COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

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 GENERATING UNIT RETIREMENTS	)))))))))	CASE NO. 2022-00402

O R D E R

On January 6, 2023,[1] Kentucky Utilities Company (KU) and Louisville Gas and Electric Company (LG&E) (jointly, LG&E/KU) filed a joint application requesting Commission approval of (1) Certificates of Public Convenience and Necessity (CPCN) to construct two natural gas combined cycle (NGCC) units and one solar generation facility and a battery storage facility, and to acquire a solar generation facility, pursuant to KRS 278.020, to replace certain generating facilities that LG&E/KU intended to retire; (2) site compatibility certificates for the NGCC units pursuant to KRS 278.216; (3) a declaratory order that four solar purchased power agreements (Solar PPA) do not require Commission approval under KRS 278.020 or KRS 278.300, and if Commission approval is required, that the Solar PPAs be approved, with recovery of the Solar PPA costs

[1] LG&E/KU submitted their application on December 15, 2022, along with a motion to deviate from certain filing requirements. By Order entered December 22, 2022, the Commission denied the motion and rejected the application for filing due to filing deficiencies regarding non-confidential exhibits to witness direct testimony (Exhibits). On December 27, 2022, LG&E/KU filed a joint motion to deviate from certain filing requirements regarding the Exhibits. On January 6, 2023, Commission entered an Order granting the motion and finding that the application was deemed filed as of January 6, 2023.

through the fuel adjustment clause (FAC);[2] (4) a regulatory asset; and (5) revisions to LG&E/KU's demand-side management and energy efficiency (DSM-EE) plans and tariff sheets.

Due to newly enacted statutes requiring prior Commission approval before retiring fossil fuel-fired generating facilities, on May 10, 2023, LG&E/KU filed a joint application in Case No. 2023-00122[3] requesting Commission approval, pursuant to KRS 278.264, to retire seven coal- or natural gas-fired units. Because issues presented in Case No. 2023-00122 were related to the subject matter at issue in this proceeding, Case No. 2023-00122 was physically consolidated into this proceeding by Order entered May 16, 2023, and subsequently closed by Order entered June 30, 2023.[4]

The following parties are Intervenors in this proceeding: (1) the Attorney General of the Commonwealth of Kentucky, by and through the Office of Rate Intervention (Attorney General); (2) Kentucky Industrial Utility Customers, Inc. (KIUC); (3) Walmart, Inc. (Walmart); (4) Sierra Club; (5) Metropolitan Housing Coalition, Kentuckians for the Commonwealth, Kentucky Solar Energy Society, and Mountain Association (collectively, Joint Intervenors); (6) Louisville/Jefferson County Metropolitan Government (Louisville Metro); (7) Lexington-Fayette County Urban County Government (LFUCG); (8) Kentucky Coal Association, Inc. (Kentucky Coal Association); and (9) the Fiscal Court of Mercer County (Mercer County Government).

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[2] In their post-hearing brief, LG&E/KU revised its request to recovery the Solar PPA costs through a PPA rider mechanism. LG&E/KU's Post-Hearing Brief (filed Sept. 22, 2023) at 43–45.

[3] Case No. 2023-00122, *Electronic Joint Application of Kentucky Utilities Company and Louisville Gas and Electric Company for Approval of Fossil Fuel-Fired Generating Unit Retirements* (filed May 10, 2023).

[4] Case No. 2023-00122, Order (Ky. PSC May 16, 2023) and Order (Ky. PSC Jun. 30, 2023).

Pursuant to a procedural schedule established on January 6, 2023, and amended on May 16, 2023, LG&E/KU responded to multiple rounds of discovery requests from Commission Staff and the Intervenors. KIUC, Mercer County Government, Joint Intervenors, and Kentucky Coal Association respectively filed witness testimony; Sierra Club filed testimony from one witness jointly with Louisville Metro, and LFUCG, and was the sole sponsor of testimony from another witness. Intervenors that filed witness testimony responded to discovery requests. LG&E/KU filed rebuttal testimony. Public comment meetings were held on July 31, 2023, in Lexington, Kentucky; August 3, 2023, in Harlan, Kentucky; August 14, 2023, in Madisonville, Kentucky; August 15, 2023, in Louisville, Kentucky; and a virtual meeting was held on August 15, 2023. A formal hearing was held on August 22–29, 2023. LG&E/KU responded to post-hearing discovery requests from Commission Staff, Sierra Club, Joint Intervenors, KIUC, and Kentucky Coal Association. Mercer County Government filed its initial brief on September 19, 2023. LG&E/KU, LFUCG and Louisville Metro, the Attorney General, KIUC, Walmart, Kentucky Coal Association, Sierra Club, and Joint Intervenors filed their respective initial briefs on September 22, 2023. LG&E/KU, LFUCG and Louisville Metro, KIUC, Walmart, Kentucky Coal Association,[5] Sierra Club, and Joint Intervenors filed their respective response briefs on October 4, 2023.

On August 15, 2023, KU and Mercer County Government entered into the case record a stipulation and recommendation to sell property in Mercer County that LG&E/KU planned to use to construct a solar facility to be owned by LG&E/KU.

[5] Kentucky Coal Association refiled its brief on October 5, 2023, with enhanced redaction.

On September 1, 2023, LG&E/KU filed a motion for the Commission to take administrative notice of their Hearing Exhibit 1, Joint Comments of Electric Reliability Council of Texas, Inc. (ERCOT), Midcontinent Independent System Operator, Inc. (MISO), PJM Interconnection, L.L.C. (PJM), and Southwest Power Pool, Inc. (SPP) in U.S. Environmental Protection Agency (EPA) Docket No. EPA-HQ-OAR-2023-0072, New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule.

This matter stands submitted for a decision by the Commission.

ANALYSIS AND FINDINGS

The Commission notes that the evidentiary record developed in this case is voluminous, consisting of hundreds of thousands of pages of documents. In addition to initial modeling runs performed by LG&E/KU and filed into the case record, numerous modeling runs were performed at the request of Commission Staff to examine an array of scenarios. The intervening parties represent diverse interests and points of view, including residential, commercial and industrial customers, government, environmental organizations, and low-income residents. Having thoroughly reviewed the extensive evidentiary record and being otherwise sufficiently advised, the Commission made an independent analysis to determine the reasonableness of LG&E/KU's proposals, based on eventual impacts to rates and the reliability of the resulting grid. Given the significance of this matter, which includes a matter of first impression regarding the Commission's authority under the newly enacted KRS 278.264, and the short statutory timeframe to reach a decision, the Commission retained an external consultant that assisted Commission Staff in propounding requests for information and developing the evidentiary record.

The Commission will first address the request to transfer property owned by LG&E/KU in Mercer County, Kentucky, to Mercer County Government and the city of Harrodsburg, and then address generation retirement, CPCNs for new facilities, the declaratory order for the Solar PPAs, the request for site compatibility certificates, the request for a regulatory asset, and the DSM-EE programs and tariff.

1. TRANSFER OF UTILITY ASSETS AND STIPULATION

LEGAL STANDARD

Under KRS 278.218, Commission approval is required for a change in ownership of assets owned by a jurisdictional utility. KRS 278.218(1)(a) provides that no person shall acquire any assets owned by a jurisdictional utility without prior approval of the Commission if the assets have an original book value of $1,000,000 or more and the assets are to be transferred by the utility for reasons other than obsolescence. Pursuant to KRS 278.218(2), the Commission shall grant its approval if the transaction is for a proper purpose and is consistent with the public interest.

STIPULATION AND PROPOSED TRANSFER OF UTILITY ASSETS

By Order entered August 30, 2023, the Commission granted KU's motion for leave to file a stipulation entered into by KU, Mercer County Government, and the city of Harrodsburg to sell property in Mercer County that KU had planned to use to construct a solar facility to be owned by LG&E/KU. As noted in the August 30, 2023 Order, the stipulation is subject to the Commission's approval, which is determined in this Order.

The property at issue is property that KU purchased with the intention of constructing a solar generating facility and upon which Mercer County Government planned to build an industrial park.[6] Mercer County Government sponsored the testimony of Mercer County Judge Executive Sarah Steele, who explained that an industrial park would create jobs and increased revenue that would benefit Mercer County.[7] Judge Steele further explained that potential industrial customers have discussed locating in an industrial park if it were built and have taken tours of the property.[8] Judge Steele stated that KU discussed with Mercer County Government how to accommodate the industrial park and the solar facility, and subsequently entered into an agreement on June 8, 2023, with the current property owner that would allow KU to relocate the solar facility to the northern end of the property, which would enable the industrial park to be constructed on the southern portion of the property.[9]

According to evidence filed in the record, the property at issue consists of 858 acres located near U.S. Highway 127 in Harrodsburg, Mercer County, Kentucky.[10] KU closed on the property on April 27, 2023, paying $20,820 per acre for 858 acres.[11]

According to the terms of the stipulation, KU proposed to sell 858 acres to Mercer County Government and the city of Harrodsburg for $20,820 per acre, subject to certain

[6] Direct Testimony of Sarah Steele (Steele Direct Testimony) (filed July 14, 2023) at 2.

[7] Steele Direct Testimony at 3.

[8] Steele Direct Testimony at 3.

[9] Steele Direct Testimony at 3–4.

[10] LG&E/KU's Supplemental Response to Staff's Second Request for Information (Staff's Second Request) (filed June 9, 2023), Item 58.

[11] LG&E/KU's Supplemental Response to Staff's Second Request, Item 58.

contingencies: (1) KU acquiring 1,007 acres in Mercer County to use to construct a solar facility; (2) Commission approving a CPCN for Mercer County Solar Facility; (3) approval of sale under KRS 278.218; and (4) KU receiving a Site Compatibility Certificate per KRS 278.216.[12] Mercer County Government and the city of Harrodsburg will also have the option to purchase another 100 acres from KU.[13]

In its post-hearing brief, Mercer County Government explained that its goal in intervening in this proceeding was to acquire the land from KU for an industrial park, with the economic benefits that will accrue to Mercer County residents.

INTERVENORS' ARGUMENTS – STIPULATION AND TRANSFER OF ASSETS

No other party filed testimony regarding the stipulation and transfer of assets or addressed the issue in briefs.

DISCUSSION AND FINDINGS – STIPULATION AND TRANSFER OF ASSETS

Based upon evidence in the case record and being otherwise sufficiently advised, the Commission concludes that approval of the sale of the Mercer County property that KU requests to sell to Mercer County Government is subject to Commission approval under KRS 278.218. This is because the transaction results in a change in ownership of an asset owned by KU, a jurisdictional utility, to Mercer County Government. Additionally, the property has an original book value of $17,863,560, and thus exceeds the $1,000,000 statutory threshold.[14] Further, because the asset is being sold to Mercer County

[12] Stipulation and Recommendation (filed Aug. 15, 2023).

[13] Stipulation and Recommendation at 2.

[14] The sale price for the property itself was $17,863,560, representing 858 acres at $20,820 per acre = $17,863,560.

Government to construct an industrial park, the assets are being sold for reasons other than obsolescence.

Based upon the stipulation and case record, the Commission finds that because the property will be transferred and used by Mercer County Government for the economic benefit of the Mercer County community and the sale price per acre is the same price LG&E/KU paid per acre, the transaction is for a proper purpose and is consistent with the public interest. For the same reason, the Commission further finds that the asset transfer and corresponding stipulation should be approved.

2. RETIREMENT OF FOSSIL FUEL-FIRED ELECTRIC GENERATING FACILITIES AND CPCN FOR NEW ELECTRIC GENERATION

LEGAL STANDARD

Service Adequacy

KRS 278.030(2) requires every utility to furnish adequate, efficient and reasonable service to its customers.

KRS 278.010(14) provides the definition of "adequate service" as follows:

> "Adequate service" means having sufficient capacity to meet the maximum estimated requirements of the customer to be served during the year following the commencement of permanent service and to meet the maximum estimated requirements of other actual customers to be supplied from the same lines or facilities during such year and to assure such customers of reasonable continuity of service.

Retirement of Fossil Fuel-Fired Generation

A newly enacted law, codified as KRS 278.262 and KRS 278.264 became effective on March 29, 2023. Under KRS 278.264(1), a jurisdictional utility must obtain prior approval from the Commission before retiring an electric generating unit. KRS 278.264(1) authorizes the Commission to approve, approve with conditions, or deny the retirement of an electric generating unit owned by a jurisdictional utility. KRS 278.264(2) creates a rebuttable presumption against the retirement of a fossil fuel-fired electric generating unit. To rebut the presumption, KRS 278.264(2) states that:

> [T]he Commission shall not approve the retirement of an electric generating unit, authorize a surcharge for the decommissioning of the unit, or take any other action which authorizes or allows for the recovery of costs for the retirement of an electric generating unit, including any stranded asset recovery, unless the presumption created by this section is rebutted by evidence sufficient for the commission to find that:
>
> (a) The utility will replace the retired electric generating unit with new electric generating capacity that:
>
> 1. Is dispatchable by either the utility or the regional transmission organization or independent system operator responsible for balancing load within the utility's service area;
>
> 2. Maintains or improves the reliability and resilience of the electric transmission grid; and
>
> 3. Maintains the minimum reserve capacity requirement established by the utility's reliability coordinator;
>
> (b) The retirement will not harm the utility's ratepayers by causing the utility to incur any net incremental costs to be recovered from ratepayers that could be avoided by continuing to operate the electric generating unit proposed for retirement in compliance with applicable law; and
>
> (c) The decision to retire the fossil fuel-fired electric generating unit is not the result of any financial incentives or benefits offered by any federal agency.
>
> (3) The utility shall at a minimum provide the commission with evidence of all known direct and indirect costs of retiring the electric generating unit and demonstrate that cost savings will result to customers as a result of the retirement of the electric generating unit.

KRS 278.262 defines “reliability” as “having adequate electric generation capacity to safely deliver electric energy in the quantity, with the quality, and at a time that the utility customers demand. KRS 278.262 defines "resilience" as “having the ability to quickly and effectively respond to and recover from events that compromise grid reliability.” Further, KRS 278.262 defines “retirement" or "retired" as “the closure or the complete and permanent cessation of operations at an electric generating unit.”

<u>CPCNs for New Generation</u>

The Commission's standard of review of a request for a CPCN is well settled. Under KRS 278.020(1), no utility may construct or acquire any facility to be used in providing utility service to the public until it has obtained a CPCN from this Commission. To obtain a CPCN, a utility must demonstrate a need for such facilities and an absence of wasteful duplication.[15]

"Need" requires:

> [A] showing of a substantial inadequacy of existing service, involving a consumer market sufficiently large to make it economically feasible for the new system or facility to be constructed or operated.
>
> [T]he inadequacy must be due either to a substantial deficiency of service facilities, beyond what could be supplied by normal improvements in the ordinary course of business; or to indifference, poor management or disregard of the rights of consumers, persisting over such a period of time as to establish an inability or unwillingness to render adequate service.[16]

[15] *Kentucky Utilities Co. v. Pub. Serv. Comm'n.*, 252 S.W.2d 885 (Ky. 1952).

[16] *Kentucky Utilities Co. v. Pub. Serv. Comm'n.*, 252 S.W.2d at 890.

"Wasteful duplication" is defined as "an excess of capacity over need" and "an excessive investment in relation to productivity or efficiency, and an unnecessary multiplicity of physical properties."[17] To demonstrate that a proposed facility does not result in wasteful duplication, we have held that the applicant must demonstrate that a thorough review of all reasonable alternatives has been performed.[18] The fundamental principle of reasonable least-cost alternative is embedded in such an analysis. Selection of a proposal that ultimately costs more than an alternative does not necessarily result in wasteful duplication.[19] All relevant factors must be balanced.[20]

A CPCN is not required for "ordinary extensions of existing systems in the usual course of business" under Commission regulation 807, KAR 5:001, Section 15(3), which states:

> A certificate of public convenience and necessity shall not be required for extensions that do not create wasteful duplication of plant, equipment, property, or facilities, or conflict with the existing certificates or service of other utilities operating in the same area . . . , and that do not involve sufficient capital outlay to materially affect the existing financial condition of the utility involved, or will not result in increased charges to its customers.

The Commission has interpreted 807 KAR 5:001, Section 15(3), as stating that no CPCN is required for extensions "that do not result in the wasteful duplication of utility

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[17] *Kentucky Utilities Co. v. Pub. Serv. Comm'n.*, 252 S.W.2d at 890.

[18] Case No. 2005-00142, *Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for a Certificate of Public Convenience and Necessity for the Construction of Transmission Facilities in Jefferson, Bullitt, Meade, and Hardin Counties, Kentucky* (Ky. PSC Sept. 8, 2005).

[19] *See Kentucky Utilities Co. v. Pub. Serv. Comm'n*, 390 S.W.2d 168, 175 (Ky. 1965). *See also* Case No. 2005-00089, *Application of East Kentucky Power Cooperative, Inc. for a Certificate of Public Convenience and Necessity for the Construction of a 138 kV Electric Transmission Line in Rowan County, Kentucky* (Ky. PSC Aug. 19, 2005).

[20] Case No. 2005-00089, Aug. 19, 2005 Order at 6.

plant, do not compete with the facilities of existing public utilities, and do not involve a sufficient capital outlay to materially affect the existing financial condition of the utility involved or to require an increase in utility rates."[21]

Under KRS 278.020(1)(e), unless a CPCN is exercised within one year from the date, the CPCN is granted by order, the authority conferred by the issuance of a CPCN is void. KRS 278.020(1)(e) further provides that the beginning of any new construction in good faith within the time prescribed by the Commission and the "prosecution" of the construction with "reasonable diligence" constitutes an exercise of authority under the CPCN.

LG&E/KU PROPOSED CPCNS AND GENERATING UNIT RETIREMENTS

LG&E/KU currently operates 11 coal units with a total summer net capacity of 4,867 MW (4,910 MW winter capacity), one NGCC unit with a net summer capacity of 662 MW (683 MW winter), 17 load-following natural gas simple cycle combustion turbine (SCCT) peaking units with a total net summer capacity of 2,054 MW (2,308 MW winter), renewable generation resources with total net summer capacity of 105 MW (72 MW winter). On a combined basis, LG&E/KU's current generation resources have a net summer capacity of 7,688 MW and a net winter capacity of 7,973 MW winter.[22]

LG&E/KU requested authority, pursuant to KRS 278.262 and KRS 278.264, to retire four of their 11 coal units and three of their 17 gas SCCT units. More specifically, their proposal is to retire coal units Mill Creek 1, Mill Creek 2, Brown 3, Ghent 2, and small

[21] Case No. 2000-00481, *Application of Northern Kentucky Water District (A) for Authority to Issue Parity Revenue Bonds in the Approximate Amount of $16,545,000; and (B) a Certificate of Convenience and Necessity for the Construction of Water Main Facilities* (Ky. PSC Aug. 30, 2001), Order at 4.

[22] *See* Direct Testimony of Stuart Wilson (Wilson Direct Testimony) (filed Dec. 15, 2022), Exhibit SAW-1 December 2022, Table 26, Table 27, and Table 29.

natural gas-fired units Haefling 1 and 2, and Paddy's Run 12. LG&E/KU described the units they proposed to retire as follows:[23]

Unit(s)	Fuel	Net Summer/Winter Capacity (MW)	Dispatchable Summer/Winter Range (MW)	In-Service Date
Mill Creek 1	Coal	300/300	Current: 185/185 w/SCR: 145/145	1972
Mill Creek 2	Coal	297/297	Current: 183/183 w/SCR: 145/145	1974
Brown 3	Coal	412/416	272/276	1971
Haefling 1-2; Paddy's Run 12	Gas	47/55	0/0	1970; 1968
Ghent 2	Coal	485/486	Current: 260/261 w/SCR: 256/257	1977

LG&E/KU stated that they plan to retire Mill Creek 1 by 2024, Mill Creek 2 by 2027, Ghent 2 by 2028, and Brown 3 in 2028.[24] LG&E/KU proposed to retire Brown 3 due to $26 million in major maintenance required in 2027 that LG&E/KU argued is not cost-effective given the overall inefficiency of the unit.[25] LG&E/KU's stated that they explained the basis for updating the retirement date of Brown 3 in their 2020 rate cases.[26] LG&E/KU

[23] Direct Testimony of Stuart A. Wilson in Case No. 2023-00122 (Wilson 2023-00122 Testimony), Exhibit SB4-1 at 8, Table 2.

[24] Direct Testimony of Lonnie E. Bellar in Case No. 2023-00122 (Bellar 2023-00122 Testimony) at 3-7.

[25] Wilson Direct Testimony at 4, 14.

[26] *See* Case No. 2020-00349, *Electronic Application of Kentucky Utilities Company for an Adjustment of Its Electric Rates, a Certificate of Public Convenience and Necessity to Deploy Advanced Metering Infrastructure, Approval of Certain Regulatory and Accounting Treatments, and Establishment of a One-Year Surcredit* (Ky. PSC June 30, 2021); Case No. 2020-00350, *Electronic Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Rates, a Certificate of Public*

stated that their analysis in this matter confirmed that updating the retirement date of Brown 3 from its previous expected retirement date is economically optimal.[27]

LG&E/KU stated that proposed amendments to the U. S. Environmental Protection Agency's (EPA) Cross State Air Pollution Rule, the Good Neighbor Plan, if enacted, will effectively require non-SCR (Selective Catalytic Reduction) equipped coal units to cease operating or operate only at very minimal levels during each year's ozone season beginning in 2026.[28] Mill Creek 1, Mill Creek 2, and Ghent 2 are not currently equipped with SCR,[29] and LG&E/KU concluded that it was economical to retire Mill Creek 2 and Ghent 2 rather than equipping them with SCR or operating the plants only outside of the ozone season.[30]

When LG&E/KU filed Case No. 2022-00402, they planned to retire Mill Creek 1 in 2024 and three existing gas SCCT units—Paddy's Run 12 and Haefling 1 and 2—in 2025 based on previous analyses. Following the enactment of Senate Bill 4, codified in KRS 278.262 and KRS 278.264, LG&E/KU explained that they planned to retire Mill Creek 1 in 2024 because operation beyond 2024 would require ELG retrofits, operation beyond 2027 would require a cooling tower, and operation beyond 2027 in ozone season would require the addition of an SCR due to the Good Neighbor Plan, which LG&E/KU indicated

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Convenience and Necessity to Deploy Advanced Metering Infrastructure, Approval of Certain Regulatory and Accounting Treatments, and Establishment of a One-Year Surcredit (Ky. PSC June 30, 2021).

