of operating on fuel oil.

48 hours before refueling.[26] Of the remaining CTs, Brown 5 is the only viable candidate for installing fuel oil backup capability. Brown 5 is of a similar make and model to Brown 8-11 and could accommodate a fuel oil retrofit at an estimated a cost of $10-15 million. The conversion of Brown 5 to a dual fuel unit would likely require an increase in the amount of fuel oil stored on plant grounds as well as a review and revision of the site's environmental permitting.

Brown 6-7 are of a different make and model than the other CTs at the station. GE Vernova has expressed caution about operating GT24s on fuel oil, citing a well-documented history of pulsation issues and fires – in fact, Brown 6-7 originally had fuel oil backup when the units were commissioned in 1999, but that capability was removed in 2016 for these very reasons. GE Vernova also indicated that only one GT24 unit in the world still operates on fuel oil, and production of replacement parts ended years ago. Given a poor track record of fuel oil performance and lack of available parts, Brown 6-7 are not considered viable candidates for fuel oil retrofits.

Brown 12 is assumed to be of a similar make and model to Mill Creek 5, which as stated previously is not considered a suitable candidate for fuel oil given a lack of operational data and post-operation component analysis related to fuel oil operation for that class of machine.

As a system, the Brown station has lower risk of fuel interruption given access to two interstate pipelines, and the current fuel oil capabilities further reduce the Companies' exposure in the event of a fuel disruption at Brown.

3.2.3 Improved Flow Controls

As noted above, the Companies currently have the capability to manually switch between TETCO and TGP for natural gas deliveries at Brown. The Companies have assessed the potential to improve operating flexibility by allowing for pressure or flow control from both natural gas sources simultaneously. While this has the potential to improve fuel reliability at the site, this enhancement would predominantly be used to accommodate the additional fuel flows associated with Brown 12.[27] The existing infrastructure is sufficient to meet needs of the existing CTs (particularly given the current compression scheme, coupled with the capability to operate four of the seven CTs on fuel oil), but improvements may be warranted to accommodate Brown 12 given increased gas consumption. The Companies performed a flow/pressure control FEED study in October 2023 and estimated the cost of this enhancement at approximately $4 million and have included this cost in the construction estimate for Brown 12. In addition to the reliability benefits associated with fuel supply diversity, this enhancement would increase the pool of suppliers from which the Companies could procure forward and spot gas, providing potential operational savings.

[26] Fully replenishing two million gallons of fuel oil inventory requires approximately 267 fuel oil tanker trucks and takes several weeks to complete, depending upon the availability of trucks and road conditions.

[27] Between 2019 and 2023, total generation from the Brown CTs averaged 252 GWh/year. Brown 12 is forecasted to generate an average of 4,168 GWh/year, or over sixteen times that of the Brown CTs. Even accounting for heat rate efficiency differences, Brown 12 is expected to consume approximately eight to nine times the volume of natural gas currently consumed by the Brown CTs.

4 Reliability Benefit Analysis

Based on the Evaluation of Alternatives, it is uncertain whether additional compression on the TGT system would materially improve reliability given the margin provided by existing compression, and LNG backup is considered cost prohibitive relative to other alternatives. Fuel oil backup for the Trimble County CTs appears to be the most effective means of improving fuel security on the TGT system, as it addresses both transportation and supply issues. Underground natural gas storage addresses supply issues and may address some transportation issues. Section 4.1 provides an analysis of the WS Elliott event and quantifies the effects that fuel oil backup for the Trimble CTs would have had under those conditions. The results of this analysis inform the alternatives considered in section 4.2 for quantification of reliability benefits. The Companies also considered the reliability benefits of underground natural gas storage in this section.

As a system, the Brown station has lower risk of fuel interruption given its access to two interstate pipelines, ability to store natural gas in a pipeline owned by the Companies, and current fuel oil capabilities. While system improvements will continue to be monitored and evaluated, the Companies believe that comparatively, Brown is well protected against losses due to natural gas supply interruptions. Therefore, this section does not attempt to quantify reliability benefits associated with alternatives at Brown.

4.1 Impact Analysis During WS Elliott Event

During WS Elliott, respective TGT delivery pressures at Trimble County and Cane Run fell below the minimum required pressures at 11:15 and 11:09 on 12/23/2022 and did not return to full contracted pressures until 16:00 and 13:00 on 12/25/2022. As a result, the Trimble County CTs and Cane Run 7 experienced derates during the event. This analysis evaluates multiple system change scenarios and how those changes would impact the capability of the combustion turbines on the TGT line during a low-pressure event like the one experienced during WS Elliott. The Companies note that the conditions of any potential future event would not necessarily mirror those of WS Elliott, as the characteristics of the TGT system, its customers, and the effect of weather conditions will not be the same. After WS Elliott, TGT installed additional weatherization equipment and altered its operating procedures to reduce the likelihood of low-pressure issues during future extreme weather events.[28] Thus, this analysis contemplates the same low-pressure event occurring despite these changes.

4.1.1 Base Scenario

The base scenario in Figure 2 and Figure 3 shows the generator output and TGT pipeline pressure for Trimble County CTs and Cane Run 7 during the WS Elliott pressure loss event. The Trimble County CTs and Cane Run 7 experienced derates averaging 431 MW and 79 MW, respectively. The Trimble County CTs were effectively held near their minimum loads, whereas Cane Run 7 derates coincided with pressure changes on the TGT system and ranged between 2 MW and 254 MW on an average hourly basis. The tie-in pressure was greater than Paddy's Run 13's requirement of 432 psig, so Paddy's Run 13 was not affected by the gas pressure issues.

[28] These changes supported reliable operations during a similar weather event (Winter Storm Heather) in January 2024.

Figure 2: Trimble County CT WS Elliott Generation and Pressure, Base Scenario

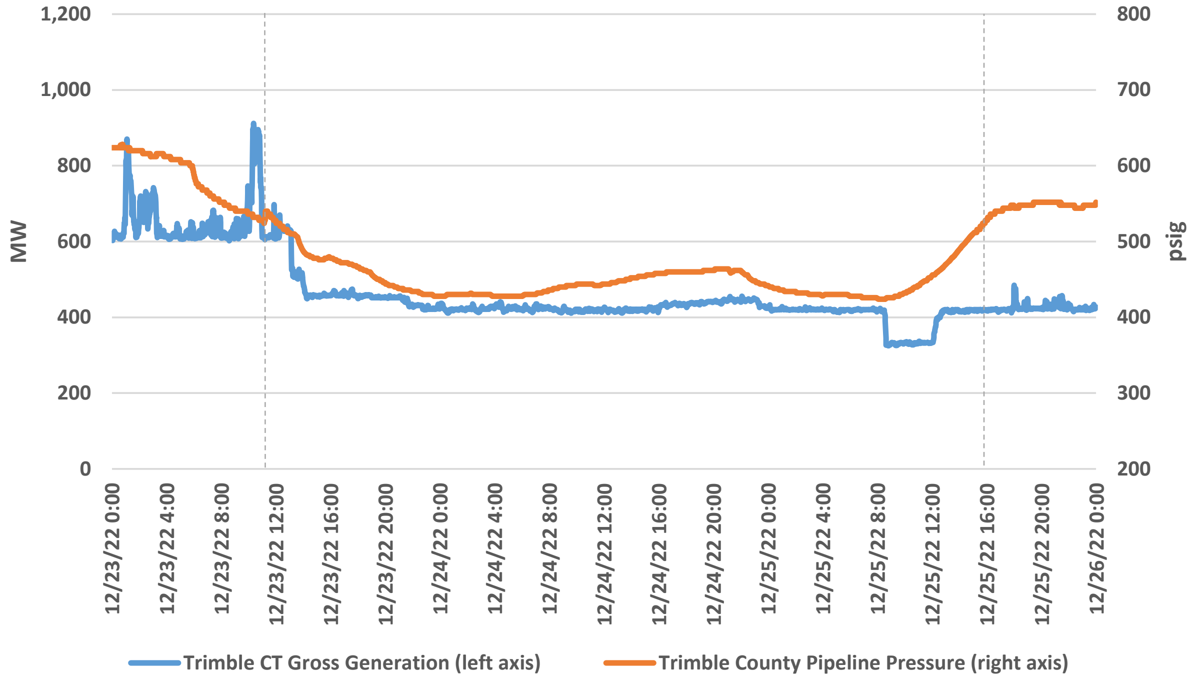
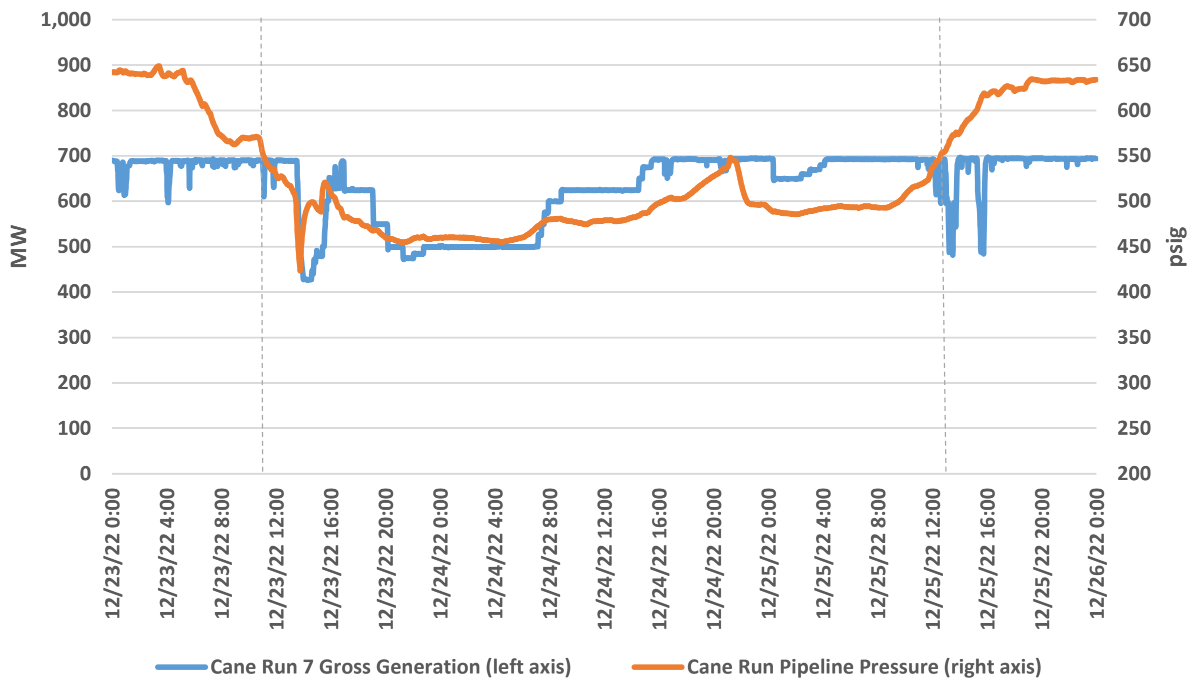


Figure 3: Cane Run 7 WS Elliott Generation and Pressure, Base Scenario

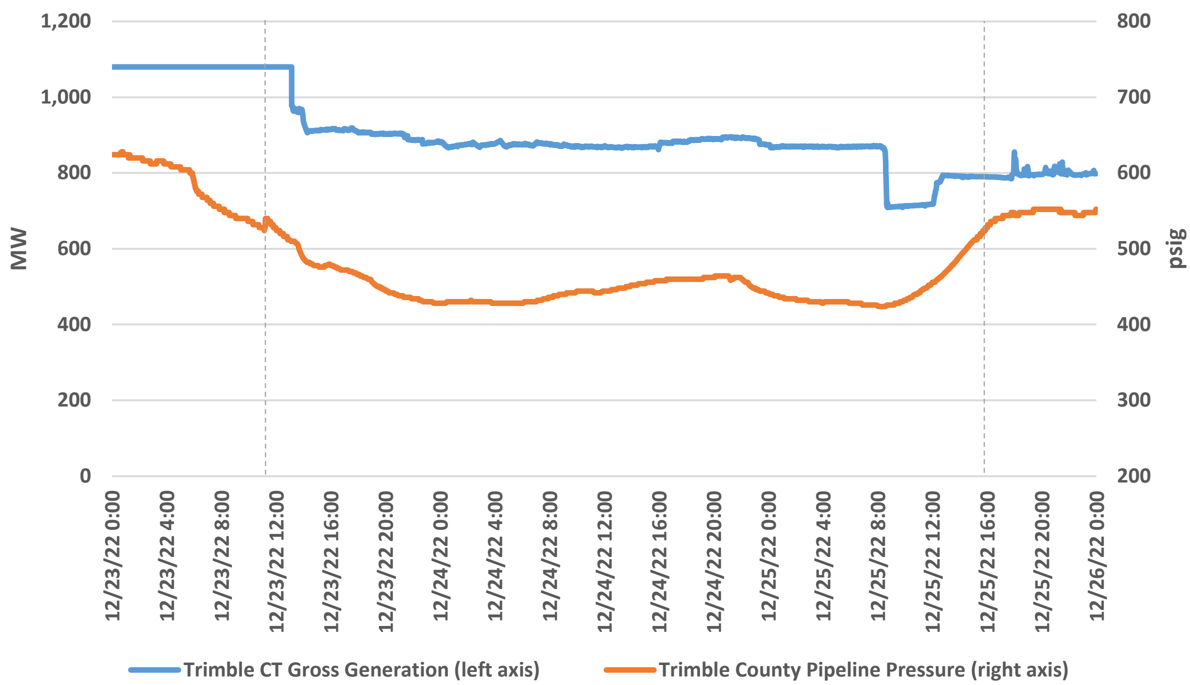


The software upgrade for the Trimble County CTs would allow for full load operation under these pressure conditions; however, increasing natural gas flows at Trimble County would increase the deficit on the TGT system and lead to additional pressure drops over time as line pack is consumed. In other words, increasing gas flows at Trimble County could result in further derates or loss of availability of other units on the TGT system – such as Cane Run 7 and Paddy's Run 13 – and it is uncertain what the net effect would be in a scenario where Trimble County CT generation is increased to full load during a hypothetical future pressure loss event.

4.1.2 Two Units with Fuel Oil Scenario

The next scenario in Figure 4 evaluates the addition of dual fuel capability (i.e., making units capable of switching to fuel oil operation) at Trimble County while keeping the total natural gas consumption flow rate of the Trimble County CTs from the scenario depicted in Figure 2 fixed by redirecting displaced natural gas to other CTs at the site and increasing their generation output consistent with this redirected gas flow. Keeping Trimble County's flow rate fixed in this scenario eliminates any potential impacts the flow rate changes may have had on other units connected to the TGT line (e.g., Cane Run 7 and Paddy's Run 13). Using these assumptions, switching two Trimble County CTs to operating on fuel oil would have reduced the average derate associated with the pressure loss event by 441 MW. Again, with the Trimble County flow rate fixed, this scenario would have kept TGT's deficit flat with no impact to supply pressures at other stations other than what was experienced during WS Elliott.

Figure 4: Trimble County CT WS Elliott Generation and Pressure, Two Units with Fuel Oil Scenario

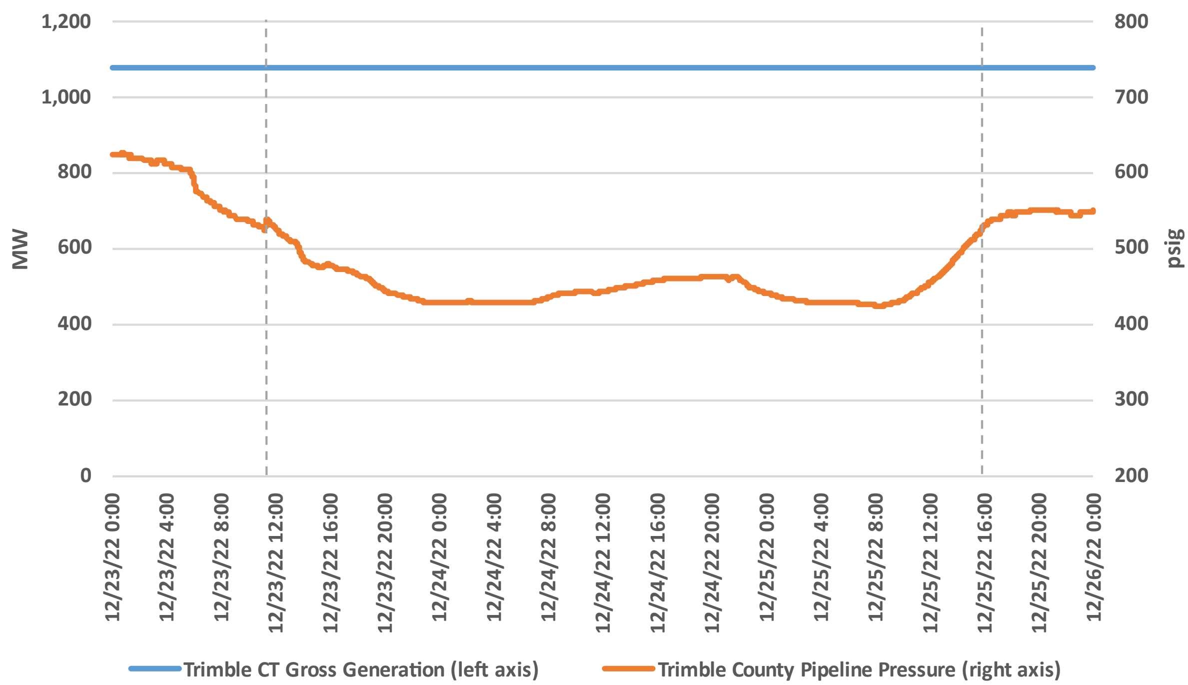


It is important to note that switching from natural gas to fuel oil requires thoughtful operating procedures and is not without risk. Switching to fuel oil can decrease unit stability and increase the probability of forced outages due to mechanical issues, particularly during an extreme weather event. Furthermore, with a limited quantity of on-site fuel oil storage, determining whether and when to switch to fuel oil requires careful consideration of system conditions and uncertain weather forecasts. As noted in footnote 21, fully replenishing 1.3 million gallons (i.e., 48 hours at max load) of fuel oil inventory for two Trimble County CTs would take several weeks to complete.

4.1.3 Four Units with Fuel Oil Scenario

The final scenario in Figure 5 evaluates the number of dual fuel capable units necessary to provide full load capability for all units on the TGT line (Trimble County 5-10, Cane Run 7, and Paddy's Run 13). The Companies modeled the effect of switching one Trimble County CT unit at a time to operating on fuel oil until the Trimble County natural gas flow rate was reduced enough to allow for full load operation of all six Trimble County CTs and Cane Run 7. This yielded the need for four dual fuel capable Trimble County CTs to allow all TGT units to achieve full load.[29] Under this scenario, the expected generation output increase would be 789 MW (649 MW at Trimble County and 140 MW at Cane Run) along with a 33.6 MMSCF/day net decrease in TGT's system deficit.[30] This decrease in system deficit would have had additional benefits over time in maintaining pressure as more line pack would have been preserved during the duration of the WS Elliott event.

Figure 5: Trimble County CT WS Elliott Generation and Pressure, Four Units with Fuel Oil Scenario



4.2 Quantification of Reliability Benefits

As noted in section 4.1, during a pressure loss event like that experienced during WS Elliott the Companies would expect an increase to available capacity by 441 MW if two of the Trimble County CTs were dual fuel capable, and would expect to retain full load capability across all units on the TGT system if four of the

[29] As noted in footnote 20, Trimble County 8 and 10 are fast-start units and would require additional capital to perform a fuel oil retrofit. For this reason, if the Companies were to install fuel oil on four units, Trimble County 8 and 10 would be chosen to remain on natural gas only.

[30] The decrease in flow of 51.0 MMSCF/day at Trimble County would be partially offset by an increase of 17.5 MMSCF/day at Cane Run to ramp back up to full load. Capacity and fuel flows for Cane Run 7 reflect the 2024 turbine upgrade project that improved unit efficiency and max output; analysis also reflects an expected increase in Cane Run 7's NITS limit from 691 MW to 775 MW.

Trimble County CTs were dual fuel capable. The sections below quantify the reliability value added by these alternatives. In addition, the Companies quantified the reliability value of underground natural gas storage on the TGT system. Costs used in this analysis are in 2024 dollars. Case-specific assumptions are provided in the respective subsections below.

The Companies assessed the reliability benefit of viable alternatives using the Equivalent Load Duration Curve ("ELDC") model. The ELDC model calculates expected unserved energy for a given portfolio of resources over a range of weather and unit availability and assesses a cost of $22,407/MWh to that unserved energy to determine the expected reliability benefit.[31]

The fundamental uncertainty in this analysis is the frequency with which fuel disruption events will occur moving forward considering the actions the Companies and TGT took after WS Elliott to limit their likelihood. Fuel disruptions are more likely to occur during cold weeks when the demand for natural gas is high. A key assumption in this analysis is the temperature below which a week is considered "cold" – for reference, the minimum hourly temperature during WS Elliott was -5° F. Fuel disruptions do not occur in all cold weeks; the Companies have experienced one low gas pressure event (during WS Elliott) and zero gas supply disruptions on the TGT pipeline since becoming a customer in 2002. This analysis uses minimum hourly temperature by week as a proxy to select weeks in which fuel disruptions occur and considers a range of temperatures from -20° F (equating to 1 event in 51 years of history) to 0° F (equating to 43 events in 51 years of history). This analysis assumes an event affects all 168 hours of a selected week, which is a conservative assumption given that the WS Elliott gas pressure loss was approximately 48 hours. The resulting scenarios are summarized in Table 6.