[27] Wilson Direct Testimony, Exhibit SAW-1 December 2022 at 22-23.

[28] Wilson Direct Testimony, Exhibit SAW-1 December 2022 at 4; Direct Testimony of Philip A. Imber (Imber Direct Testimony) at 3-5 (filed Dec. 23, 2023).

[29] Wilson Direct Testimony, Exhibit SAW-1 December 2022 at 4.

[30] Wilson Direct Testimony, Exhibit SAW-1 December 2022 at 22-23.

makes Mill Creek 1 uneconomical to operate.[31] LG&E/KU explained that they plan to retire the three SCCTs, which together only account for about 47 MW of capacity in the summer and 55 MW of capacity in the winter, because it would be uneconomical to repair any major mechanical issues and they anticipate mechanical failures will require retirement by 2025 based on their age and experience with other similar units.[32]

LG&E/KU stated that they used PLEXOS, PROSYM, an Excel Financial Model, and SERVM to find an "economically optimized" portfolio that could serve their forecasted load and maintain what they determined to be their minimum reserve margin.[33] LG&E/KU indicated that they conducted their evaluation of resource options in "three stages," with multiple steps in each stage. LG&E/KU indicated that Stage One sought to identify economically optimal portfolios across six fuel price scenarios that assured minimum reliability by meeting economic reserve margin and Good Neighbor Plan compliance; Stage Two compared the economically optimal portfolio selected in Stage One to other portfolios across six fuel price scenarios and three CO_2 price scenarios; and Stage Three sought to account for the risk that the Solar PPAs would not be built, consider "reliability enhancements" in the form of dispatchable DSM, battery energy storage systems, and gas SCCT capacity, and consider the effects of retiring the Ohio Valley Electric Corp.'s (OVEC) coal units early.[34]

[31] Wilson 2023-00122 Testimony, Exhibit SB4-1 at 3.

[32] Wilson 2023-00122 Testimony, Exhibit SB4-1 at 4, 6.

[33] Wilson Direct Testimony, Exhibit SAW-1 December 2022 at 16-18.

[34] Wilson Direct Testimony, Exhibit SAW-1 December 2022 at 16-18.

LG&E/KU indicated that their initial Stage One analysis, which assumed the retirement of Mill Creek 1, Paddy's Run 12 and Haefling 1-2 in all scenarios, produced the following least-cost resource portfolios in the various fuel price scenarios:[35]

	Least-Cost Resource Portfolio	
Fuel Price Scenario (Gas, CTG Price Ratio)	Dispatchable Resources	Solar Resources
Low Gas, Mid (expected) CTG Ratio	Replace MC2, GH2, BR3 w/ MC5 and BR12*	104 Solar
Mid Gas, Mid (expected) CTG Ratio	Replace MC2, GH2, BR3 w/ MC5 and BR12	637 Solar
High Gas, Mid (expected) CTG Ratio	Replace MC2, GH2, BR3 w/ MC5 and BR12	2,322 Solar
Average Low, Mid, High Gas, Mid CTG Ratio	Replace MC2, GH2, BR3 w/ MC5 and BR12	637 Solar
Low Gas, High CTG Ratio	Replace MC2, GH2, BR3 w/ MC5 and BR12	104 Solar
High Gas, Low CTG Ratio	Replace MC2, BR3 w/ MC5; Add SCR at GH2	2,222 Solar
High Gas, "Current" CTG Ratio	Replace MC2, GH2, BR3 w/ MC5 and BR12	2,322 Solar
Average Excluding High Gas, Current CTG Ratio	Replace MC2, GH2, BR3 w/ MC5 and BR12	637 Solar
Average All Fuel Prices	Replace MC2, GH2, BR3 w/ MC5 and BR12	1,322 Solar

LG&E/KU noted that a portfolio that kept Ghent 2, the most efficient coal unit they proposed to retire, open with SCR was only cost-effective in the High Gas, Low CTG Ratio scenarios and then only with a retirement date beyond 2049.[36] Based on the results of the model and its subsequent analysis of the results discussed above, LG&E/KU proposed to construct two NGCC units, one at Mill Creek (Mill Creek 5) and one at E.W.

[35] Wilson Direct Testimony, Exhibit SAW-1 December 2022 at 25.

[36] Wilson Direct Testimony, Exhibit SAW-1 December 2022 at 26-27.

Brown (Brown 12), to be online by the summers of 2027 and 2028, respectively, and proposed to enter into four Solar PPAs totaling 637 MW.[37]

However, LG&E/KU argued that there is a risk that some of their Solar PPAs will not be built, as they experienced with two solar PPAs they executed in 2019 and 2021, Rhudes Creek and Ragland, respectively, which LG&E/KU indicated have not received all necessary approvals, have not begun construction, and are not likely to proceed any time soon due to issues with financing.[38] To mitigate that risk, LG&E/KU proposed to self-build one solar facility, the 120 MW Mercer County Solar Facility, and purchase another solar facility built specifically for LG&E/KU, the 120 MW Marion County Solar Facility.

LG&E/KU performed production cost and financial modeling to estimate the present value revenue requirement (PVRR) effect of adding the Mercer Solar Facility and the Marion Solar Facility in the six fuel cost scenarios, three carbon cost scenarios, and 3 renewable energy credit (REC) price scenarios. LG&E/KU indicated that the solar facilities were cost-effective in three of the fuel price scenarios even with no carbon costs or a value to the RECs, and that modeling some cost of Greenhouse Gas regulation in the future made the solar facilities cost-effective most scenarios.[39] LG&E/KU stated that, based on the PVRR results and given the uncertainties concerning the solar industry, gas prices, and future Greenhouse Gas regulations, they concluded that the Mercer Solar

[37] Wilson Direct Testimony, Exhibit SAW-1 December 2022 at 25-26.

[38] Wilson Direct Testimony, Exhibit SAW-1 December 2022 at 34.

[39] Wilson Direct Testimony, Exhibit SAW-1 December 2022 at 35-36.

Facility and the Marion Solar Facility, along with the Solar PPAs, are a reasonable hedge against market uncertainties going forward.[40]

LG&E/KU indicated that they next looked at additional options to enhance reliability, including gas SCCTs and battery storage. LG&E/KU argued that the proposed Brown battery energy storage system (BESS) enhances reliability in scenarios both with and without solar but they acknowledged that Brown BESS was not the most cost-effective means to enhance reliability.[41] LG&E/KU argued that Brown BESS's primary benefit would be to provide them valuable operational experience with a technology at utility scale that will likely be vital to ensuring the reliability of the grid in the future, including effectively integrating large amounts of renewable generation reliably in the future.[42]

LG&E/KU asserted that the retirements in the plan they originally proposed in Case No. 2022-00402 satisfy the requirements of KRS 278.262 and KRS 278.264 (Senate Bill 4). LG&E/KU argued that their resource assessment established that the proposed plan is the most reasonable, least-cost method to serve load for the reasons discussed above. LG&E/KU also noted that they performed additional PVRR calculations, which included costs for Mill Creek 1 and Haefling 1-2 and Paddy's Run 12. LG&E/KU argued that the updated PVRR analysis demonstrated that their proposed portfolio "will not harm customers; rather, including all known direct and indirect costs that affect revenue

[40] Wilson Direct Testimony, Exhibit SAW-1 December 2022 at 35-36.

[41] Wilson Direct Testimony, Exhibit SAW-1 December 2022 at 38.

[42] Wilson Direct Testimony, Exhibit SAW-1 December 2022 at 38-39.

requirements (and therefore customers' bills), it will likely result in substantial PVRR benefits to customers."[43]

LG&E/KU also asserted that their proposed CPCNs for replacement generation satisfy the reliability and resilience requirements of KRS 278.264. LG&E/KU argued that any plan that has a loss-of-load expectation (LOLE) that is lower than the LOLE aligned with their minimum economic reserve margin—3.57 days every 10 years—maintains adequate reliability and meets the requirements of KRS 278.264(2)(a)(2).[44] LG&E/KU indicated that they used the SERVM model to calculate seasonal and total LOLE for a number of portfolios and that a portfolio that included only their DSM programs and their dispatchable generation had an annual LOLE of 0.77 days every 10 years.[45] Thus, LG&E/KU argued that their proposed plan maintains or improves reliability as required by KRS 278.264(2)(a)(2).

LG&E/KU stated that they looked at generating unit start-up times, ramp rates, and range of dispatchable capacity to evaluate whether their proposed plan maintains or improves resilience as required by KRS 278.264(2)(a)(2). LG&E/KU argued that these are objective, established metrics that can be used to determine responsiveness to events affecting load.[46] LG&E/KU argued that proposed NGCC units have faster start-up times and ramp rates than each unit they proposed to retire.[47] LG&E/KU also argued that the proposed NGCC units, owned solar, and Brown BESS collectively have a broader

[43] Wilson 2023-00122 Testimony, Exhibit SB4-1 at 19.

[44] Wilson 2023-00122 Testimony, Exhibit SB4-1 at 13-14.

[45] Wilson 2023-00122 Testimony, Exhibit SB4-1 at 14-15.

[46] Wilson 2023-00122 Testimony, Exhibit SB4-1 at 15-16.

[47] Wilson 2023-00122 Testimony, Exhibit SB4-1 at 15-16.

range of dispatchable capacity (i.e., the difference between dispatchable minimum and maximum capacity) than the combined dispatchable capacity of the retiring units.[48] Thus, LG&E/KU argued that their proposed plan maintains or improves resiliency as required by KRS 278.264(2)(a)2.[49]

LG&E/KU asserted that they have contracted with the Tennessee Valley Authority (TVA) to act as their reliability coordinator since they exited MISO, but that TVA does not have the contractual obligation or authority to prescribe a reserve margin requirement for LG&E/KU.[50] Rather, LG&E/KU stated that they establish their own reserve margins and that they are meeting those required margins.[51] Thus, LG&E/KU argued that their proposed plan maintains the minimum reserve capacity requirement established by their reliability coordinator.

INTERVENORS' ARUGMENTS – PROPOSED CPCNS AND GENERATION RETIREMENTS

Attorney General

The Attorney General argued that the Good Neighbor Plan is currently stayed in Kentucky and unlikely to survive legal challenge based on the EPA's recent track record. Specifically, the Attorney General noted that there are currently stays in five U.S. Circuit Courts of Appeals covering ten states.[52] The Attorney General also argued that the EPA experienced a major curtailment of its authority in *West Virginia v. EPA* and that the EPA

[48] Wilson 2023-00122 Testimony, Exhibit SB4-1 at 15-16.

[49] Wilson 2023-00122 Testimony, Exhibit SB4-1 at 15-16.

[50] Wilson 2023-00122 Testimony, Exhibit SB4-1 at 16-17

[51] Wilson 2023-00122 Testimony, Exhibit SB4-1 at 16-17.

[52] Attorney General's Post-Hearing Brief (filed Sept. 22, 2023) at 24-25.

was recently enjoined from its attempt to alter the Waters of United States rule.[53] The Attorney General asserted that "it would foolish for the Companies or the Commission to make any decision based on the Good Neighbor Rule or any other proposed EPA rule given the Biden EPA's poor record in the courts."[54]

The Attorney General asserted that renewable resources have become more cost-competitive due to heavy subsidization and the lack of onerous up-front environmental compliance. However, the Attorney General argued that the trend has halted and is reversing itself and that wind and solar are becoming more expensive.[55] The Attorney General provided an example of a solar a battery facility being more expensive than expected due to the rising cost of components and because the utility was forced to purchase power at higher market rates until the solar facilities were constructed.[56] The Attorney General also argued that the higher cost of renewables is evident, because rates have increased as renewable penetration has increased.[57]

The Attorney General stated that "Kentucky does not need to acquiesce to EPA's war on coal."[58] The Attorney General noted that with the enactment of Senate Bill 4, the General Assembly sent a clear message not to "surrender our coal plants."[59] The Attorney General stated that once a coal plant is retired, the options to retain and provide

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[53] Attorney General's Post-Hearing Brief at 24-25.

[54] Attorney General's Post-Hearing Brief at 25.

[55] Attorney General's Post-Hearing Brief at 26.

[56] Attorney General's Post-Hearing Brief at 26.

[57] Attorney General's Post-Hearing Brief at 27.

[58] Attorney General's Post-Hearing Brief at 30.

[59] Attorney General's Post-Hearing Brief at 30.

dispatchable and reliable electricity become severely limited. The Attorney General argued that it would be imprudent for the Commission to limit Kentucky's options in the current energy environment.[60]

The Attorney General argued that LG&E/KU's plan to retire four coal units will result in a weaker less reliable electrical grid prone to prolonged outages.[61] The Attorney General stated that coal-fired electric generation plants have been "providing safe, reliable largely base-load power during all weather conditions, 24-hours per day, 365 days per year, year-in and year-out" for over a century.[62] The Attorney General stated that "[t]he predictable start-up times and trustworthiness of these dispatchable plants allow utilities and grid operators to meet the needs of the grid and energy markets," while renewable generation lacks reliability and is subject to constantly changing weather.[63] The Attorney General also indicated that dispatchable, turbine-driven, synchronous generation resources such as coal-fired plants provide a natural inertia that forces the flow of electrons down the wires in a way that helps to regulate electric frequency and retard its decay.[64] The Attorney General stated that "thermal generation—coal, natural gas, and nuclear—are necessary today, tomorrow and will continue to be well into the future."[65]

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[60] Attorney General's Post-Hearing Brief at 30.

[61] Attorney General's Post-Hearing Brief at 14.

[62] Attorney General's Post-Hearing Brief at 13.

[63] Attorney General's Post-Hearing Brief at 13.

[64] Attorney General's Post-Hearing Brief at 13.

[65] Attorney General's Post-Hearing Brief at 14.

The Attorney General stated that “Kentucky experienced what may have been its first reliability crisis” in December 2022 when a frozen valve on a gas transportation pipeline caused LG&E/KU to back down several gas-fired units tied to the affected gas transportation main.[66] The Attorney General asserted that coal-fired plants are capable of maintaining a thirty-to-sixty day supply of coal in a stockpile immediately adjacent to the plant’s boiler, minimizing chances for a fuel supply interruption.[67] Thus, the Attorney general argued that coal-fired plants provide an essential part of Kentucky’s grid reliability such that retiring Mill Creek 1 and 2, Ghent 2, and Brown 2 would not be wise.[68]

The Attorney General also argued that LG&E/KU failed to meet the requirements of KRS 278.264(2)(b). Specifically, the Attorney General argued that:

> [T]he mandate of KRS 278.264 (2)(b), that the proposed retirement of a fossil fuel plant must not: “. . . harm the utility’s ratepayers by causing the utility to incur any net incremental costs to be recovered from ratepayers that could be avoided by continuing to operate the electric generating unit proposed for retirement in compliance with applicable law,” cannot be satisfied if ratepayers are saddled with stranded costs arising from the premature retirement of the four subject coal-fired units.[69]

The Attorney General argued that “[k]eeping the coal plants operating gives flexibility and opportunity for the Companies.”[70] The Attorney General stated that other utilities in the Commonwealth, such as Kentucky Power Company, face a capacity shortage in a few years and argued that Ghent 2, if fitted with SCR, could make a

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[66] Attorney General’s Post-Hearing Brief at 20.

[67] Attorney General’s Post-Hearing Brief at 20.

[68] Attorney General’s Post-Hearing Brief at 20-21.

[69] Attorney General’s Post-Hearing Brief at 22-23.

[70] Attorney General’s Post-Hearing Brief at 30.

significant dent in the coming capacity shortfall. The Attorney General argued that energy from Ghent 2 could be sold on the open market to the benefit of LG&E/KU's ratepayers but that closing Ghent 2 would foreclose the possibility of such sales.[71] The Attorney General asserted that "coal plants may become more valuable as their numbers decline because of their ability to deliver dispatchable power."[72]

The Attorney General noted that LG&E/KU's annual studies regarding the costs and benefits of joining a regional transmission organization (RTO) have consistently shown that RTO membership is not beneficial to customers at this time. The Attorney General also noted that LG&E/KU have a limited ability to import power from neighboring regions. The Attorney General argued that the Commission should reject any recommendation that LG&E/KU be required to join an RTO.[73] The Attorney General also argued that the Commission should reject LG&E/KU's Brown BESS because it is not generation, is inefficient, and is an experiment to gain experience and data.[74]

KIUC

KIUC noted that Kentucky's legislature expressed a clear preference for coal-fired generation through KRS 278.278.264 but that the EPA, among other things, is proposing a plan that will limit coal generation to only the seven non-ozone months unless SCRs for nitrogen oxides (NOx) control are installed.[75] KIUC asserted that the generation portfolio proposed by the LG&E/KU reasonably balances conflicting state and federal directives in

[71] Attorney General's Post-Hearing Brief at 30.

[72] Attorney General's Post-Hearing Brief at 30.

[73] Attorney General's Post-Hearing Brief at 33-35.

[74] Attorney General's Post-Hearing Brief at 36-37.

[75] KIUC's Post-Hearing Brief (filed Sept. 22, 2023) at 1.

a way that is realistic, flexible, reliable, and least-cost under a wide range of reasonable assumptions.[76] Thus, KIUC argued that LG&E/KU's proposed portfolio should be approved with some limited exceptions, including that the proposed retirement of Ghent 2 and the proposed CPCN for Brown BESS be denied.[77]

KIUC asserted that NGCC technology is highly efficient and highly reliable. KIUC stated that the heat rate (conversion efficiency of fossil fuel to electricity) for Mill Creek 5 will be approximately 6,200 Btu/Kwh, versus the coal units slated for retirement at over 10,000 Btu/Kwh; the average forced outage rate from 2018 to 2022 for LG&E/KU's current NGCC unit, Cane Run 7, was only 1.8 percent compared to Brown 3's forced outage rate over the same period of 6.06 percent; the ramp rate and load following capability of NGCC generation is superior to coal generation; and NGCC generation provides greater resilience by ramping at 80 MW per minute versus 10 MW per minute for coal.[78] KIUC also asserted that delays in procuring new NGCC units may make them difficult to obtain or run the risk that firm gas transportation becomes unavailable.[79]

KIUC also argued that NGCC units perform reasonably well under the EPA's proposed 111(b) and 111(d) Greenhouse Gas Rules.[80] KIUC noted that Mill Creek Unit 5 will emit 65 percent less carbon dioxide (CO2) per MWh than a coal unit, and that under

[76] KIUC's Post-Hearing Brief at 1-2.

[77] KIUC's Post-Hearing Brief at 1-2.

[78] KIUC's Post-Hearing Brief at 3.

[79] KIUC's Post-Hearing Brief at 3.

[80] KIUC's Post-Hearing Brief at 3.

a worst-case scenario, LG&E/KU could comply with 111(b) by electing intermediate load operations and restricting NGCC capacity factors to 50 percent.[81]

KIUC indicated that Mill Creek 1 has been scheduled for retirement in 2024 since 2020. KIUC stated that Mill Creek 1 would require process water equipment for Effluent Limitation Guidelines (ELG) compliance to operate beyond 2024, a cooling tower to comply with Clean Water Act 316(b) regulations to operate beyond 2027, and an SCR prior to the 2027 ozone season to operate year-round in compliance with the Good Neighbor Plan.[82] KIUC argued that Mill Creek 1 will have reached the end of its economic life in 2024.[83]

KIUC asserted that a $110 million SCR for controlling NOx emissions would probably be required under existing environmental rules to continue operating Mill Creek 2 even if the Good Neighbor Plan does not go into effect, because the greater Louisville attainment area in which Mill Creek is located is in non-attainment for ozone purposes and Mill Creek 2 is the largest source of NOx in the greater Louisville attainment area.[84] KIUC noted that LG&E/KU previously entered into an Agreed Order at Mill Creek to not exceed 15 tons of NOx on a daily basis from May through October (6 months) in support of local attainment to the ozone national ambient air quality standards (NAAQS), which limits LG&E/KU's ability to operate both units at that time.[85] KIUC argued that these operating restrictions, which would not apply to Mill Creek 5, significantly reduce the

[81] KIUC's Post-Hearing Brief at 4.

[82] KIUC's Post-Hearing Brief at 6.

[83] KIUC's Post-Hearing Brief at 6.

[84] KIUC's Post-Hearing Brief at 6.

[85] KIUC's Post-Hearing Brief at 6-7.

economic, reliability, and resilience attributes of Mill Creek 1 and 2 for purposes of newly enacted KRS 278.264.[86] KIUC stated that if Mill Creek 1 and 2 are not retired, then LG&E/KU's application for an air permit for Mill Creek 5 would have to be restarted and likely would not be approved.[87]

KIUC argued that the Commission should approve the retirement of Mill Creek 1 and 2 for the reasons discussed above. However, KIUC noted that if Mill Creek 5 ultimately cannot be built for permitting or other reasons, then the capacity at Mill Creek 1 and 2 would be needed. Thus, KIUC argued that the retirement of Mill Creek 1 and 2 should be contingent on LG&E/KU receiving a permit for Mill Creek 5.[88]

KIUC also argued that LG&E/KU's proposed retirement of Brown 3 should be approved, because Brown 3 is LG&E/KU's least efficient and highest cost coal unit and the air permit process for Brown 12 would have to start over if Brown 3 is not retired, which would likely delay the construction of the NGCC unit and increase costs.[89] However, as with Mill Creek 1 and 2, KIUC argued that the retirement of Brown 3 should be contingent on LG&E/KU receiving a permit for Brown 12.[90]

KIUC questioned whether LG&E/KU's proposed utility-owned solar would be dispatchable as that term is used in KRS 278.264. However, KIUC supported approving

[86] KIUC's Post-Hearing Brief at 7.

[87] KIUC's Post-Hearing Brief at 5, 7.

[88] KIUC's Post-Hearing Brief at 8.

[89] KIUC's Post-Hearing Brief at 8.