Table 6: Frequency of Fuel Disruption Events, 1973-2023

Minimum Hourly Temperature	Number of Weeks in 1973-2023 History	Frequency Expressed as 1-in-X Years
-20° F	1	1-in-51 years
-17° F	3	1-in-17 years
-15° F	4	1-in-12.8 years
-10° F	10	1-in-5.1 years
-5° F	19	1-in-2.7 years
0° F	43	1-in-1.2 years

Regarding the assumed impact of an event on unit availability without any dual fuel capability on the Trimble County CTs or underground natural gas storage, this analysis considers an outage scenario that is informed by the unit availability experienced during WS Elliott. Specifically, during an event, Cane Run 7 and the Trimble County CTs are assumed to have increased EFOR values that reflect their unavailable capacity during the pressure loss event as described in section 4.1.1. Mill Creek 5 and Paddy's Run 13 are assumed to be fully available based on expected and existing compression at the respective stations. Trimble County 1-2 are assumed to have increased EFOR to reflect the probability of each of those units being offline during an event and unable to start when natural gas is constrained. Cane Run 7 and the Trimble County CTs are modeled in blocks to reflect correlated outages for this scenario analysis, with each Trimble County CT also assumed to have an independent outage risk consistent with its planned

[31] This cost of unserved energy is consistent with the value used in the 2024 IRP Resource Adequacy Analysis.

EFOR of 4.3%.[32] These modeled EFOR values are summarized in Table 7.[33] The fuel disruption EFOR values reflect at least 360 MW of the Trimble County CTs and 140 MW of Cane Run 7 being unavailable.

Table 7: Modeled EFOR with No Fuel Oil Backup or Gas Storage (EFOR %)

Unit	Normal EFOR	Fuel Disruption EFOR
Cane Run 7: 634-774 MW	1.6%	100.0%
Cane Run 7: 0-634 MW	1.6%	1.6%
Mill Creek 5	1.6%	1.6%
Paddy's Run 13	6.8%	6.8%
Trimble County 1	3.1%	6.1%
Trimble County 2	2.7%	5.7%
Trimble County CTs: 901-1,080 MW	23.2%	100.0%
Trimble County CTs: 721-900 MW	2.5%	100.0%
Trimble County CTs: 541-720 MW	0.1%	98.6%
Trimble County CTs: 361-540 MW	0.005%	80.8%
Trimble County CTs: 181-360 MW	0.0001%	0.0001%
Trimble County CTs: 0-180 MW	0.000001%	0.000001%

The following sections quantify the benefits of fuel oil backup and underground gas storage over the range of fuel disruption frequency scenarios in Table 6.

4.2.1 Fuel Oil Backup for Two Trimble County CTs

For this alternative, the Companies assume fuel oil backup is installed on Trimble County 5-6, restoring the fuel disruption EFOR for these units back to their normal levels of 4.3%.[34] In addition, the EFOR of the other Trimble County CTs was reduced to reflect the redirecting of displaced natural gas to those CTs as shown in section 4.1.2. The modeled EFOR in this scenario is summarized in Table 8.

[32] EFOR values for blocks of energy from Trimble County CTs are equivalent to those derived from a binomial distribution with a 4.3% chance of each Trimble County CT being unavailable and a 95.7% chance of each Trimble County CT being available.

[33] The characteristics of any fuel disruption event would be unique and unknowable in advance. These assumptions provide a reasonable baseline for unit availability during an event where natural gas is constrained as they are based on actual data from a real-world event. In such an event, the Companies would prioritize gas flows to NGCCs where possible (given their higher unit efficiency), leaving less fuel available for CTs. Also, the effect of fuel oil installations on Trimble County CTs is more straight-forward given the analysis performed in section 4.1.

[34] As noted in section **Error! Reference source not found.**, switching to fuel oil can decrease unit stability and increase the probability of forced outages due to mechanical issues. Thus, adding fuel oil backup would likely increase the base EFOR of CTs that receive the retrofit; however, as a conservative assumption this analysis assumes no material increase in EFOR related to fuel oil retrofits.

Table 8: Modeled EFOR Values with Fuel Oil Backup for Two Trimble County CTs

Unit	Fuel Disruption EFOR
Cane Run 7: 635-764 MW	100.0%
Cane Run 7: 0-634 MW	1.6%
Mill Creek 5	1.6%
Paddy's Run 13	6.8%
Trimble County 1	6.1%
Trimble County 2	5.7%
Trimble County CTs: 901-1,080 MW	96.7%
Trimble County CTs: 721-900 MW	21.0%
Trimble County CTs: 541-720 MW	1.4%
Trimble County CTs: 361-540 MW	0.03%
Trimble County CTs: 181-360 MW	0.0001%
Trimble County CTs: 0-180 MW	0.000001%

The Companies calculated the impact of adding dual fuel capability to two Trimble County CTs on expected unserved energy based on the fuel disruption EFOR assumptions in Table 7 and Table 8 for each of the frequency scenarios discussed in section 4.2 and assessed the cost of unserved energy to determine the expected reliability benefit. The results of this analysis are shown in Table 9.

Table 9: Reliability Benefit of Fuel Oil Backup for Two Trimble County CTs ($M)

Fuel Disruption Frequency	Annual Reliability Benefit	PVRR Over Remaining Depreciable Life of Trimble County CTs
1-in-51 years	$1.4	$15.7
1-in-17 years	$3.6	$42.0
1-in-12.8 years	$3.8	$44.0
1-in-5.1 years	$5.9	$68.5
1-in-2.7 years	$7.1	$81.9
1-in-1.2 years	$8.6	$99.3

The present value of revenue requirements ("PVRR") associated with a 2026 commissioning of fuel oil backup for two Trimble County CTs using the costs in Table 4 is $38.8 million. The annual reliability and generation production cost benefit needed to fully offset this cost over the remaining depreciable lives of the Trimble County CTs (17 years) is $3.4 million. The expected reliability benefit of fuel oil backup for two CTs is sufficient to cover the costs if a loss of pressure like that experienced during WS Elliott occurs once every 17 years but is insufficient to cover the costs if such an event occurs once every 51 years.

4.2.2 Fuel Oil Backup for Four Trimble County CTs

For this alternative, the Companies assume fuel oil backup is installed on Trimble County 5, 6, 7, and 9, restoring EFOR of those units back to their normal levels of 4.3%. In addition, the EFOR of the other units served by TGT was reduced to reflect the redirecting of displaced natural gas to those units as described in section 4.1.3. The modeled EFOR in these scenarios is summarized in Table 10.

Table 10: EFOR Values with Fuel Oil Backup for Four Trimble County CTs

Unit	Fuel Disruption EFOR
Cane Run 7: 635-774 MW	1.6%
Cane Run 7: 0-634 MW	1.6%
Mill Creek 5	1.6%
Paddy's Run 13	6.8%
Trimble County 1	3.1%
Trimble County 2	2.7%
Trimble County CTs: 901-1,080 MW	23.2%
Trimble County CTs: 721-900 MW	2.5%
Trimble County CTs: 541-720 MW	0.14%
Trimble County CTs: 361-540 MW	0.005%
Trimble County CTs: 181-360 MW	0.0001%
Trimble County CTs: 0-180 MW	0.000001%

The Companies calculated the impact of adding duel fuel capability to four Trimble County CTs on expected unserved energy based on the fuel disruption EFOR assumptions in Table 7 and Table 10 for each of the frequency scenarios discussed in section 4.2 and assessed the cost of unserved energy to determine the expected reliability benefit. The results of this analysis are shown in Table 11.

Table 11: Reliability Benefit of Fuel Oil Backup for Four Trimble County CTs ($M)

Fuel Disruption Frequency	Incremental Annual Reliability Benefit of 3rd and 4th CTs	Total Annual Reliability Benefit	PVRR Over Remaining Depreciable Life of Trimble County CTs
1-in-51 years	$0.3	$1.7	$19.4
1-in-17 years	$0.9	$4.5	$52.4
1-in-12.8 years	$0.9	$4.8	$54.8
1-in-5.1 years	$1.3	$7.3	$84.1
1-in-2.7 years	$1.5	$8.6	$99.7
1-in-1.2 years	$1.8	$10.4	$119.6

The PVRR associated with a 2026 commissioning of fuel oil backup for four Trimble County CTs using the costs in Table 4 is $77.6 million. The annual reliability and generation production cost benefit needed to fully offset this cost over the remaining depreciable lives of the Trimble County CTs is $6.7 million. The expected reliability benefit of fuel oil backup for four Trimble County CTs is sufficient to cover the costs if a loss of pressure like that experienced during WS Elliott occurs once every 5.1 years but is insufficient to cover the costs if such an event occurs once every 12.8 years. Table 11 also shows that the incremental value of the third and fourth fuel oil retrofits of Trimble CTs is considerably lower than the first and second.

4.2.3 TGT Underground Natural Gas Storage

For this alternative, the Companies assume a new resource with the same properties as the 5.79 Bcf of underground natural gas storage referenced in section 3.1.4 becomes available as a resource to assist in transportation and supply events.[35] The incremental natural gas volumes of 51,000 Mcf/day equate to increased gas flows of 49.1 MMSCF/day, allowing the Companies to generate an incremental 227 MW from the Trimble County CTs relative to the base scenario in section 4.1.1, restoring some of the derated capacity from that scenario. The modeled EFOR in these scenarios is summarized in Table 12.

Table 12: EFOR Values with 5.79 Bcf of Underground Natural Gas Storage

Unit	Fuel Disruption EFOR
Cane Run 7: 635-774 MW	100.0%
Cane Run 7: 0-634 MW	1.6%
Mill Creek 5	1.6%
Paddy's Run 13	6.8%
Trimble County 1	6.1%
Trimble County 2	5.7%
Trimble County CTs: 901-1,080 MW	99.97%
Trimble County CTs: 721-900 MW	96.4%
Trimble County CTs: 541-720 MW	14.1%
Trimble County CTs: 361-540 MW	0.005%
Trimble County CTs: 181-360 MW	0.0001%
Trimble County CTs: 0-180 MW	0.000001%

The Companies calculated the impact of adding underground natural gas storage on expected unserved energy based on the fuel disruption EFOR assumptions in Table 7 and Table 12 for each of the frequency scenarios discussed in section 4.2 and assessed the cost of unserved energy to determine the expected reliability benefit. The results of this analysis are shown in Table 13.

Table 13: Reliability Benefit of 5.79 Bcf of Underground Natural Gas Storage ($M)

Fuel Disruption Frequency	Annual Reliability Benefit
1-in-51 years	$1.1
1-in-17 years	$2.8
1-in-12.8 years	$2.9
1-in-5.1 years	$4.6
1-in-2.7 years	$5.6
1-in-1.2 years	$6.8

As noted in section 3.1.4, the annual cost of the proposed storage was approximately $3.4 million. In addition to the average annual net savings of $2.6 million associated with leveraging storage to reduce forward purchase costs, the annual reliability and generation production cost benefit needed to fully offset the cost of this proposed storage is $0.8 million. The expected reliability benefit of underground natural gas storage is sufficient to cover the remaining net costs if a loss of pressure like that experienced during WS Elliott occurs at least once every 51 years assuming such storage would actually have an impact on the loss of pressure event, which seems unlikely at best. As noted in the analysis above, the underground storage most recently available on the TGT system would not have helped with the loss of

[35] As noted in footnote 22, the proposed storage would not have addressed the transportation issues experienced during WS Elliott because it is located on the other side of the pressure station at Slaughters. However, this analysis assumes the proposed storage would improve future transportation and supply issues as a simplifying assumption.

pressure the Companies experienced during WS Elliott. Thus, though having such storage might be justified if price arbitrage strategies could support it, any reliability benefit such storage might provide is unclear at this time.

5 Conclusions

Based on the Evaluation of Alternatives and Reliability Benefit Analysis, it is debatable whether additional compression on the TGT system would materially improve reliability given the margin provided by existing compression, and LNG backup is considered cost prohibitive at this time relative to other alternatives.

Fuel oil backup for the Trimble County CTs appears to be the most effective means of improving fuel security on the TGT system. Based on the analysis performed retrofitting two of the Trimble County CTs with fuel oil backup is cost justified if a gas interruption event is expected to occur at an interval greater than approximately once every 17 years, and retrofitting is cost justified for four of the Trimble County CTs with an event occurring at an interval greater than approximately once every 5.1 years. Considering the WS Elliott event and the results of this analysis, it is recommended that a more refined cost estimate with appropriate contingencies be developed for fuel oil backup for up to four Trimble County CTs. Once that is complete, decisions concerning how and whether to move forward can be made.

Underground natural gas storage is not currently available but would be cost justified if a loss of pressure like that experienced during WS Elliott was expected to occur at least approximately once every 51 years *and* such storage would actually have an impact on such a loss of pressure event, which seems unlikely. As noted in the analysis above, the underground storage most recently available on the TGT system would not have helped with the loss of pressure the Companies experienced during WS Elliott, which resulted from a lack of sufficient *compression*, not a lack of *supply*. Indeed, the Companies have never encountered a supply problem on the TGT system, which is typically the type of issue underground gas storage would help address. Therefore, although there might be non-reliability-related justifications for acquiring underground storage capacity at some point in the future, there is not a clear reliability-based justification for incurring the cost of such storage at this time.

Regarding the TETCO/TGP system, the Brown station has lower risk of fuel interruption given its access to two interstate pipelines, ability to store natural gas in a Company-owned pipeline, and current fuel oil capabilities. System improvements, such as compression and improved flow controls, are not needed at this time but will be needed to support additional gas flows associated with Brown 12 when it comes online.

Generation Forecast Process

PPL companies

Generation Planning & Analysis
2024

Table of Contents

1 Introduction

The Generation Planning group annually prepares a generation and off-system sales (“OSS”) forecast for Louisville Gas and Electric Company (“LG&E”) and Kentucky Utilities Company (“KU”) (collectively “the Companies”). This forecast provides the basis for – among other things – the Companies’ forecasts of fuel costs, generation-related variable operating and maintenance costs, economy purchased power, and OSS margin. This document summarizes the process used to prepare the generation forecast.

2 Production Cost Model

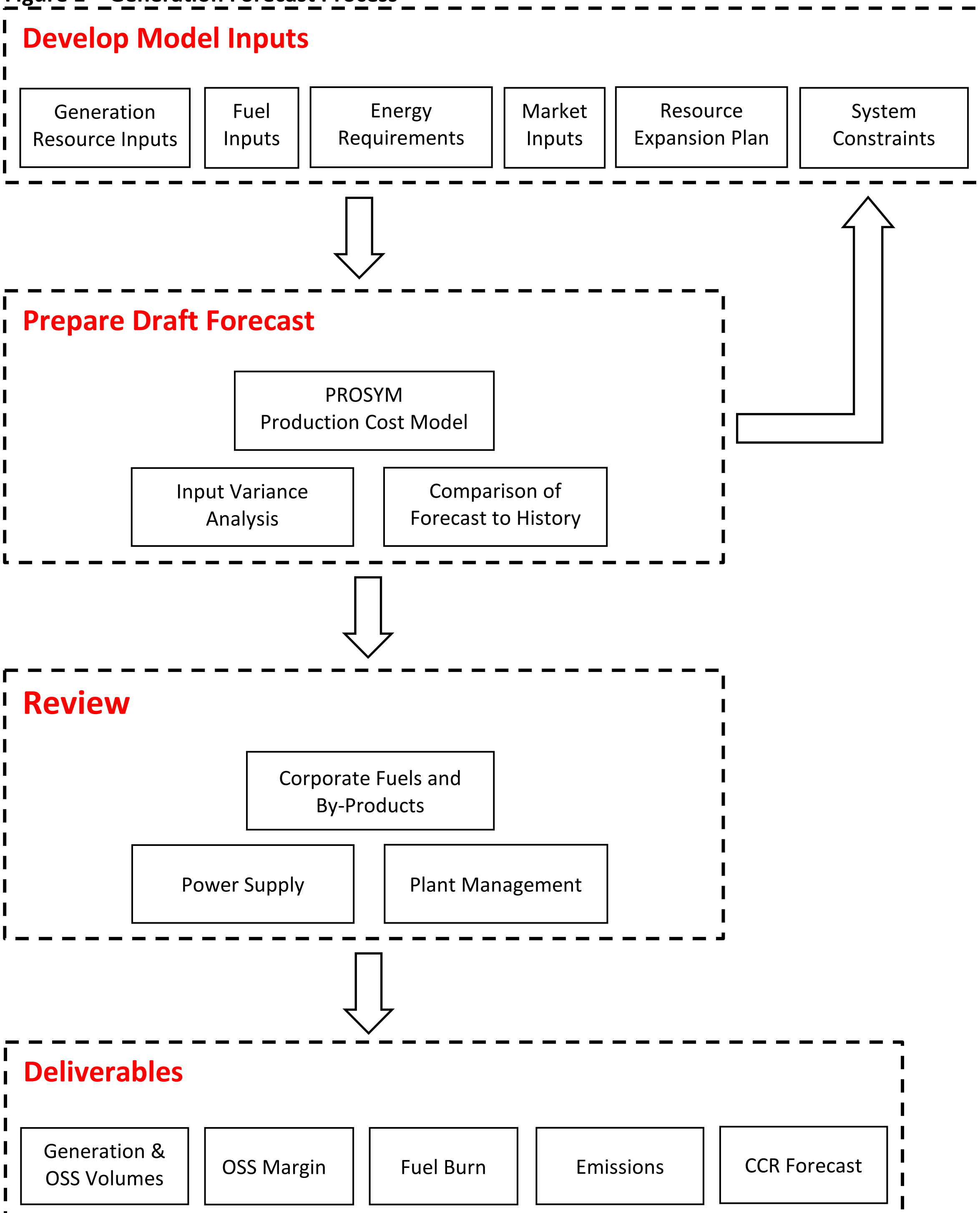
The Companies’ generation forecast is developed using Hitachi ABB Power Grids’ PROSYM, a proprietary production cost model. PROSYM is a chronological simulation engine that optimizes unit commitment and economic dispatch to meet the load for an interconnected electric system, considering the reserve requirements and other aspects of the electric system. PROSYM is a proven production cost model that has been used by utilities throughout the United States for decades.

In addition to PROSYM, SAS, R, Microsoft Access, and Microsoft Excel are used to develop inputs and process and analyze forecast results. Presentations containing forecast assumptions and results are prepared using Microsoft PowerPoint.

3 Process Overview

Figure 1 provides an overview of the process used to develop the Companies’ generation forecast. In the first part of the process, model inputs are developed. Then, the model inputs are loaded into PROSYM and a draft generation forecast is prepared. PROSYM is a complex model, so extensive review takes place to ensure that the inputs are correctly loaded into the model and that the model results are reasonable. An input variance analysis evaluates the impact of changing each input or group of related inputs to ensure that the associated output changes are reasonable. Then, various elements of the generation forecast are compared to historical trends for reasonableness. If the forecast results are not deemed reasonable, the applicable model inputs are adjusted and the process is repeated. In the third part of the process, the results of the forecast are reviewed by other departments. This review process ensures that the forecast considers feedback from a broad range of perspectives. After all parties are satisfied with the results, the generation forecast is finalized and distributed to the groups who use the forecast to prepare financial budgets. Each part of this process is discussed further in the following sections.

Figure 1 – Generation Forecast Process



3.1 Develop Model Inputs

The first part of the process used to develop the Companies' generation forecast involves developing and vetting model inputs. Well-vetted inputs are essential to a good forecast. Wherever possible (and applicable), model inputs are initially developed based on an analysis of historical data. Then, these inputs are reviewed with plant management for reasonableness. Model inputs are adjusted when historical trends are not expected to continue in the future. Table 1 lists the six main categories of model inputs along with the inputs in each category. Each of these categories is discussed further in the following sections.

Table 1 - Key Inputs to the Generation Forecast

Input Category	Inputs
Generation Resource Inputs	Minimum and maximum capacity, heat rate, emissions rates, variable operating and maintenance costs, operating limits, unit availability, company allocation, renewable resources
Fuel Inputs	Coal, natural gas, and oil prices, fuel cost multipliers, CCR production rates and prices, other fuel-related inputs
Energy Requirements	Hourly energy requirements
Market Inputs	Electricity prices, emission allowance prices, off-system sales and purchase limits, off-system sales and purchase price thresholds
Expansion Plan Inputs	Timing and type of expansion plan resources
System Constraints	Transmission constraints, spinning reserve requirements, off-system sales constraints, dispatch order rules

3.1.1 Generation Resource Inputs

The generation resources modeled in PROSYM include the Companies' existing and (if applicable) planned generation resources. Generation resources include generating units owned by the Companies, power purchase agreements with other power producers, and the capacity associated with the Companies' curtailable service rider ("CSR") customers.[1]

Generation resource inputs define the operating characteristics of the generation resources. These inputs include each resource's minimum and maximum capacity, heat rate, emissions rates, variable operating and maintenance costs, operating limits, unit availability, company allocation, and renewable resources. Each of these inputs is discussed further in the following sections.

3.1.1.1 Minimum and Maximum Capacity

The operating minimum, SCR minimum,[2] and maximum capacity (or output) is specified for each generation resource as a megawatt ("MW") value for the summer, winter, fall, and spring seasons. SCR minimum applies only to units with SCRs and is the minimum capacity at which the SCR can operate (i.e., operation at a capacity level lower than the SCR minimum requires that the SCR be nonoperational). Capacity inputs are specified based on an analysis of historical data and unit rating tests but rarely change materially from forecast to forecast.

Brown units 5 and 8-11 are equipped with Inlet Cooling ("ICE") to increase output if needed during the summer months. The Companies model these ICE units as separate units with rules to ensure they do not operate simultaneously with their non-ICE counterparts.

[1] The Companies own 75% of Trimble County 1 and 2. Model inputs reflect 75% ownership.
[2] An "SCR" is a selective catalytic reduction system.

3.1.1.2 Heat Rate

The heat rate specifies the amount of fuel required to produce a megawatt-hour ("MWh") of electricity. Where applicable, a heat rate curve is specified for each generation resource for the summer, winter, fall, and spring seasons. The heat rate curves are specified based on an analysis of historical data and heat rate tests performed by the plants.

3.1.1.3 Emissions Rates

Where applicable, the Companies model the emissions of sulfur dioxide ("SO_2"), nitrogen oxides ("NO_x"), and carbon dioxide ("CO_2") for each generation resource:

- SO_2 Emissions: For coal units, SO_2 emissions are modeled as a function of the unit's SO_2 removal rate and the sulfur content of the fuel. The SO_2 removal rate for each coal unit depends on the vintage of the unit's flue-gas desulfurization ("FGD") equipment and is specified based on an analysis of historical data.[3] The sulfur content of the fuel is provided by the Corporate Fuels and By-Products group. For gas units, SO_2 emissions are modeled as an average SO_2 emission rate (specified in lb/MMBtu) estimated by the unit manufacturer.
- NO_x Emissions: For coal units, NO_x emissions are modeled as a function of a NO_x emission curve (specified in lb/MMBtu). NO_x emissions vary seasonally and with the unit's generation output and are lower for units retrofitted with selective catalytic reduction ("SCR") equipment. The NO_x emission curve is specified based on an analysis of historical data in conjunction with performance expectations associated with the timing of catalyst replacement. Cane Run 7's NO_x emission rate is specified based on an analysis of historical data. For other gas units, NO_x emissions are modeled as an average NO_x emission rate (also specified in lb/MMBtu) estimated by the unit manufacturer.
- CO_2 Emissions: CO_2 emissions are modeled as an average CO_2 emission rate (specified in lb/MMBtu), which is dependent on the type of fuel burned in the unit and is based on engineering estimates.

3.1.1.4 Variable Operating and Maintenance Cost

Variable operating and maintenance ("O&M") costs include all incremental non-fuel costs that are incurred when operating the generation resource. For coal units, variable O&M includes the cost of operating environmental controls, including Flue Gas Desulfurization ("FGD"), Selective Catalytic Reduction ("SCR"), Sulfuric Acid Mist ("SAM")/SO3 Mitigation, Fabric Filter ("FF")/Baghouse, and Process Water Systems ("PWS"), as applicable. For Cane Run 7, variable O&M is specified as "Operating Charge" in dollars per operating hour and "Start Cost Adder" in dollars per start. These inputs reflect the cost of its long-term program contract ("LTPC"), which is paid quarterly based on the number of starts and operating hours for the unit. For simple-cycle combustion turbines ("SCCTs"), the cost of major maintenance is specified as "Start Cost Adder" in dollars per start and considered in unit commitment and dispatch decisions but not included in the model's forecast of production costs.

3.1.1.5 Operating Limits

The following operating limits are modeled in PROSYM for each generation resource. Each of these inputs is specified based on operational experience.

- Minimum Up-Time: Minimum up-time is the minimum number of hours after coming online that a generation resource must remain online before it can be taken offline for economic reasons.

[3] Mill Creek Units 1-2 share the same FGD.

- Minimum Down-Time: Minimum down-time is the minimum number of hours after coming offline that a generation resource must remain offline before it can be brought back online.
- Mean Time to Repair: Mean time to repair is the average length (specified in hours) of forced outages.
- Ramp-Up Rate: Ramp-up rate is the rate (specified in MW/hour) at which a generation resource can increase its output.
- Ramp-Down Rate: Ramp-down rate is the rate (specified in MW/hour) at which a generation resource can decrease its output.
- Run-Up Rate: Run-up rate is the rate (specified in MW/hour) at which a generation resource can increase its output when it is first committed.
- Run-Up Hours: Run-up hours is the number of hours during which the run-up rate applies immediately after a generation resource is committed.

3.1.1.6 Unit Availability

The following unit availability inputs are modeled for each resource. These inputs determine the extent a resource is available for operation.

- Planned Maintenance Schedule: The planned maintenance schedule specifies the timing and duration of planned maintenance events. The schedule is developed with input from plant management, Generation Dispatch, and Project Engineering, such that the outages will have the least economic and reliability impact to customers.
- Equivalent Unplanned Outage Rate ("EUOR"): EUOR inputs determine the amount of time the generation resource is unavailable due to a forced outage, derate, or maintenance outage. EUOR inputs are specified based on an analysis of historical data.

3.1.1.7 Company Allocation

The energy and capacity for all generation resources modeled are either wholly or jointly allocated to LG&E and/or KU. For each generation resource, the Companies' allocation is specified to facilitate the process of creating generation and other forecasts by company.

3.1.1.8 Renewables

The Companies model renewable resources depending on the characteristics of each resource. KU's hydro facility, Dix Dam, is modeled using a monthly energy forecast which is based on history. LG&E's hydro facility, Ohio Falls, is modeled using monthly maximum capacity, also based on history. For solar facilities and power purchase agreements, the Companies model an hourly generation forecast which is correlated to the weather forecast on which the hourly energy requirements forecast is based.

3.1.2 Fuel Inputs

Each thermal generation resource is associated with one or more fuel forecasts for startup and for online operation. The fuel inputs specify the cost of fuel, the fuel's heat and SO_2 content, the quantity of fuel required for startup, and – for generation resources where the fuel price is a blend of multiple fuel forecasts – the blend ratio of each fuel forecast. For coal, the fuel inputs also include coal combustion residuals ("CCR") production rates and prices based on forecasted CCR revenues and costs.[4] The model makes commitment and dispatch decisions based on replacement fuel costs, while an estimate of total fuel cost is based on inventory fuel costs including fixed costs.

[4] CCR are by-products such as fly ash and bottom ash left over after coal is burned and gypsum, which is created as sulfur dioxide is removed from flue gas.

3.1.2.1 Coal Prices

A forecast of delivered coal prices is developed for each station in conjunction with the Coal Supply and By-Products Marketing department. These forecasts reflect the cost curve for the Companies' contracted coal volumes, the assumed cost of coal that will be contracted in the future, and the cost of transporting fuel from mines to the stations. Based on the coal burn forecast by unit, the Corporate Fuels and By-Products group calculates the target coal purchase tonnage needed each year to maintain desired inventory levels while meeting the forecasted coal burn. The forecasted price per MMBtu for each coal type is the result of computing the volume weighted average of the price of coal already under contract and the market price of coal. In the initial years of the forecast, the market price is a blend of coal bids received, but not under contract, and a forecast that reflects the historical relationship between coal and natural gas prices. This relationship is also used to develop a long-term coal price forecast based on the long-term natural gas price forecast.

3.1.2.2 Natural Gas Prices

A forecast of Henry Hub natural gas prices is developed as a starting point for undelivered gas. The initial years of the Henry Hub price forecast reflect monthly forward market prices from NYMEX as of a specific recent quote date, which reflects a current view of forward prices at the time the forecast is prepared. In the subsequent years, the market prices are interpolated to a price forecast published in the EIA's most recent Annual Energy Outlook. The Henry Hub forward market prices are then shaped monthly and adjusted to local delivered prices to KU and LG&E units using an average annual loss factor and a variable charge per MMBtu, which also adjusts for average assumed basis differentials. For each station that uses natural gas for startup or online operations, a forecast of delivered natural gas prices is developed by adding transportation costs and a cost for pipeline losses to the forecast of Henry Hub prices.

3.1.2.3 Oil Prices

A forecast of delivered oil prices is developed for coal units that use fuel oil for startup and for SCCTs that can use fuel oil for online operation as an alternative to natural gas. The fuel oil price forecast consists of market prices in the short term that are then interpolated to a long-term forecast. The Companies' delivered oil price forecast first uses NYMEX New York Harbor #2 fuel oil monthly contract settled prices as long as there is market liquidity.

Long-term #2 fuel oil prices are developed by applying the historical relationship between New York Harbor #2 fuel oil and West Texas Intermediate ("WTI") oil prices to forecasted WTI prices derived from a third party's latest long-term macro forecast. To integrate the two forecast periods, the short-term market-based fuel oil price forecast is interpolated to the long-term regression-based price forecast. The forecasted #2 fuel oil prices are then multiplied by the historical average ratio of the Companies' fuel purchase price to the New York Harbor #2 fuel oil price to arrive at the Companies' delivered fuel oil purchase price forecast.

3.1.2.4 Fuel Cost Multiplier

Fuel cost multipliers ("FCM") are defined for large-frame combustion turbines to align the generation forecast to history and prevent an unreasonable forecast of generation from energy-limited resources. The model uses FCM as a factor applied to fuel cost in order to determine the fuel cost used for commitment and dispatch decisions, but it is not included in the model's forecast of total fuel costs. The Companies develop the FCMs by setting an artificial price floor at a cost that allows the capacity factors of the large-frame combustion turbines to more closely reflect historical usage and remain below any environmental or operational restrictions. The Companies also use FCMs to distribute generation across the combustion turbines from more efficient units like those at Trimble County to less efficient units like those at Brown to reflect real-world considerations such as the availability of firm delivery capacity.

3.1.2.5 CCR Production Rates and Prices

A forecast of revenues and costs resulting from the Companies' sales and management of CCR is developed for each station based on inputs from plant management and the Corporate Fuels and By-products department. CCR prices and handling costs are combined to calculate a net value of CCR by CCR type and station (in $/ton), to account for the value and cost of CCR production and management. A forecast of CCR production rates (in lb/MMBtu) is developed based on historical data and forecasted fuel characteristics.

3.1.2.6 Other Fuel-Related Inputs

Other fuel inputs include the fuel blend ratio, the quantity of startup fuel, and the fuel's heat and SO_2 content.

- Fuel Type: For each generation unit, the type of fuel burned during operation is specified.
- Fuel Blend Ratio: Trimble County 2 burns a blend of Illinois Basin and Powder River Basin coals. Because the prices of these coals are specified in separate forecasts, the fuel blend ratio determines the weighting that is used to compute the price of coal for Trimble County 2.
- Type and Quantity of Startup Fuel: For each generating unit, the startup fuel type and quantity are the type and amount of fuel required to start the unit. These inputs are specified by fuel type and in MMBtu based on an analysis of historical data with input from plant management.
- Heat Content and SO_2 Content: Fuel heat and SO_2 contents are provided by the Corporate Fuels and By-products group.

3.1.3 Energy Requirements

PROSYM simulates the dispatch of the Companies' generating units to meet hourly energy requirements. The forecast of hourly energy requirements, which consists of native load sales and transmission and distribution losses, is developed by the Sales Analysis and Forecasting group.

3.1.4 Market Inputs

Market inputs define the market in which the Companies operate. These inputs include spot hourly wholesale electricity prices, emission allowance prices, hourly OSS and economy purchase volume limits, and OSS and economy purchase price threshold values. Each of the market inputs is discussed in the following sections.

3.1.4.1 Electricity Prices

A forecast of spot hourly electricity prices is developed to model the Companies' interactions with the electricity market. The Companies buy and sell electricity primarily with PJM through the PJM-South ("PJM-S") interface/pricing point, which is used in the planning process to represent the electricity market.[5] In the initial years, monthly forward market prices for PJM West Hub ("PJM-WH")[6] as of a specific recent quote date are used as a basis for developing an hourly forecast of PJM-S prices, reflecting the most current view of forward prices at the time the forecast was prepared.[7] In the

[5] The Companies also transact electricity with counterparties other than PJM. The Companies model PJM as a representative market, considering liquidity and availability of market data.

[6] The PJM market is used as a proxy for all markets available to the Companies because most of the Companies' off-system sales and purchases are expected to be transacted with the PJM market.

[7] The quoted "off-peak wrap" forward prices for PJM-WH are split into off-peak (7x8) and weekend (2x16) peak types using historical ratios.

subsequent years, annual peak market prices are derived by applying a market implied heat rate to the Companies' natural gas price forecast. Annual off-peak and weekend prices are derived by applying market implied ratios relative to peak pricing to the aforementioned peak market price forecast. Monthly prices are derived by applying monthly weighting factors by peak type to the annual price forecasts. The monthly weighting factors are based on the forward average of the monthly weighting by peak type.

Monthly prices are shaped to daily average prices by peak type by maintaining a correlation between the Companies' forecasted daily average energy and the forecasted daily average electricity price in each month, based on their historical correlation. This relationship serves as a proxy for the correlation between the daily load level in the PJM market and the corresponding daily average electricity price. The daily average prices are derived by multiplying the forecasted monthly average prices (by peak type) by a daily weighting that reflects the correlated variances between forecasted daily vs. average monthly loads and forecasted daily vs. average monthly electricity prices, based on historical observations. Hourly prices are then derived by multiplying the daily prices by hourly price multipliers that reflect the historical average ratios of hourly prices to daily prices by month and by peak type and then applying an historical PJM WH/PJM-S discount factor.

3.1.4.2 Emission Allowance Prices

The dispatch cost for each unit includes the unit's fuel cost, variable O&M costs, the cost or revenue from CCR management, and the cost of emission allowances.[8] Emission allowance price forecasts are developed for SO_2, ozone seasonal NO_x, and annual NO_x emission allowances. Initial prices reflect market prices as of a specific recent quote date for allowances under the Cross-State Air Pollution Rule. Longer-term prices reflect those in a third-party's most recent long-term planning scenario. No CO_2 emission allowance prices are included.

3.1.4.3 Hourly Off-System Sales and Purchase Volume Limits

The OSS and purchase limit inputs determine the maximum quantity (in MW) of OSS and economy purchases that can be made in any given hour. Because the volatility of available transmission capacity cannot be modeled effectively in PROSYM, limits on hourly OSS and economy purchases are used to align the volume of modeled OSS and economy purchase transactions with recent historical experience.

3.1.4.4 Off-System Sales and Purchase Price Thresholds

When making an OSS or economy purchase, the Companies incur various costs related to the transaction. These costs are referred to as OSS and purchase "thresholds." OSS and purchase thresholds include the cost of transmission and transmission losses, independent system operator balancing charges, and a risk premium the Companies' Power Supply group uses to manage the uncertainty that exists between real-time prices and aggregated hourly (or settled) prices.

3.1.5 Resource Expansion Plan Inputs

The expansion plan inputs specify the timing and type of generation resources planned, if any, to be added to the Companies' generation portfolio to meet customers' needs for energy and capacity. These generation resources can take the form of new generating units or power purchase agreements with a third-party provider. Generation resource inputs are discussed in Section 3.1.1.

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[8] Ozone seasonal NO_x emission allowance prices are dispatched at $0 through 2024 to maximize allocations in the Good Neighbor Plan.

3.1.6 System Constraints

PROSYM enables the user to model a variety of physical constraints that exist within the Companies' transmission system and generation portfolio. These constraints are discussed in the following sections.

3.1.6.1 Transmission Constraints

The Companies' transmission and distribution system is designed to deliver electricity from generation resources to load under a variety of circumstances. Despite the flexibility that is afforded the Companies, some constraints can occur in real time. For example, the Companies model a limit to the energy that can flow from LG&E to KU.

3.1.6.2 Spinning Reserve Requirements

As a NERC balancing area, the Companies are required to carry contingency reserves to ensure the reliability of the grid. To meet these obligations in a least-cost manner, the Companies are party to a reserve sharing agreement with TVA. By sharing reserves with TVA, the Companies are able to reduce the amount of contingency reserves they need to carry. The Companies model these reserve requirements.

3.1.6.3 Off-System Sales Constraints

As a general rule, because hourly market prices can fluctuate, potential OSS margins from SCCTs do not justify the wear and tear associated with starting a unit in anticipation of potential OSS margins. Therefore, the Companies' SCCTs are generally only committed to meet customers' need for peak energy. For this reason, a constraint is modeled in PROSYM that reduces OSS by limiting modeled OSS when SCCTs are operating, which results in a proportion of OSS from SCCTs in line with historical volumes.

3.1.6.4 Dispatch Order Rules

Dispatch order rules determine the order in which different types of generation resources are dispatched. The majority of generation resources are dispatched economically, as specified with the "Commit" variable as "=economic" or "3." However, some units are specified with "Commit" as "4" or "5," meaning these units aren't available for commitment until all the economically dispatched units are online. For example, curtailment of the Companies' CSR customers is limited to times when most or all other company-owned resources have been or are being dispatched. The dispatch order rules enable the Companies to model this constraint.

3.2 Prepare Draft Generation Forecast

In the second part of the process used to develop the Companies' generation forecast, model inputs are loaded into PROSYM and PROSYM is used to prepare a draft generation forecast. PROSYM is a complex model, so extensive review takes place to ensure that the inputs are correctly loaded and that the model results are reasonable. An input variance analysis evaluates the impact of changing each input or group of related inputs to ensure that the associated output changes are reasonable. Then, various elements of the generation forecast are compared to historical trends for reasonableness. The input variance analysis and comparison of the forecast to history are discussed in more detail in the following sections.

3.2.1 Input Variance Analysis

The process of performing an input variance analysis begins with the previous year's generation forecast and is completed in steps. As each input or group of inputs is updated, PROSYM is used to create a new forecast. A comparison of forecast results for each step reveals the impact of changing each input (or group of related inputs) incrementally, and includes a comparison of native load production costs, OSS margin, generation volumes, unit capacity factors, fuel burn, and other factors. In most cases, the change from the previous year's forecast to the current year's forecast is explained primarily by a limited number of factors. Despite this fact, the impact of all input changes is evaluated carefully. If the impact of a change is not deemed reasonable, the model inputs are adjusted and the process is repeated.

3.2.2 Comparison of Forecast to History

The goal of the generation forecasting process is to produce the most accurate forecast possible. In addition to the input variance analysis, numerous elements of the forecast are compared to historical trends to further assess the reasonableness of the forecast. In many cases, the forecast should be consistent with historical trends. When this is not the case, it is important to ensure that forecasted deviations from historical trends are reasonable. The following is a sample of forecast elements that are compared to historical data.

- Annual/monthly/hourly generation by generation resource
- Annual/monthly fuel burn by generation resource
- Annual startup fuel by generation resource
- Annual SCCT starts and run hours
- Annual/monthly/hourly OSS volumes by peak type
- Annual/monthly/hourly OSS margin by peak type
- Annual/monthly/hourly economy purchase volumes by peak type
- Annual SO_2/NO_x emissions
- Annual/monthly capacity factor by generation resource
- Annual/monthly intercompany transaction volumes
- Annual/monthly dispatch order

3.3 Review

In the third part of the process used to develop the Companies' generation forecast, the results of the forecast are reviewed by other departments. This review process ensures that the forecast considers feedback from a broad range of perspectives.

The following groups are primary consumers of the forecast results and review various elements of the forecast to help ensure that the results are reasonable:

- Corporate Fuels and By-products: The Corporate Fuels and By-Products group reviews the fuel burn forecast by generating station and fuel type.
- Power Supply: The Power Supply group reviews the forecasts of OSS margin, OSS volumes, and economy purchase volumes by peak type.
- Plant Management: Plant managers review the forecasts of generation by station and fuel type.

3.4 Deliverables

After forecast reviews are completed, the forecast deliverables are distributed to the groups within the company who use the forecast to prepare financial budgets. The following is a list of key deliverables:

- Generation Forecast
- Fuel Burn Forecast
- Fuel Expense Forecast
- OSS Margin Forecast

- Emissions Forecast
- CCR Production Forecast

2024 IRP – Transmission Section

Introduction

In this section of the IRP, the Companies provide a general explanation of the Companies' transmission posture; the primary objectives of the Companies' transmission planning and operations, including a brief explanation of some changes to the transmission planning process that will be implemented in the near future; and specific transmission planning analysis supportive of this IRP.

LG&E/KU Transmission System Overview

In 1998, LG&E and KU's transmission operations were merged after LG&E Energy acquired KU Energy. Today, LG&E and KU together operate the largest Transmission System in Kentucky.[1] The Transmission System serves more than 1,030,500 retail customers, and an additional 125,000 electric customers connected either directly or through interconnections with other smaller distribution companies (cooperatives) and municipal utility systems. The Transmission System spans more than 5,400 miles with voltages from 69kV to 500kV.

Since the LG&E and KU merger in 1998, the Transmission Systems of both utilities have been jointly planned, operated, and maintained as one combined system under the LG&E and KU Joint Pro Forma Open Access Transmission Tariff ("OATT") on file with the Federal Energy Regulatory Commission ("FERC").[2] However, the KU portion of the Transmission System and LG&E portion of the Transmission System do vary significantly in both design and performance due to dissimilar geography and customer bases. The KU portion of the Transmission System is mostly rural, with low customer density, long circuits and more infrastructure required to serve customers. The LG&E portion of the Transmission System is more compact, with built-in redundancy and circuit ties, serving a mostly urban customer base in and around Louisville.

[1] For the purposes of this discussion, the Transmission System should be considered to be inclusive of all LG&E/KU networked transmission facilities at 69 kV and above.
[2] Unless otherwise defined, all terms used herein shall have the meaning as defined in the OATT.

Figure 1 below shows the LG&E and KU service territory and Table 1 lists the count by Transmission asset type and voltage.