[90] KIUC's Post-Hearing Brief at 8.

the CPCNs for the utility-owned solar projects based on the testimony of KIUC's witness, Lane Kollen.[91]

KIUC stated that Brown BESS is not cost-effective even with very favorable investment tax credits. KIUC noted that the present value cost to consumers from the Brown BESS ranges from a low of $78 million to a high of $130 million.[92] KIUC argued that the operational experience that would be gained from Brown BESS is not worth the significant added cost to consumers.[93] KIUC also stated that the after-tax cost of Brown BESS is $113 million whereas an SCR on Ghent 2 would cost $126 million and that adding an SCR to Ghent 2 would be more consistent with the legislative policy behind SB4.[94]

KIUC asserted that the retirement of Ghent 2 would violate the requirement in KRS 278.264(2)(b) that the retirement "not harm the utility's ratepayers by causing the utility to incur any net incremental costs" and the requirement in KRS 278.264(3) that the retirement result in cost savings.[95] KUIC asserted that Ghent 2 is the most efficient and reliable of the units LG&E/KU propose to retire. KIUC noted that Ghent 2 currently operates year-round.[96]

[91] KIUC's Post-Hearing Brief at 10.

[92] KIUC's Post-Hearing Brief at 10.

[93] KIUC's Post-Hearing Brief at 10-11; *See also* Direct Testimony of Lane Kollen (Kollen Direct Testimony) at 15–18.

[94] KIUC's Post-Hearing Brief at 11.

[95] KIUC's Post-Hearing Brief at 12-13.

[96] KIUC's Post-Hearing Brief at 12-13.

KIUC asserted that keeping Ghent 2 open will not affect the air-permitting process for either proposed NGCC unit. KIUC further asserted that keeping Ghent 2 open would provide LG&E/KU with more options in the future. KIUC argued that LG&E/KU could continue to operate Ghent 2 year-round with an SCR at a cost of $126 million if the EPA continues to pursue the Good Neighbor Plan or similar NOx reductions in Kentucky. KIUC also argued that LG&E/KU could continue operate Ghent 2 during non-ozone season if the EPA continues to pursue NOx reductions at an annual incremental cost of about $6.5 million.[97]

KIUC argued that if Ghent 2 remained open and was operated in non-ozone season, then the annual incremental costs of operating it could be more than offset by earning from off system sales of the energy generated.[98] KIUC stated that Ghent 2 could also be part of a least-cost solution for Kentucky Power's ratepayers. KIUC maintained that LG&E/KU failed to look at off-system sales for Ghent 2 or provide evidence regarding how the value of Ghent 2 could be maximized. KIUC argued that LG&E/KU assumed that if they no longer needed Ghent 2, then it did not have value.[99]

Although KIUC argued that recovery of the costs of the Solar PPAs should be through a new Solar PPA rider as opposed to the FAC proposed by LG&E/KU, KIUC did not oppose the proposed Solar PPAs. Specifically, KIUC stated that Exhibit DSS-2 to David S. Sinclair's Rebuttal Testimony demonstrated that at the current prices the four

[97] KIUC's Post-Hearing Brief at 13-15.

[98] KIUC's Post-Hearing Brief at 14-15.

[99] KIUC's Post-Hearing Brief at 14-15; *see also* KIUC's Post-Hearing Reply Brief at 1-3; Kollen Testimony at 10-15.

Solar PPAs will lower costs for consumers over five of six fuel cost scenarios.[100] KIUC noted that based on Lonnie Bellar's Rebuttal Testimony, the Solar PPAs are a supplement to, not a replacement of, the retiring coal plants.[101]

KIUC argued that Sierra Club's conclusion that joining PJM Interconnection, LLC (PJM) would save LG&E/KU $125 to $140 million annually is unreliable due to three significant errors. Specifically, KIUC asserted that Sierra Club's PJM analysis does not include any cost of joining PJM; assumes that LG&E/KU will have 6,790 MW of generation in 2028 (without adding any new NGCC capacity) and that virtually all of that same capacity (6,647 MW) will still be in operation 32 years later in 2050 despite evidence to the contrary; and Sierra Club makes unrealistic assumptions about the cost of market-based generation capacity in PJM.[102]

Sierra Club

In witness testimony and briefing, Sierra Club argued that maintaining both Mill Creek 1 and 2, Ghent 2, and Brown 3 was not "economically or legally viable."[103] Consequently, Sierra Club argued that LG&E/KU established the requisite statutory elements of KRS 278.264 to retire all the coal-fired units at issue in this proceeding. In doing so, Sierra Club stated that KRS 278.264 requires utilities to demonstrate that generating units will be replaced with new electric generating capacity.[104] Sierra Club argued that the plain language of the statute does not require "megawatt for megawatt"

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[100] KIUC's Post-Hearing Brief at 16-17.

[101] KIUC's Post-Hearing Brief at 16-17.

[102] KIUC's Post-Hearing Reply Brief at 4-5.

[103] Sierra Club's Post-Hearing Brief at 34.

[104] Sierra Club's Post-Hearing Brief at 12.

replacement generation and does not require utilities to replace each retired electric generating unit with a new generating unit.[105]

In arguing that LG&E/KU met its burden under KRS 278.264 and KRS 278.020 to retire the relevant electric generating facilities, Sierra Club noted that the EPA's Good Neighbor Plan would effectively require both Mill Creek 1 and 2, and Ghent 2 to cease operating during the ozone season beginning in 2026, because installing SCRs at those units, which would allow them to continue operating, would carry significant capital costs, including an estimated $110 million for each Mill Creek unit and $126 million for the unit at Ghent 2.[106] Sierra Club also noted that while Brown 3 did not require an SCR, it was nonetheless the most expensive unit for LG&E/KU to operate and was also slated for major overhaul repairs in 2027.[107] Sierra Club argued that those costs, as modeled by LG&E/KU, made the units uneconomical to operate in all but one of the one of the scenarios evaluated by LG&E/KU. Moreover, Sierra Club stated that even in the "high gas, zero CO2 price" model, only Ghent 2 remained marginally economical.[108]

While Sierra Club noted that the Good Neighbor Plan is currently being litigated, Sierra Club argued that the EPA's approach to regulating interstate ozone emissions is long standing and that their prior iterations have been upheld by the United States Supreme Court.[109] Sierra Club noted that the judicial challenges in Kentucky would be unlikely to result in a wholesale invalidation of the rule, because the contribution threshold

[105] Sierra Club's Post-Hearing Brief at 12.

[106] Sierra Club's Post-Hearing Brief at 34.

[107] Sierra Club's Post-Hearing Brief at 34.

[108] Sierra Club's Post-Hearing Brief at 34.

[109] Sierra Club's Post-Hearing Brief at 35.

being challenged by Kentucky was previously upheld by the United States Supreme Court.[110] Moreover, Sierra Club argued that even in the unlikely event that the Good Neighbor Plan was invalidated, Mill Creek 1 and 2 and Ghent 2 face independent regulatory pressures likely to result in higher compliance costs for NOx emissions.

Relying in part on LG&E/KU's witness Philip Imber's hearing testimony, Sierra Club argued that under Section 126 of the Clean Air Act, LG&E/KU could be required to install SCRs on Mill Creek 1 and 2, and Ghent 2. In fact, Sierra Club noted that several states had already filed Section 126 actions alleging that Kentucky sources, including those units, interfere with those states' ability to comply with EPA's air quality standards.[111] Additionally, Sierra Club argued that the current iteration of the Clean Air Act's "reasonably available control technology" provisions could provide the EPA with the authority to require those units to install SCR technology if LG&E/KU wished to continue operating them.[112]

Sierra Club stated that Mill Creek 1 and 2, Ghent 2, and Brown 3 were likely to face future regulatory challenges independent of the NOx emissions regulations discussed above. Specifically, Sierra Club noted that in May 2023, the EPA proposed CO2 emissions limits for new and existing electric generating units. Those regulations, colloquially known as 111(d) regulations, establish four subcategories of emission limitations, known as the "best system of emissions reductions," which are based on the

[110] Sierra Club's Post-Hearing Brief at 40.

[111] Sierra Club's Post-Hearing Brief at 44.

[112] Sierra Club's Post-Hearing Brief at 45-48.

anticipated retirement date of the unit in question.[113] Under the proposed rule, Sierra Club argued that if LG&E/KU's coal units continued to operate beyond 2032, it would incur significant compliance costs, in the form of either extraordinarily low capacity factors or hundreds of millions in capital investments to retrofit those units with carbon capture and sequestration technology.[114] Relying on the EPA's cost estimates, Sierra Club also stated that the cost of installing and operating carbon capture and storage system (CCS) would likely be between $26 and $35 per ton removed even with the Inflation Reduction Act's 45Q $85 per ton tax credit.[115] However, Sierra Club noted, based in part on Mr. Imber's testimony, that the cost of installing and operating CCS could be significantly higher.[116]

Sierra Club also argued that the forced outages experienced during Winter Strom Elliot demonstrated that coal-fired generation is not fully reliable.[117] Sierra Club asserted that, during the winter storm, roughly 18 percent of LG&E/KU's coal-fired generation was unavailable during peak demand periods.[118] Sierra Club stated that LG&E/KU were forced to shed 317 MW of load and that 390 MW of LG&E/KU's coal-fired generation was unavailable directly because of the storm, though it noted that, for various reasons, a total of 887 to 986 MW of coal-fired generation was unavailable to LG&E/KU during the period

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[113] Sierra Club's Post-Hearing Brief at 63.

[114] Sierra Club's Post-Hearing Brief at 63.

[115] Sierra Club's Post-Hearing Brief at 65.

[116] Sierra Club's Post-Hearing Brief at 67-68.

[117] Sierra Club's Post-Hearing Brief at 70.

[118] Sierra Club's Post-Hearing Brief at 71.

in which it was forced to shed load.[119] Sierra Club stated that LG&E/KU failed to add up the relevant megawatts of coal outages correctly in their after-action report, which underrepresented its contribution to the outage.[120] Sierra Club argued for an effective load-carrying capability (ELCC) type of analysis that accounts for coal and gas reliability failures.[121]

Relying, at least in part, on the events of the winter storm, Sierra Club also argued that LG&E/KU would benefit from joining an RTO, such as PJM, because the larger system would provide LG&E/KU with geographic and fuel diversity.[122] Moreover, Sierra Club continued to argue that being a member of an RTO during periods of load scarcity would allow LG&E/KU greater access to generation they cannot as easily obtain now as they are isolated from those resources.[123]

Relying on its witness, Andrew Levitt, Sierra Club argued that there were serious flaws in the methodology used by LG&E/KU when they calculated the costs and benefits of joining an RTO. Those apparent flaws included the fact that the model used by LG&E/KU treated retiring existing generation as a fixed input, instead of being allowed to optimally add or retire those resources and that the model's net present value analysis also only represented 15 years of annualized capital costs.[124] Sierra Club also disagreed with LG&E/KU's assertions that PJM has a greater reliability problem than LG&E/KU,

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[119] Sierra Club's Post-Hearing Brief at 72.

[120] Sierra Club's Post-Hearing Brief at 76–78.

[121] Sierra Club Post-Hearing Brief at 81–83.

[122] Sierra Club's Post-Hearing Brief at 96.

[123] Sierra Club's Post-Hearing Brief at 97–98.

[124] Sierra Club's Post-Hearing Brief at 99–100.

arguing that PJM did not experience rolling blackouts during the winter storm and reiterating that the PJM resource portfolio was more diverse than LG&E/KU's portfolio.[125]

Regarding the proposed CPCNs at issue in these proceedings, Sierra Club contended that LG&E/KU met the CPCN standard for the approval of the solar facilities and Brown BESS. However, Sierra Club argued that LG&E/KU did not satisfy the CPCN standard for approval of the two proposed NGCC units. Sierra Club argued that the Commission should, at a minimum, deny one NGCC unit outright because building two generating units is an extreme overbuild that amounts to approximately five times LG&E/KU's energy needs.[126] Sierra Club argued that the Commission should deny the second NGCC because LG&E/KU failed to adequately explore reasonable alternatives, such as joining PJM.[127]

Specifically, Sierra Club argued that LG&E/KU's own modeling showed that if they retired all of the units LG&E/KU proposed, but built no new generation, they would have a 1,733 GWh shortfall in 2028. However, Sierra Club noted, if both NGCC units were built under the same portfolio, those units would generate a combined 8,567 GWh of energy in 2028. Consequently, each NGCC unit would produce roughly 4,250 GWh of energy that year, more than twice the shortfall produced by the retirements.[128]

By contrast, Sierra Club stated that the owned solar project, the Solar PPAs, and the Brown BESS satisfied KRS 278.020 and that the Commission should approve those

[125] Sierra Club's Post-Hearing Brief at 102–103.

[126] Sierra Club's Post-Hearing Brief at 107.

[127] Sierra Club's Post-Hearing Brief at 108.

[128] Sierra Club's Post-Hearing Brief at 110.

CPCNs. Sierra Club argued that the renewable resources would bring diversity to LG&E/KU's generation portfolio and that LG&E/KU underestimated the value of solar by nearly 200 MW because LG&E/KU assigned solar a zero MW value during the winter months in their models.[129] Finally, regarding the Brown BESS, Sierra Club stated that stored power was important as the grid transitioned and that gaining this technology was important to LG&E/KU's resiliency moving forward.[130]

Louisville Metro and LFUGC

In witness testimony jointly sponsored with Sierra Club and in briefing, Louisville Metro and LFUCG argued in favor of LG&E/KU's plan to retire each of the fossil fuel-fired generating facilities. In support, Louisville Metro and LFUCG pointed to Louisville Metro Legislative Council's Resolution No. 0009, Series 2020, which supported a 100 percent clean, renewable energy goal for Louisville Metro by 2040. The Resolution also supported revising building codes to require energy efficiency, conservation, and renewable energy applications to attain a net zero goal for Louisville Metro.[131]

Louisville Metro and LFUCG also pointed to the Louisville Metro Air Pollution Control District (LMAPCD), which must meet the air quality standards established by the EPA. Louisville Metro and LFUCG argued that the margins to meet those air quality standards are "razor thin," and that in the January 2021 to August 9, 2023 period, Louisville metropolitan statistical area's (MSA) 8-hour ozone concentration was 72 parts

[129] Sierra Club's Post-Hearing Brief at 109-110.

[130] Sierra Club's Post-Hearing Brief at 109.

[131] Louisville Metro and LFUCG's Post-Hearing Brief at 3.

per billion (ppb), more than the 70-ppb standard set by the EPA.[132] Additionally, Louisville Metro and LFUCG noted that even in areas where the LMAPCD was in attainment, it was only succeeding marginally. For example, Louisville Metro and LFUCG argued that the current EPA standard for particulate matter with diameters 2.5 micrometers and smaller (PM2.5) is 12 micro grams per cubic meter (µg/m3), and that the latest data showed a measurement of 11.2 µg/m3. Louisville Metro and LFUCG argued that this data was concerning because the EPA has proposed new standards for PM2.5 with a range of 9-10 µg/m3, which is lower than LMAPCD can currently meet. By not being in attainment, Louisville Metro and LFUCG argued, LMAPCD would be required to prepare a compliance plan "indicating means and methods to get back into attainment."[133] In that circumstance, Louisville Metro and LFUCG argued, LMAPCD would be required to look to point sources of emissions to find avenues of enforceable reductions. Given that Mill Creek 1 and 2 are LMAPCD's largest emitters of relevant pollutants, closing those units would be crucial to Louisville MSA's quest for attainment.[134]

In contrast to their support for closure of the fossil fuel-fired units, Louisville Metro and LFUCG argued against LG&E/KU's proposal to build two new NGCC units. In support of their position, Louisville Metro and LFUCG made the following arguments: (1) that LG&E/KU had overestimated their capacity needs by undervaluing the contribution of imports; (2) that LG&E/KU understated the reliability of renewable and storage resources; (3) that LG&E/KU had overstated the capacity contributions of gas generation,

[132] Louisville Metro and LFUCG's Post-Hearing Brief at 4.

[133] Louisville Metro and LFUCG's Post-Hearing Brief at 5.

[134] Louisville Metro and LFUCG's Post-Hearing Brief at 5.

citing the rolling blackouts during the 2022 winter storm; (4) that LG&E/KU overstated the need for additional capacity by assuming unreasonably high costs associated with generation shortages in their modeling; and (5) that BESS provided better flexible capacity as compared to NGCC units.[135]

Instead, Louisville Metro and LFUCG argued that LG&E/KU should join an RTO, such as PJM. Doing so, they argued, would reduce LG&E/KU's capacity requirements by at least 900 MW as it would allow LG&E/KU to have greater regional diversity of demand patterns as well as being able to utilize lower installed reserve margins.[136] Additionally, Louisville Metro and LFUCG argued that the avoided capacity costs realized by joining PJM would save customers more than $125 million per year, on top of the additional annual production cost benefits of up to $66 million.[137] Finally, Louisville Metro and LFUCG noted that joining PJM would also give LG&E/KU better access to low-cost renewable energy.[138] In the alternative, Louisville Metro and LFUCG argued that the Commission should order LG&E/KU to perform and submit a comprehensive analysis focused on joining PJM.[139]

Regarding LG&E/KU's proposals to acquire the Marion County Solar facility, building a solar facility in Mercer County, and constructing the Brown BESS, Louisville Metro and LFUCG stated their support for each. Louisville Metro and LFUCG argued that the owned solar projects were cost-effective and would serve to "modernize"

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[135] Louisville Metro and LFUCG's Post-Hearing Brief at 6.

[136] Louisville Metro and LFUCG's Post-Hearing Brief at 6.

[137] Louisville Metro and LFUCG's Post-Hearing Brief at 6-7.

[138] Louisville Metro and LFUCG's Post-Hearing Brief at 6-7.

[139] Louisville Metro and LFUCG's Post-Hearing Brief at 7.

LG&E/KU's generation sources.[140] Louisville Metro and LFUCG noted that while the proposed Brown BESS was not the most economical due to its estimated capital costs, it nonetheless represented a useful means by which LG&E/KU could manage its operating reserve requirements as the BESS has the ability to instantly respond to generation needs.[141] This quick response, Louisville Metro and LFUCG argued, would improve the reliability and dispatchability of LG&E/KU's existing and proposed generation fleet. Louisville Metro and LFUCG also recommended that LG&E/KU be required to file a report detailing the operational, reliability, and dispatchability benefits associated with the Brown BESS.[142]

Walmart

Walmart did not file witness testimony. In briefing, Walmart noted that, regarding LG&E/KU's application to close the seven fossil fuel-fired electric generating units, only two parties, KIUC and Kentucky Coal Association, opposed closing those units. KIUC opposed only the Ghent 2 EGU and Kentucky Coal Association opposed closing all fossil fuel-fired units on the grounds that LG&E/KU's application was premature and that it could not therefore satisfy the requirements KRS 278.264.[143]

Utilizing its own analysis, Walmart argued that the evidence presented by LG&E/KU satisfied their burden to close at least six of the proposed fossil fuel-fired generating units: Mill Creek 1 and 2, Brown 3, Haefling 1 and 2, and Paddy's Run 12.

[140] Louisville Metro and LFUCG's Post-Hearing Brief at 7.

[141] Louisville Metro and LFUCG's Post-Hearing Brief at 7-8.

[142] Louisville Metro and LFUCG's Post-Hearing Brief at 7-8.

[143] Walmart's Post-Hearing Brief at 5-6.

Walmart disagreed that the Ghent 2 unit should be retired. Additionally, Walmart argued that LG&E/KU's proposal to build two NGCC units should be approved.[144]

Regarding LG&E/KU's specific justifications on which they relied to retire the fossil fuel-fired generating units, Walmart disagreed with Kentucky Coal Association's assertion that the status of the Good Neighbor Plan was dispositive and required denying LG&E/KU's application to close the fossil fuel-fired units. In support of its contention, Walmart noted that the Good Neighbor Plan was not the only regulatory scheme weighing on the units and that those other federal regulations would nonetheless likely require the installation of selective catalytic reduction (SCR) technology on any units lacking the technology currently.[145] Moreover, Walmart argued that even if Kentucky's federal litigation pertaining to EPA denial of Kentucky's NAAQS state implemental plan was ultimately successful, based on Walmart's understanding of the federal litigation, the most likely outcome was that Kentucky would be allowed to redraft a State Implementation Plan, which would not invalidate the EPAs actions.[146]

Walmart also argued that LG&E/KU's proposal to place the NGCC units at Brown and Mill Creek was in the best interest of customers. Walmart stated that placing the new NGCC units at these sites would allow LG&E/KU to take advantage of the "netting" process and avoid significant environmental regulations, which would otherwise have been present if "greenfield" sites were chosen.[147] However, Walmart noted that by

[144] Walmart's Post-Hearing Brief at 7.

[145] Walmart's Post-Hearing Brief at 7-8.

[146] Walmart's Post-Hearing Brief at 8.

[147] Walmart's Post-Hearing Brief at 8.

placing the units at Mill Creek and Brown, LG&E/KU could not also operate the coal-fired units without incurring substantial additional costs.[148]

Regarding whether the new NGCC units satisfied the strictures of KRS 278.264, Walmart argued that LG&E/KU had adequately demonstrated that their application met the novel statutory requirements. In support, Walmart disagreed with Kentucky Coal Association's position that the NGCC units were not as dispatchable as the coal units because there would be no on-site storage of fuel at the facilities. Walmart argued that constructing the NGCC units at the two sites would create a diverse gas supply, making the proposed units more reliable and resilient to service interruptions.[149]

Additionally, regarding the net incremental costs associated with closing the units and building new NGCC units, Walmart argued that LG&E/KU's 30-year net present value analysis should be accepted, as opposed to the 10-year residential rate impact analysis proposed by the Kentucky Coal Association. In support, Walmart argued that it was undisputed that the proposal would result in higher rates during the first 10 years, but that over the course of the 30-year horizon, there would be a more than $600 million benefit to ratepayers.[150]

Turning to the Brown BESS, Walmart stated that it supported granting a CPCN for the battery system. Walmart noted that while it agreed with KIUC regarding the cost of Brown BESS, Walmart concluded that the operational experience gained and that the BESS would improve reliability favored granting the CPCN. However, Walmart argued

[148] Walmart's Post-Hearing Brief at 8.

[149] Walmart's Post-Hearing Brief at 12.

[150] Walmart's Post-Hearing Brief at 13–14.

that LG&E/KU should be required to provide contemporaneous updates concerning their experiences with Brown BESS, including "lessons learned, reliability impacts, cost savings, peak demand impacts, and emissions reductions, as well as any other metrics the Commission may deem worthy of tracking."[151]

Walmart also supported LG&E/KU's application for CPCNs for the owned solar projects in Mercer and Marion counties. Walmart stated that the only party opposing the owned solar projects was the Kentucky Coal Association and argued that it had no specific objections to the projects, and instead opposed any change in the generation mix of LG&E/KU. Walmart further argued that the owned solar projects would diversify LG&E/KU's generation mix at the lowest cost to ratepayers.[152]

Walmart stated its general position is in support of RTO membership given the potential for decreased utility costs, greater access to renewable generation facilities, and improved grid reliability. However, Walmart recognized the conflicting testimony in these proceedings and argued that the Commission did not need to decide the RTO membership in this case. Instead, Walmart suggested that it was sufficient for the Commission to require LG&E/KU to consider and evaluate membership as part of its Integrated Resource Plan (IRP) and at every new CPCN application.[153]

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[151] Walmart's Post-Hearing Brief at 15.

[152] Walmart's Post-Hearing Brief at 16.

[153] Walmart's Post-Hearing Brief at 20.

Joint Intervenors

In witness testimony and briefing, Joint Intervenors argued that LG&E/KU's proposal to retire Haefling 1 and 2, Paddy's Run 12, Mill Creek 1 and 2, Brown 3, and Ghent 2 was justified and that the Commission should approve the retirements.[154]

Regarding the retirements of the gas SCCTs at Haefling 1 and 2 and Paddy's Run 12 by 2025, Joint Intervenors argued that once major mechanical repairs were required, the cost of those repairs would exceed their reliability value to LG&E/KU as secondary peaking units.[155] Joint Intervenors argued that this position was reflected in LG&E/KU's modeling as each portfolio independently chose to retire those units. Moreover, Joint Intervenors noted that given the low efficiency of the units coupled with the high costs of maintaining them the modeling did not show that those units would contribute to the need of securing replacement generation.[156]

Joint Intervenors stated that replacement of those specific generation sources was not required under KRS 278.264 because the statute, in their view, does not require a one-to-one replacement of resources as EGUs are retired.[157] Moreover, given the fact that the units did not materially impact the reliability, resilience, and reserve margin, Joint Intervenors argued that replacing the units with new generation would not survive scrutiny under KRS 278.020 because LG&E/KU would be unable to demonstrate need and lack of wasteful duplication. Additionally, Joint Intervenors noted that LG&E/KU had retired

[154] Joint Intervenors' Post-Hearing Brief at 58.

[155] Joint Intervenors' Post-Hearing Brief at 61.

[156] Joint Intervenors' Post-Hearing Brief at 61.

[157] Joint Intervenors' Post-Hearing Brief at 47.

four other similar units in the past ten years, demonstrating that retirement was done in the ordinary course of business.[158] Finally, Joint Intervenors noted that no party in these proceedings has contested the units' retirement or requested direct replacement for those units.[159]

Regarding Mill Creek Units 1 and 2, Joint Intervenors stated that LG&E/KU's proposal to retire the units was consistent with the Commission's prior Order in Case No. 2020-00061.[160] Joint Intervenors noted that in Case No. 2020-00061, LG&E/KU demonstrated that Mill Creek Unit 1 would require additional wastewater treatment equipment by 2024 to comply with Effluent Limitations Guidelines, and that the unit would also require a cooling tower by 2027 in order to comply with Section 316(b) of the Clean Water Act. Joint Intervenors argued that those expected regulatory costs were still required and made any additional investment in Mill Creek 1 not cost-effective.[161] Additionally, Joint Intervenors stated that LG&E/KU signed an agreement with the LMAPCD barring LG&E/KU from operating Mill Creek 1 and 2 simultaneously during the ozone season.[162] Finally, Joint Intervenors noted that LG&E/KU's application assumed that Mill Creek 1 would be retired in every portfolio, and that retirement of Mill Creek 1 would not require any direct replacement generation.[163]

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[158] Joint Intervenors' Post-Hearing Brief at 62.

[159] Joint Intervenors' Post-Hearing Brief at 62.

[160] *See* Case No. 2020-00061, *Electronic Application of Louisville Gas and Electric Company for Approval of an Amended Environmental Compliance Plan and Revised Environmental Surcharge* (Ky. PSC Sept. 29, 2020), Order.

[161] Joint Intervenors' Post-Hearing Brief at 63-64.

[162] Joint Intervenors' Post-Hearing Brief at 64-65.

[163] Joint Intervenors' Post-Hearing Brief at 65.

While subject to many of the same rationales for retirement as Mill Creek 1, Joint Intervenors provided several additional considerations regarding Mill Creek 2. Joint Intervenors stated that LG&E/KU estimated a cost of $110 million to install an SCR on Mill Creek 2 for LG&E/KU to operate the unit during the ozone season starting in 2027. Moreover, LG&E/KU's modeling showed that there was only a 0.53 increase in full-year LOLE, which was offset by more cost-effective resources in LG&E/KU's proposed replacement portfolio, such as LG&E/KU owned solar facilities, and the Solar PPAs.[164]

These were not the only concerns involving the Mill Creek units, Joint Intervenors argued, because it is likely that Mill Creek 1 and 2 will be subject to further environmental regulations moving forward. Joint Intervenors asserted that the Good Neighbor Plan would require LG&E/KU to install SCRs at Mill Creek 1 and 2, and the Regional Haze Rule and proposed Greenhouse Gas Rule were likely to impose even further burdens.[165] Joint Intervenors further asserted that the Greenhouse Gas Rules, as proposed by the EPA, "would require 40 percent natural gas co-firing for existing coal units retiring between January 2032 and January 2040 and 90 percent carbon capture and sequestration for any existing coal units operating beyond January 2040."[166]

Relying on LG&E/KU's testimony, Joint Intervenors argued that retiring Brown Unit 3 by 2027 would avoid $27 million in costs and that while the unit was already equipped with an SCR, the unit was nonetheless subject to additional regulatory hurdles,

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[164] Joint Intervenors' Post-Hearing Brief at 67-68.

[165] Joint Intervenors' Post-Hearing Brief at 65.

[166] Joint Intervenors' Post-Hearing Brief at 65.

much as the Mill Creek units.[167] Joint Intervenors asserted that, as with the Mill Creek units, Brown 3 would still be subject to independent environmental regulations decoupled from the Good Neighbor Plan. Those regulations included, Joint Intervenors argued, requiring additional wastewater treatment equipment and the risk of facing requirements for natural gas co-firing or CCS technology.[168] However, Joint Intervenors acknowledged that Brown 3 was not evaluated for retirement independent of replacing resources, though Joint Intervenors noted that in the modeling portfolios that building Brown 12, the proposed NGCC unit, reduced full year LOLE by 0.28 and significantly reduced PVRR.[169] Joint Intervenors argued that their witness Anna Sommer's alternative portfolio, which included only a single new NGCC unit produced an LOLE of 0.91 and an NPVRR difference in the capital cost sensitivity of $81,887,968.[170] For these reasons, Joint Intervenors stated their support for retiring Brown 3 conditional on LG&E/KU's CPCN approvals.[171]

Regarding the retirement of Ghent 2, Joint Intervenors again noted that the unit would likely face all the current and future environmental concerns that the other units faced and have been discussed above. Additionally, Joint Intervenors stated that only in a single scenario (High Gas/Low CTG) did the model give a "slight preference" to operating Ghent 2 with a $7 million PVRR difference if the unit remained operational

[167] Joint Intervenors' Post-Hearing Brief at 68.

[168] Joint Intervenors' Post-Hearing Brief at 68.

[169] Joint Intervenors' Post-Hearing Brief at 69.

[170] Joint Intervenors' Post-Hearing Brief at 69.

[171] Joint Intervenors' Post-Hearing Brief at 69.

during the non-ozone season without installing the SCR.[172] Notably, Joint Intervenors disputed KIUC's position that continuing operating Ghent 2 may be economic. In support, Joint Intervenors stated that KIUC's witness Mr. Kollen did not dispute that retiring Ghent 2 was a lower-cost option, and that the witness in fact agreed that operating Ghent 2 would result in a $71 million to $77 million PVRR penalty in which LG&E/KU add an SCR; and a $117 million to $218 million PVRR penalty in which the unit only operated during the non-ozone season without an SCR.[173]

Additionally, Joint Intervenors argued that KIUC's argument in favor of keeping Ghent 2 open to provide LG&E/KU with the opportunity to sell excess energy was "speculative" and unsupported by the record.[174] Joint Intervenors pointed to LG&E/KU witness Mr. Bellar's testimony, which stated that "there is no reason to take on such a risk that could adversely affect all customers."[175] Joint Intervenors argued that these factors taken together were sufficient to justify the position that Ghent 2's retirement should be approved by the Commission "subject to the Companies submitting sufficient CPCN requests for replacement resources."[176]

Turning to the question of approving the CPCNs for the two NGCC units proposed by LG&E/KU, Joint Intervenors argued that the Commission should deny the proposed units. As support for their position, Joint Intervenors stated that LG&E/KU's load forecast overstated future energy and capacity needs as LG&E/KU had "unreasonably low

[172] Joint Intervenors' Post-Hearing Brief at 70.

[173] Joint Intervenors' Post-Hearing Brief at 71.

[174] Joint Intervenors' Post-Hearing Brief at 72.

[175] Joint Intervenors' Post-Hearing Brief at 72.

[176] Joint Intervenors' Post-Hearing Brief at 73.

projections of energy savings" which could be achieved either through DSM-EE or DER programs.[177] Specifically, Joint Intervenors argued that there was a significant discrepancy in the provided data, stating that:

> Compared to the 2,612 GWh of cumulative economic savings potential by 2043 (or 3,199 GWh of cumulative economic savings potential by 2035/2038) identified in Table 1 of Ex. LI-1, the proposed DSM-EE plan's cumulative savings do not come close, remaining below 1,000 GWh of energy savings.[178]

Additionally, Joint Intervenors argued that LG&E/KU's load forecast exaggerated the forecasted capacity need. Joint Intervenors argued that LG&E/KU's incorporation of distributed energy resources (DER) was unreasonable because LG&E/KU assumed zero behind the meter storage, an inconsistency with LG&E/KU's 2021 IRP,[179] and that the data used did not reflect the actual adoption rates experienced by LG&E/KU from 2010 to 2021.[180] Moreover, Joint Intervenors argued, LG&E/KU only provided their models with four thermal options from which to choose.[181]

Joint Intervenors also found fault with LG&E/KU's continued use of the PROSYM cost modeling software. Joint Intervenors argued that PROSYM was outdated, as the software developer hasn't provided an update since 2019.[182] Instead, Joint Intervenors stated that LG&E/KU should rely on alternative modeling software, such as PLEXOS.[183]

[177] Joint Intervenors' Post-Hearing Brief at 79.

[178] Joint Intervenors' Post-Hearing Brief at 81.

[179] Joint Intervenors' Post-Hearing Brief at 82-83.

[180] Joint Intervenors' Post-Hearing Brief at 85.

[181] Joint Intervenors' Post-Hearing Brief at 89.

[182] Joint Intervenors' Post-Hearing Brief at 93.

[183] Joint Intervenors' Post-Hearing Brief at 95.

Moving to the likely capital costs of the NGCC units proposed by LG&E/KU, Joint Intervenors argued that LG&E/KU underestimated the likely costs involved. Joint Intervenors stated that for much of these proceedings the only direct price of gas builds was based on the HDR Engineering's 2022, and that new evidence stemming from engineering, procurement and construction bids submitted in response to a request for proposal (RFP) showed that the estimates were "unreasonably low."[184] Joint Intervenors also argued that LG&E/KU failed to accurately analyze future regulatory costs, such as those stemming from the EPA's proposed Greenhouse Gas rules.[185]

Joint Intervenors opposed the Brown BESS, asserting that the data did not support a finding that the BESS was not the least-cost battery storage option.[186] Joint Intervenors took issue with LG&E/KU's justification that the self-build battery storage was required for LG&E/KU to gain operational experience. Joint Intervenors countered that instead of owning the resource, LG&E/KU could include structured roles for their employees in a third-party owned BESS at a lower cost.[187] Moreover, Joint Intervenors argued, the evidence showed that operating the Brown BESS would increase emission from fossil fuel generating units.[188] Joint Intervenors stated that they would support LG&E/KU issuing a new RFP seeking more storage proposals and allowing bidders the option to utilize LG&E/KU's facilities.[189]

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[184] Joint Intervenors' Post-Hearing Brief at 96.

[185] Joint Intervenors' Post-Hearing Brief at 100.

[186] Joint Intervenors' Post-Hearing Brief at 105.

[187] Joint Intervenors' Post-Hearing Brief at 105.

[188] Joint Intervenors' Post-Hearing Brief at 105-106.

[189] Joint Intervenors' Post-Hearing Brief at 107.

Kentucky Coal Association

Kentucky Coal Association maintained that KRS 278.264(2)(a)(2) requires LG&E/KU to establish that they will replace an electric generating unit to be retired with generating capacity that is dispatchable and maintains or improves the reliability and resilience of the grid. Kentucky Coal Association indicated that the statute, in requiring that the replacement generation maintain or improve the reliability and resilience of grid, requires that the grid be as reliable as it was with the generation to be retired.[190] Kentucky Coal Association asserted that the common meaning of "dispatchable," which controls, is a source of electricity that is available for use on demand and that can be dispatched upon request of a power grid operator.[191] Kentucky Coal Association argued that LG&E/KU seek to have the Commission adopt a self-serving definition of dispatchable that is inconsistent with both industry norms and the legislative purpose of the statute.[192]

Kentucky Coal Association maintained that dispatchable generation includes resources like coal, gas, and nuclear, whereas non-dispatchable generation includes resources such as solar and wind.[193] Kentucky Coal Association asserted that DSM-EE programs are not "dispatchable," because they do not generate power and are not controlled.[194] Kentucky Coal Association argued that a significant portion of LG&E/KU's proposed new electric capacity is non-dispatchable or non-generating. Kentucky Coal Association stated that the "inclusion of such a significant amount of non-dispatchable

[190] Kentucky Coal Association's Post-Hearing Brief (filed Sept. 22, 2023) at 8-9.

[191] Kentucky Coal Association's Post-Hearing Brief at 4-6.

[192] Kentucky Coal Association's Post-Hearing Brief at 4-6.

[193] Kentucky Coal Association's Post-Hearing Brief at 4.

[194] Kentucky Coal Association's Post-Hearing Brief at 4-6.

and non-generating capacity in the proposed portfolio, fails to satisfy the reliability and resiliency requirements of [KRS 278.264] necessary to overcome the presumption against retiring the four (4) coal fired plants at issue."[195]

Kentucky Coal Association criticized the use of LOLE to assess the reliability of the system, though Kentucky Coal Association indicated that the LOLEs reported by LG&E/KU supported a finding that LG&E/KU's proposed portfolio does not maintain or improve reliability and resiliency of the grid as required by KRS 278.264.[196] Kentucky Coal Association stated that LG&E/KU reported that the LOLE for the existing portfolio of fossil fuel-powered plants is 0.45.[197] Conversely, Kentucky Coal Association noted that LG&E/KU indicated that the LOLE for a portfolio with the proposed retirements, NGCC units, owned solar, and DSM programs would be 0.77, which is less reliable and not consistent with KRS 278.264 requirements.[198] Kentucky Coal Association stated that if owned solar and DSM-EE programs are removed from the reliability analysis, which Kentucky Coal Association argued is required by KRS 278.264, then the LOLE would increase even further.[199]

Kentucky Coal Association stated that the unreliability of non-dispatchable and non-generating assets in conjunction with gas-fired plants was highlighted by the experience faced during Winter Storm Elliott. Kentucky Coal Association asserted that LG&E/KU's existing gas plant at Cane Run and Trimble County received inadequate

[195] Kentucky Coal Association's Post-Hearing Brief at 6-7.

[196] Kentucky Coal Association's Post-Hearing Brief at 8.

[197] Kentucky Coal Association's Post-Hearing Brief at 8.

[198] Kentucky Coal Association's Post-Hearing Brief at 8.

[199] Kentucky Coal Association's Post-Hearing Brief at 8–9.

pipeline pressure from Texas Gas Transmission, which contributed to rolling black outs.[200] Conversely, Kentucky Coal Association claimed that the operational coal plants operating during Winter Strom Elliott ran at an extremely high-capacity factor and on-site fuel storage of coal eliminated the same inability of the natural gas plants to effectively respond to the events that compromised the electric grid's reliability.[201]

Kentucky Coal Association noted that LG&E/KU indicated that dual fuel for the NGCC units could address the issue of the loss of pressure on the gas line, but noted that LG&E/KU could not identify the cost of such a dual fuel option. Kentucky Coal Association stated that LG&E/KU instead sought to address the issue by pointing to a letter from the Texas Gas listing proposed system improvements. Kentucky Coal Association argued that those proposals, while likely well-intentioned, do not provide an objective basis for the Commission to currently evaluate the statutory reliability and resiliency requirements for purposes of proposed replacement capacity under KRS 278.264.[202] Kentucky Coal Association asserted that all that can be gleaned objectively is that NGCC units have a potential Achilles heel in obtaining fuel in extreme cold, and therefore providing electricity as needed, as compared to coal.[203] Thus, Kentucky Coal Association argued that replacing coal-fired plants with NGCC units fails to improve resiliency or reliability as required by KRS § 278.264(2).[204]

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[200] Kentucky Coal Association's Post-Hearing Brief at 9.

[201] Kentucky Coal Association's Post-Hearing Brief at 9.

[202] Kentucky Coal Association's Post-Hearing Brief at 10-11.

[203] Kentucky Coal Association's Post-Hearing Brief at 11.

[204] Kentucky Coal Association's Post-Hearing Brief at 11.

Kentucky Coal Association next argued that LG&E/KU failed to establish that the new electric generating capacity will maintain the minimum reserve capacity requirement established by the utility's reliability coordinator as required by KRS 278.264(2)(a)3. Kentucky Coal Association noted that LG&E/KU have contracted with TVA to be their reliability coordinator but asserted that LG&E/KU failed to provide any evidence of the minimum reserve capacity established by TVA. Thus, Kentucky Coal Association argued that there is insufficient evidence to establish that the requirement has been met.[205] Further, Kentucky Coal Association noted that given the planned retirement of Mill Creek Unit 1 in 2024, if approved as proposed, such retirement could create a scenario by which LG&E/KU would fall below the minimum reserve capacity determined by TVA.[206]

Kentucky Coal Association next argued that LG&E/KU failed to establish that the proposed retirements will not harm ratepayers by causing LG&E/KU to incur any net incremental costs to be recovered from ratepayers that could be avoided by continuing to operate the electric generating unit proposed for retirement in compliance with applicable law as required by KRS 278.264(2)(b). Kentucky Coal Association argued that LG&E/KU failed to satisfy this requirement because they could retrofit the coal plants with SCRs, there is undepreciated capital for the coal plants at the time of the proposed accelerated depreciation, and that those costs will be paid by ratepayers, which will result in harm to the ratepayers.[207]

[205] Kentucky Coal Association's Post-Hearing Brief at 11.

[206] Kentucky Coal Association's Post-Hearing Brief at 11.

[207] Kentucky Coal Association's Post-Hearing Brief at 12.

Kentucky Coal Association noted that LG&E/KU used PVRR to assess the relative costs of various portfolios. Kentucky Coal Association asserted that PVRR uses levelized costs as opposed to straight-line depreciation, which serves to underestimate near term costs. Kentucky Coal Association noted that if LG&E/KU looked at the costs over the first ten years, then LG&E/KU's proposal would be more costly even based on their own standard.[208] Kentucky Coal Association also claimed that PVRR improperly ignores stranded costs by counting them on both sides of the equation as costs that will be incurred regardless of whether a plant is retired.[209] Kentucky Coal Association also argued that KRS 278.264(2)(b) required a rate impact analysis, which LG&E/KU failed or refused to perform.

Kentucky Coal Association stated that LG&E/KU included the benefit of federal tax credits in their financial modeling.[210] Kentucky Coal Association noted that LG&E/KU indicated that it would be unreasonable and unfair to customers to have such benefits eliminated from consideration when evaluating generation units but asserted that the legislature thought otherwise. Kentucky Coal Association argued that the exclusion of federal incentives from the PVRR analysis materially impacts the viability of the CPCN proposal and LG&E/KU's ability to satisfy the requirements of KRS 278.264.[211]

Kentucky Coal Association next asserted that LG&E/KU failed to provide the Commission with evidence of all the known direct and indirect costs of retiring the electric

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[208] Kentucky Coal Association's Post-Hearing Brief at 13.

[209] Kentucky Coal Association's Post-Hearing Brief at 13-14.

[210] Kentucky Coal Association's Post-Hearing Brief at 17.

[211] Kentucky Coal Association's Post-Hearing Brief at 17.

generating unit and demonstrate that cost savings will result to customers as a result of the retirement of the electric generating unit as required by KRS 278.264(3). Kentucky Coal Association asserted that LG&E/KU's presentation of costs was limited to costs that affect customer rates (e.g., capital costs, environmental compliance, etc.) and nothing else. Kentucky Coal Association argued that KRS 278.264(3) required LG&E/KU to consider costs other than those that affected customer rates such as the loss of tax base, jobs at suppliers of the plants, and other local and state economic losses. Kentucky Coal Association acknowledged that "[i]ndirect costs of retiring the fossil fuel fired plants may or may not impact customers" but argued that they "remain part of the overall analysis for the Commission to consider in determining compliance with SB4."[212]

Kentucky Coal Association also raised objections to certain cost assumptions LG&E/KU included in their financial modeling. Kentucky Coal Association noted that LG&E/KU projected coal prices using a coal-to-gas price ratio that LG&E/KU developed by looking at the historical relationship of coal and gas prices and assuming that they would follow similar trends.[213] Kentucky Coal Association's witness Emily Medine testified that this is a non-standard method for projecting coal prices, that it is unreasonable, and that it should not be relied on. Ms. Medine asserted that the assumption that pricing will follow similar trends flies in the face of common sense and recent trends.[214]

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[212] Kentucky Coal Association's Post-Hearing Brief at 18.