Figure 1- LG&E and KU Service Territory

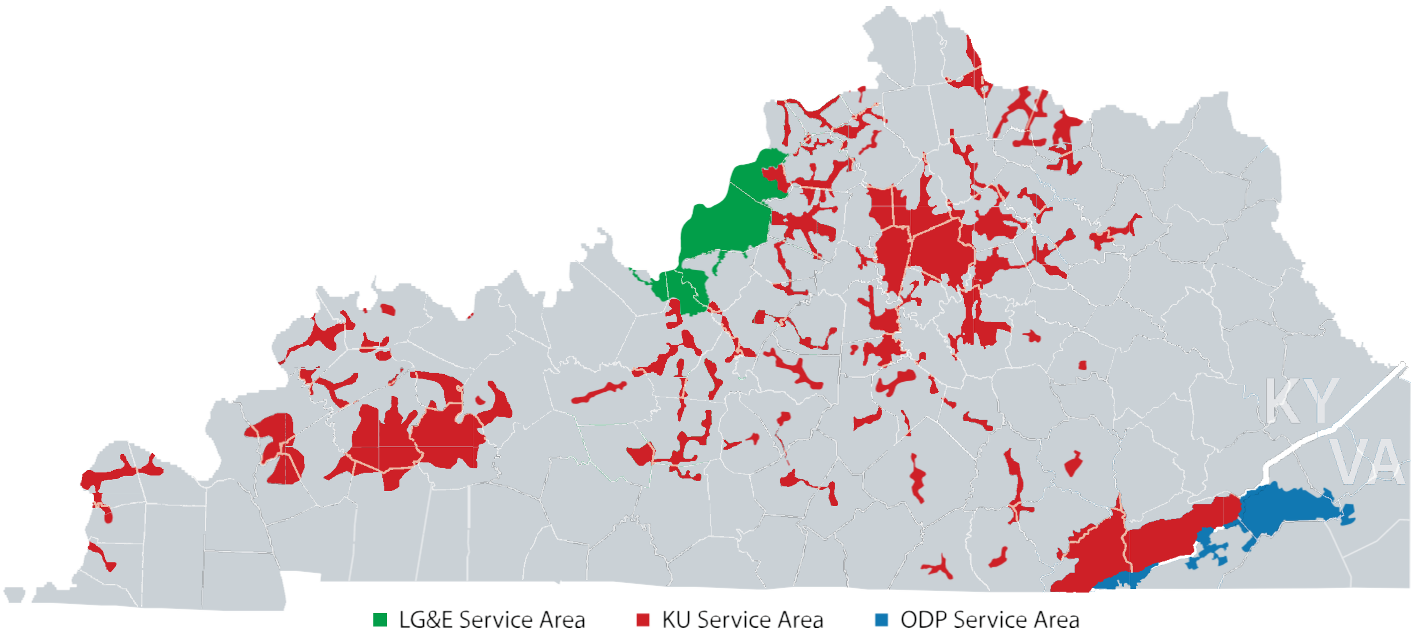

Table 1 – Asset Counts by Voltage

			Transmission Voltages				
Company	**Assets**	**Totals**	69 kV	138 kV	161 kV	345 kV	500 kV
Total	Circuits	472	269	131	29	41	2
	OH Circuit Miles	5,402	2,704	1,301	657	683	57
	UG Circuit Miles	10.1	6.0	4.1	-	-	-
	Substations (High Voltage)	176	60	59	34	21	2
	Transformers	135	-	75	32	26	2
	Circuit Breakers	1,319	677	447	85	107	3
	Switches	744	681	49	14	-	-
	Motor Operators	275	232	29	14	-	-
	Poles/Structures	43,803	28,685	8,511	3,638	2,745	224
	Retail Customers	1,169,964	954,974	214,620	368	2	-

The Companies are providing a map of their transmission system as Appendix A.

The LG&E/KU Transmission Department (Transmission) provides transmission and ancillary services to Transmission Customers, including the Companies themselves as load-serving entities, in accordance with the OATT.[3] Transmission treats all Transmission Customers on a non-discriminatory basis in accordance with the OATT and the FERC standards of conduct.

A. Interconnections with Adjacent Transmission Systems

The LG&E/KU Transmission System is well connected with neighboring Transmission Systems. Since 2013, new Bulk Electric System interconnections have been put in service, including a 345 kV interconnection with Duke Indiana (Kenzig Rd.), a 345 kV interconnection with Big Rivers (Redmon Rd.), and a 161 kV interconnection with Big Rivers (Matanzas).

The following list details the LG&E/KU interconnections by the neighboring Transmission System in alphabetical order:

Interconnections	Neighboring Transmission System
Hyden Tap - Wooton 161 kV	AEP (PJM)
Sardinia - Kenton 138 kV	AEP (PJM)
Morehead - Rodburn 69 kV	AEP (PJM)
Clinch River - Virginia City 138 kV	AEP (PJM)
Cloverport - New Hardinsburg 138 kV	BREC (MISO)
Green River - Wilson 161 kV	BREC (MISO)
Hardinsburg - New Hardinsburg 138 kV	BREC (MISO)
Hartford Tap 69	BREC (MISO)
Daviess County EHV - Coleman EHV 345 kV	BREC (MISO)
Daviess County EHV - Wilson 345 kV	BREC (MISO)
Wilson - Matanzas 161 kV	BREC (MISO)
Matanzas - BR Tap 161 kV	BREC (MISO)
Redmon Road - Otter Creek 345 kV	BREC (MISO)
Joppa - Joppa 345 - Grahamville 854	GLH (MISO)
Joppa - Grahamville 804	GLH (MISO)
Blackwell KU to Blackwell Duke 138/69 kV Transformer	DUKE IN (MISO) DUKE OH (PJM)
Clifty Tap 2 - Miami Fort 138 kV	DUKE IN (MISO) DUKE OH (PJM)
Ghent to Batesville 345 kV	DUKE IN (MISO) DUKE OH (PJM)
Ghent to Fairview 138 kV	DUKE IN (MISO) DUKE OH (PJM)
Jeffersonville Tap to Jeffersonville 138 kV	DUKE IN (MISO) DUKE OH (PJM)
Kenzig Rd - Ramsey 345 kV	DUKE IN (MISO) DUKE OH (PJM)
Kenzig Rd - Speed 345 kV	DUKE IN (MISO) DUKE OH (PJM)
Northside to Louisville Cement 138 kV	DUKE IN (MISO) DUKE OH (PJM)
Paddys West to Gallagher 138 kV	DUKE IN (MISO) DUKE OH (PJM)
Trimble County to Ghent 345 kV (Duke-owned line section)	DUKE IN (MISO) DUKE OH (PJM)

[3] Other customers, include (but not limited to) Big Rivers Electric Corporation, East Kentucky Power Cooperative, Hoosier Energy REC, Kentucky Municipal Energy Agency, Kentucky Municipal Power Agency, Owensboro Municipal Utilities, and the Tennessee Valley Authority

Trimble County to Speed 345 kV	DUKE IN (MISO) DUKE OH (PJM)
Baker Lane Jct. - Baker Lane 138 kV	EKPC (PJM)
Bardstown Industrial - East Bardstown 69 kV	EKPC (PJM)
Beattyville 161/69 kV Transformer	EKPC (PJM)
Beattyville EKPC Jct. - Delvinta 161 kV	EKPC (PJM)
Beattyville KU - Beattyville EKPC 69 kV	EKPC (PJM)
Black Branch - Central Hardin 138 kV	EKPC (PJM)
Blue Lick - Cedar Grove Industrial Park 161 kV	EKPC (PJM)
Bonds Mill (634) - South Anderson (634) 69 kV	EKPC (PJM)
Bonds Mill (644) - South Anderson (624) 69 kV	EKPC (PJM)
Bonnieville 138/69 kV Transformer (W8-628)	EKPC (PJM)
Boonesboro North Tap - Boonesboro North 138 kV	EKPC (PJM)
Brodhead - KU Brodhead 69 kV	EKPC (PJM)
Bromley KU - Owen County 69 kV	EKPC (PJM)
Buckner-Bluegrass Generating Station 4550 345kV	EKPC (PJM)
Buckner-Bluegrass Generating Station 4551 345kV	EKPC (PJM)
Bullitt Co - Bullitt Tap 161 kV	EKPC (PJM)
Carntown - Bracken County 69 kV	EKPC (PJM)
Carrollton - Hunters Bottom 69 kV	EKPC (PJM)
Cedar Grove - Bullitt Co 161 kV	EKPC (PJM)
Clay Lick Tie - KU Clay Lick Tie 69 kV	EKPC (PJM)
Clay Village Tap - Clay Village 69 kV	EKPC (PJM)
Cynthiana Jct - KU Cynthiana Tie 69 kV	EKPC (PJM)
Cynthiana Switching - Renaker 69 kV	EKPC (PJM)
Davis - KU Spears 69 kV	EKPC (PJM)
Delvinta - Green Hall Jct. 161 kV	EKPC (PJM)
Eastview - Stephensburg 69 kV	EKPC (PJM)
EKPC Davis N.O. - Fawkes-West Hickman 69 kV	EKPC (PJM)
Elihu - Cooper 161 kV	EKPC (PJM)
Etown - Kargle 69 kV	EKPC (PJM)
Etown - Tharp 69 kV	EKPC (PJM)
Farley - Liberty Church 69 kV	EKPC (PJM)
Fawkes - Duncannon Lane 69 kV	EKPC (PJM)
Fawkes KU - Fawkes EKPC 138 kV	EKPC (PJM)
Fawkes Tap - Fawkes EKPC 138 kV	EKPC (PJM)
Ferguson South - Somerset 69 kV	EKPC (PJM)
Floyd - KU Floyd 69 kV	EKPC (PJM)
Fogg Pike - KU Spencer Road 69 kV	EKPC (PJM)
Ghent - Gallatin County 138 kV	EKPC (PJM)

Ghent - Gallatin Steel Industrial 345 kV	EKPC (PJM)
Greensburg KU - Green County 69 kV	EKPC (PJM)
Hardin County - Central Hardin 138 kV	EKPC (PJM)
Hodgenville KU - Hodgenville EKPC 69 kV	EKPC (PJM)
Hopewell - Laurel County 69 kV	EKPC (PJM)
Kenton - Murphysville 69 kV	EKPC (PJM)
Kenton - Spurlock 138 kV	EKPC (PJM)
KU Bedford Tap - KU Lawrence 69 kV	EKPC (PJM)
KU Vine Grove Tap - KU Vine Grove 69 kV	EKPC (PJM)
Lake Reba Tap - Union City 138 kV	EKPC (PJM)
Lancaster - Garrard County 69 kV	EKPC (PJM)
Lebanon - Marion County 138 kV	EKPC (PJM)
Loudon Avenue - Avon 138 kV	EKPC (PJM)
Manchester - KU Manchester 69 kV	EKPC (PJM)
Millersburg Tap - KU Carlisle 69 kV	EKPC (PJM)
Nelson County Tap - Nelson County 138 kV	EKPC (PJM)
New Haven - Hodgenville 69 kV	EKPC (PJM)
North London KU - North London EKPC 69 kV	EKPC (PJM)
Owen County Tap - Owen County 138 kV	EKPC (PJM)
Paint Lick-605 tap (normally open) to Paint Lick-605 tap EKPC 69 kV	EKPC (PJM)
Paris - Paris Tap 138 kV	EKPC (PJM)
Pittsburg 161/69 kV Transformer	EKPC (PJM)
Pleasant Grove - LGE Pleasant Grove 69 kV	EKPC (PJM)
Rodburn - Rowan County 138 kV	EKPC (PJM)
Rogersville - Rogersville Jct. 69 kV	EKPC (PJM)
Sardis - Murphysville 69 kV	EKPC (PJM)
Scott County - Penn 69 kV	EKPC (PJM)
Sharon - Bracken County 69 kV	EKPC (PJM)
Shelby County - Shelby County Tap 69 kV	EKPC (PJM)
Somerset - Oak Hill 69 kV	EKPC (PJM)
Somerset South - Somerset 69 kV	EKPC (PJM)
Springfield - North Springfield 69 kV	EKPC (PJM)
Taylor County - Taylor County Jct. 161 kV	EKPC (PJM)
Union Underwear - Sewellton 69 kV	EKPC (PJM)
West Garrard KU - West Garrard EK 345 kV	EKPC (PJM)
West Nicholasville Tap - KU West Nicholasville Tap 69 kV	EKPC (PJM)
West Shelby to Bekaert 69kV	EKPC (PJM)
Wofford - Goldbug 69 kV	EKPC (PJM)
Daviess County - Smith 345 kV	OMU

Green River Steel - Smith 138 kV	OMU
Green River Steel - Smith 69 kV	OMU
Smith - Smith Tap 138 kV	OMU
Carrollton - Clifty Creek 138 kV	OVEC (PJM)
Clifty Tap 1 (Northside) - Clifty Creek 138 kV	OVEC (PJM)
Clifty Tap 2 (Miami Fort) - Clifty Creek 138 kV	OVEC (PJM)
Trimble County - Clifty Creek 345 kV	OVEC (PJM)
Bullitt County EKPC - TVA Summer Shade Tap (161 kV)	TVA (TVA)
Calvert City - Livingston County 161 kV	TVA (TVA)
Eddyville Prison - Kentucky Dam 69 kV	TVA (TVA)
Kentucky Dam - Livingston County 161 kV	TVA (TVA)
Kentucky Dam - South Paducah 69 kV #1	TVA (TVA)
Lebanon Jct. - Summershade 161 kV	TVA (TVA)
Phipps Bend - Pocket North 500 kV	TVA (TVA)
Pineville (KU) SS - Pineville (TVA) SS 161 kV	TVA (TVA)
Cloverport - Cannelton 138 kV (Z82)	VECTREN (MISO)

LG&E/KU coordinate with neighboring systems on both planning and operational needs. This coordination is memorialized in the interconnection agreements between neighboring systems and LG&E/KU and the Joint Reliability Coordination Agreement between LG&E/KU, the Tennessee Valley Authority ("TVA"), and PJM.

B. Service Under the OATT

The OATT is a FERC-approved tariff under which LG&E/KU provides open and comparable access to the LG&E/KU Transmission System for all potential Transmission Customers.[4] The OATT provides transparent standard processes that are applied to all Transmission Customers in a non-discriminatory manner to ensure entities have equitable access to the LG&E/KU Transmission System. The OATT describes the process for submitting and evaluating Transmission Service Requests ("TSRs") on the LG&E/KU Transmission System. When granted, these TSRs reserve transmission capacity for their term on the LG&E/KU Transmission System for use in the delivery of electric energy from power supply or resources to load, or use of the LG&E/KU Transmission System for wheeling (e.g., through service). The LG&E/KU OATT also describes the process for submitting and evaluating Generator Interconnection Requests ("GIRs") on the LG&E/KU Transmission System. These GIRs are submitted from any entity (including LG&E/KU) desiring to connect a generating resource to the Transmission System.

[4] The OATT generally adopts the FERC pro-forma tariff language (established by FERC Order 888 in 1996, and subsequently amended thereafter) with very limited deviations.

The OATT is publicly available on LG&E/KU's Open Access Same-Time Information System ("OASIS").[5] Additionally, LG&E/KU maintains and posts publicly detailed business practices, policies and procedural documents that aid customers in the TSR and GIR submission processes. These documents also clearly articulate the requirements of TSR and GIR customers. Notably, the *FAC-001 Facility Interconnection Requirements* procedure is posted and contains LG&E/KU's minimum interconnection requirements for generators or loads connecting to the Transmission System and outlines the requirements for transmission tie-line interconnections as well. There are also publicly posted documents that provide customers with clear and transparent guidance on the allocation of costs associated with the construction of LG&E/KU facilities that allow the interconnection of load or generation; these documents are the *Allocation of Costs for End-User Customers* and *Allocation of Costs for Generator Interconnections*.

C. Role of the Independent Transmission Organization

As part of LG&E/KU's departure from MISO in 2006, FERC stipulated that LG&E/KU have an independent entity perform most of the administrative functions of the OATT. This independent entity, the Independent Transmission Organization ("ITO"),[6] is to independently administer various sections of the OATT, including:

- Receipt, processing, and approval or denial of TSRs (including administration of the Available Transfer Capability calculation process);
- Receipt, processing, and approval or denial of GIRs;
- Independent oversight of and approval authority with respect to the LG&E/KU transmission planning criteria and the annual Transmission Expansion Plan ("TEP") for the LG&E/KU Transmission System;
- Facilitation of various opportunities for stakeholder engagement and review, including two stakeholder meetings (one in July and another in November); and
- Maintaining the LG&E/KU OASIS website.

Reliability Performance

A. Transmission System Improvement Plan

In connection with their 2016 applications for adjustment of base rates and for issuance of certificates of public convenience and necessity, KU (Case No. 2016-00370) and LG&E (Case No. 2016-00371) submitted a spending plan for improvement of the LG&E and KU combined Transmission System. This plan, entitled the Transmission System Improvement Plan ("TSIP"), projected $108.3 million in spending on reliability investments over a five-year period from 2017-

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[5] LG&E/KU's OASIS website is available at: www.oasis.oati.com/LGEE/index.html.

[6] TranServ International, LLC is currently LG&E/KU's ITO.

2021, and $429.5 million in system integrity and modernization investments over the same period.

At that time the LG&E portion of the Transmission System was a 1st quartile performer for system SAIDI exclusive of major event days ("MED"). The KU portion of the Transmission System was a 4th quartile performer. The TSIP was a targeted program to improve reliability performance with a long term (15-20 year) goal of becoming a combined (LG&E/KU) first quartile performer in SAIDI, with a medium term (5-10 year) goal of becoming a combined 2nd quartile performer. The program set a goal of improving system SAIDI by 3-6 minutes over the 5-year window 2017-2021.

In the 2022 final annual report to the Commission on this program, LG&E/KU were able to realize a reduction of 6.3 total minutes of SAIDI, excluding MEDs, throughout the five years of the TSIP, successfully meeting the program goal.

While the TSIP plan focused specifically on reducing outage durations, the strategic transmission investments have more broadly delivered optimized value to all Transmission Customers by improving the reliability and resiliency of the LG&E/KU system.

Examples of such investments include line sectionalizing devices like in-line breakers and motor operated switches ("MOS") to reduce outage durations and enhance operational awareness and Automatic Reclosing Schemes ("ARS") that sectionalize transmission lines during the breaker reclose cycle to eliminate the SAIDI impact for a portion of customers on certain lines.

Transmission's investments through the TSIP resulted in significant reliability improvements and enhanced resiliency that benefit customers. Specifically, as a result of these efforts the Companies have seen a decline of Transmission SAIDI from a system average of 12.6 from 2010 to 2016 to a system average of 4.8 from 2017 – 2024 YTD (62% improvement) as well as a decline of Transmission SAIFI from a system average of 0.19 from 2010 to 2016 to a system average of 0.08 from 2017 – 2024 YTD (58% improvement) as seen in Figure 2 and Figure 3 below. The Companies' transmission SAIDI and SAIFI metrics are now consistently in the second quartile and have been since 2019.

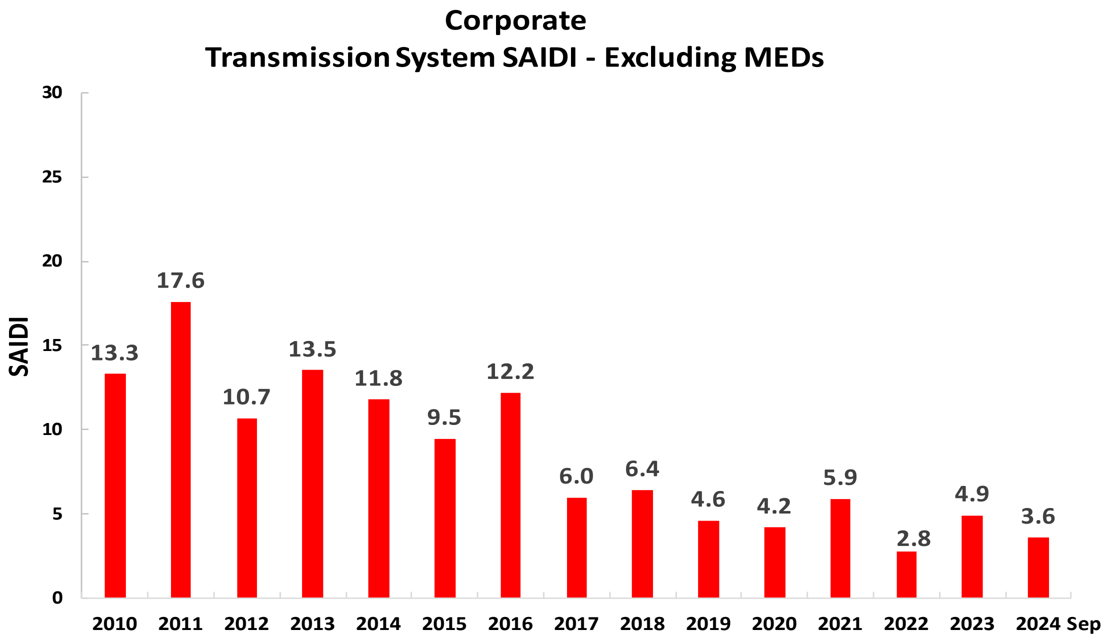

Figure 2 – LG&E/KU Transmission SAIDI through Sep. 2024

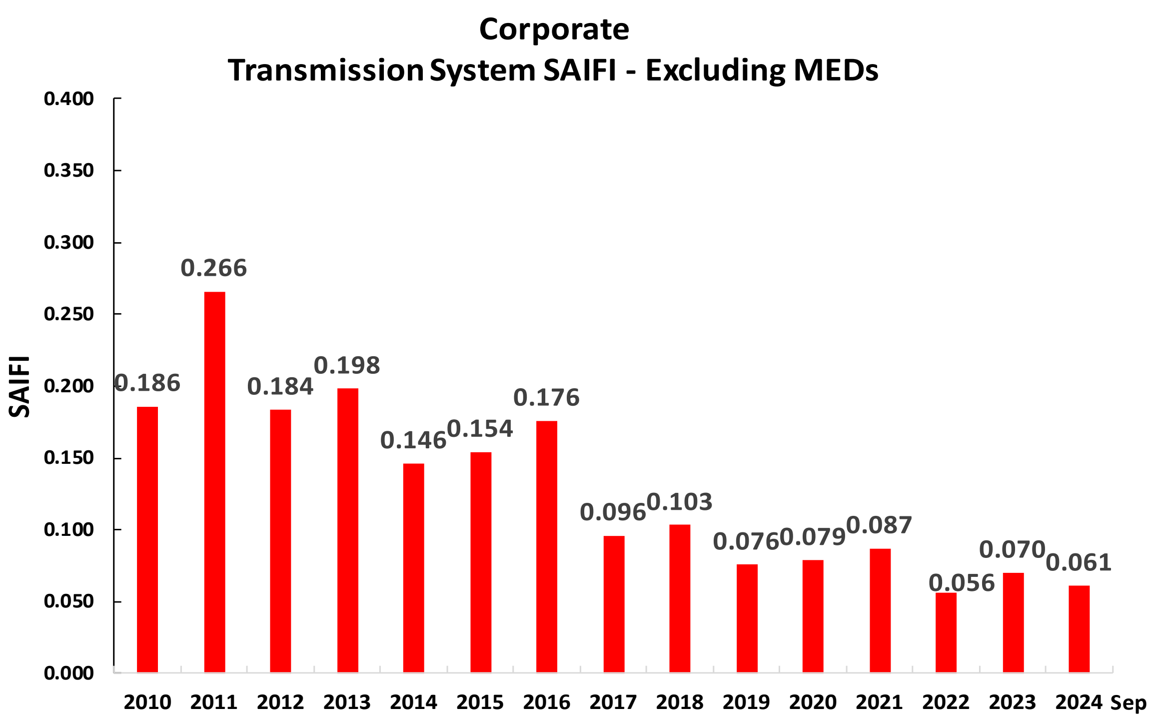

Figure 3- LG&E/KU Transmission SAIFI through Sep. 2024

Prior to the TSIP program, the worst offenders for total SAIDI, exclusive of MEDs, had a total of 29 minutes of SAIDI from 2010-2016. By contrast, the top ten worst offenders from 2017-2023 had a combined total of 11.17 minutes of SAIDI. This is reflective of system-wide improvement. Significant improvements in reliability resulting from TSIP investments on specific lines were described in the final TSIP annual report issued in 2022 on file with the Commission.[7]

In addition to SAIDI reduction, LG&E/KU evaluate Customer Minutes Interrupted ("CMI") to measure the benefits of completed reliability projects. The table below shows the CMI caused by outages, CMI avoided thanks to MOS additions (with or without ARS schemes), and percent reduction in CMI for the lines in question.