[213] Kentucky Coal Association's Post-Hearing Brief at 24.

[214] Direct Testimony of Emily S. Medine (Medine Direct Testimony) (filed July 14, 2023) at 37-49.

Kentucky Coal Association asserted that many coal-fired plants have closed in the last decade, which reduced demand for coal. Conversely, Kentucky Coal Association argued that based on LG&E/KU's own assumptions, the demand for gas is likely to increase while the demand for coal is likely to fall. Kentucky Coal Association also asserted that LG&E/KU failed to produce a contract or information regarding the predicted cost of firm transportation.[215] Kentucky Coal Association argued that the Commission must know this information before approving the CPCNs for the proposed NGCC units.[216]

Kentucky Coal Association also argued that LG&E/KU failed to obtain updated bids prior to the hearing and that updated bids indicated that the expected cost of the NGCC units increased substantially, which reduced the overall benefit of LG&E/KU's proposed plan.[217] Kentucky Coal Association noted that LG&E/KU argued that the increase in costs is a reason to move forward with the proposal quickly while also suggesting that the prices are not final and could potentially be negotiated down. Kentucky Coal Association asserted that based on the current inflationary and labor constrained atmosphere, a downward negotiation seemed unlikely.[218] However, Kentucky Coal Association also argued that costs are likely to go down over time.[219]

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[215] Kentucky Coal Association's Post-Hearing Brief at 24–26; *see also* Kentucky Coal Association's Post-Hearing Reply Brief (filed Oct. 5) at 15–17.

[216] Kentucky Coal Association's Post-Hearing Brief at 25–26; Kentucky Coal Association's Post-Hearing Reply Brief at 11–12.

[217] Kentucky Coal Association's Post-Hearing Reply Brief at 10–11.

[218] Kentucky Coal Association's Post-Hearing Reply Brief at 11.

[219] Kentucky Coal Association's Post-Hearing Reply Brief at 11.

Kentucky Coal Association objected to the "strained assumption that forecasted demand will be effectively stagnant from 2027 through 2050."[220] Kentucky Coal Association appeared to assert that this assumption is unreasonable because it does not account for any economic growth from 2027 to 2050.[221] Kentucky Coal Association asserted that the assumption "helps support the closure of coal units" in LG/KU's analysis.[222]

Kentucky Coal Association argued that LG&E/KU's flawed assumptions are the result of bias against coal-fired generation arising from incentive packages paid by LG&E/KU's parent company for the closure of coal-fired generation.[223] Kentucky Coal Association asserted that additional costs would also be necessary for the proposed NGCC units to comply with the zero emissions plan of LG&E/KU's parent company.[224]

Kentucky Coal Association alleged that LG&E/KU failed to clearly demonstrate cost savings as a result proposed plan. Kentucky Coal Association asserted that Greenhouse Gas rules proposed by the EPA during the pendency of this case affect the economics of the proposed NGCC units. Kentucky Coal Association, like the Attorney General, also noted that Good Neighbor Rule, which is the basis of the LG&E/KU's assertion that certain coal units are no longer economic to operate, has been stayed in Kentucky. Given the uncertainty surrounding the Greenhouse Gas Rule and Good

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[220] Kentucky Coal Association's Post-Hearing Brief at 23.

[221] Kentucky Coal Association's Post-Hearing Reply Brief at 20–21.

[222] Kentucky Coal Association's Post-Hearing Reply Brief at 23.

[223] Kentucky Coal Association's Post-Hearing Brief at 22–23.

[224] Kentucky Coal Association's Post-Hearing Brief at 26.

Neighbor Rule, Kentucky Coal Association argued that the proposed CPCN is premature.[225]

Kentucky Coal Association specifically argued that the Commission should not approve the approximately $270 million, or $135 million assuming the benefit of a federal subsidy, Brown BESS. Kentucky Coal Association noted that LG&E/KU stated that the BESS is not a generating resource and that LG&E/KU acknowledged that they are merely requesting the money for the purpose of gaining operational knowledge that will benefit LG&E/KU in the future in their ability to serve its customers. However, Kentucky Coal Association noted that the cost of the battery exceeds the cost of almost two SCRs that could allow existing coal plants to operate in non-ozone season. Kentucky Coal Association stated that the proposed battery further highlights the financial motives of LG&E/KU to promote shareholder and executive compensation over pragmatic decisions to utilize existing coal plants. Kentucky Coal Association asserted that if the Commission approves the battery project that LG&E/KU should not receive a return on the capital costs for the battery.[226]

Mercer County Government

Mercer County Government intervened for the sole purpose of addressing the Mercer County property that is the subject of the stipulation discussed above. Mercer County Government took no position on this issue.

[225] Kentucky Coal Association's Post-Hearing Brief at 21.

[226] Kentucky Coal Association's Post-Hearing Brief at 27.

LG&E/KU'S RESPONSE TO INTERVENOR ARGUMENTS – PROPOSED CPCNS AND GENERATION RETIREMENTS

LG&E/KU argued that the briefs of other parties confirm the prudence of LG&E/KU's proposed supply and demand-side resource portfolio. LG&E/KU asserted that the parties fall into three categories—the status quo parties, like Kentucky Coal Association; the anti-fossil fuel parties; and parties that generally support LG&E/KU's proposal. LG&E/KU argued that Kentucky Coal Association and the anti-fossil parties have interests other than providing adequate service to customers at the lowest possible cost. Conversely, LG&E/KU noted that the parties that generally support their proposed plan consist of KIUC, which represents large industrial customers, and Walmart, which is one of LG&E/KU's largest commercial customers.[227]

LG&E/KU noted that KIUC acknowledged that keeping Ghent 2 open along with the other proposed resources would increase costs to customers. However, LG&E/KU acknowledged that the Commission must weigh that benefit against ensuring sufficient capacity resources to provide reliability to their current and future customers in the light of KRS 278.264, economic development, and public reaction to Winter Storm Elliot.[228]

LG&E/KU also argued that notwithstanding KIUC's economic based concerns, Brown BESS satisfies the CPCN requirements. LG&E/KU asserted that they have established that the system is not wastefully duplicative given its unique operating characteristics (near instant dispatch), helps with compliance with proposed EPA Greenhouse Gas regulations by enabling additional renewable energy penetrations while

[227] LG&E/KU's Post-Hearing Reply Brief at 2–7.

[228] LG&E/KU's Post-Hearing Reply Brief at 7–8.

ensuring reliability, and has the potential to gain invaluable experience with utility-scale battery storage by building and then dispatching the system along with the rest of its generating portfolio. LG&E/KU argued that these factors support the Commission approving Brown BESS.[229]

LG&E/KU disagreed with Joint Intervenors assertion that LG&E/KU's preferred two-NGCC unit portfolio was never compared to any other significantly different plan on the basis of cost and reliability once identified in the Stage One analysis. LG&E/KU argued that they compared their Stage One optimal replacement resource portfolio to nine other portfolios on the basis of reliability (reserve margins), then to eight of those portfolios on the basis of cost across 18 different combinations of fuel and Greenhouse Gas cost scenarios.

DISCUSSION AND FINDINGS – PROPOSED CPCNS AND GENERATION RETIREMENTS

Based upon the case record, the Commission concludes that the methodology used by LG&E/KU to make resource decisions, broadly speaking, was reasonable and consistent with Kentucky law. Assuming the validity of various assumptions and proper implementation, LG&E/KU's methodology would produce a reasonable, least-cost plan to satisfy their expected resource requirements. However, based on the evidence presented, the Commission disagrees with some of the assumptions used by LG&E/KU as discussed below. Thus, as discussed in more detail below, the Commission finds that LG&E/KU's requests for CPCNs and retirement approval for the fossil fuel-fired generating facilities should be granted in part, with conditions, and denied in part.

[229] LG&E/KU's Post-Hearing Reply Brief at 8–9.

Need for Proposed Generation Resources

KRS 278.030(2) requires every utility to furnish adequate, efficient and reasonable service to its customers. KRS 278.010(14) provides the definition of “adequate service” as follows:

> “Adequate service” means having sufficient capacity to meet the maximum estimated requirements of the customer to be served during the year following the commencement of permanent service and to meet the maximum estimated requirements of other actual customers to be supplied from the same lines or facilities during such year and to assure such customers of reasonable continuity of service.

When conducting resource planning to determine whether and the extent to which additional resources are needed to provide adequate service, electric utilities forecast their projected loads during the planning periods and seek to ensure that they have resources available to serve their projected load and meet reserve margin requirements.[230]

New generation resources may be needed if a utility is experiencing load growth that prevents it from providing adequate service with existing resources or if existing resources are being taken out of service.[231] LG&E/KU primarily justified their need for the resources proposed in this case based on the planned retirement of a number of existing resources due to the cost of generation upgrades, related primarily to proposed environmental regulations, that they alleged made the continued operation of the units

[230] *See* 807 KAR 5:058.

[231] *See* Wilson Direct Testimony at 2-5 (discussing the effect of load on a utilities need generally and explaining that the immediate need is driven by planned retirements); *see also* Direct Testimony of Tim A. Jones Testimony (Jones Direct Testimony) at 14-15 (discussing the effect of BlueOval on LG&E/KU’s load).

uneconomic.[232] However, LG&E/KU's projected load and their planning reserve margin are potentially still relevant to determine whether and the extent to which new generation capacity is needed to replace the generating units LG&E/KU are proposing to retire.

Kentucky Coal Association and Joint Intervenors have taken opposing positions and asserted that LG&E/KU projected its load unreasonably low and unreasonably high, respectively. Kentucky Coal Association asserted that LG&E/KU's load forecast is unreasonable, because it is based on the strained assumption that demand will be effectively stagnant from 2027 through 2050.[233] While its argument on this point is limited, Kentucky Coal Association appeared to assert that this assumption is unreasonable because it does not account for any economic growth from 2027 to 2050.[234] Joint Intervenors argued that LG&E/KU's load forecast is unreasonable, because LG&E/KU underestimated future energy efficiency savings, including potential DSM-EE savings, and DER adoption. Joint Intervenors and Sierra Club also argued that LG&E/KU overestimated its minimum economic reserve margin, which LG&E/KU used to determine the amount of resources necessary to serve load. Thus, Kentucky Coal Association and Joint Intervenors, along with Sierra Club, argued, respectively, that LG&E/KU underestimated and overestimated its need for generation.

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[232] *See* Wilson Direct Testimony at 4-5 (discussing the impetus for the resource assessment); Wilson Direct Testimony, Exhibit SAW-1 December 2022 at 16-40 (discussing LG&E/KU's modeling process and indicating that a portfolio that retires Mill Creek 1 and 2, Ghent 2, Brown 3, Haefling 1 and 2, and Paddy's Run 12 and replaces them with the proposed NGCC units and 627 MWs of solar PPAs is more economic than upgrading existing resources to comply with the Good Neighbor Plan).

[233] Kentucky Coal Association's Post-Hearing Brief at 23.

[234] Kentucky Coal Association's Reply Brief at 20-21.

LG&E/KU asserted that no other party produced a load forecast; that their load forecast witness explained that the forecast is reasonable and that the methodology is consistent with previous forecasts; and that the parties objecting to the load forecast have interests other than the provision of “adequate, efficient and reasonable service” that are consistent with the opposing positions they take with respect to LG&E/KU’s load forecast.[235] LG&E/KU’s Manager of Sales Analysis and Forecasting explained that his team projected load by using historical data to develop models that relate electricity usage, demand, sales, and number of customers by rate classes to exogenous factors such as economic activity, appliance efficiencies and adoption, demographic trends, and weather conditions.[236] He acknowledged both high-side and low-side risks to the forecast but indicated that he and his team sought to present what they concluded is the most reasonable load forecast.[237]

The Commission finds that LG&E/KU’s treatment of economic growth in this load forecast is reasonable despite certain risks acknowledged by LG&E/KU. Contrary to Kentucky Coal Association’s assertion, LG&E/KU’s load forecast does account for economic growth. LG&E/KU projected load for most customer classes using econometric models that considered, among other things, national and local economic projections and demographic trends.[238] LG&E/KU also projected load for its largest customers based, in part, on information obtained from discussions with those customers regarding future

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[235] LG&E/KU Post-Hearing Reply Brief at 17-18.

[236] Jones Direct Testimony at 3.

[237] Aug. 24, 2023 Hearing Video Transcript (HVT) at 13:48:30-13:50:18.

[238] *See* Jones Direct Testimony, Exhibit TAJ-2 at 7-13; Jones Direct Testimony at 14.

plans and their expected usage and demand.[239] However, growth in load is partially offset by increased efficiency, which results in very low aggregate load growth between 2027 and 2050.[240]

As acknowledged by LG&E/KU, there is a possibility that an entirely new facility or industry like BlueOval will move to LG&E/KU's service territory and that such an addition might not be captured in LG&E/KU's econometric modeling or discussions with existing large customers.[241] However, LG&E/KU's witness Tim Jones argued that such a risk is at least partially balanced by the downside risk that customers will leave LG&E/KU's service territory,[242] and there are other downside risks to the load forecast as raised by Joint Intervenors and discussed below. In fact, the evidence indicates that LG&E/KU's weather normalized load was decreasing slightly from 2010 to 2022,[243] which would indicate that the addition of single customers with significant demand are not a regular occurrence (or that the load of such new customers is being balanced by decreases elsewhere). Thus, while the Commission does ultimately agree with Kentucky Coal Association that there is a high-side "risk" to the load associated with unexpected economic growth, the Commission finds that such a risk does not render LG&E/KU's load forecast unreasonable.

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[239] Jones Direct Testimony, Exhibit TAJ-2 at 9; Aug. 24, 2023 HVT at 13:51:00-13:51:37.

[240] *See* Aug. 24, 2023 HVT at 13:48:30-13:51:37; *see also* Jones Direct Testimony, Exhibit TAJ-2 at 18 (discussing how the positive and negative energy impacts of the IRA and DSM-EE on load are nearly offsetting from an energy prospective but not necessary from a peak demand prospective).

[241] *See* Aug. 24, 2023 HVT at 13:48:30-13:50:18

[242] *See* Aug. 24, 2023 HVT at 13:48:30-13:50:18.

[243] Jones Direct Testimony at 6. Kentucky Coal Association also acknowledged that LG&E/KU and other electric utilities have been experiencing stagnant demand since 2008. *See* Kentucky Coal Association's Post-Hearing Brief at 26.

As discussed in the DSM-EE section, LG&E/KU has improved their DSM-EE methodology by, among other things, adopting several of the recommendations in Commission Staff's report regarding its most recent IRP, but there is room to improve its methodology. LG&E/KU has similarly improved their projection of the effects of DERs on load, and additional improvements are possible. However, the Commission does not conclude that the low-side risks raised with respect to LG&E/KU's load forecast or its minimum reserve margin analysis materially affected LG&E/KU's need in this matter.

First, as noted above with respect to Kentucky Coal Association's argument, there are corresponding high-side risks with respect to LG&E/KU's load forecast, and the Commission, if anything, would prefer that utilities err on the high side to ensure that they have sufficient reliability to serve load. Further, as discussed below, the Commission has found that there is not currently a need to construct Brown 12 or take action with respect to Ghent 2 and Brown 3, but expects the status of those generating units to come up again in the near future when LG&E/KU have a better idea of what the Greenhouse Gas rules will look like and when they will be implemented. Such a delay will also provide additional time to see the effects of additional DSM-EE and DERs on load and whether there is additional offsetting economic development. This additional information and experience will help inform future resource decisions and help alleviate many of the concerns expressed in this matter on the subject. By not making so many generation decisions based on a single, contentious, load forecast, the Commission hopes to mitigate the risk of overbuilding to the detriment of customers' rates, or underbuilding to the detriment of the Commonwealth's energy adequacy. However, the Commission finds that those potential effects will not materially affect the need for Mill Creek 5 or some alternative generation in 2027.

When LG&E/KU filed their application, they alleged that EPA's Good Neighbor Plan, as proposed, would effectively require Mill Creek 1 and 2 and Ghent 2 to cease operating during the ozone season (May through September) each year beginning in 2026, unless LG&E/KU install SCR equipment at each of the units or obtain sufficient NOx emission credits to reduce their emissions by approximately 80 percent,[244] though LG&E/KU assumed as part of their resource planning that the Good Neighbor Plan would allow them to continue operating a non-SCR equipped unit if the unit was replaced by the 2028 ozone season.[245] During the pendency of this case, the EPA published the final Good Neighbor Plan, and LG&E/KU indicated that it did not materially change from the proposed plan and that it would require SCRs for coal units to continue operating during ozone season.[246]

Among other things, LG&E/KU stated that the final Good Neighbor Plan:

1. Adjusted the 2026 control period allocations to be based on state-of-the-art combustion control limit for half of the ozone season and SCR control limit for half of the ozone season,[247] whereas the proposed rule set the control period allocations in 2026 based on the stricter SCR control limit alone;[248]

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[244] Wilson Direct Testimony, Exhibit SAW-1 December 2022 at 4. In the initial filing, LG&E/KU indicated that Mill Creek 2 and Ghent 2 would require SCRs to continue operating, because it was assuming Mill Creek Unit 1 would be retired based on a previous analysis. However, Mill Creek 1 is not equipped with an SCR, so following the passage of Senate Bill 4, LG&E/KU indicated that an SCR would need to be added to Mill Creek 1 for it to continue operating.

[245] Wilson Direct Testimony, Exhibit SAW-1 December 2022 at 18.

[246] Imber Rebuttal Testimony at 3.

[247] LG&E/KU Response to Attorney General's Second Request, Item 4.

[248] *See* Imber Direct Testimony at 3.

2. Imposed a backstop limit to be applicable no later than the 2030 ozone season whereas the proposed rule applied the backstop limit beginning in the 2027 ozone season;

3. Exempted 50 tons of NOx from a unit with existing SCR controls prior to implementing a 3-for-1 allowance surrender ratio for backstop limit emissions exceedances, which LG&E/KU indicated would allow non-SCR units self-compliant ozone season operation for approximately 25 days (150/6) from 2026-2029 and approximately 8 days in 2030 based on the allocations available to non-SCR units; and

4. Set a target percentage of 21 percent of the sum of the state budgets for the 2024-2029 control periods as part of the allowance bank recalibration process.[249]

LG&E/KU indicated that non-SCR equipped unit availability will be severely impacted by the State Budget, Unit Allocations, and Bank Recalibration aspects of the final rule. LG&E/KU provided tables showing the expected NOx emissions at Mill Creek 2, Ghent 2, and Brown 3 in various fuel price scenarios as compared to projected NOx allocations under the final rule, and stated that LG&E/KU will have to start relying on the allocations market in 2027 to continue operating the units during ozone season. However, LG&E/KU indicated that they expected a shortage of allowances in the timeframe of 2026, 2027, or 2028 that supports the retirement or idling of non-SCR equipped units and the resulting need for lower-emitting replacement generation as posed in the CPCN filing.[250] Further, LG&E/KU indicated that the backstop rule in the Good Neighbor Plan would effectively prohibit Mill Creek 1 and 2 and Ghent 2 from operating beyond 2030.[251]

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[249] LG&E/KU Response to Attorney General's Second Request, Item 4.

[250] LG&E/KU Response to Attorney General's Second Request, Item 4.

[251] Aug. 22, 2023 HVT at 19:25:35-19:27:00.

The Commission finds LG&E/KU's evidence regarding the manner in which the Good Neighbor Plan will function to be credible. LG&E/KU's description of the Good Neighbor Plan is consistent with the final rule published by the EPA,[252] and their assumptions regarding unit emissions are based on the projected operating characteristics of its actual units in the fuel price scenarios modeled in this matter.[253] Further, most other parties to this case agree with LG&E/KU's assessment of the effect of the Good Neighbor Plan.[254] Kentucky Coal Association, through its witness, alleged that the Good Neighbor Plan, as modified after comments, was materially different from the plan initially proposed such that it created uncertainty regarding the need for LG&E/KU's proposed plan,[255] but neither Kentucky Coal Association nor its witness identified any specific changes that would eliminate the need for LG&E/KU to significantly limit the operation of non-SCR units in ozone season. Thus, the Commission finds that the final Good Neighbor Plan would impose significant limits on the operation of non-SCR units in ozone season.

Without the addition of SCRs on at least some of the non-SCR units or the addition of new resources, LG&E/KU would be unable to provide adequate service. For instance,

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[252] Final Federal "Good Neighbor Plan" for the 2015 Ozone National Ambient Air Quality Standards, 88 FR 36654 (June 5, 2023).

[253] *See* LG&E/KU Response to Attorney General's Second Request, Item 4.

[254] See Joint Intervenors' Post-Hearing Brief at 65-69 (discussing the effect of the Good Neighbor Plan on Mill Creek Unit 1 and 2 and Ghent Unit 2); KIUC's Post-Hearing Brief at 5-7 (discussing the effect of Good Neighbor Plan with respect to Mill Creek Unit 1 and 2); *see also* Walmart's Post Hearing Brief at 7-8 ("First, while it is true that the GNR is not a final and enforceable regulation, the evidence in the record established conclusively that numerous other, entirely independent EPA regulations exist that would impose similar obligations on the Companies to address emissions at the Fossil Fuel Electric Generating Units, nearly all of which would require the installation of [SCR] technology on units lacking such technology.").

[255] Medine Direct Testimony at 5.

assuming no generation is added or retired and SCRs are not built on Mill Creek 1 and 2 and Ghent 2 (and allowances are not available in any market), LG&E/KU projected an LOLE of 35.15,[256] which would mean that LG&E/KU would expect to have a loss of load event 35.15 days out of every ten years. Notably, while some parties have questioned the analysis LG&E/KU used to develop their minimum economic reserve margin, an LOLE of 35.15 is as much as 10 times higher than the LOLEs of portfolios that meet LG&E/KU's economic reserve margin,[257] and it is over 35 times higher than the standard 1-in-10 reliability target used by a number of RTOs and others for planning purposes.[258] Such a large LOLE indicates an inability to provide adequate service.