Table 2 - Annual CMI Reductions

Year	Actual CMI (million)	Avoided CMI (million)	Percent Reduction
2017	0.8	0	0%
2018	0.92	2.0	69%
2019	1.35	1.6	54%
2020	1.52	3.6	71%
2021	1.12	1.4	55%
2022	2.18	3.7	63%
2023	3.29	3.9	54%

B. Making the Right Investment

One of the most important ways Transmission ensures reliability for customers and resiliency of its system is by investing in replacing aging, end-of-life equipment to improve system hardening (such as wooden poles with steel) and to reduce failure of high-risk assets (such as circuit breakers and relays) while enabling smart restoration and fault detection. Replacement of aging transmission assets not only contributes to Transmission System reliability now, but also improves the resiliency and reliability of the Transmission System long into the future. The assets being replaced are nearing end-of-life or obsolete. Replacement parts for many of these aging assets are costly and difficult to obtain, and do not necessarily extend the life of the assets. Replacement assets installed also employ modern technology which enhances the overall safety and resiliency of the system.

Furthermore, many of the lines being improved were previously designed for medium loading under the National Electrical Safety Code ("NESC"). New equipment installed on these lines is designed for heavy loading under the NESC, improving the ability of the line to withstand severe weather events such as wind and ice storms. For example, while most of the poles being replaced

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[7] *Application of Louisville Gas and Electric Company for an Adjustment of its Electric and Gas Rates and for Certificates of Public Convenience and Necessity*, Case No. 2016-00371, LG&E and KU Transmission System Improvement Plan Annual Report (June 1, 2022), available at https://psc.ky.gov/pscecf/2016-00371/andrea.fackler@lge-ku.com/06012022125621/Closed/2-2022_TSIP_Annual_Report.pdf.

on the Transmission System are wood, most of the replacement poles are steel. Steel poles have a longer expected life than wood poles, are more resilient to hazards and severe weather events, and do not deteriorate like wood poles. This approach is typical in the industry for transmission structures, particularly in areas where woodpeckers are common, such as Kentucky.

Replacement of aging infrastructure also reduces the risk and potential impact of environmental contamination. Replacing oil circuit breakers reduces the amount of oil in the Transmission System, thus reducing environmental risks posed thereby.

C. Summary

In summary, the investments the Companies have made provide long lasting benefits to system resilience, public and employee safety, and operational efficiency in addition to improving overall system reliability.

- ○ Over 7,200 wood structures have been replaced with steel, 245 oil circuit breakers have been replaced by sulfur hexafluoride (SF6) gas circuit breakers or vacuum circuit breakers and 133 miles of circuits have been rebuilt since 2017.
- ○ More than 221 motor-operated switches with ARS have been added, saving over 3.9 million minutes of interruptions in 2023 and over 16.7 million minutes since 2017.

Improved System Efficiency

A. Investments Yielding Improved Efficiency

Other investments have also yielded operational efficiencies. By reducing the frequency and duration of events, streamlining event response, and identifying fault locations more accurately, these investments have enabled remote operation and efficient re-energization. In practice this has allowed the Companies to optimize crew deployments and reduce the need for manual operation, which drives down deployment durations and customer costs. Some of the tools, methods, and operational processes that Transmission has deployed to increase efficiencies include:

- The transmission data warehouse ("TRODS") enables LG&E/KU to leverage data from several sources across Transmission to identify and prioritize strategic investments.
- Installation of additional MOS and ARSs on the Transmission System beyond the TSIP.
- Implementation and use of a GIS fault location tool that pairs digital fault recorder ("DFR") data with a geospatial view of the Transmission System to provide system operators with detailed fault location predictions in real time.
- Line fault indicators ("LFI") have been installed in strategic locations throughout the Transmission System to aid Transmission system operators in fault location and restoration.
- Installation of modern microprocessor relays that provide greater event details and more precise fault locations and the ongoing transition to IP connectivity to make even more data from microprocessor relays available in real-time.

- A pilot installation of SEL-T401L relays was installed in 2023 to explore the new and emerging technology of ultra high-speed protection (sub-cycle tripping time) and explore the benefits of traveling wave data for fault location and monitoring asset health.

B. Planning for Additional Efficiency Investments in the Future

Transmission is actively engaged in a project that will focus on the targeted installation of ultra-high-speed relays in other locations. In addition, Transmission continues to explore new technologies and their benefits for the LG&E/KU Transmission System, such as Viper reclosers that can be installed on 69kV lines. Reclosers are commonly used in Distribution applications but are relatively new technology for Transmission System applications due to the higher voltage class and predominantly networked systems.

Transmission System Planning

Transmission completes annual Transmission System planning in accordance with NERC Reliability Standard, TPL-001-5, and Attachment K of the OATT. Annual Transmission System planning includes local transmission planning, which focuses on the LG&E/KU Transmission System; regional transmission planning, which involves coordinated planning across multiple systems that compose a region; and interregional transmission planning, which involves consideration of planning among neighboring regions. The primary objective of Transmission is to provide reliable transmission service from power supply to load in a least cost manner, safely and in compliance with applicable rules and regulations. Transmission Customers are responsible for forecasting their load, ensuring they have adequate power supply or resources to serve their load, arranging for adequate transmission capacity rights for the delivery of power supply or resources to load, and communicating this information to Transmission. Transmission uses this information to conduct transmission planning and identify any needs and projects that must be constructed so that the LG&E/KU Transmission System meets reliability performance requirements.

A. Local Transmission Planning

The LG&E/KU TEP is the product of the local transmission planning process that is set forth in OATT Attachment K, Sections 1-10. As noted in Attachment K, Section 3 – Transparency, local transmission planning is performed in accordance with the Transmission System Planning Guidelines, available on LG&E/KU's OASIS site,[8] under the heading "Transmission Planning" and then "LGE-KU Transmission Planning Guidelines."

The Transmission System Planning Guidelines outline the basic criteria, assumptions, and data that underlie transmission planning for the LG&E/KU Transmission System, including:

[8] http://www.oasis.oati.com/LGEE/index.html

- Adherence to NERC and SERC Reliability Standards;[9]
- Treatment of native load;
- Transmission contingencies and measurements;
- Thermal and voltage limits;
- Minimum operating voltage at generating stations; and
- Modeling considerations.

The Transmission System Planning Guidelines have been developed in compliance with NERC Reliability Standard TPL-001-5.1 and establish the minimum planning criteria for the LG&E/KU Transmission System, including all equipment and facilities operated at 69 kV and above.

Each year, Transmission issues data requests through its NERC Reliability Standard MOD-032 process requiring all the generators, load serving entities, and transmission owners in the LG&E/KU Planning Coordinator area to provide planning information. Transmission uses the information received from these entities to create base models throughout the 10-year transmission planning horizon (specifically, Years 2, 5, and 10). For each model year, summer and winter models are created, and off-peak models are created for Year 2. Two different sets of summer and winter models are created using two different load forecasts: 1) a 50/50 load forecast, where the load has a 50% probability of reaching that level, and 2) a 90/10 load forecast, where the load has a 10% probability of reaching that level. Transmission then creates a list of system contingencies that are expected to produce more severe System impacts, based upon NERC Reliability Standard TPL-001-5.1 Table 1.

Using these models and contingencies, Transmission performs three types of analysis: Steady State, Dynamic Stability, and Short Circuit. In Steady State analysis, the Transmission System is evaluated to determine if any thermal or voltage limits are violated in our base models under normal or contingency conditions. In Dynamic Stability analysis, we observe whether, after a contingency and within the appropriate period (e.g., within 4 seconds of the contingency taking place), the Transmission System responded reliably or there were voltage or frequency stability issues observed. In Short Circuit analysis, the amount of power flow through each circuit breaker during a short circuit fault on the Transmission System is determined and whether that circuit breaker's breaker duty rating is sufficient to interrupt the flow of power and isolate the fault.

After these three types of analyses have been completed, Transmission identifies all violations of our criteria, along with the equipment and time within the planning horizon in which they occurred. For each criteria violation, Transmission then develops Corrective Action Plans ("CAPs"). These CAPs are generally projects to upgrade the LG&E/KU physical Transmission System, but could also be a temporary operating guide, if the violation is temporary.

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[9] SERC Reliability Corporation ("SERC") is the regional entity with delegated authority from NERC for enforcement of NERC reliability standards and the development of regional reliability standards for a portion of the southeastern and central regions of the United States, including the LG&E/KU Transmission System.

Transmission compiles all this information—models, contingency list, criteria violations, and CAPs—and sends to the ITO by October 31 of each year. The ITO reviews all information and provides feedback. There are usually several rounds of feedback, lasting months. The Reliability Coordinator ("RC") for LG&E/KU, which is TVA, also reviews this information and approves from a regional coordination perspective. Once LG&E/KU Transmission, the ITO, and the TVA RC agree that the Transmission System expansion plan has been completed according to all applicable rules and regulations, the ITO approves the plan, which is then posted to OASIS.

The Companies' latest ITO-approved TEP is their 2023 Transmission Expansion Plan, which is attached as Appendix B.

B. Transparency and Opportunities to Participate in Local Planning

The ITO holds two meetings each year in which interested stakeholders of the LG&E/KU Transmission System can participate. In the first stakeholder meeting, held each July, Transmission presents the preliminary TEP in addition to providing an update on the construction progress of any initiated project since the previous stakeholder meeting. In the second stakeholder meeting, held each November, Transmission presents the final TEP in addition to an update on the construction progress of any initiated projects since the previous stakeholder meeting. Additionally, at this second meeting, the ITO provides their independent assessment of the TEP and asks for stakeholder feedback and comments. At both meetings, the ITO provides status updates on TSRs and GIRs studies and provides a transparent overview of TSRs approved and denied since the prior stakeholder meeting. Stakeholders are invited to ask questions and engage in these discussions.

Stakeholders also have the opportunity to ask questions and suggest alternatives to the TEP via their participation in the Stakeholder Planning Committee ("SPC"). The SPC is independently organized and led by stakeholders, and membership on the SPC is open to all interested parties. The SPC provides a forum for stakeholders to provide input to Transmission regarding the transmission planning process, including the opportunity to comment on the development of accurate data inputs for study simulations, the appropriateness of study simulations being performed, and the correctness of the execution of study simulations. The SPC also enables members to review study results as they are performed over the study development cycle.

Stakeholders also have the ability to request that Transmission perform up to five informational studies, free of charge. These studies, known as Economic Planning Studies, provide valuable insight about the Transmission System's ability to accommodate power transfers into, out of, and within the LG&E/KU Planning Coordinator area. Additionally, each year, Transmission requests stakeholders to provide possible transmission needs as a result of enacted state, federal and local laws and regulations.

Stakeholders also are encouraged to provide feedback on business practices and impactful procedural documents developed by Transmission. These documents are posted publicly on

OASIS for a comment period, typically lasting thirty calendar days. The ITO and Transmission consider comments prior to finalizing these documents.

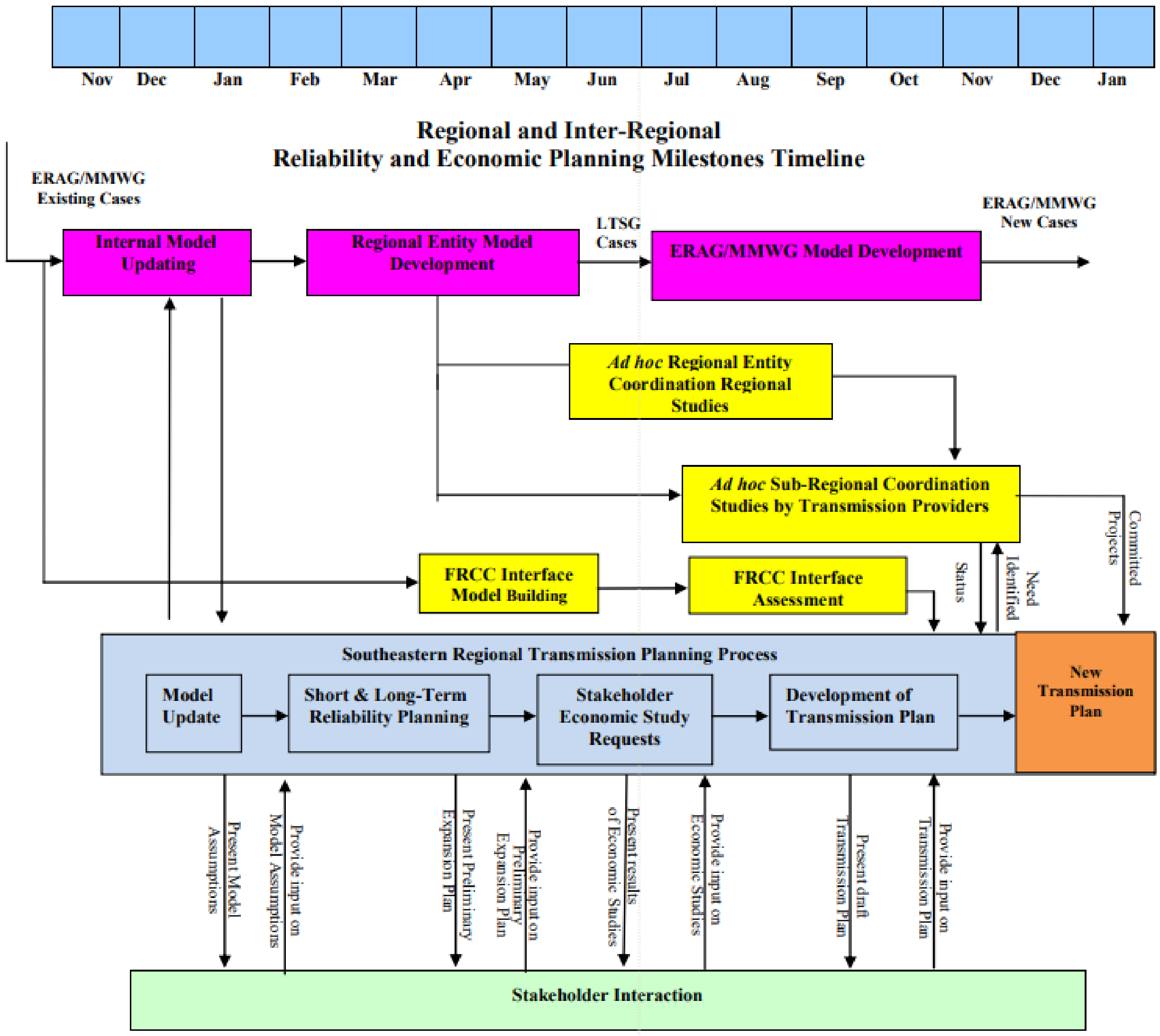
C. Regional Transmission Planning

The LG&E/KU regional transmission planning process is set forth in OATT Attachment K, Sections 11-32. During each transmission planning cycle, Transmission conducts regional transmission analyses to assess if the then-current regional transmission plan addresses the LG&E/KU Transmission System's transmission needs, including those of its Transmission Customers and those which may be driven by economic considerations or Public Policy Requirements. This regional analysis will include assessing whether there may be more efficient or cost-effective transmission projects to address transmission needs than transmission projects included in the latest regional transmission plan.

As noted in OATT Attachment K, LG&E/KU meet the regional planning requirements of the OATT through the Companies' participation in the Southeast Regional Transmission Planning ("SERTP") process. SERTP includes the following sponsors ("Sponsors"):

- Southern Company
- Dalton Utilities
- Georgia Transmission Corporation
- Municipal Electric Authority of Georgia
- PowerSouth
- LG&E/KU
- Associated Electric Cooperative Inc.
- TVA
- Duke Energy (specifically, Duke Energy Carolinas, LLC and Duke Energy Progress, LLC)

A flowchart diagramming the SERTP process, as well as providing the general timelines and milestones for the performance of the reliability planning activities is provided below.



D. Transparency and Opportunities to Participate in Regional Planning

Each calendar year, the SERTP generally conducts and facilitates four meetings ("Annual Transmission Planning Meetings") that are open to all SERTP stakeholders, and the details regarding any such meeting are posted on the Regional Planning Website.[10] During the meeting held in the first quarter of each calendar year, a Regional Planning Stakeholders Group ("RPSG") is formed for that year. The RPSG and any other interested stakeholders may select up to five stakeholder requested Economic Planning Studies that they would like to have studied by the

[10] https://www.southeasternrtp.com/home.cshtml

Sponsors. The Sponsors also host an Assumptions Input Session, which provides an open forum for discussion with, and input from, the SERTP stakeholders regarding the data gathering and transmission model assumptions that will be used for the development of the Sponsors' following year's ten year transmission expansion plan.

E. Interregional Transmission Planning

Interregional transmission planning coordination with the transmission planning regions that neighbor the SERTP occurs biennially with each of those regions.[11] Interregional transmission planning coordination is a process between the SERTP and each neighboring region (i) with respect to an interregional transmission facility that is proposed to be located in both transmission planning regions and (ii) to identify possible interregional transmission facilities that could address transmission needs more efficiently or cost-effectively than transmission facilities included in the respective regional transmission plans.

Key Regulatory and Compliance Considerations

A. Additional Transmission Planning Activities

In addition to local, regional, and interregional transmission planning activities outline above, Transmission also contributes to SERC transmission planning efforts. Transmission participates in the following transmission planning groups within SERC:

- Long-Term Working Group – updates model for entire SERC region, which then gets incorporated into the Eastern Interconnection model at NERC
- Geomagnetic Disturbance Working Group – develops guidelines and best practices for meeting performance criteria and sharing and developing models and data related to geomagnetic disturbances
- Interregional Transmission Capacity Study Task Force – reviews SERC models, data, and preliminary results used in the NERC Incremental Capacity Transfer Study
- Planning Coordination Subcommittee – provides input to the SERC Engineering Committee on risk prioritization efforts and directs reliability assessment strategy and process
- Dynamics Working Group – coordinates and submits dynamic stability models and data for the SERC region to be incorporated into the Eastern Interconnection model at NERC
- Variable Energy Resource Working Group – oversees Inverter-Based Resource-related activities

[11] These regions include: the Florida Reliability Coordinating Council region, the Midcontinent Independent System Operator region, the PJM Interconnection region, the South Carolina Regional Transmission Planning Process region, and the Southwest Power Pool region.

For additional considerations into large interregional transfers, please refer to the Eastern Interconnection Planning Collaborative ("EIPC") ITC White Paper that is attached as Appendix C. LG&E/KU is a member and active participant in the EIPC.

B. Significant Changes Ahead

As the Commission knows, electric transmission is highly regulated, and has been increasingly in focus by stakeholders and regulators. In addition to existing and continuously changing NERC Reliability Standards, FERC recently issued major orders that significantly impact how Transmission conducts business. Specifically, Order Nos. 2023 and 1920 pose notable changes to the generation interconnection process and regional and interregional transmission planning processes, respectively.

Transmission and the ITO spent much of the past year developing plans to comply with Order 2023. This work resulted in a compliance filing at FERC on May 15, 2024. FERC Order 2023 required Transmission to change the way it and the ITO evaluated GIRs, from a serial process, in which each GIR was studied individually, to a cluster study process, in which all GIRs submitted within a request window are studied together. This change required an overhaul of Transmission and the ITO's GI processes and study criteria. To allow for stakeholders to transition to the new process, FERC required all transmission providers to study all existing GIRs in one transitional cluster study. Transmission and the ITO started the transitional cluster study process on October 1, 2024, expecting to complete the study later in 2025.