As noted by both the Attorney General and Kentucky Coal Association, implementation of the final Good Neighbor Plan is currently stayed in the state of Kentucky as well as several other states. If the stay remains in place or the Good Neighbor Plan otherwise does not apply in Kentucky, then it would affect LG&E/KU's claimed need in this matter because LG&E/KU likely could provide adequate service with its existing resources if they are not limited as they would be by the Good Neighbor Plan.[259] However, while the Commission agrees that the stay creates uncertainty as to the implementation of the Good Neighbor Plan, or similar standards based on the 2015

[256] LG&E/KU's Response to Staff's Second Request, Item 50.

[257] *See* Wilson Direct Testimony, Exhibit SAW-1 December 2022 at 13.

[258] *See* Sommer Direct Testimony at 25 (noting that she sought to develop plans based on a 1 in 10 LOLE, which she described as a typical reliability planning target); PJM Manual 20: PJM Adequacy Analysis, Revision 12, Section 1.2-1.5, pgs. 11-14 4 (dated August 25, 2021) (indicating that PJM establishes its reserve margin requirement based on capacity percent above the forecasted peak load required to satisfy a loss of load expectation of, on average, 1 day every 10 years).

[259] *See* LG&E/KU's Response to Staff's Post-Hearing Request, Item 20 (indicating the LOLE, LOLH, and EUE of LG&E/KU's existing system with SCRs added to Mill Creek Units 1 and 2, and Ghent Unit 2, which would be at least as good as the same units without SCRs if SCRs were not required).

NAAQS, the Commission does conclude that the Good Neighbor Plan or a similar standard will ultimately be implemented in Kentucky.

The stay of the Good Neighbor Plan in Kentucky pertained to the disapproval of the State Implementation Plan for the 2015 NAAQS standards and was based primarily on due process considerations.[260] Since disapproval of the State Implementation Plan was necessary for the EPA to adopt the Federal Implementation Plan, i.e. the Good Neighbor Plan, the EPA is not enforcing the Good Neighbor Plan in Kentucky due to the stay of the action disapproving the State Implementation Plan.[261] However, as noted by LG&E/KU and many of the Intervenors, the EPA has a long history of regulating ozone through NOx emission standards[262] that has been upheld by the U.S. Supreme Court.[263] In fact, LG&E/KU's Director of Environmental and Federal Regulatory Compliance testified that regulation of NOx through trading programs is not novel and that "there is no question" that the EPA will continue to regulate NOx emissions from major sources that contribute to downwind nonattainment.[264] Further, in testimony before the Sixth Circuit Court of Appeals, the EPA indicated its continued intention of enforcing that Good Neighbor Plan or similar rules based on the 2015 NAAQS in Kentucky.[265] Thus, while there is a possibility that the U.S. Supreme Court will reverse itself with respect to NOx

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[260] Aug. 25, 2023 HVT at 11:44:50-11:47:30; *see also Commonwealth of Kentucky et al. v. EPA*, Cir. Nos. 23-3216, 23-3225 (Doc. 39-2) (6th Cir., July 25, 2023); Imber Rebuttal Testimony at 7-8

[261] Imber Rebuttal Testimony at 4-5 (acknowledging the stay of the Good Neighbor Plan pending resolution of the litigation pertaining to the State Implementation Plan).

[262] Aug. 25, 2023 HVT at 11:51:06-11:52:00 (indicating that there have Cross State Air Pollution Rules limiting NOx emissions, of which the Good Neighbor Plan is the latest iteration, since the 1990s).

[263] *See EPA v. EME Homer City Generation, L.P.*, 572 U.S. 489 (2014)

[264] Aug. 25, 2023 HVT at 11:52:00-11:52:32.

[265] Imber Rebuttal Testimony at 6.

regulation, the Commission does not think that it would be reasonable to conduct resource planning based on that remote assumption, and therefore, finds that it is reasonable to assume that the Good Neighbor Plan or a similar standard implementing the 2015 NAAQS for ozone will ultimately be applied (and the EPA will then start work to implement to 2020 NAAQS).[266]

The Commission does agree with the Attorney General's position in the underlying litigation opposing the Good Neighbor Plan that the EPA should afford Kentucky the process it is entitled to by law, and questions LG&E/KU's assumption that the stay will have no effect on the timing of the Good Neighbor Plan or another similar plan implementing the 2015 NAAQS for ozone in Kentucky. The Commission also notes, as discussed in more detail below, that there is uncertainty regarding what the proposed Greenhouse Gas rule and other regulations will look like when finalized that could affect the cost of and need for various resource options. While there are cost risks to waiting to construct the proposed NGCC units, there are also risks associated with spending money to comply with one expected regulation only to have the value of that investment affected by the significant cost of a subsequent regulation. To minimize that risk, the Commission concludes that resource decisions such as whether to upgrade existing units to comply with environmental regulations or replace them with new units should be delayed to the extent practical to obtain more clarity regarding final environmental rules.

LG&E/KU asserted that it would take three years to plan, obtain approvals for, and construct SCRs on Mill Creek 1 and 2 and Ghent 2. For that reasons, LG&E/KU argued

[266] Imber Rebuttal Testimony at 4-8 (discussing the stay and the likelihood that the Good Neighbor Rule or a similar standard will likely be implemented).

that they would need to act now to replace or upgrade those units to ensure they have the necessary capacity to serve load when the Good Neighbor Plan or a similar standard implementing the 2015 NAAQS for ozone is ultimately be implemented. The Commission agrees, in part, that it would be a risk to wait on the outcome of litigation pertaining to the Good Neighbor Plan, but does not agree that the risk justifies taking immediate action with respect to all of the coal units at issue in this case.

As noted above, LG&E/KU will experience significant reliability issues if they are not able to operate Mill Creek 1 and 2 and Ghent 2 during ozone season in 2028 or do not have replacement generation. Further, the EPA included short timelines in the final Good Neighbor Plan, and as noted by LG&E/KU, the EPA indicated a commitment to reducing NOx emissions from sources in Kentucky in testimony and argument before the Sixth Circuit Court of Appeals,[267] so it is unfortunately difficult to imagine the EPA giving LG&E/KU significant additional time, if any, to comply following litigation, which could jeopardize LG&E/KU's ability to operate the non-SCR equipped units in ozone season, materially impacting reliability. More importantly, given the even longer construction timelines for new plants, potentially more than a decade for a nuclear resource, a utility would also often be locked into simply upgrading existing units if it did not plan based on environmental regulations or standards until they are final with all litigation complete. Thus, because the Commission concludes that the Good Neighbor Plan or a similar standard implementing the 2015 NAAQS will ultimately be implemented, the Commission finds that there is a need that must be addressed now to ensure there is time to implement a reasonable, least-cost plan to serve LG&E/KU's load.

[267] Imber Rebuttal Testimony at 5-6.

However, there is not an immediate need with respect to all of LG&E/KU's non-SCR units. Specifically, if LG&E/KU did not retire or construct any of the units at issue in this case and added SCRs to Mill Creek 1 and 2 but not Ghent 2, then LG&E/KU would have a summer reserve margin of 20.0 percent if all resources are included, and a summer reserve margin of 12.8 percent if intermittent and limited duration resources are excluded,[268] which LG&E/KU indicated would be sufficient to reliably serve load in the summer.[269] If Mill Creek 5 were substituted for Mill Creek 1 and 2, then the resulting portfolio would similarly meet the minimum reserve margin requirements established by LG&E/KU because Mill Creek 5 would be larger than Mill Creek 1 and 2 combined.[270] Thus, it would be possible to delay taking action on Ghent 2 without jeopardizing reliability to obtain more clarity on the proposed environmental rules, and therefore, the need is not immediate with respect to Ghent 2 if action is taken with respect to the Mill Creek 1 and 2.[271]

[268] Wilson Direct Testimony, Exhibit SAW-1 December 2022 at 45, Table 26 (showing LG&E/KU's projected peak load in the summer of 2028 as 6,319 MW and its total available resources in the summer of 2028, without any of the proposed retirements, as 7,721 MW, including 456 MW of intermittent/limited duration resources); Wilson Direct Testimony, Exhibit SAW-1 December 2022 at 50, Table 29 (indicating that the max summer capacity of Ghent Unit 2 is 485 MW). The available capacity values in Table 26 do not include Mill Creek Unit 1 or the small CTs at issue in this case, because Mill Creek Unit 1 cannot be operated with Unit 2 due to NOx emissions limitations and LG&E/KU did not believe the small CTs would be available. To calculate the summer reserve margins with the assumption that Mill Creek Units 1 and 2 had SCRs but Ghent Unit 2 did not, the Commission added 300 MW to the available capacity to account for both Mill Creek 1 and 2 becoming available, added 47 MW to account of the availability of the small CTs, and then removed 485 MW to account for Ghent Unit 2 being unavailable. For instance, the calculation without intermittent resources is as follows: Available Resources = 7,265 MW + 300 MW (Mill Creek 1) + 47 MW (Small CTs) – 485 MW = 7,127 MW; Reserve Margin = 808 MW / 6,319 = 12.8 percent.

[269] Wilson Direct Testimony, Exhibit SAW-1 December 2022 at 10.

[270] *See also* LG&E/KU Response to Post-Hearing Request, Item 22 (indicating that a portfolio with Mill Creek Unit 5, Ghent Unit 2 in non-ozone season only, Brown Unit 3, and the proposed solar PPAs have an LOLE of 0.62 days every 10 years)

[271] The Commission is not necessarily finding that meeting LG&E/KU's minimum reserve margin is sufficient to reliably serve load in the long term. However, if LG&E/KU can meet its minimum reserve

The need to take action with respect to Mill Creek 1 and 2 is much more immediate. Most urgently, Mill Creek 1 is not able to operate beyond 2024 without ELG retrofits and operation beyond 2027 would require a cooling tower.[272] In fact, LG&E/KU have planned to retire Mill Creek 1 at the end of 2024 since 2020 based on an analysis in a 2020 update to its Environmental Compliance Plan that found that ELG retrofits were not cost-effective as a result of LG&E/KU's expected load and limitations on Mill Creek 1's ability to operate with Mill Creek 2,[273] which is why Mill Creek 1 would now need urgent upgrades to continue operating. Further, as noted above, the ability to delay action on Ghent 2 without risking reliability is premised on ensuring that Mill Creek 1 and 2 or some replacement generation will be available because LG&E/KU could not reliably serve load if Mill Creek 1 and 2 and Ghent 2 were unavailable in ozone season. LG&E/KU would also not meet its minimum summer reserve margins in 2028 if SCRs were added to Ghent 2 alone and no other resources were added.[274] Further, the continued operation of Mill Creek 1 and

margins without an SCR on Ghent Unit 2, then the risk that the EPA will quickly implement the Good Neighbor Plan following the litigation is somewhat mitigated.

[272] Direct Testimony of Lonnie E. Bellar (Bellar May 10, 2023 Direct Testimony) (filed May 10, 2023) at 4.

[273] *See* Case No. 2020-00061, *Electronic Application of Louisville Gas and Electric Company for Approval of an Amended Environmental Compliance Plan and Revised Environmental Surcharge* (Ky. PSC Sept. 29, 2020), Order.

[274] *See* Wilson Direct Testimony, Exhibit SAW-1 December 2022 at 45, Table 26 (showing LG&E/KU's projected peak load in the summer of 2028 as 6,319 MW and its total available resources in the summer of 2028, without any of the proposed retirements, as 7,721 MW, including 456 MW of intermittent/limited duration resources); Wilson Direct Testimony, Exhibit SAW-1 December 2022 at 50, Table 29 (indicating that the max summer capacity of Mill Creek 2 is 297 MW). As noted above, the available capacity values in Table 26 do not include Mill Creek Unit 1 or the small CTs, because Mill Creek Unit 1 cannot be operated with Unit 2 due to NOx emissions limitations and LG&E/KU did not believe the small CTs would be available. The calculation of the reserve margin without intermittent resources was completed as follows: Available Resources = 7,265 MW + 47 MW (Small CTs) – 297 MW = 7,015 MW; Reserve Margin = 696 MW / 6,319 = 11.0 percent.

2 could also affect LG&E/KU's ability to obtain a permit for a new NGCC unit at that site,[275] whereas the continued operation of Ghent 2 would not have that effect. Thus, the Commission finds that it would be unreasonable to wait to address compliance with respect to Mill Creek 1 and 2, and therefore, finds that there is a current need that must be addressed with respect to Mill Creek 1 and 2 to ensure LG&E/KU's ability to continue to reliably serve load.

The Commission notes that this finding is further supported by other regulatory risks at Mill Creek that will likely require additional compliance measures such as the addition of SCRs even in the absence of the Good Neighbor Plan. For instance, the 2015 NAAQS established a threshold of 70 ppb for NAAQS for ozone as measured over the highest 8-hour average for each day.[276] In the most recent three-year range of 2020–2022, the Louisville Metropolitan Statistical Area (Louisville MSA) registered 70 ppb—i.e., the highest level it can be before Louisville is considered to be in nonattainment.[277] However, LG&E/KU and Louisville Metro noted that the Louisville MSA has historically been in nonattainment of NAAQS for ozone, and based on the 2021 through 2023 data, as of the date of the hearing, the Louisville MSA was not in attainment.[278] Further, the EPA reviews NAAQS every 5 years,[279] and the Clean Air Scientific Advisory Committee,

[275] *See* Aug. 25, 2023 HVT at 11:27:35 (explaining the permitting process).

[276] Aug. 25, 2023 HVT at 10:52:19-10:52:45.

[277] Aug. 25, 2023 HVT at 10:55:30-10:56:36; Louisville Metro Hearing Exhibit 1 at 4; *see also* Aug. 25, 2023 HVT at 10:40:50-10:43:44 (generally discussing LMAPDC's obligation to monitor ambient air quality and to ensure that federal standards are met in the Louisville MSA); Aug. 25, 2023 HVT at 10:43:44-10:48:44 (discussing what is represented Louisville Metro Hearing Exhibit 1).

[278] Aug. 25, 2023 HVT at 10:55:40-10:56:36.

[279] Aug. 25, 2023 HVT at 11:00:30.

which provides technical advice to the EPA administrator, has recommended the standard be lowered to 55–60 ppb.[280]

Mill Creek 1 and 2 are located in Louisville and are the largest emitters of NOx in that area,[281] so Louisville's nonattainment of NAAQS for ozone likely would subject Mill Creek 1 and 2 to additional limits on NOx emissions even in the absence of the Good Neighbor Plan. In fact, due to Louisville's previous nonattainment of NAAQS for ozone, NOx emissions limits were placed on Mill Creek that prevent LG&E/KU from operating Mill Creek 1 and 2 at the same time.[282] Despite that limitation, Louisville has generally still failed to achieve attainment of NAAQS for ozone. Given the current five-year review of the NAAQS for ozone, Mill Creek's contribution to Louisville's historic nonattainment, and Louisville's nonattainment despite limits that prevent Mill Creek 1 and 2 from operating at the same time, it is likely that local nonattainment of NAAQS for ozone will result in additional limits being placed on Mill Creek 1 and 2 that will require additional controls even if not required by the Good Neighbor Plan. Thus, again, the Commission finds that it would not be prudent to wait to address compliance with respect to Mill Creek 1 and 2.[283]

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[280] Aug. 25, 2023 HVT at 10:58:00-10:58:58.

[281] Aug. 25, 2023 HVT at 10:58:58-11:00:00.

[282] *See* Aug. 22, 2023 HVT at 19:24:25-19:25:35 (indicating that except in the case of emergencies the total Mill Creek station is currently prohibited from emitting more than 15 tons of NOx a day, which requires LG&E/KU to limit the operation of either Mill Creek 1 or 2 during ozone season if it is also operating Mill Creek 3 and 4).

[283] In Case No. 2020-00061, the Commission approved an environmental compliance plan that anticipated the retirement of Mill Creek Unit 1 in 2025 due to the necessary ELG upgrades and LG&E/KU's inability to operate Mill Creek Units 1 and 2 at the same time due to NOx emissions limitations, among other things. *See* Case No. 2020-00061, *Electronic Application of Louisville Gas and Electric Company for Approval of an Amended Environmental Compliance Plan and Revised Environmental Surcharge* (Ky. PSC Sept. 29, 2020), Order.

LG&E/KU are proposing to retire Brown 3 based on the assertion that it is not economic. Given the alleged economics of Brown 3, LG&E/KU argued that it would be cost-effective to retire that unit in 2028 and replace it and other units with the full portfolio proposed in this matter. However, Brown 3 notably is equipped with SCRs such that it could operate in compliance with the Good Neighbor Plan without any necessary upgrades. Thus, the need to comply with the Good Neighbor Plan is not driving the timing or the economics of the Brown 3 retirement.

Rather, LG&E/KU indicated that when they filed their application in this matter, the timing of the Brown 3 retirement was driven by a major, and expensive, overhaul planned in 2028. However, LG&E/KU's witness acknowledged at the hearing that it would be possible to delay the planned overhaul of Brown 3 for a couple years.[284] Further, as discussed above, the Commission believes that it would be possible for LG&E/KU to reliably serve load with Ghent 2 and Brown 3 while they wait for more certainty with respect to the Good Neighbor Plan and other environmental regulations. Thus, in light of the current regulatory environment and LG&E/KU's ability to delay the major upgrades on Brown 3, the Commission finds that there is not an immediate need that justifies the construction of replacement generation with respect to Brown 3.

LG&E/KU indicated a preference to constructing Mill Creek 5 in the event they were only approved to construct a single NGCC unit. Further, among other things, LG&E/KU indicated that it would affect their ability to obtain permitting for Brown 12 if Brown 3 remained in operation, that it would affect their ability to obtain permitting for Mill Creek 5 at a later date if they retired Mill Creek 1 and 2 without constructing Mill Creek 5,

[284] Aug. 23, 2023 HVT at 10:32:34.

and that costly transmission upgrades would be necessary to operate Brown 12 and Brown 3 at the same time. For those among other reasons, LG&E/KU appeared to consider Brown 12 to be replacing Brown 3 and, to a lesser extent, Ghent 2. However, because the Commission finds that the impetus for upgrading or replacing Brown 3 and Ghent 2 can be delayed at this time for the reasons discussed above, the Commission finds that there is currently no need that justifies the construction of Brown 12, and therefore, finds that the CPCN for Brown 12 should be denied.

LG&E/KU noted that the proposed Mercer Solar Facility and Marion Solar Facility would result in savings in three of the six fuel price scenarios studied even without considering a cost of Greenhouse Gas regulation compliance or income from the sale of RECs and indicated that it planned to add those facilities as a hedge against market uncertainties concerning the solar industry, gas prices, and future environmental regulations.[285] The Commission has previously granted CPCNs for new facilities based on savings to customers. In Case No. 2014-00002, the Commission recognized the importance of LG&E/KU diversifying its portfolio to hedge against environmental compliance risks even if the resource may result in a slightly higher cost.[286] Thus, the Commission finds that there is a need for the Mercer Solar Facility and Marion Solar Facility to the extent that LG&E/KU are able to establish that the facilities will not result in wasteful duplication.

Absence of Wasteful Duplication

[285] Wilson Direct Testimony, Exhibit SAW-1 December 2022 at 35-36, Table 17.

[286] *See* Case No. 2014-00002, *Joint Application of Louisville Gas & Electric Company and Kentucky Utilities Company for Certificates of Public Convenience and Necessity for the Construction of a Combined Cycle Combustion Turbine at the Green River Generating Station and a Solar Photovoltaic Facility at the E.W. Brown Generating Station* (Ky. PSC Dec. 19, 2014), Order at 10-13.

The resource expansion, financial, and reliability modeling conducted in this case establish that replacing Mill Creek 1 and 2, Haefling 1 and 2, and Paddy's Run 12 with Mill Creek 5 is the most cost-effective means of reliably serving load in the most likely scenarios. Further, the modeling indicates that the proposed owned solar and solar PPAs add reliability in all scenarios and reduce costs in most scenarios, especially in scenarios with higher fuel costs or in which a risk of Greenhouse Gas regulation is modeled. The evidence also indicates that LG&E/KU's proposed Brown BESS will allow them to gain experience with utility scale batteries, which will likely be necessary to mitigate the risks associated with Greenhouse Gas regulation. Thus, for the reasons discussed below in more detail, the Commission finds that Mill Creek 5, the owned solar facilities, and Brown BESS will not result in wasteful duplication, and therefore, finds that LG&E/KU's CPCNs for those facilities should be approved.

A portfolio that replaced Mill Creek 1 and 2, Haefling 1 and 2, and Paddy's Run 12 with Mill Creek 5 would meet the minimum reserve margin requirements that LG&E/KU indicated were necessary for them to provide adequate service.[287] Further, even if LG&E/KU did not add any of the other resources proposed in this matter, a portfolio that retired Mill Creek 1 and 2, Haefling 1 and 2, and Paddy's Run 12 and added Mill Creek 5 would be marginally more reliable than LG&E/KU's current portfolio, assuming the addition of SCRs and other required environmental controls on coal units in both

[287] The portfolio with Mill Creek 5 would give LG&E/KU significantly more capacity than it currently has in the summer due to its inability to Mill Creek Unit 1 and 2 at the same time in the summer. In winter, or if SCRs were added to Mill Creek Unit 1 and 2, LG&E/KU would have roughly the same capacity, because Mill Creek 5 is roughly the same size as Mill Creek Unit 1 and 2, Haefling Units 1 and 2, and Paddy's Run Unit 12 combined but is likely to be more reliable given its age. *See* LG&E/KU Response to Post-Hearing Request, Items 9 and 10 (showing the equivalent forced outage rates for LG&E/KU's coal units and NGCC unit and reasons for unusually high equivalent for outage rates).

scenarios.[288] Even without any of the planned solar or dispatchable DSM, the portfolio with Mill Creek 5 would have an LOLE of 0.70 days every 10 years,[289] which is significantly lower than even the lowest LOLE, 3.57, associated with the portfolios that met LG&E/KU's minimum economic reserve margin.[290] An LOLE of 0.70 is also lower than the standard 1-in-10 reliability target used by PJM and others to ensure reliability in capacity planning.[291] Thus, retiring Mill Creek 1 and 2, Haefling 1 and 2, and Paddy's Run 12 and replacing them with Mill Creek 5 will allow LG&E/KU to continue to provide adequate service.

The evidence also indicated that constructing Mill Creek 5 is the least-cost method of serving load in the most likely scenarios. Based on the cost estimates included in the application, a portfolio that replaces Mill Creek 1 and 2, Haefling 1 and 2, and Paddy's Run 12 with Mill Creek 5 would have a lower PVRR than the status quo in five of the six fuel price scenarios modeled by LG&E/KU—Low Gas, Mid CTG; Mid Gas, Mid CTG; High

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[288] *See* LG&E/KU's Response to Post-Hearing Request, Item 20 (which shows the LOLE, LOLH, EUE for both portfolios).

[289] *See* LG&E/KU's Response to Post-Hearing Request, Item 20.

[290] Wilson Direct Testimony, Exhibit SAW-1 December 2022 at 13. As discussed in more detail with respect to KRS 278.264, the Commission concludes that LOLE, LOLH, and EUE are the best metrics to assess the reliability of portfolios, because they provide an objective means to evaluate the likelihood that a utility will lose load, the likely duration of expected loss of load events, and the likely magnitude of such events.

[291] *See* PJM Manual 20: PJM Adequacy Analysis, Revision 12, Section 1.2-1.5, pgs. 11-14 4 (dated August 25, 2021) (indicating that PJM establishes its reserve margin requirement based on capacity percent above the forecasted peak load required to satisfy a loss of load expectation of, on average, 1 day every 10 years); *see also* Sommer Direct Testimony at 25 (noting that she sought to develop plans based on a 1 in 10 LOLE, which she described as a typical reliability planning target);

Gas, Mid CTG; Low Gas, High CTG; and High Gas, Current CTG.[292] However, the updated bids for the NGCC units affect the economics of the proposed units.[293]

Regardless, with the exception of the High Gas, Current CTG fuel price scenario in which the PVRR of the portfolio with Mill Creek 5 is significantly lower, both with and without the updated bids, the differences in the PVRRs represent only a small portion of the total cost of the portfolios. For instance, the portfolio that replaces Mill Creek 1 and 2, Haefling 1 and 2, and Paddy's Run 12 with Mill Creek 5 went from having a PVRR that is 0.34 percent, 0.25 percent, 0.16 percent, and 0.54 percent lower than the status quo to having a PVRR that is [redacted] percent, [redacted] percent, [redacted] percent, and [redacted] percent higher than the status quo portfolio during the 2023 to 2050 planning period in the Low Gas, Mid CTG; Mid Gas, Mid CTG; High Gas, Mid CTG; and Low Gas, High CTG scenarios, respectively.[294] Regardless, there are also a number of likely costs that are not included in that PVRR analysis.

First, the PVRR analysis based on the updated bids only included cost updates for the NGCC units. However, it is highly likely that other capital costs increased from the time applications were filed in this matter, including those related to environmental compliance. This is an economically reasonable assumption given the current inflationary

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[292] *See* LG&E/KU's Response to Post-Hearing Request, Item 20, *PSC PH LGE KU Attach to Q20 - Attach 1 LOLE EUE PVRR of Alternative Portfolios – CONFIDENTIAL.xlsx*, OriginalBid Tab.

[293] *See* LG&E/KU's Response to Post-Hearing Request, Item 20, *PSC PH LGE KU Attach to Q20 - Attach 1 LOLE EUE PVRR of Alternative Portfolios – CONFIDENTIAL.xlsx*, UpdatedBid Tab.

[294] LG&E/KU's Response to Staff's Post-Hearing Request, Item 20, *PSC PH LGE KU Attach to Q20 - Attach 1 LOLE EUE PVRR of Alternative Portfolios – CONFIDENTIAL.xlsx* (showing the Absolute PVRRs for the status quo portfolio, Portfolio a, and the portfolio with Mill Creek 5, Portfolio d, both with and without the updated bids). To calculate the percentage differences, the Commission simply subtracted the Absolute PVRR for Portfolio d from the Absolute PVRR for Portfolio a, divided the difference by the Absolute PVRR for Portfolio d, and multiplied 100.

environment as evidenced by the increase in the bids for the NGCC units as well as the fact that numerous other coal units across the United States will be subject to more stringent NOx limitations. As with the NGCC units, the cost of SCRs is likely to increase in the short term due to increased demand and limited supply of contractors associated with Good Neighbor Plan compliance, as well as the short time to comply with the rule. More importantly, the PVRR analyses assumed that Mill Creek 1 and 2, Haefling 1 and 2, and Paddy's Run 12, which were placed in service in the late 1960s and 1970s, will be able to remain in service through 2050 without significant additional compliance and upgrade costs.[295] In light of the current regulatory environment and the age of the units, the Commission finds that is not a reasonable assumption. Directionally, any additional environmental compliance costs for those units incurred until 2050, particularly ones that would not apply to natural gas-fired generation, only further adds to the cost-effectiveness of adding Mill Creek 5 as opposed to continuing operation of Mill Creek 1 and 2, Haefling 1 and 2, and Paddy's Run 12

When LG&E/KU filed its initial application in this matter, it recognized the risk of potential Greenhouse Gas regulation to both the coal and NGCC units and stress tested various portfolios with $15 and $25 per ton Greenhouse Gas emission abatement costs.[296] LG&E/KU indicated that a Greenhouse Gas cost favored portfolios with Mill Creek 5 and Brown 12 because they are lower emitting than the units they would be replacing.[297] Thus, as would be expected, adding a Greenhouse Gas emission

[295] *See* Wilson 2023-00122 Testimony, Exhibit SB4-1, Table 11 (showing the stay open cost of the units through the planning period).

[296] Wilson 2023-00122 Testimony, Exhibit SAW-1 at 13, 20, 31-32, 60-61.

[297] Wilson Direct Testimony, Exhibit SAW-1 December 2022 at 31-33.

abatement cost to the portfolios discussed above would favor the portfolio in which Mill Creek 5 is added to replace Mill Creek 1 and 2, Haefling 1 and 2, and Paddy's Run 12 over the status quo portfolio.

Specifically, retiring Mill Creek 1 and 2, Haefling 1 and 2, and Paddy's Run 12 and replacing them with Mill Creek 5 becomes the lower-cost option in all six fuel price scenarios with a $15 per ton Greenhouse Gas emission abatement cost. Increasing the emission abatement cost simply makes Mill Creek 5 more cost-effective as compared to the status quo,[298] because the status quo portfolio with Mill Creek 1 and 2, Haefling 1 and 2, and Paddy's Run 12 has significantly higher emissions than the portfolios in which Mill Creek 5 replaces those units.[299]

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[298] In response to the Commission Staff's Post-Hearing Request for Information, Item, LG&E/KU performed several production cost study runs with portfolios defined by the Commission Staff. Included in these were Portfolio a, which had no retirements and no additions, and Portfolio d, which had retirements of Mill Creek 1 and 2, Haefling 1 and 2, and Paddy's Run12, with the addition of only Mill Creek 5. These studies were run under the six fuel price scenarios used throughout the case, and with a cost of Greenhouse Gas emission abatement of $0/ST CO2.

To assess the impact of Green House Gas Regulation on the cost-effectiveness of Portfolio d as compared to Portfolio a, Company workpaper PSC PH LGE KU Attach to Q20 - Attach 2 CONFIDENTIAL Workpapers.zip, CONFIDENTIAL, FinancialModel, *CONFIDENTIAL_20230505_FinancialModel_0314_D01_UpdatedBid.xlsx* was used to determine the total CO2 emissions by year for Portfolios a and d under the six fuel price scenarios. Two price scenarios ($15/ST CO2 and $25/ST CO2) were then analyzed starting in 2030 consistent with LG&E/KU's stress testing. A NPV calculation was then done using LG&E/KU's-assumed discount rate of 6.43 percent. The estimated cost of abatement based on LG&E/KU's stress test was then added to the Absolute PVRRs for Portfolio a and d with the updated bids provided in the excel sheet entitled PSC PH LGE KU Attach to Q20 - Attach 1 LOLE EUE PVRR of Alternative Portfolios – CONFIDENTIAL.xlsx. Portfolio d was lower cost than Portfolio a in all six fuel price scenarios for both the $15 and $25 prices, as shown in the following table:

[redacted]

[299] *See* LG&E/KU's Response to Staff's Post-Hearing Request, Item 20, *CONFIDENTIAL_20230505_FinancialModel_0314_D01_UpdatedBid.xlsx* (showing the emissions associated with both of the portfolios).

The risk of Greenhouse Gas regulation is also more certain now than it was when LG&E/KU filed their application in this matter. On May 23, 2023, the EPA proposed CO2 emission limits for new and existing electric generating units that would impact the cost-effectiveness of LG&E/KU's existing coal units, including Mill Creek 1 and 2, Ghent 2, and Brown 3, and the NGCC units LG&E/KU is proposing in this matter. Pursuant to the EPA's proposed emission limits, Mill Creek 1 and 2, Ghent 2, and Brown 3 would not be able to operate beyond 2032 without significantly reducing the capacity factor of the unit and agreeing to retire the unit by 2035; adding natural gas co-firing to the unit and agreeing to retire the unit by 2040; or adding CCS to the unit with 90 percent capture efficiency.[300] In order to operate beyond 2032, the EPA's proposed regulation would require new NGCC units, like those proposed by LG&E/KU in this matter, to (1) operate at a capacity factor of 50 percent and operate as an intermediate-load unit indefinitely with a CO2 emission restriction of no more than 1,000 lbs./MWh gross; (2) meet a lowered 680 lbs./MWh gross CO2 emission standard, which EPA stated will be achievable by co-firing low-Greenhouse Gas hydrogen; or (3) meet the 90 lbs./MWh gross CO2 emission standard by 2035, which EPA stated will be achievable by adding CCS to the units.[301]

In response to requests for information in this case, LG&E/KU modeled the effects of the EPAs proposed Greenhouse Gas rules. To do so, among other things, LG&E/KU placed a 50 percent capacity factor limit on new NGCC units and a $0, $15, and $25 per ton Greenhouse Gas emission abatement cost on the coal units it was proposing to retire. LG&E/KU argued that the 50 percent capacity factor limit on the new NGCC units, which

[300] LG&E/KU's Response to Staff's Fifth Request, Item 2.

[301] LG&E/KU's Response to Staff's Fifth Request, Item 2.

it had the ability to model, is the worst case compliance scenario for those units because it would choose another option such as adding CCS if it was ultimately cheaper, and assuming no additional CO2 regulation, the Commission finds that assumption to be reasonable because it was modeling the new NGCC units in a manner that complied with the proposed rule and in which costs could be known. Conversely, LG&E/KU noted that the only compliance option that would permit the coal units to operate beyond 2040 was adding CCS, and indicated that they modeled compliance for the coal units with a cost per ton of CO2 emitted, because they did not have reliable cost estimates for CCS, though they argued it would be unreasonable to assume no cost of compliance even with the 45Q tax credits for CCS.[302]

LG&E/KU's modeling of the Greenhouse Gas rules indicated that the optimum portfolio from their Stage One analysis (retiring all units as proposed, constructing the two NGCC units, and adding 637 MW of solar PPAs) had a lower PVRR in all scenarios with a cost of Greenhouse Gas emission abatement than every portfolio that they reviewed as part of their Stage One stress testing analysis, including the lowest-cost portfolio that did not retire all coal units (adding SCR to Ghent Unit 2, retiring all other units as planned, adding Mill Creek 5, and adding 637 MW of solar PPAs).[303] LG&E/KU's modeling of the proposed Greenhouse Gas rules also indicated that a portfolio that added Mill Creek 5 to replace Mill Creek 2 (Portfolio 3) would have a PVRR between $289 million and $1.331

[302] LG&E/KU's Response to Staff's Fifth Request, Item 2; *see also* LG&E/KU's Response to Joint Intervenor's First Request, Item 1; LG&E/KU's Response to Sierra Club's First Request, Item 20 (noting that converting a coal unit to gas was not economical).

[303] LG&E/KU's Response to Staff's Fifth Request, Item 2, Table 2, Table 3, CONFIDENTIAL_20221209_FinancialModel_0308_Ph2_D01_PSC5-2.xlsx; *see also* Wilson 2023-00122 Testimony, Exhibit SAW-1 at 28-29, Table 10, Table 11 (indicating the resources that are included in the portfolios used for stress testing).

billion lower than an otherwise identical portfolio that kept Mill Creek 2 without SCR (Portfolio 6) in the scenarios in which a $15 or $25 per ton cost of complying with the Greenhouse Gas rules was imposed on Ghent 2, Brown 3, and Mill Creek 2.[304] The lower PVRR in all scenarios indicates Mill Creek 5 would be much more cost-effective than Mill Creek 2 if the proposed Greenhouse Gas rules or something similar become effective.

One problem with comparing the referenced Portfolio 3 to Portfolio 6 to establish that operating Mill Creek 5 would be more cost-effective under the proposed Greenhouse Gas rules is that the modeling of Portfolio 3 did not include the updated costs of Mill Creek 5. However, the updated bid increased the PVRR effect of adding Mill Creek 5 by [redacted] during the planning period,[305] such that the referenced Portfolio 3 would still be less expensive than Portfolio 6 during the planning period in all scenarios in which a cost of complying with the Greenhouse Gas rules is imposed on the coal units. The Commission also notes that replacing Mill Creek 2 with Mill Creek 5, which is the only difference between the referenced Portfolio 3 and Portfolio 6, is not a one-for-one trade. Mill Creek 5 is more than two times larger than Mill Creek 2; and while Mill Creek 5 would be limited to a 50 percent capacity factor under the proposed rules, that limitation would not reduce its energy generation by 50 percent as compared to scenarios without the

[304] These amounts were determined by calculating the differences between the amounts reflected in Table 2 of LG&E/KU's Response to Staff's Fifth Request, Item 2 for Portfolio 3 and Portfolio 6. The resources included in the portfolios are discussed in Exhibit SAW-1 at pages 28 through 29.

[305] By looking at the differences in the costs of various portfolios provided in the Excel file titled *PSC PH LGE KU Attach to Q20 - Attach 1 LOLE EUE PVRR of Alternative Portfolios – CONFIDENTIAL.xlsx* filed in response to Staff's Post-Hearing Request, Item 20, both with and without the updated bids, it is possible to determine the incremental effect of the updated bids on the cost of the portfolios throughout the planning period. As would be expected, because the change is only in a capital cost that would not affect unit dispatching, the incremental changes caused by the updated bids for each unit are the same in all portfolios. Thus, that incremental change can be applied to other PVRR analyses to reflect the effect of the updated bids on those portfolios.

proposed Greenhouse Gas rules, because it would not operate at a 100 percent capacity factor even without an emissions restriction.[306] Thus, assuming a cost of compliance with the proposed Greenhouse Gas rules or similar rules for the coal units, a portfolio that replaces Mill Creek 1 and 2, Haefling 1 and 2, and Paddy's Run 12 with Mill Creek 5 would cost LG&E/KU's customers less in all fuel price scenarios.

The Commission also agrees with LG&E/KU that it is unreasonable to assume no cost of compliance with the Greenhouse Gas rules for coal plants. The EPA estimated as part of its analysis of the proposed Greenhouse Gas rules that it would cost between $26 and $35 per ton of CO2 emitted and removed for the installation and operation of CCS at Ghent 2, Mill Creek 1 and 2, and Brown 3 even with the 45Q tax credit.[307] The EPA has an incentive, if anything, to underestimate the cost of compliance with the proposed Greenhouse Gas rules to justify emission limits, so the Commission does not believe such numbers would be purposefully inflated. Further, as noted by LG&E/KU's witnesses, there are likely significant indirect costs to adding CCS to LG&E/KU's coal units such as the need for pipelines to transport CO2, the energy used to operate CCS, and the potential for additional environmental controls that could be needed to operate CCS.[308] Thus, the Commission finds that a portfolio that replaces Mill Creek 1 and 2, Haefling 1 and 2, and Paddy's Run 12 with Mill Creek 5 would be cheaper in all fuel price

[306] *See* LG&E/KU's Response to Staff's Post-Hearing Request, Item 23(a) (indicating that the NGCC units were operating at capacity factors of between 64 percent and 84 percent in the various fuel price scenarios without any cost for greenhouse gas regulation included in the modeling).

[307] EPA Doc. EPA-HQ-OAR-2023-0072-0061_attachment_3, which can be found at https://downloads.regulations.gov/EPA-HQ-OAR-2023-0072-0061/attachment_3.xlsx; *see also* Sierra Clubs Post-Hearing Brief at 65-67.

[308] Sinclair Rebuttal Testimony at 64-65; Aug. 25, 2023 HVT at 06:54:22-06:57:56.

scenarios in the event the proposed Greenhouse Gas rules or similar rules are implemented under similar timeframes.

Mill Creek 1 and 2 are also subject to the risk of additional environmental compliance costs that were not considered as part of the PVRR analysis discussed above. For instance, as previously mentioned, there is substantial likelihood that Mill Creek 1 and 2 will be subject to additional NOx limitations due to local nonattainment. The Louisville MSA is also subject to air quality limitations for fine particulate matter. The EPA's current standard of attainment for fine particulate matter is 12 micro grams per cubic meter (µg/m3), which the Louisville MSA currently meets narrowly. For instance, one monitoring station in the Louisville MSA registered fine particulate matter in the range of 10.1 to 10.4 µg/m3 on average for the three-year periods ending in 2020, 2021, and 2022, and it has measured 11.2 µg/m3 on average for the period running from January 2021 to August 9, 2023.[309] However, the EPA has proposed a new standard for fine particulate matter of 9-10 µg/m3 and has requested comment on a standard of 8 µg/m3.[310] If the new standard is adopted and the Louisville MSA is deemed to be in non-attainment, LMAPCD will be required to develop a state implementation plan indicating means and methods it will use to get back into attainment, including potential restrictions on plants like Mill Creek.[311] Mill Creek 1 and 2 also face environmental compliance risk related to compliance with the regional Clean Air Act's Regional Haze Rule, which could require SCRs to limit NOx emissions and modern flue gas desulfurization systems to limit

[309] Aug. 25, 2023 HVT at 11:02:13, Louisville Metro Hearing Exhibit 1 at 2.

[310] Aug. 25, 2023 HVT at 11:06:45-11:08:00.

[311] Aug. 25, 2023 HVT at 11:08:00.

Sulphur-dioxide emissions that affect visibility at national parks such as Mammoth Cave.[312] Given that regulatory gauntlet, Mill Creek 1 and 2 are likely to face additional environmental compliance risks in the near term, which will increase their costs as compared to Mill Creek 5.

The Commission recognizes that there is some uncertainty as to the nature and timing of additional limitations that are likely to be imposed on Mill Creek 1 and 2. However, given the currently proposed rules and the history of increasing regulation, the Commission finds that it is unreasonable to assume no additional compliance costs for Mill Creek 1 and 2 through 2050. Rather, the Commission finds that Mill Creek 1 and 2 are likely to face significant additional environmental compliance costs in the next 10 years to comply with regulatory limits and as those environmental compliance costs are recovered from customers,[313] they should be considered.[314] Thus, for the reasons discussed above, the Commission finds that a portfolio in which Mill Creek 5 replaces Mill Creek 1 and 2, Haefling 1 and 2, and Paddy's Run 12 is the least-cost portfolio in the most likely future scenarios, and therefore, finds that the construction of Mill Creek 5 will not result in wasteful duplication and that a CPCN should be granted for that unit.

With respect to LG&E/KU's proposed Mercer Solar Facility and Marion Solar Facility, the Commission notes that their addition to the portfolio with Mill Creek 5 will

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[312] *See* Aug. 25, 2023 HVT at 01:05:00-01:08:50; Imber Rebuttal Testimony, Imber Rebuttal Exhibit at 2.

[313] *See* KRS 278.183.

[314] *See* Case No. 2020-00290, *Electronic Application of Bluegrass Water Utility Operating Company, LLC for an Adjustment of Rates and Approval of Construction* (Ky. PSC Aug. 2, 2021), Order at 20-24 (indicating that allowing parties to break up projects to compare against alternatives in piecemeal fashion avoids the review of CPCNs anticipated by KRS 278.020(1)).

result in savings in three of the six fuel price scenarios LG&E/KU studied, even without considering a cost of Greenhouse Gas regulation compliance or income from the sale of RECs.[315] Further, LG&E/KU produced evidence that a $5 per MWh REC price would reduce the costs of the owned solar by about $35 million over the planning period and that a $10 per MWh REC price would reduce the costs of the owned solar by about $70 million over the planning period.[316] Further, LG&E/KU's modeling indicated that a $15 per ton Greenhouse Gas emission abatement cost would increase the favorability of portfolios with the owned solar facilities by about $100 million over the planning period.[317] Those numbers, which represent likely scenarios, would make the PVRRs for the owned solar favorable in four of six fuel price scenarios and would make the PVRRs nearly equal in the other two fuel price scenarios.[318] Further, while LG&E/KU's proposed PPAs are more cost-effective than the utility owned solar, the Commission agrees with LG&E/KU that there is an execution risk, which justifies LG&E/KU building and owning some solar directly. Thus, the Commission finds that the Mercer Solar Facility and Marion Solar Facility are needed to reduce costs and mitigate fuel price and regulatory risk and will not

[315] *See* LG&E/KU Response to Staff's Post-Hearing Request, Item 20, *PSC PH LGE KU Attach to Q20 - Attach 1 LOLE EUE PVRR of Alternative Portfolios – CONFIDENTIAL.xlsx* (Portfolio d and e show the Mill Creek 5 portfolio with and without the proposed owned solar and indicate that the PVRR is lower in three of six fuel price scenarios with owned solar).

[316] *See* Wilson Direct Testimony, Exhibit SAW-1 December 2022, Table 17.

[317] *See* Wilson Direct Testimony, Exhibit SAW-1 December 2022, Table 17.