Order 1920 was issued by FERC on May 13, 2024. Major elements of Order 1920 include:

- Requirement to conduct and periodically update long-term (20-year) regional transmission planning to anticipate future needs using at least three scenarios that include consideration of several FERC-specified factors.
- Requirement to consider a broad set of FERC-specified benefits when making a determination as to whether to select a project to address transmission needs identified through the long-term regional transmission planning process.
- Requirement to identify opportunities to modify in-kind replacement of existing transmission facilities to increase their transfer capability, known as "right-sizing."
- Requirement to have on file a default cost allocation methodology for projects selected for cost allocation, in which costs are allocated roughly commensurate with benefits.
- Requirement to engage with the states on several issues associated with selecting and determining how to pay for projects identified through the long-term regional transmission planning process.
- Changes to stakeholder engagement processes for local, long-term regional, and interregional planning.

Transmission and the other SERTP Sponsors will be reaching out to our respective state entities in the near future to initiate a formal engagement period to discuss certain changes mandated by Order 1920. Compliance filings modifying all but the interregional process in accordance with Order 1920 are due June 12, 2025. Compliance filings meeting Order 1920's requirements with respect to interregional planning are due August 12, 2025.

C. Strong Record of Compliance

Transmission has a strong compliance culture and successful track record of compliance with NERC Reliability Standards. SERC conducts audits of the Companies' compliance with the NERC Operations and Planning and NERC Critical Infrastructure Protection Reliability Standards on a three-year cycle. However, the Company has also gone through several "spot checks" (SERC compliance reviews outside the three-year cycle). In the past 3 years, the Companies successfully completed a full audit of compliance with the Operations and Planning Reliability Standards with no violations and have completed three additional "spot checks" with no violations. The three "spot checks" were related to FAC-008 (Facility Ratings) and two on the suite of Extreme Weather (EOP-011, Emergency Operations; EOP-012, Extreme Weather Preparedness and Operations; and TOP-002, Operations Planning).

Value Transmission (Regional and Interregional) and Imports Provide

As explained above, the primary objective of Transmission is to provide reliable transmission service from power supply to load in a least cost manner, safely and in compliance with applicable rules and regulations. Transmission carries this objective forward when planning and responding to the needs identified by Transmission Customers. To plan appropriately, Transmission looks to Transmission Customers to provide their forecasts and plans for use of the system to ensure transmission planning aligns with this future use.

For example, Transmission Customers may elect to purchase power supply interconnected to the LG&E/KU Transmission System or other Transmission Systems. If these customers indicate an increase in power supply sourced on another Transmission System, Transmission will evaluate the LG&E/KU Transmission System to identify any need for increased import capability. Location of the power supply dictates what, if any, expansion is needed to provide transmission service. Transmission does not plan or build in a manner to direct or influence Transmission Customer action; instead, Transmission plans and builds in a manner that is responsive to its Transmission Customers projected needs while still ensuring the Transmission System can operate safely and reliably in accordance with the NERC Reliability Standards.

A broad-brush view exists that an expanded grid capacity, especially regional and interregional, is needed to accommodate generation retirements, new power supply, and to improve resiliency and reliability. Transmission continues to look to Transmission Customers and stakeholders, through the information these entities provide and engagement in the stakeholder processes to ensure transmission planning is aligned with the real, forecasted needs and use of the Transmission System. Transmission is not pursuing or obligated to engage in speculative transmission development or to pursue an "if you build it, they will come" approach. In addition, incremental regional or interregional transmission capacity is not a substitute for power supply. Instead, Transmission intends to continue to plan for increased grid capacity in a manner that is aligned with customer and stakeholder needs. Transmission can thereby ensure that the projects it undertakes to increase grid capacity remain economical to satisfy potential demands on the system while maintaining reliability.

Transmission Analysis in this IRP

2024 IRP Generation Replacement & Retirement Scenarios – Impact to the LG&E/KU Transmission System

As part of the 2024 LG&E/KU IRP, Transmission was tasked with determining the expected impact that certain generation replacement scenarios would have on the LG&E/KU Transmission System and identify any transmission projects and an estimate of associated costs that would be required as a result.[12] These generation replacement scenarios included seven potential generation retirements and seventeen potential generation replacements starting in 2030.

Transmission system planning models were modified to represent each of the generation replacement scenarios. The next step was to conduct P0, P1, and P3 analyses defined in the North American Electric Reliability Corporation ("NERC") Transmission Planning Reliability Standard, TPL-001-5.1 Table 1, on each of the models.[13] The results of the study were then analyzed to determine any additional projects that would be required due to voltage or MVA flow violations resulting from each of the generation replacement scenarios.

For purposes of this study, the self-build NGCC generators were assumed to be capable of 645 MW in the summer (net) and 660 MW in the winter (net). Each scenario includes the retirement(s) and addition(s) of all units in the previous scenarios. Finally, for scenarios that follow the retirement of any generation at Ghent (i.e., Scenarios 4-7), the replacement generation was assumed to be at Ghent.

Once the required projects were determined, planning level cost estimates were assigned to each project using a process consistent with our cost estimation process for Generation Interconnection Feasibility Studies.

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[12] *See* IRP Vol. III, Generation Replacement & Retirement Scenarios – Impact to the LG&E/KU Transmission System.
[13] P0 is a simulation of the normal operating system with no contingencies. P1 is a simulation of a normal operating system with a single contingency (loss of a generator, transmission circuit, transformer, or shunt device). P3 is a simulation of the loss of a single generator unit, followed by system adjustments. Once the generator outage is simulated followed by system adjustments, all P1 contingencies were simulated. This includes a second generator, transmission circuit, transformer, and shunt devices on BES contingencies. *See* NERC TPL-001-5 — Transmission System Planning Performance Requirements at Table 1, pages 21-22, available at https://www.nerc.com/pa/Stand/Reliability%20Standards/TPL-001-5.pdf.

While the study does identify the Transmission System projects that would be required to accommodate these replacement scenarios, the study is based on the information that is available today. The projects identified in this study may change or additional projects may be identified as the Transmission System and adjacent Transmission Systems continue to change and new information is provided (e.g., transmission topology, generation changes, revised load forecasts, and large load additions).

Also, FERC Order 2023 has required Transmission Planners to change the way our Generator Interconnections are studied, from a serial process that studies one generator at a time to a study process that studies several generators at once together on a "cluster" basis. The Order also formalized how Transmission Planners must process Affected Systems Studies, or the effects a generator may have on a neighboring Transmission System. These changes in study methodology may very well change what upgrades are identified and costs allocated to each generator at the time an official Interconnection Study is conducted.

2024 IRP Long-Term Firm Transfer Analysis – Impact to the LG&E/KU Transmission System

As part of the 2024 LG&E/KU IRP, Transmission was also asked to identify any network upgrades that could be required on the LG&E/KU Transmission System if long-term firm transmission service was requested for various import/export scenarios.[14] The analysis focused on scenarios involving importing energy from a neighboring Transmission Owner ("TO") to LG&E/KU and exporting energy from LG&E/KU to a neighboring TO. Energy transfer volumes used in the analysis were 100 MW, 300 MW, 500 MW, and 1000 MW. The neighboring TOs included were MISO, PJM, and TVA.

The models used in this analysis were based on LG&E/KU's 2024 TEP and include a 2033 summer peak model and 2033/34 winter peak model. Base models were then modified to simulate the energy transfers between LG&E/KU and the neighboring TOs.

The study included all contingencies for P0, P1, and P3 categories and all monitored elements consistent with the LG&E/KU TEP and study procedure for Transmission Service Requests.

Once the required projects were determined, planning level cost estimates were developed for each project.

While the study does identify the Transmission System projects that would be required to accommodate these replacement scenarios, the study is based on the information that is available today. The projects identified in this study may change or additional projects may be identified as the Transmission System and adjacent Transmission Systems continue to change and new information is provided (e.g., transmission topology, generation changes, revised load forecasts, and large load additions).

[14] *See* IRP Vol. III, Long-Term Firm Transfer Analysis – Impact to the LG&E/KU Transmission System.

[redacted]

N

0 20 40 60 80 Miles

Transmission System Map

Scale: 1:2,000,000 Feet

User: e027998

Plot Date: 10/15/2024

Transmission Section
Appendix B
2023 Transmission Expansion Plan

Project Number	DESCRIPTION	ETI Date
1164	Install a second 345/138 kV, 450 MVA transformer at Brown N. Upgrade the terminal equipment associated with breaker 152-724 at Brown N for the Brown N to Pisgah 138 kV line including the 1200 amps disconnects (GO002266 & GO002267) associated with breaker 152-724, 1200 amp switch 152-725 (GO002457) and 1590 MCM 54x19 ACSR Risers (SC001042 & SC006096) with equipment capable of at least 2000 amps summer emergency. The switches need to be at least 2000 amp switches.	11/29/2022
1163	Shift distribution load from Terry 69kV to International and Pleasure Ridge 138kV.	11/30/2022
1158	Replace the 69kV Power Fuse (701-625F) associated with the Bedford KU - Lawrence 69kV line with a fuse capable of a minimum of 325 amps winter emergency.	12/8/2022
1156	Install redundant bus differential and lockout relays at the Brown CT 138kV bus.	1/1/2023
1043	Conductor replacement of the 0.75 miles of 556 ACSR conductor in the Elihu to Ferguson South section of Elihu to Somerset EKPC 69 kV line with 795 ACSR conductor. Replace breaker 096-604 and associated bushing CTs (x135 & x246) with a breaker and bushing CTs capable of a minimum rating of 1600 Amps.	4/11/2023
840	Increase the MOT of 1.15 miles of 795 MCM 26X7 ACSR conductor to a minimum of 212°F and replace 0.61 miles of 795 MCM 61X AA conductor with 795 MCM 26X7 ACSR, in the Canal to Madison 69 kV line.	5/9/2023
1206	Wickliffe 69 kV Sectionalization – Change the status of switches 401-605 at Wickliffe City and 581-605 at Clinton 581 to normally open.	6/1/2023
887	Upgrade the maximum operating temperature of the 12.46 miles of 397.5 ACSR in the Kentucky Dam (TVA) to Eddyville Prison tap 69 kV line from 176°F to a minimum of 205°F.	6/29/2023
1189	Replace breakers 664-604 and 664-614 at Race Street with breakers capable of at least a 40 kA interrupting capability	6/30/2023

927	Install a breaker at Bonds Mill, separate the six-wired conductor in the existing Bonds Mill to Lawrenceburg to Florida Tile Tap line into parallel 69 kV circuits and connect to existing Tyrone to Ninevah to Florida Tile to Florida Tile Tap 69 kV line. This creates a Tyrone to Ninevah to Florida Tile to Bonds Mill 69 kV line in addition to the Tyrone to Lawrenceburg to Bonds Mill 69 kV line. Increase the Maximum Operating temperature of the 6.88 miles of 397 ACSR between Bonds Mill and Florida Tile tap (both circuits) from 140F to 165F.	8/9/2023
1180	Relocate the normally open switch (848-605) at Stanford to Cemetery Road (573-625).	11/30/2023
1199	Add Transient Recovery Voltage (TRV) capacitors to breakers TC-4512 and TC-4542 at Trimble County to increase their fault interrupting capabilities from 50 kA to 63 kA.	1/1/2024
908	Replace 0.1 miles of 795 MCM 61X AA, 4.6 miles of 500 MCM 19X CU conductor, and 795 MCM 61X AA line risers and jumper in the Blue Lick to Cedar Grove Tap 161 kV line with 954 MCM 45X7 ACSR or better.	5/30/2024
1191	Install redundant relaying at Blue Lick 345 kV for breaker BL-4532-38 TIE.	5/30/2024
832	Increase the maximum operating temperature of the 2.53 miles of 397 ACSR in the Hodgenville to Hodgenville EKPC section of the Etown to Hodgenville EKPC 69 kV line to 176F	5/30/2024
92	Conductor replacement of 7.16 miles of 397.5 MCM 26X7 conductor in the Middletown to Mid Valley Simpsonville 69 kV line including the line risers, using 795 MCM 26X7 ACSR or better conductor.	11/30/2024
169	Replace the 345 kV 2000A breakers at Middletown and Buckner associated with the Middletown-Buckner 345 kV line (circuit 4543) with 3000A breakers.	3/10/2025
659	Increase the maximum operating temperature of the 3.37 miles of 795 MCM AA (176/176) in the Aiken to Eastwood West section of the Aiken to Eastwood to WHAS 69kV line to 212°F.	5/30/2026
1200	Disable reclosing on the Bluegrass Parkway to Hurstbourne 138kV line.	1/1/2027
870	Conductor replacement of 1.37 miles of 397.5 MCM 26x7 ACSR conductor in the Bardstown - Bardstown Industrial Tap section of the Bardstown - EKPC East Bardstown 69 kV line using 556.5 MCM 26X7 ACSR.	5/30/2027

967	Increase the maximum operating temperature of the 397.5 MCM 26X7 ACSR conductor (0.58 miles, 176°F) in the Bardstown Industrial Tap to East Bardstown 69 kV line to 212°F. The limiting facility will become EKPC's terminal equipment at East Bardstown.	5/30/2027
1105	Increase the MOT of 0.76 mile of 397.5 ACSR in the Greenville West tap to Greenville 69 kV line to 140F.	5/30/2027
661	Replace 0.83 miles of 556 ACSR conductor in the Ferguson South to Somerset EKPC section of the Elihu to Somerset EKPC 69 kV line with 795 ACSR.	11/30/2028
612	Increase the MOT to 185°F of the 397.5 MCM 26X7 ACSR conductor in the Elizabethtown #4 to Hodgenville section of the Elizabethtown to Hodgenville 69 kV line. (8.51 miles, currently 170F.)	5/30/2029
728	Replace 1.6 miles of 795 MCM 61X AA conductor in the Worthington - 6659 Tap section of the Worthington - Freys Hill 69 kV line using 795 MCM 26X7 ACSR.	5/30/2031
734	Increase the MOT to 212F of the 795 kCM 45X7 ACSR (5.02 miles) in the Taylor to Harrods Creek 69 kV line.	5/30/2031
1171	Replace the 1000 Amp 69kV Bushing CT associated with the Pittsburg 161/69 kV transformer with a minimum rated 1200 Amp CT.	11/30/2031
1201	Reset /Replace the free standing CT less than 1215 amps (emergency) and increase the loadability of the relays on the Fawkes to Ducannon Lane EKPC 69kV.	11/30/2024

Eastern Interconnection Planning Collaborative

Technical Considerations for Large Power Transfers Between Regions

EXECUTIVE SUMMARY

The Eastern Interconnection Planning Collaborative (EIPC)[1] provides this analysis for policymakers to outline some of the important technical considerations associated with determining an appropriate level of interregional transfer capability (ITC). Enhancing interregional transfer capability can carry with it many benefits but not without consideration of challenges and costs that can sizably tilt the cost/benefit analysis. It is for this reason that choosing an arbitrary target level of interregional transfer capability is not the best approach. Rather, careful analysis using common metrics can help to provide the information that policymakers need to make informed judgments on a case-by-case basis as to the application of those metrics.

EIPC and its members, who are responsible for planning and operation of the bulk power system for the Eastern Interconnection, stand ready to continue to serve as a resource to policymakers and stakeholders alike as these important issues are discussed and debated to ensure continued delivery of power to meet customers' needs in a reliable and efficient manner into the future.

[1] The Eastern Interconnection Planning Collaborative is an organization that was formed in 2009 by North American Electric Reliability Corporation ("NERC")-registered Planning Coordinators in the Eastern Interconnection ("EI") to perform coordinated interconnection-wide transmission analysis. The EIPC is a "Technical Organization" pursuant to its Mission Statement, which provides a forum for interregional coordination of the combined plans of its regional members (representing both ISO/RTO and non-ISO/RTO regions) to evaluate how well the regional plans mesh to maintain the reliability of the bulk electric system. The EIPC develops transmission system models and performs interregional scenario analysis to identify stress points on the EI-wide system, providing feedback to enhance the regional plans of our members. The EIPC also publishes periodic reports to assess the state of the Eastern Interconnection. By way of example, in 2022 the EIPC published its 'State of the Grid' Report and a White Paper on "Planning the Grid for A Renewable Future" and has published technical reports on other analyses related to planning of the transmission grid in the Eastern Interconnection. For more information, please visit http://www.eipconline.com

Eastern Interconnection Planning Collaborative

OVERVIEW

EIPC is pleased to provide this whitepaper to outline for policymakers and stakeholders some of the key technical issues associated with:

(a) determining an appropriate level of interregional transfer capability between regions within the Eastern Interconnection; and
(b) then expanding the high voltage transmission system to achieve the appropriate level of transfer capability.

The current Eastern Interconnection transmission system reliably enables the delivery of economic transfers, firm transactions and emergency power purchases. A robust transmission system also helps to maintain reliability between regions during extreme events, when reliable power is needed the most. Understanding and planning to an appropriate level of interregional transfer capability will lead to enhanced reliability, enabling the continuous delivery of electric power to customers during extreme weather, fuel supply disruptions and physical or cyber-attacks.

This document has been prepared by the EIPC to ensure awareness for regulators, policy makers, and other interested parties of the technical issues that should be considered when expanding interregional transfer capability (ITC). It is intended to raise awareness of the engineering complexities and technical issues that must be considered when assessing the benefits and costs of committing to any substantial investments required to enhance interregional transfer capability. As with other issues facing the electric grid, regulators and policymakers should consider a measured and informed approach on this complex issue.

ENHANCING INTERREGIONAL TRANSFER CAPABILITY – AN OUTLINE OF THE POLICY DEBATE

A. Activity to Date

Although policymakers have traditionally focused on the planning, cost allocation and siting of specific transmission projects, there has been a suggested movement towards determining an appropriate fixed level of interregional transfer capability and then requiring transmission expansion to meet that pre-determined level.

The Federal Energy Regulatory Commission (FERC) has led this effort through its various notices of proposed rulemaking on transmission planning which have raised specific questions for stakeholder comment as to whether the FERC should mandate such a pre-determined level or otherwise enhance interregional transfer capability both within the nation's interconnections and across the nation's three interconnections. On December 5-6, 2022, the Commission held a Technical Conference on this specific issue which featured a variety of speakers on the topic. The EIPC was represented by PJM's Executive Director of System Planning and EIPC Technical Committee Chairman David Souder who stated:

> *"The EIPC can assist in the development of metrics and a methodology that would be informative to transmission planners to facilitate their determination of the appropriate level of interregional transfer capability (i.e., minimum interregional transfer criteria) between regions under extreme conditions. The resultant minimum interregional transfer criteria would be informative to help ensure adequate transfer capability between regions, enhancing both reliability and resilience as the nation faces more extreme weather and other transmission-related challenges. Although the metrics and analysis should be common across the Interconnection … the application of those metrics and analysis to any particular interregional tie would reflect the specific locational and regional characteristics of the two adjoining regions."*[2]

Mr. Souder went on to note EIPC's intention to examine this issue in greater depth, to identify areas within the Interconnection where interregional transfer capability could be improved and provide input into the determination, ultimately to be made by state and federal policymakers, as to the proper metrics to consider in determining the appropriate level of interregional transfer capability between regions within the Eastern Interconnection.[3]

B. Issues Under Consideration in the Debate

Debate on the issue has been wide ranging. In particular, questions have arisen as to:

- Whether it is prudent as a policy-matter to pre-determine a level of interregional transfer capability among regions and direct transmission enhancements to meet that level?
- Should the level of interregional transfer capability be uniform across an interconnection (and across interconnections), or should the level of transfer capability vary given the differences between regional grid topologies and local considerations?
- What decision-making tools and metrics should be utilized to determine a particular level of interregional transfer capability?

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[2] EIPC Testimony for Interregional Transfer Workshop - December 5 2022

[3] More recently, through H.R.3746, the Fiscal Responsibility Act of 2023, Congress directed the North American Electric Reliability Corporation (NERC) to study various aspects of this issue.

- How to best measure the cost and benefits of an appropriate level of interregional transfer capability and how best to apply that analysis given the different grid topologies within the interconnections?
- Who should ultimately decide the appropriate metrics and weigh the costs vs benefits of such grid enhancements on a case-by-case basis?
- Should the level of interregional transfer capability be driven by reliability needs or should this determination also include a goal of equalizing economics or policy outcomes across regions within an interconnection?
- Which entity is best to perform the detailed analysis to inform policymakers and what should that analysis include?

As noted above, this paper will outline some of the key technical and engineering-related questions associated with determining an appropriate level of interregional transfer capability and in building out the transmission system to meet that level. In the view of the EIPC, these technical considerations and engineering challenges need to be considered as inputs to policymakers' determinations on the above list of issues.

KEY TECHNICAL AND ENGINEERING CONSIDERATIONS

At the outset, it should be noted that interregional transfer capability is not a new concept. From the inception of the electric grid, steps were taken to interconnect regions to reflect the greater reliability value and strength of an interconnected grid. Joint ownership and operating agreements were developed across the country to allow for the sharing of power from jointly developed generators which were sized to serve more than any single region.

Enhancing interregional transfer capability remains a valuable step to help ensure that diversity of both supply and load patterns are reliably managed and to effectuate economic transactions that benefit customers. Nevertheless, enhancing interregional transfer capability is not without its costs and challenges. Nor should it serve as a substitute for individual regions taking responsibility to ensure resource adequacy within their region. With these thoughts in mind, EIPC outlines below various technical challenges that, although not by any means insurmountable, are issues that policymakers should consider when addressing whether they should require additional interregional transfer capability and how the grid should be expanded to enable such increases in transfer capability.

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RELIABILITY ISSUES FOR CONSIDERATION

In considering whether to increase interregional transfer capabilities, policymakers need to avoid unintended consequences that could actually result in a degradation of reliability. There are many factors that could increase the reliability risk associated with large increases in interregional transfer capability which include line distance and generation supply.

1. ***Increased exposure to high impact, low frequency events*** – Enhanced interregional transfer capability should not become a substitute for each region ensuring it is meeting its resource adequacy needs, since reliability risks could increase. Specifically, regions will become more impacted by forced outages of major transmission facilities and other high impact events that can now cascade into adjoining regions. Risks associated with dependencies on distant systems become harder to model in transmission planning and resource adequacy analyses as the number of potential outages and the electrical distances that could adversely impact a given system increase exponentially. By way of example, the loss of multiple key transmission lines in one region in conjunction with other lower probability events can now have a much greater interregional impact than might have existed previously.

2. ***Issues associated with long-distance transmission lines*** – To the extent enhanced interregional transfer capability entails the development of more long-distance transmission lines (including High Voltage Direct Current "HVDC") there can be increased reliability risk due to their length and a corresponding increased risk of outage due to severe weather including lightning, hurricanes, tornados, physical attack, wildfires, etc. The probability of a transmission outage is increased as line distances are increased and as such, may not meet the intended level of reliability or resiliency. A recent example occurred on July 5, 2023, when heavy smoke from Canadian wildfires caused the New England electric system to call for emergency measures.[4]

   A special consideration that comes into play with long-distance (also known as "long-haul") HVDC lines is the significant amount of power that can be lost under a single contingency. Most HVDC lines, especially those that have recently been or are planned to be placed in service in the next few years are designed to deliver thousands of megawatts (MW) of

[4] Canada Wildfire Smoke Triggered New England Grid Emergency - Bloomberg

energy on a single connection. Such an HVDC line originates in one Balancing Authority Area and terminates in a separate Balancing Authority Area (BAA), normally hundreds of miles distant from each other. If the line is taken out of service by an event such as a tornado, then the source BAA instantly has an energy surplus and the sink BAA is left with an energy deficit of thousands of MW that must be addressed. For most receiving BAAs, this means that they must account for an HVDC line of this nature to be its most severe single contingency which could require costly mitigation measures to ensure reliability (such as construction of a parallel circuit over a separate route or maintaining higher levels of Contingency Reserves).

3. ***<u>Countervailing Considerations</u>*** – These factors do not mean that enhanced interregional transfer capability should be avoided. By contrast, relying solely on local resources, particularly in small Balancing Authority Areas, exposes that region to greater risk from local weather impacts or fuel supply constraints that can be ameliorated in part through strong ties with larger neighboring regions with surplus capacity to sell and the transmission capacity to deliver that surplus energy to its neighbors. Enhancing interregional transfer capability in those situations can increase the likelihood of reliable operations when local resources are subject to common mode failure risk. As a result, balance is needed and a specific case-by-case analysis, using reliability standards and recognized metrics, can help to better identify those instances when enhanced interregional transfer capability can increase reliability and reduce reliability risk.

4. ***<u>Considerations for the Planning Process</u>*** **–** Existing transmission planning processes already consider a certain degree of transfer capability between adjoining regions. Consideration must also be given to whether regions should modify their existing planning processes to provide a greater degree of interregional transfer capability that a region could normally count on from its neighbors in certain circumstances. Extreme weather events can simultaneously affect several regions within the Eastern Interconnection. These events could include plausible scenarios such as a widespread storm that impacts transmission and generation infrastructure across multiple regions or a physical or cyberattack on infrastructure such as interstate pipelines that serve multiple regions within the Eastern

Interconnection,[5] The end result of this being that in true extreme events generation resources may not be available for transfer between regions.

5. ***Addressing Resource Adequacy Concerns with Remote Capacity*** – Increasing transfer capability needs to be examined as to its impact on retaining needed generation resources in a given region. There needs to be a balance between the appropriate level and types of generation from imports and internal resources both of which need to work together to enhance reliability. Enhancing interregional transmission capability can, for example, vastly increase the ability to transfer renewable generation into a region. This could have the effect of accelerating the pace of retirements of needed conventional generation to supplement the intermittent nature of renewable resources and the increased resources need to manage steeper ramp rates that can occur with increased generation output variability.

   To the extent the pace of retirements of existing generation with attributes needed to reliably manage the grid substantially exceeds the pace of new remote and/or local additions, reliability can be significantly impacted. Here too, a balance is needed between the policy goals of increasing deployment of renewable resources with the realties that reliability can be degraded during those hours when renewable resources are not available to meet the demands. If the pace of premature retirements accelerates, extreme events that impact multiple regions (*e.g.,* winter storms Uri and Elliott, heat dome across the entire south, Superstorm Sandy) there might not be enough excess resources to send to neighboring regions and/or the transmission to transfer the power may be damaged from the extreme event. With increased retirements of local generation, this could cause larger resource adequacy risks for different regions. Regions may need to take actions, potentially out of market, to ensure the continued quantity of resources is available to meet resource adequacy criteria in the future.

6. ***Time Requirement for Construction of High-Voltage Transmission Lines*** – To facilitate a significant increase in the current level of transfer capability between Transmission Planning Regions, a significant number of new, long-distance high-voltage transmission lines will likely be required. An important consideration for regulators and policy makers is

[5] EIPC Testimony, Sec IV, Pg 6
https://static1.squarespace.com/static/5b1032e545776e01e7058845/t/639cd78a50f0d438d326b361/1671223179859/Souder+EIPC+Testimony+for+Interregional+Transfer+Workshop.pdf

the substantial lead time for siting, permitting, and construction associated with high-voltage transmission lines including both AC and DC. On average it can take 8-10 years or more to build a high-voltage transmission line. This timeline includes planning, scoping, routing, environmental review, public comment, project approval, procurement of materials, permitting, land acquisition, and construction. Additionally, if there are multiple lines simultaneously required to increase transfer capability, other issues may come into play that could further increase the timeline including supply chain constraints or the availability of skilled labor.

While Grid Enhancing Technologies (GETs) or alternative transmission technologies such as advanced power flow control devices and synchronous condensers, may have the ability to be more quickly deployed and may provide solutions for issues specific to localized areas, deployment of those technologies will not replace the need for additional transmission lines to support any requirement for large interregional power transfers. Deployment of GETs may provide increased flexibility to real-time operations of the transmission system, however from a long-range transmission planning perspective, the construction of additional transmission lines is likely the better long-term solution to ensure a robust system if the intent is to increase firm interregional transfer capability.

7. ***Delivery Implications and Affected Systems*** – Requirements for increasing the reliable transfer of power go well beyond simply adding a new high-voltage transmission line that connects two regions. Often other components of the system that are involved in the transfer will have thermal constraints near the generation resources that limit the energy that can be sent, as well as constraints near the final load being served, all of which must be addressed to reliably deliver from source to sink. The variety of generation resources that may be required to deliver energy and the combination of loads and sink possibilities within a large region could require many additional transmission improvements to existing facilities or even new transmission lines, which could unintentionally result in significant upgrades to the local transmission systems in order to support interregional deliveries during extreme conditions. By the same token, in analyzing the costs and benefits of new long-distance transmission lines, planners will need to factor in electricity losses which are magnified over lines covering great distances. Losses increase as generation resources are located further away from load centers, which means that more generation is required than would have been needed if the resources were sited closer to the end-use customer.

Given that the Eastern Interconnection is an interconnected network of transmission systems, consideration must also be given to regions that may be impacted by a large amount of interregional power transfer between two other regions. These are known as affected systems and the likely side effects are transmission constraints that may occur and will need to be addressed either through transmission system improvement in those affected systems or thru interchange curtailments.

Here too, these issues are not insurmountable. However, policymakers need to analyze the total impact and resultant costs associated with large interregional transfers as part of a comprehensive benefit to cost assessment.

8. ***Transfer Capability Usage***

As new legislation or regulatory requirements are being developed, consideration must be given to the intent of any required increases to interregional transfer capability and how it is intended to be used. For example, if the intent is to hold any portion of the capability for emergency purposes, then limitations would need to be in place on the use in day-to-day economic transfers. Additionally, complications may arise from the use of HVDC given that the flow is scheduled. If a large number of HVDC lines are used to increase interregional transfer capability, enhanced coordination with respect to scheduling flows may be required during emergency or extreme conditions.

9. ***Networked HVAC vs Long-Haul HVDC***

As noted elsewhere, HVDC lines can be built with much greater length than HVAC, since AC is limited by the requirements of reactive power. However, the cost and complexity of HVDC terminals mean that HVDC is typically limited to a single terminal at each end of the line. Multiterminal HVDC is technically possible but is uncommon. HVAC lines are commonly built in multiterminal configurations which can provide greater flexibility in integrating and operating new lines.

HVDC transmission offers optionality and values well beyond those of HVAC, when and where required. For example, the flow across an HVDC transmission line is scheduled, while HVAC flow is less controllable. HVDC paths could be built to handle an ultimate capacity level while staging could be applied to local terminal upgrades with minimal impacts to rights-of-way or substations.

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CONCLUSION

Enhancing interregional transfer capability can carry with it many benefits but not without consideration of challenges and costs that can sizably tilt the cost/benefit analysis. It is for this reason that choosing an arbitrary target level of interregional transfer capability can create more problems than it solves. Rather, careful analysis using common metrics can help to provide the information that policymakers need to make informed judgments on a case-by-case basis as to the application of those metrics. It is for this reason that EIPC and its members, who are responsible for planning and operation of the bulk power system for the Eastern Interconnection, stand ready to continue to serve as a resource to policymakers and stakeholders alike as these important issues are discussed and debated to ensure the continued delivery of power to meet customers' needs in a reliable and efficient manner into the future.

PPL companies

Generation Replacement & Retirement Scenarios – Impact to the LG&E/KU Transmission System

2024 Integrated Resource Plan

October 16, 2024

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Executive Summary

This study was performed as part of the 2024 LG&E/KU Integrated Resource Plan ("IRP") to identify what transmission upgrades could be required on the LG&E/KU transmission system given various generation replacement scenarios. The generation replacement scenarios consisted of seven potential generation retirements and seventeen potential generation replacements starting in 2030.

Once the transmission system planning models were modified to represent each of the generation replacement scenarios, P0, P1, and P3 analyses, per NERC Reliability Standard TPL-001, Table 1, were conducted on each of the models.[1] Once the P0, P1, and P3 simulations were complete, the results were analyzed to determine any additional projects that would be required due to voltage or MVA flow violations resulting from each of the generation replacement scenarios.

Below is a description of the various replacement scenarios and an estimated LG&E/KU transmission system network upgrade cost beyond the Point of Interconnection ("POI"). For purposes of this study, each scenario includes the retirement(s) and addition(s) of all units in the previous scenarios. For scenarios that follow the retirement of any generation at Ghent, the replacement generation was assumed to be at Ghent. The self-build NGCC generators were assumed to be capable of 645 MW in the summer (net) and 660 MW in the winter (net).

- **Scenario 1 - $13.25 million:**
  - Generator Retirements: Brown Unit 3
    - Brown 3 POI: Brown North 138kV
    - Brown 3 Net MW: 416 MW
  - Generator Additions: NGCC generator interconnected at Brown North 345kV
  - Year: 2030

- **Scenario 2:**
  - Generator Retirements: Ghent 1 and Ghent 2
    - Ghent 1 POI: Ghent 138kV
    - Ghent 1 Net MW: 481 MW
    - Ghent 2 POI: Ghent 345kV
    - Ghent 2 Net MW: 495 MW
  - Generator Additions: NGCC generator interconnected at one of the following locations.
    a) Ghent 345 kV - **$0.00**
    b) Brown 345 kV - **$41.32 million**
    c) Mill Creek 345 kV - **$39.00 million**
    d) Trimble Co 345 kV - **$13.74 million**
    e) Green River 138 kV - **$82.22 million**
    f) Cane Run NGCC 138 kV **-$74.09 million**

[1] P0 is a simulation of the normal operating system with no contingencies. P1 is a simulation of a normal operating system with a single contingency (loss of a generator, transmission circuit, transformer, or shunt device). P3 is a simulation of the loss of a single generator unit, followed by system adjustments. Once the generator outage is simulated followed by system adjustments, all P1 contingencies were simulated. This includes a second generator, transmission circuit, transformer, and shunt devices on BES contingencies. *See* NERC TPL-001-5 — Transmission System Planning Performance Requirements at Table 1, pages 21-22, available at https://www.nerc.com/pa/Stand/Reliability%20Standards/TPL-001-5.pdf.

- Year: 2034

- **Scenario 3:**
  - Generator Retirements: Ghent 3 and Ghent 4
    - Ghent 3 POI: Ghent 345kV
    - Ghent 3 Net MW: 489 MW
    - Ghent 4 POI: Ghent 345kV
    - Ghent 4 Net MW: 491 MW
  - Generator Additions: NGCC generator interconnected at one of the following locations.
    a) Ghent 345 kV - **$3.10 million**
    b) Brown 345 kV - **$62.33 million**
    c) Mill Creek 345 kV - **$27.56 million**
    d) Trimble Co 345 kV - **$22.83 million**
    e) Green River 161 kV - **$109.18 million**
    f) Cane Run NGCC 138 kV - **$73.14 million**
  - Year: 2037

- **Scenario 4 - $0.00:**
  - Generator Retirements: Mill Creek Unit 3 and Mill Creek Unit 4
    - Mill Creek 3 POI: Mill Creek 345kV
    - Mill Creek 3 Net MW: 394 MW
    - Mill Creek 4 POI: Mill Creek 345kV
    - Mill Creek 4 Net MW: 486 MW
  - Generator Additions: NGCC generator interconnected at Mill Creek 345kV
  - Year: 2039

- **Scenario 5 - $0.00:**
  - Generator Retirements: OVEC units
    - LG&E/KU portion of 179 MW
  - Generator Additions: Proportionally increase member utilities generation.
  - Year: 2040

- **Scenario 6 - $0.00:**
  - Generator Retirements: Trimble Co 1
    - Trimble County 1 POI: Trimble County 345kV
    - Trimble County 1 Net MW LG&E/KU Portion: 386 MW
  - Generator Additions: NGCC generator interconnected at Trimble Co 345kV
  - Year: 2045

- **Scenario 7 - $0.00:**
  - Generator Retirements: Trimble Co #2 (POI Trimble Co 345 kV, 809 MW winter and 781 summer)
    - Trimble County 2 POI: Trimble County 345kV
    - Trimble County 2 Net MW LG&E/KU Portion: 575 MW
  - Generator Additions: NGCC generator interconnected at Trimble Co 345kV
  - Year: 2066

Introduction

Transmission Planning analyzed seven potential generation retirements and seventeen potential generation replacements starting in 2030. All the scenarios studied included the retirement of Mill Creek Unit 1 and Mill Creek Unit 2 with the previously approved Mill Creek Unit 5 installed on the Mill Creek 345 kV.

For purposes of this study each scenario includes the retirement(s) and addition(s) of all units in the previous scenarios. For scenarios that follow the retirement of any of generation at Ghent, the replacement generation was assumed to be at Ghent.

Below is a description of the various replacement scenarios that were analyzed as part of this study. The self-build NGCC generators were assumed to be capable of 645 MW in the summer (net) and 660 MW in the winter (net).

- **Scenario 1:**
    - Generator Retirements: Brown Unit 3
        - Brown 3 POI: Brown North 138kV
        - Brown 3 Net MW: 416 MW
    - Generator Additions: NGCC generator interconnected at Brown North 345kV
    - Year: 2030

- **Scenario 2:**
    - Generator Retirements: Ghent 1 and Ghent 2
        - Ghent 1 POI: Ghent 138kV
        - Ghent 1 Net MW: 481 MW
        - Ghent 2 POI: Ghent 345kV
        - Ghent 2 Net MW: 495 MW
    - Generator Additions: NGCC generator interconnected at one of the following locations.
        a) Ghent 345 kV
        b) Brown 345 kV
        c) Mill Creek 345 kV
        d) Trimble Co 345 kV
        e) Green River 138 kV
        f) Cane Run NGCC 138 kV
    - Year: 2034

- **Scenario 3:**
    - Generator Retirements: Ghent 3 and Ghent 4
        - Ghent 3 POI: Ghent 345kV
        - Ghent 3 Net MW: 489 MW
        - Ghent 4 POI: Ghent 345kV
        - Ghent 4 Net MW: 491 MW
    - Generator Additions: NGCC generator interconnected at one of the following locations.
        a) Ghent 345 kV
        b) Brown 345 kV
        c) Mill Creek 345 kV

    d) Trimble Co 345 kV
    e) Green River 161 kV
    f) Cane Run NGCC 138 kV
  - Year: 2037

- **Scenario 4:**
  - Generator Retirements: Mill Creek Unit 3 and Mill Creek Unit 4
    - Mill Creek 3 POI: Mill Creek 345kV
    - Mill Creek 3 Net MW: 394 MW
    - Mill Creek 4 POI: Mill Creek 345kV
    - Mill Creek 4 Net MW: 486 MW
  - Generator Additions: NGCC generator interconnected at Mill Creek 345kV
  - Year: 2039

- **Scenario 5:**
  - Generator Retirements: OVEC units
    - LG&E/KU portion of 179 MW
  - Generator Additions: Proportionally increase member utilities generation.
  - Year: 2040

- **Scenario 6:**
  - Generator Retirements: Trimble Co 1
    - Trimble County 1 POI: Trimble County 345kV
    - Trimble County 1 Net MW LG&E/KU Portion: 386 MW
  - Generator Additions: NGCC generator interconnected at Trimble Co 345kV
  - Year: 2045

- **Scenario 7:**
  - Generator Retirements: Trimble Co #2 (POI Trimble Co 345 kV, 809 MW winter and 781 summer)
    - Trimble County 2 POI: Trimble County 345kV
    - Trimble County 2 Net MW LG&E/KU Portion: 575 MW
  - Generator Additions: NGCC generator interconnected at Trimble Co 345kV
  - Year: 2066

Transmission Planning was tasked with determining the expected impact these replacement scenarios would have on the LG&E/KU Transmission System and identify any Transmission projects and associated costs that would be required as a result. The process used to make this determination is described below:

1. Develop model representing the generation replacement scenarios. Both expected load forecast (i.e. 50/50) and high load forecast (90/10) models were used.[2]

[2] A 50/50 peak demand scenario represents 50% probability of load being higher than forecast and 50% probability of load being fewer than forecast. A 90/10 peak demand scenario represents 10% probability of load being higher than forecast and 90% probability of load being lower than forecast.

2. Conduct P0, P1, and P3 contingency analyses on the modified models and compare with the base case models.

3. Use the results from the contingency analyses to determine if any violations of TPL-001-5 occur for the various generation replacement scenarios.

4. Determine projects that would need to be completed to mitigate any identified violations.

5. Apply a planning level project cost estimate based on the type of project to determine a total cost estimate for each scenario.

System Models

The most current 2025 TEP models were selected to perform this study:

- **2034 summer peak (50/50) –** ten-year model; peak demand scenario represents 50% probability of load being higher than forecast and 50% probability of load being fewer than forecast.

- **2034 summer peak (90/10) –** ten-year model; peak demand scenario represents 10% probability of load being higher than forecast and 90% probability of load being lower than forecast.

- **2034/35 winter peak (50/50) –** ten-year model; peak demand scenario represents 50% probability of load being higher than forecast and 50% probability of load being fewer than forecast.

- **2034/35 winter peak (90/10) –** ten-year model; peak demand scenario represents 10% probability of load being higher than forecast and 90% probability of load being lower than forecast.

The first step in the study process was to modify the models above to represent the expected system conditions for each of the generation replacement scenarios.

Study Analysis

Once the models were modified to represent each of the generation replacement scenarios, P0, P1, and P3 analyses were conducted on each of the models. These select analyses were chosen because no Non-Consequential Load Loss is allowed per TPL-001-5 Table 1, and the vast majority of LG&E/KU TEP Projects are a result of these analyses.

P0 is a simulation of the normal operating system with no contingencies.

P1 is a simulation of a normal operating system with a single contingency including loss of a generator, transmission circuit, transformer, or shunt device.

P3 is a simulation of the loss of a single generator unit followed by system adjustments. Once the generator outage is simulated followed by system adjustments, all P1 contingencies were simulated. This includes a second generator, transmission circuit, transformer, and shunt devices on BES contingencies.

This study included all contingencies and monitored elements that are consistent with the LG&E/KU Transmission Expansion Plan (TEP).

Once the P0, P1, and P3 simulations were complete, the results were analyzed to determine any additional projects that would be required due to voltage or MVA flow violations resulting from each of the generation replacement scenarios.

Study Results & Economic Impact

The sections below describe the projects identified that would be needed to prevent MVA flow and low voltage violations identified for each of the generation replacement scenarios.

Once the required projects were determined, planning level cost estimates were assigned to each project. If a cost estimate for the project already existed, it was used. If there was not an existing cost estimate for a project, the planning level cost estimates in the table below were used. This process was consistent to what is done for Generation Interconnection Feasibility Studies.

Project Type	Voltage	Lines Cost	Subs Cost	Units
Conductor Replacement	345kV	$2.25M	N/A	per mile
	161/138kV	$1.75M	N/A	
	69kV	$1.5M	N/A	
Increase MOT	345kV	$1M	N/A	per mile
	161/138kV	$500K	N/A	
	69kV	$250K	N/A	
Capacitor Bank		N/A	$3.1M	each
Transformer Addition		N/A	$9.2M	each
Breaker Replacement	345kV	N/A	$1.5M	each
Breaker Replacement	161/138kV	N/A	$1.1M	each
Breaker Replacement	69kV	N/A	$385k	each
Other Terminal Equipment		N/A	$77k	each piece

The following tables show the identified projects associated with each scenario and the estimated cost for each project.

Scenario 1:

Scenario 1 (Brown 3 with NGCC at Brown 345)		
Year	**Construction**	**Investment '24 $M's**
2030	[redacted]	$4.05M
2030	[redacted]	$9.20M
	Total Cost	**$13.25M**

Scenario 2a:

Scenario 2a (Ghent 1 and 2 with NGCC at Ghent 345)		
Year	**Construction**	**Investment '24 $M's**
2034	No upgrades necessary	$0
	Total Cost	**$0**

Scenario 2b:

Scenario 2b (Ghent 1 and 2 with NGCC at Brown 345)		
Year	**Construction**	**Investment '24 $M's**
2034	[redacted]	$3.10M
2034	[redacted]	$0.32M
2034	[redacted]	$9.20M
2034	[redacted]	$9.20M
2034	[redacted]	$9.20M
2034	[redacted]	$9.20M
2034	[redacted]	$1.10M
	Total Cost	**$41.32M**

Scenario 2c:

Scenario 2c (Ghent 1 and 2 with NGCC at Mill Creek 345)		
Year	**Construction**	**Investment '24 $M's**
2034	[redacted]	$3.10M
2034	[redacted]	$8.09M
2034	[redacted]	$4.80M
2034	[redacted]	$0.95M
2034	[redacted]	$0.18M
2034	[redacted]	$1.46M
2034	[redacted]	$9.20M
2034	[redacted]	$1.10M
2034	[redacted]	$0.32M
2034	[redacted]	$9.80M
	Total Cost	**$39.00M**

Scenario 2d:

Scenario 2d (Ghent 1 and 2 with NGCC at Trimble Co 345 kV)		
Year	**Construction**	**Investment '24 $M's**
2034	[redacted]	$3.10M
2034	[redacted]	$8.09M
2034	[redacted]	$0.95M
2034	[redacted]	$0.18M
2034	[redacted]	$1.10M
2034	[redacted]	$0.32M
	Total Cost	**$13.74M**

Scenario 2e:

Scenario 2e (Ghent 1 and 2 with NGCC at Green River 138 kV)		
Year	**Construction**	**Investment '24 $M's**
2034	[redacted]	$3.10M
2034	[redacted]	$4.80M
2034	[redacted]	$0.32M
2034	[redacted]	$9.20M
2034	[redacted]	$9.20M
2034	[redacted]	$1.46M
2034	[redacted]	$0.52M
2034	[redacted]	$1.45M
2034	[redacted]	$52.17M
	Total Cost	**$82.22M**

Scenario 2f:

Scenario 2f (Ghent 1 and 2 with NGCC at Cane Run NGCC 138 kV)		
Year	**Construction**	**Investment '24 $M's**
2034	[redacted]	$3.10M
2034	[redacted]	$1.46M
2034	[redacted]	$8.09M
2034	[redacted]	$4.80M
2034	[redacted]	$0.95M
2034	[redacted]	$0.18M
2034	[redacted]	$0.32M
2034	[redacted]	$9.20M
2034	[redacted]	$9.20M
2034	[redacted]	$4.02M
2034	[redacted]	$7.17M
2034	[redacted]	$0.20M
2034	[redacted]	$3.78M
2034	[redacted]	$3.80M
2034	[redacted]	$3.71M
2034	[redacted]	$3.81M
2034	[redacted]	$2.68M
2034	[redacted]	$5.92M
2034	[redacted]	$0.11M
2034	[redacted]	$1.19M
2034	[redacted]	$0.20M
2034	[redacted]	$0.20M
	Total Cost	**$74.09M**

Scenario 3a:

Scenario 3a (Ghent 3 and 4 with NGCC at Ghent 345 kV)		
Year	**Construction**	**Investment '24 $M's**
2037	[redacted]	$3.10M
	Total Cost	**$3.10M**

Scenario 3b:

Scenario 3b (Ghent 3 and 4 with NGCC at Brown 345)		
Year	**Construction**	**Investment '24 $M's**
2037	[redacted]	$3.10M
2037	[redacted]	$0.32M
2037	[redacted]	$9.20M
2037	[redacted]	$9.20M
2037	[redacted]	$4.80M
2037	[redacted]	$0.5M
2037	[redacted]	$35.21M
	Total Cost	**$62.33M**

Scenario 3c:

Scenario 3c (Ghent 3 and 4 with NGCC at Mill Creek 345)		
Year	**Construction**	**Investment '24 $M's**
2037	[redacted]	$3.10M
2037	[redacted]	$8.09M
2037	[redacted]	$4.80M
2037	[redacted]	$0.95M
2037	[redacted]	$9.20M
2037	[redacted]	$1.10M
2037	[redacted]	$0.32M
	Total Cost	**$27.56M**

Scenario 3d:

Scenario 3d (Ghent 3 and 4 with NGCC at Trimble Co 345 kV)		
Year	**Construction**	**Investment '24 $M's**
2037	[redacted]	$3.10M
2037	[redacted]	$8.09M
2037	[redacted]	$0.99M
2037	[redacted]	$0.95M
2037	[redacted]	$0.18M
2037	[redacted]	$9.20M
2037	[redacted]	$0.32M
	Total Cost	**$22.83M**

Scenario 3e:

Scenario 3e (Ghent 3 and 4 with NGCC at Green River 161 kV)		
Year	**Construction**	**Investment '24 $M's**
2037	[redacted]	$3.10M
2037	[redacted]	$4.80M
2037	[redacted]	$0.95M
2037	[redacted]	$0.18M
2037	[redacted]	$9.20M
2037	[redacted]	$9.20M
2037	[redacted]	$1.46M
2037	[redacted]	$0.52M
2037	[redacted]	$9.20M
2037	[redacted]	$9.20M
2037	[redacted]	$9.20M
2037	[redacted]	$52.17M
	Total Cost	**$109.18M**

Scenario 3f:

Scenario 3f (Ghent 3 and 4 with NGCC at Cane Run NGCC 138 kV)		
Year	**Construction**	**Investment '24 $M's**
2034	[redacted]	$3.10M
2034	[redacted]	$1.46M
2034	[redacted]	$8.09M
2034	[redacted]	$4.80M
2034	[redacted]	$0.18M
2034	[redacted]	$0.32M
2034	[redacted]	$9.20M
2034	[redacted]	$9.20M
2034	[redacted]	$4.02M
2034	[redacted]	$7.17M
2034	[redacted]	$0.20M
2034	[redacted]	$3.78M
2034	[redacted]	$3.80M
2034	[redacted]	$3.71M
2034	[redacted]	$3.81M
2034	[redacted]	$2.68M
2034	[redacted]	$5.92M
2034	[redacted]	$0.11M
2034	[redacted]	$1.19M
2034	[redacted]	$0.20M
2034	[redacted]	$0.20M
	Total Cost	**$73.14M**

Scenario 4:

Scenario 4 (Mill Creek 3 and 4 with NGCC at Mill Creek 345kV)		
Year	**Construction**	**Investment '24 $M's**
2039	No upgrades necessary	$0
	Total Cost	**$0**

Scenario 5:

Scenario 5 (OVEC units retired)		
Year	**Construction**	**Investment '24 $M's**
2040	No upgrades necessary	$0
	Total Cost	**$0**

Scenario 6:

Scenario 6 (Trimble Co 1 with NGCC at Trimble County 345kV)		
Year	**Construction**	**Investment '24 $M's**
2045	No upgrades necessary	$0
	Total Cost	**$0**

Scenario 7:

Scenario 7 (Trimble Co 2 with NGCC at Trimble County 345)		
Year	**Construction**	**Investment '24 $M's**
2066	No upgrades necessary	$0
	Total Cost	**$0**

Although this study identifies the Transmission System projects that would be required to accommodate these replacement scenarios, the study is based on the information that is available today. The projects identified in this study may change or additional projects may be identified as the Transmission System and adjacent transmission systems continue to change and new information is provided (e.g., transmission topology, generation changes, revised load forecasts).

Interconnection Facilities Costs

Interconnection Facilities refer to all the facilities and equipment between the Interconnection Customer and transmission system that are necessary to physically and electrically interconnect the two. Interconnection Facilities do not include the Network Upgrades discussed thus far in the report. The cost of Interconnection Facilities is primarily driven by the interconnection configuration, but can vary based on several factors, such as existing infrastructure, location, and availability of resources. The table below provides planning level cost estimates for various typical interconnection configurations:

Generation Interconnection to Existing Transmission Line	Voltage	Lines Cost	Subs Cost	Units
Line Tap (less than 20MW)	69kV	*	385k	each
New Ring Bus	345kV	$2M	$15.4M	each
	161/138kV	$1.75M	$12.3M	
	69kV	$1.5M	$9.2M	

Generation Interconnection to Existing Transmission Station	Voltage	Lines Cost	Subs Cost	Units
Existing Ring Bus	345kV	*	$10.8M	each
	161/138kV	*	$7.7M	
	69kV	*	$4.6M	
Existing Straight Bus	345kV	*	N/A	each
	161/138kV	*	$7.7M	
	69kV	*	$4.6M	
Existing Breaker and a Half Bus	345kV	*	$10.8M	each
	161/138kV	*	$7.7M	
	69kV	*	$6.2M	

PPL companies

Long-Term Firm Transfer Analysis – Impact to the LG&E/KU Transmission System

2024 Integrated Resource Plan

October 16, 2024

Table of Contents

Executive Summary

This study was performed as part of the 2024 LG&E/KU Integrated Resource Plan ("IRP") to identify what network upgrades could be required on the LG&E/KU transmission system if long-term firm transmission service was requested for various import or export scenarios. The analysis focused on scenarios involving importing energy from a neighboring Transmission Owner ("TO") to LG&E/KU and exporting energy from LG&E/KU to the neighboring TO. Energy transfer volumes used in the analysis were 100 MW, 300 MW, 500 MW, and 1000 MW. The neighboring TOs included were MISO, PJM, and TVA.

Ten-year summer peak and winter peak models (50/50) from LG&E/KU's 2024 transmission expansion planning were developed for each scenario.[1] For scenarios involving importing to LG&E/KU, LG&E/KU generation was reduced via an economic merit dispatch order in the amount of the energy import while neighboring TO generation was scaled up in the amount of the TO's energy export. For scenarios involving exporting from LG&E/KU, LG&E/KU generation was increased via an economic merit dispatch order in the amount of the energy export while neighboring TO generation was scaled down in the amount of the TO's energy import. Spinning reserve was maintained if possible for all scenarios.

NERC TPL-001-5 Table 1 P0, P1, and P3 analyses were performed on the models to determine any projects required to upgrade the LG&E/KU Transmission System to accommodate these different scenarios.[2] The contingencies simulated and facilities monitored were consistent with the LG&E and KU Transmission Planning Guidelines and the annual Transmission Expansion Plan ("TEP") process. The study methodology used is also consistent with LG&E/KU's study procedure for a Transmission Service Request ("TSR") that the Independent Transmission Organization ("ITO") would conduct when evaluating a TSR.

For scenarios where LG&E/KU exported energy to neighboring TOs, the results indicated that no network upgrades are required to accommodate the export. For scenarios where LG&E/KU imported energy from neighboring ITOs, the results indicated network upgrades will be required in several cases as summarized in the following table. No LG&E/KU voltage violations were identified in the study.

[1] A "50/50" peak demand scenario represents a 50% probability of load being higher than forecast and 50% probability of load being lower than forecast.

[2] P0 is a simulation of the normal operating system with no contingencies. P1 is a simulation of a normal operating system with a single contingency (loss of a generator, transmission circuit, transformer, or shunt device). P3 is a simulation of the loss of a single generator unit, followed by system adjustments. Once the generator outage is simulated followed by system adjustments, all P1 contingencies were simulated. This includes a second generator, transmission circuit, transformer, and shunt devices on BES contingencies. *See* NERC TPL-001-5 — Transmission System Planning Performance Requirements at Table 1, pages 21-22, available at https://www.nerc.com/pa/Stand/Reliability%20Standards/TPL-001-5.pdf.

Transfer Study Results

Export Area	Import Area	Transfer MW	Violations - Flow	Violations - Volt	Network Upgrade Costs
LGEE	MISO	100	0	0	$0
		300	0	0	$0
		500	0	0	$0
		1000	0	0	$0
	PJM	100	0	0	$0
		300	0	0	$0
		500	0	0	$0
		1000	0	0	$0
	TVA	100	0	0	$0
		300	0	0	$0
		500	0	0	$0
		1000	0	0	$0
MISO	LGEE	100	0	0	$0
		300	0	0	$0
		500	1	0	$2,812,500
		1000	4	0	$6,498,000
PJM		100	0	0	$0
		300	0	0	$0
		500	2	0	$3,090,000
		1000	9	0	$54,792,500
TVA		100	0	0	$0
		300	1	0	$2,812,500
		500	2	0	$3,090,000
		1000	9	0	$54,792,500

Introduction

This study was performed as part of the 2024 LG&E/KU IRP to identify what network upgrades could be required on the LG&E/KU transmission system if long-term firm transmission service was requested for various import or export scenarios. The analysis focused on scenarios involving importing energy from a neighboring TO to LG&E/KU and exporting energy from LG&E/KU to a neighboring TO. Energy transfer volumes used in the analysis were 100 MW, 300 MW, 500 MW, and 1000 MW. The neighboring TOs included were MISO, PJM, and TVA.

The following table outlines scenarios that were analyzed in this study.

Export Area	Import Area	Transfer MW
LGEE	MISO	100
		300
		500
		1000
	PJM	100
		300
		500
		1000
	TVA	100
		300
		500
		1000
MISO	LGEE	100
		300
		500
		1000
PJM		100
		300
		500
		1000
TVA		100
		300
		500
		1000

Study Models and Analysis

The models used in this analysis were based on LG&E/KU's 2024 Transmission Expansion Plan ("TEP"). Base models were modified to simulate the energy transfers between LG&E/KU and the neighboring TOs.

- **2033 summer peak (50/50) –** ten-year model; peak demand scenario represents 50% probability of load being higher than forecast and 50% probability of load being lower than forecast

- **2033/34 winter peak (50/50) –** ten-year model; peak demand scenario represents 50% probability of load being higher than forecast and 50% probability of load being lower than forecast

Contingency analysis was performed for the P0, P1, and P3 categories. The following summarizes the categories:

- P0 – simulation of the normal operating system with no contingencies

- P1 – simulation of a normal operating system with a single contingency (loss of a generator, transmission circuit, transformer, or shunt device)

- P3 – simulation of the loss of a single generator unit, followed by system adjustments. Once the generator outage is simulated followed by system adjustments, all P1 contingencies were simulated. This includes a second generator, transmission circuit, transformer, and shunt devices on BES contingencies.

This study included all contingencies and monitored elements that are consistent with the LG&E/KU TEP and study procedure for Transmission Service Requests. This study did not analyze any potential upgrades that could be required on the neighboring TOs transmission systems.

The results of the P0, P1, and P3 simulations were reviewed to identify projects that would be required due to either MVA flow or voltage violations for the energy transfer scenarios.

Study Results

The sections below describe the projects identified that would be needed to prevent MVA flow and low voltage violations identified by the P0, P1, and P3 simulations for each of the energy transfer scenarios.

Once the required projects were determined, planning level cost estimates were developed for each project. If a cost estimate for the project already existed, it was used instead of a planning level cost estimate. Planning level cost estimates in the following table were used.

Project Type	Voltage	Lines Cost	Subs Cost	Units
Conductor Replacement	345kV	$2.25M	N/A	per mile
	161/138kV	$1.75M	N/A	
	69kV	$1.5M	N/A	
Increase MOT	345kV	$1M	N/A	per mile
	161/138kV	$500K	N/A	
	69kV	$250K	N/A	
Capacitor Bank		N/A	$3.1M	each
Transformer Addition		N/A	$9.2M	each
Breaker Replacement	345kV	N/A	$1.5M	each
Breaker Replacement	161/138kV	N/A	$1.1M	each
Breaker Replacement	69kV	N/A	$385k	each
Other Terminal Equipment		N/A	$77k	each piece

Summer Export from LG&E/KU and Import to MISO:

There were no MVA flow or voltage violations identified for any of the MW transfer volumes.

Summer Export from LG&E/KU and Import to PJM:

There were no MVA flow or voltage violations identified for any of the MW transfer volumes.

Summer Export from LG&E/KU and Import to TVA:

There were no MVA flow or voltage violations identified for any of the MW transfer volumes.

Summer Export from MISO and Import to LG&E/KU:

- 100 MW transfer – no MVA flow or voltage violations
- 300 MW transfer – no MVA flow or voltage violations
- 500 MW transfer – [redacted] ($2,812,500) [redacted]
- 1000 MW transfer – [redacted] ($3,398,000) [redacted]

Summer Export from PJM and Import to LG&E/KU:

- 100 MW transfer – no MVA flow or voltage violations
- 300 MW transfer – no MVA flow or voltage violations
- 500 MW transfer – [redacted] ($3,090,000)
  [redacted]
- 1000 MW transfer – ($51,692,500)
  [redacted]

Summer Export from TVA and Import to LG&E/KU:

- 100 MW transfer – no MVA flow or voltage violations
- 300 MW transfer – [redacted] ($2,812,000)
  [redacted]
- 500 MW transfer – [redacted] ($3,090,000)
  [redacted]
- 1000 MW transfer – [redacted] ($51,692,500)
  [redacted]

The following table summarizes summer transfer study results.

Summer Transfer Study Results

Export Area	Import Area	Transfer MW	Violations - Flow	Violations - Volt	Network Upgrade Costs
LGEE	MISO	100	0	0	$0
		300	0	0	$0
		500	0	0	$0
		1000	0	0	$0
	PJM	100	0	0	$0
		300	0	0	$0
		500	0	0	$0
		1000	0	0	$0
	TVA	100	0	0	$0
		300	0	0	$0
		500	0	0	$0
		1000	0	0	$0
MISO	LGEE	100	0	0	$0
		300	0	0	$0
		500	1	0	$2,812,500
		1000	3	0	$3,398,000
PJM		100	0	0	$0
		300	0	0	$0
		500	2	0	$3,090,000
		1000	8	0	$51,692,500
TVA		100	0	0	$0
		300	1	0	$2,812,500
		500	2	0	$3,090,000
		1000	8	0	$51,692,500

Winter Export from LG&E/KU and Import to MISO:

There were no MVA flow or voltage violations identified for any of the MW transfer volumes.

Winter Export from LG&E/KU and Import to PJM:

There were no MVA flow or voltage violations identified for any of the MW transfer volumes.

Winter Export from LG&E/KU and Import to TVA:

There were no MVA flow or voltage violations identified for any of the MW transfer volumes.

Winter Export from MISO and Import to LG&E/KU:

- 100 MW – no MVA flow or voltage violations
- 300 MW – no MVA flow or voltage violations
- 500 MW – no MVA flow or voltage violations
- 1000 MW transfer – [redacted] ($3,100,000) [redacted]

Winter Export from PJM and Import to LG&E/KU :

- 100 MW – no MVA flow or voltage violations
- 300 MW – no MVA flow or voltage violations
- 500 MW – no MVA flow or voltage violations
- 1000 MW transfer – [redacted] ($3,100,000) [redacted]

Winter Export from TVA and Import to LG&E/KU:

- 100 MW – no MVA flow or voltage violations
- 300 MW – no MVA flow or voltage violations
- 500 MW – no MVA flow or voltage violations
- 1000 MW transfer – [redacted] ($3,100,000) [redacted]

The following table summarizes winter transfer study results.

Winter Transfer Study Results

Export Area	Import Area	Transfer MW	Violations - Flow	Violations - Volt	Network Upgrade Costs
LGEE	MISO	100	0	0	$0
		300	0	0	$0
		500	0	0	$0
		1000	0	0	$0
	PJM	100	0	0	$0
		300	0	0	$0
		500	0	0	$0
		1000	0	0	$0
	TVA	100	0	0	$0
		300	0	0	$0
		500	0	0	$0
		1000	0	0	$0
MISO	LGEE	100	0	0	$0
		300	0	0	$0
		500	0	0	$0
		1000	1	0	$3,100,000
PJM		100	0	0	$0
		300	0	0	$0
		500	0	0	$0
		1000	1	0	$3,100,000
TVA		100	0	0	$0
		300	0	0	$0
		500	0	0	$0
		1000	1	0	$3,100,000

Total Network Upgrade Costs (Summer and Winter)

Total network upgrade costs for each transfer scenario are summarized in the following table.

Combined Transfer Study Results

Export Area	Import Area	Transfer MW	Violations - Flow	Violations - Volt	Network Upgrade Costs
LGEE	MISO	100	0	0	$0
		300	0	0	$0
		500	0	0	$0
		1000	0	0	$0
	PJM	100	0	0	$0
		300	0	0	$0
		500	0	0	$0
		1000	0	0	$0
	TVA	100	0	0	$0
		300	0	0	$0
		500	0	0	$0
		1000	0	0	$0
MISO	LGEE	100	0	0	$0
		300	0	0	$0
		500	1	0	$2,812,500
		1000	4	0	$6,498,000
PJM		100	0	0	$0
		300	0	0	$0
		500	2	0	$3,090,000
		1000	9	0	$54,792,500
TVA		100	0	0	$0
		300	1	0	$2,812,500
		500	2	0	$3,090,000
		1000	9	0	$54,792,500

While this study does identify Transmission System projects that would be required to accommodate various long-term firm transfers, the study is based on information available today. Projects identified in this study may change or additional projects may be identified as the LG&E/KU Transmission System and adjacent transmission systems continue to change and new information is provided (e.g., transmission topology, generation changes, revised load forecasts).