[318] *See* LG&E/KU Response to Staff's Post-Hearing Request, Item 20, *PSC PH LGE KU Attach to Q20 - Attach 1 LOLE EUE PVRR of Alternative Portfolios – CONFIDENTIAL.xlsx* (Portfolio d and e show the Mill Creek 5 portfolio with and without the proposed owned solar and indicate that the PVRRs without the solar is about $110 to $180 million more favorable in three fuel price scenarios and is less favorable in the other 3 fuel price scenarios and that moving the favorability based on Greenhouse abatement and RECs as discussed above would make the owned solar more favorable in more scenarios).

result in wasteful duplication, and therefore, finds that CPCNs should be granted for those facilities.

The Commission notes that Sierra Club and Joint Intervenors criticized the resources LG&E/KU included in their resource assessment modeling and stress testing, and argued that additional resources should have been included. However, Joint Intervenors' witness, Anna Sommer, was the only witness other than those presented by LG&E/KU to conduct resource assessment and reliability modeling and propose alternative portfolios that she contended could serve load at a lower cost than the portfolio proposed by LG&E/KU. She acknowledged in her testimony that other than converting Mill Creek 2 to a gas unit, which she included in her modeling, that there were no other generation resources that LG&E/KU should have considered as part of their resource assessment modeling due to timing constraints associated compliance with the Good Neighbor Plan.[319] Further, Ms. Sommer indicated that based on her modeling, a portfolio that included a single NGCC unit, along with solar, was the lowest-cost alternative she identified that was not considered by the LG&E/KU.[320] Thus, while the Commission does have some concerns about the manner in which new resources were identified, the Commission does not conclude that limits on the resources or portfolios that LG&E/KU modeled would affect the effect the selection of a single NGCC unit to replace Mill Creek 1 and 2, Haefling 1 and 2, and Paddy's Run 12.

The Commission further notes that Kentucky Coal Association criticized the manner in which LG&E/KU projected coal prices. Specifically, Kentucky Coal Association

[319] Aug. 29, 2023 HVT at 15:32:30.

[320] Sommer Direct Testimony at 29-35; *see* Aug. 29, 2023 HVT at 15:30:00 (explaining how she came up with the portfolios).

indicated that LG&E/KU should have projected coal prices directly as opposed to projecting coal prices based on a relationship between coal and natural gas prices. Kentucky Coal Association's witness, Emily Medine, indicated that the coal price forecasts should have considered the supply curves for each coal type, demand for coal in domestic and export markets, and the price of alternative energy sources.[321] Ms. Medine acknowledged that there is a relationship between coal and natural gas markets but stated that the methodology used by LG&E/KU is not based on an established methodology for forecasting coal prices.[322] Ms. Medine alleged that LG&E/KU used the coal to gas price methodology to support its desired result and as proof noted that LG&E/KU's coal price projections from their 2021 IRP, which Ms. Medine indicated were projected directly, were significantly lower than coal price projections in this case.[323] Ms. Medine also stated that due to the longer-term nature of coal contracts, utilities are able to hedge against price changes in a way that is not possible with natural gas contracts.[324]

LG&E/KU argued that an important factor in an economic analysis comparing coal to natural gas units is the spread between the prices of those fuels.[325] Due to uncertainties in fuel prices through 2050, LG&E/KU argued that it is important to use a range of fuel price scenarios and that their methodology did that by evaluating a broad range of relationships (i.e., coal-to-gas price ratios) between coal prices and projected

[321] Medine Testimony at 37.

[322] Medine Testimony at 39.

[323] Medine Testimony at 39-40; Aug. 29, 2023 HVT 09:23:10 (in which Medine discusses her review of the coal price projections in the IRP).

[324] Medine Testimony at 37-38; *but see* Aug. 29, 2023 HVT at 09:18:25-09:20:00 (in which Medine did not directly answer when asked whether the volatility would matter in a long term projection).

[325] Rebuttal Testimony of David Sinclair (Sinclair Rebuttal Testimony) (filed Aug. 9, 2023) at 50.

gas prices.[326] LG&E/KU indicated that the range of coal-to-gas price ratios they used in this matter were based on historical relationships between its actual coal and gas prices.[327] LG&E/KU also asserted that coal prices are tied much more closely to gas prices than they have been historically because the reduction in coal mines has resulted in reduced coal-on-coal competition that previously kept coal prices in check when natural gas prices rose.[328] As an example, LG&E/KU indicated that their two largest coal suppliers supplied 79 percent of their coal in 2022, whereas their two largest suppliers in 2010 supplied only 45 percent of its coal.[329] LG&E/KU also argued that when looking at prices over long periods, it is not necessary to attempt to project random fluctuations but rather is important to test the possible ranges of long-term price trends.[330]

The Commission finds that LG&E/KU's evidence regarding the relationship between coal and natural gas prices is credible. The average ratios[331] and a recent spike in coal prices that followed a spike in natural gas prices[332] both indicate a relationship between coal and gas prices. Further, LG&E/KU provided evidence showing a correlation between a reduction in the number of coal mines and its increased reliance on two suppliers who are now providing 79 percent of LG&E/KU's coal, which supports its

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[326] Sinclair Rebuttal Testimony at 51.

[327] Wilson Direct Testimony, Exhibit SAW-1 December 2022 at 56-58.

[328] Sinclair Rebuttal Testimony at 52-53.

[329] Sinclair Rebuttal Testimony at 53.

[330] Sinclair Rebuttal Testimony at 54.

[331] *See* Wilson Direct Testimony, Exhibit SAW-1 December 2022 at 57, Table 36 (reflecting a six and ten year coal to gas price ratios that are relatively consistent).

[332] *See* Wilson Direct Testimony, Exhibit SAW-1 December 2022 at 57, Figure 11 (showing a significant spike in coal prices following a similar spike in natural gas prices as well as other less dramatic price changes that appear to correspond),

assertion of reduced coal on coal competition that, if anything, could tie coal prices more closely to gas prices.[333] Thus, whether projected separately or together, the Commission believes that it is reasonable to assume a relationship between coal prices and natural gas prices.

Further, while Ms. Medine is correct that coal price projections in the 2021 IRP were significantly lower than coal price projections in this case, natural gas price projections in the 2021 IRP were also significantly lower,[334] though the difference is presumably due to the spike in both prices in 2021 to 2022.[335] Further, the coal and natural gas price projections in the 2021 IRP, which Ms. Medine discussed favorably, followed a ratio consistent with the ratios used by LG&E/KU in this case.[336] LG&E/KU also considered a spread of fuel price scenarios and ratios both above and below the historical correlation between coal prices and fuel prices, which permitted stress testing of projected prices.[337] Finally, it is not necessary to capture volatility in long-term forecasts, because it should balance out over time.[338] Thus, the Commission finds that LG&E/KU's fuel price scenarios were reasonable and that they did not affect the reasonableness for LG&E/KU's production cost and financial modeling.

[333] Sinclair Rebuttal Testimony at 53.

[334] *See* LG&E/KU's Response to Staff's Post Hearing Request, Item 18, PSC PH LGE KU Attach to Q18 - CONFIDENTIAL 2021 IRP Fuel Prices.xlsx (showing the coal and gas prices from the 2021 IRP).

[335] *See* Wilson Direct Testimony, Exhibit SAW-1 December 2022 at 57, Figure 11.

[336] *See* LG&E/KU's Response to Staff's Post Hearing Request, Item 18 (noting that the average coal to gas price ratio in the base fuel price scenario in the 2021 IRP was 0.58, which is similar to the mid coal to fuel price ratio of 0.57 used in this case, and that the range of ratios is also similar—0.49 to 0.75 in the 2021 IRP as compared to 0.52 to 0.84 in this case).

[337] Wilson Direct Testimony, Exhibit SAW-1 December 2022 at 56-58.

[338] Aug. 29, 2023 HVT at 09:18:25.

Furthermore, the Commission declines to direct LG&E/KU to join an RTO in this matter. LG&E/KU are under an ongoing obligation to periodically study RTO membership, and recently filed their interim review of such an option. However, whatever benefits there may be to RTO membership, a capacity market is not a replacement for a vertically integrated utility having sufficient generation capacity owned or contracted for to serve their retail customers. The Commission expects our vertically integrated utilities, in furtherance of their service, and now reliability, obligations to replace generation capacity with "steel in the ground" or a Purchase Power Agreement. To expect otherwise would open the door to runaway costs and turning over our reliability fate to out-of-state and unaccountable entities. Relatedly, the Commission declines to take up any proposal to depend on unstudied generation imports in this case, particularly in furtherance of compliance with Senate Bill 4. However, the Commission exhorts LG&E/KU to study the value and opportunities that transmission (regional and interregional) and imports provide in their next IRP. In their past IRPs, any serious consideration or discussion of transmission has been notably absent. Further failure to discuss these options in future proceedings may result in the Commission's own investigation into LG&E/KU's processes in this regard.

CPCN for Brown BESS

LG&E/KU argued that Brown BESS enhances reliability in scenarios both with and without solar, but they acknowledged that it was not the most cost-effective means to enhance reliability. LG&E/KU argued that Brown BESS's primary benefit would be to provide them valuable operational experience with a technology at utility scale that will likely be vital to integrating large amounts of renewable generation reliably in the future.

A number of Intervenors argued that Brown BESS was too costly and that the operational experience LG&E/KU will gain is not worth the cost. Conversely, some Intervenors, such as Walmart and Sierra Club, argued that the cost of Brown BESS is worth the operational experience.

The Commission is concerned about the cost of Brown BESS but also recognizes that LG&E/KU has limited resource options in light of the EPA regulations discussed above and constraints on those resources are likely to increase. For instance, as LG&E/KU's generation resources age, environmental regulations will likely prevent LG&E/KU from building certain new resources, as they essentially already do with respect to new coal plants, while simultaneously making existing resources uneconomic due to increasing compliance cost. Given those likely limitations, the Commission finds that the operational experience LG&E/KU will be able to obtain from Brown BESS is worth the expected cost. The Commission believes that such experience is necessary given the current regulatory environment, and that it will allow LG&E/KU and the Commission to make more informed decisions in the future regarding whether it makes sense from an economic standpoint to make more significant investments in battery storage in the future, which could ultimately save customers money in the long term and will help ensure that LG&E/KU can continue to provide service in a more resource constrained environment. Thus, the Commission finds that Brown BESS is needed and will not result in wasteful duplication, and therefore, a CPCN should be granted for Brown BESS. Regardless of the granting of a CPCN, as discussed below, additional regulatory requirements will be necessary prior to the construction and operation of Brown BESS. The Commission agrees with a number of parties to this case that given the need for the BESS, namely operational experience, the Commission intends on setting subsequent reporting requirements related to LG&E/KU's operational experiences with the facility. Those requirements will be developed and determined in subsequent proceedings closer to the start of Brown BESS operations.

<u>Retirement Approvals</u>

LG&E/KU proposed and requested authority to retire Mill Creek 1, Mill Creek 2, Brown 3, Ghent 2, Haefling 1 and 2, and Paddy's Run 12 with the intention of replacing those units with two NGCC units and owned solar, while at the same time entering into four Solar PPAs and building Brown BESS. However, as discussed above, the Commission denied a CPCN for Brown 12, LG&E/KU's proposed NGCC unit at Brown station, because the Commission found there is currently no need that justified its construction and the retirement of Ghent 2 and Brown 3. Thus, LG&E/KU have failed to establish that approval to retire Brown 3 and Ghent 2 should be given at this time. However, as discussed in more detail below, the Commission finds that LG&E/KU met their burden and rebutted the presumption against retirement with respect to Mill Creek 1, Mill Creek 2, Haefling 1 and 2, and Paddy's Run 12 but that they failed to establish that approval to retire Brown 3 and Ghent 2 should be given at this time.

<u>Replacement Capacity that is Dispatchable and Reliable</u>

To rebut the presumption against the retirement of a fossil fuel generating unit, KRS 278.264(2)(a) requires LG&E/KU to establish that it will replace the retired unit with new electric generating capacity that:

> 1. Is dispatchable by either the utility or the regional transmission organization or independent system operator responsible for balancing load within the utility's service area;

> 2. Maintains or improves the reliability and resilience of the electric transmission grid; and
>
> 3. Maintains the minimum reserve capacity requirement established by the utility's reliability coordinator.

The parties disagree regarding the interpretation of most of the provisions of KRS 278.264(2)(a), particularly as to the meaning of "dispatchable" and what is necessary to establish that the replacement generation capacity will maintain or improve reliability and resilience.

<u>Dispatchable</u>

The term dispatchable was not defined in Senate Bill 4 and is not defined elsewhere in KRS Chapter 278. Further, the Commission finds that its meaning is ambiguous as used in the statute. As noted by Kentucky Coal Association, the term dispatchable has often been used to refer to thermal resources for which the generation is not dependent on factors outside of humans control such as the sun or wind.[339] However, as noted by LG&E/KU as well as other Intervenors in this matter, dispatchable is also used by RTOs and other grid operators, including both MISO and PJM, to refer to resources that are able to respond to dispatch instructions.[340] Thus, there is ambiguity regarding which usage should apply to the term as used in the statute.

The goal when interpreting a statute is to effectuate the intent of the General Assembly.[341] A statute should be read in context and under the assumption that the

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[339] *See* Kentucky Coal Association's Post-Hearing Brief at 4-5, FN 4; *see also* Exhibit SAW-1 (in which LG&E/KU uses the term dispatchable to refer to its thermal resources).

[340] *See* Wilson 2023-00122 Testimony, Exhibit SB4-1 at 7; LG&E/KU's Response to Staff's Fourth Request, Item 4.

[341] *King Drugs, Inc. v. Commonwealth*, 250 S.W.3d 643, 645 (Ky. 2008).

legislature intended it to be read as a whole such that each of its constituent parts have meaning.[342] A statute should be liberally construed to carry out the intent of the legislature. However, the language of the statute, as defined by the General Assembly or as generally understood in the context of the matter under consideration, is presumed to reflect the intent of the legislature.[343] Statutory terms should be interpreted based on their plain and ordinary meaning, unless they are technical terms, in which case they should be given the accepted technical meaning.[344] "Where legislative intent is apparent on the face of a statute and there is no question as to its meaning, 'there is no room for construction, liberal or otherwise.'"[345]

Here, the context in which dispatchable is used supports an interpretation that does not exclude intermittent resources, because it refers to generation capacity as being dispatchable by the RTO or ISO[346] for balancing load. Based on the definitions provided by LG&E/KU, both RTOs that are present in the state, MISO and PJM, consider intermittent resources that can respond to dispatch instructions when their fuel source is available to be dispatchable from the perspective of the transmission operator.[347] If the

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[342] *Wilson v. Commonwealth*, 628 S.W.3d 132, 140 (Ky. 2021); *see also University of Louisville v. Rothstein*, 532 S.W.3d 644, 648 (Ky. 2017) *quoting Cosby v. Commonwealth*, 147 S.W.3d 56, 59 (Ky. 2004))(stating that "[w]e have a duty to accord to words of a statute their literal meaning unless to do so would lead to an absurd or wholly unreasonable conclusion").

[343] *Kindred Healthcare v. Harper*, 642 S.W.3d 672, 680 (Ky. 2022); *see also Revenue Cabinet v. O'Daniel*, 153 S.W.3d 815, 819 (Ky. 2005) (indicating that the plain language of the statute controls unless it is ambiguous).

[344] *Hause v. Com.*, 83 S.W.3d 1, 8 (Ky. App. 2001).

[345] *Kindred Healthcare*, 642 S.W.3d at 680.

[346] For purposes of this determination, the legal distinctions between RTO and ISO are immaterial.

[347] *See* Wilson 2023-00122 Testimony, Exhibit SB4-1 at 7; LG&E/KU's Response to Staff's Fourth Request, Item 4.

RTOs that operate in the state would consider a resource to be dispatchable, then it is reasonable to infer that a statute that refers to generation capacity as being dispatchable by an RTO was intended to adopt a similar technical meaning.

However, it is actually not necessary to resolve the meaning of the term dispatchable in this case, because KRS 278.264(2)(a) does not prohibit a utility from constructing non-dispatchable resources. Rather, it only requires that the generation capacity that will replace the retired units to meet the reliability, resilience, and reserve margin requirements in KRS 278.264(2)(a)2 and KRS 278.264(2)(a)3 be dispatchable. As discussed in more detail below, replacing Mill Creek 1 and 2, Haefling 1 and 2, and Paddy's Run 12 with Mill Creek 5, which is dispatchable even under Kentucky Coal Association's more narrow definition, would, at minimum, maintain the reliability and resilience of the electric transmission grid and would satisfy any reserve margin requirement. Thus, KRS 278.264(2)(a)2 and KRS 278.264(2)(a)3 are satisfied without including resources that Kentucky Coal Association contends are not dispatchable.

<u>Maintains or Improves Reliability and Resilience</u>

With respect to KRS 278.264(2)(a)2, LG&E/KU indicated that they have a robust process for establishing the minimum economic reserve margin they use for planning purposes and asserted that a LOLE aligned with its minimum economic reserve margin—3.57 days every 10 years—maintains adequate reliability.[348] LG&E/KU then argued that any plan that has a lower LOLE than the LOLE aligned with its minimum economic reserve margin satisfies the requirement of KRS 278.264(2)(a)2 that a utility replace retired generation units with new electric generating capacity that maintains or improves the

[348] *See* Wilson 2023-00122 Testimony, Exhibit SB4-1 at 13.

reliability and resilience of the electric transmission grid. Assuming LOLE is an appropriate reliability metric, Kentucky Coal Association argued the replacement generation capacity must maintain or improve on the reliability of the existing system such that the LOLE of the resulting system, excluding non-dispatchable resources, must be lower than the LOLE of the existing system.

The Commission generally agrees with Kentucky Coal Association that a utility must establish that their system with the retirements and replacement generation will be at least as reliable as the current system to satisfy the requirements of KRS 278.264(2)(a)2. The term “maintains” as used in KRS 278.264(2)(a)2, is ambiguous, because taken alone it could reasonably be read as either requiring a utility to maintain some minimum reliability or resiliency standard or requiring a utility to maintain the current level of reliability or resiliency. However, by using the phrase “maintains or improves” reliability, KRS 278.264(2)(a)(2) indicates that the replacement generation must maintain or improve the current level of reliability, because the use of the term “improves” makes logical sense if it is referring to the current state of the system but would not make sense if referring to a requirement to meet a minimum established reliability standard.

The Commission concludes that LOLE, along with Loss of Load Hour (LOLH) and Expected Unserved Energy (EUE), is an appropriate measure of the reliability and resiliency for various portfolios. Further, LOLE, LOLH and EUE are modeled using the operating characteristics of a utility’s actual and proposed units, the equivalent force outage rates of a utility’s actual and proposed units, and a mix of load and unit availability scenarios to provide an idea regarding how a portfolio will perform under various circumstances.[349] Taken together, those metrics should reflect the likelihood that a system will experience a loss of load event, as well as the duration and magnitude of the loss of load events that a system might experience in the relevant periods.[350] In fact, as noted above, LOLE is a commonly accepted metric to assess the reliability of integrated electric systems, including RTOs. Thus, assuming the validity of assumptions included in the model, LOLE, along with LOLH and EUE, provide a reasonable basis for measuring the reliability and resilience of a utility's generation and transmission assets.

Conversely, simply comparing the installed capacity, ramp rates, and other characteristics of individual units does not provide a clear picture of the reliability and resilience of the entire electric transmission grid. This is illustrated by LG&E/KU's discussion of their portfolios that meet their minimum economic reserve margin in Exhibit SB4-1, which have LOLE's that vary wildly from 3.57 days every 10 years to over 15 days every 10 years.[351] Thus, while the operating characteristics of units may be useful in understanding the results of modeling, comparing the operating characteristics of individual units, taken alone, would generally not be useful in determining whether replacement generation capacity will maintain the reliability and resilience of the electric transmission grid as a whole as required by KRS 278.264(2)(a)3.

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[349] *See* Wilson 2023-00122 Testimony, Exhibit SB4-1 at 22 (discussing how LG&E/KU modeled LOLE using SERVM with 49 load scenarios and 300 unit availability scenarios); Aug. 24, 2023 H.V.T at 09:10:20 (indicating that LG&E/KU's LOLE and EUE models include the operating characteristics of units).

[350] LOLE, as modeled by LG&E/KU, provides the number of days that LG&E/KU would expect its system to lose load in a 10 year period. LOLH provides the number of hours in which available resources may not meet the demand of the system during a ten year period. EUE provides the expected unserved energy during a ten year period. *See* LG&E/KU Response to Staff's Post-Hearing Request, Item 20, *PSC PH LGE KU Attach to Q20 - Attach 1 LOLE EUE PVRR of Alternative Portfolios – CONFIDENTIAL.xlsx* (reflecting that LG&E/KU calculated LOLE, LOLH, and EUE based on a 10 year period).

[351] Wilson 2023-00122 Testimony, Exhibit SB4-1 at 13.

Here, a portfolio that retires Mill Creek 1 and 2, Haefling 1 and 2, and Paddy's Run 12 and adds Mill Creek 5 would be marginally more reliable than LG&E/KU's current portfolio, assuming the addition of SCRs on coal units in both scenarios.[352] Specifically, even without any of the planned solar or dispatchable DSM, the portfolio that adds Mill Creek 5 would have an LOLE of 0.70 days every 10 years, an LOLH of 1.43 hours every 10 years, and a EUE of 290 MWh every 10 years.[353] Conversely, the portfolio that keeps Mill Creek 1 and 2, Haefling 1 and 2, and Paddy's Run 12 would have an LOLE of 0.74 days every 10 years, an LOLH of 1.46 hours every 10 years, and a EUE of 280 MWh every 10 years.[354] Based on this information, the portfolio with Mill Creek 5 would be slightly less likely to have a loss of load event, and the loss of load event would be slightly shorter in the events they occurred, but the magnitude of unserved energy in a loss of load event would be slightly larger. Thus, the Commission finds a portfolio that retires Mill Creek 1 and 2, Haefling 1 and 2, and Paddy's Run 12 and adds Mill Creek 5 would, at minimum, maintain the reliability and resilience of the electric transmission grid.

The Kentucky Coal Association and Joint Intervenors, among other parties, argued that LG&E/KU failed to properly consider risks associated with fuel assurance and correlated outages for the NGCC units. The Commission does believe that there is fuel assurance risk with respect to natural gas units and questions the manner in which

[352] *See* LG&E/KU's Response to Post-Hearing Request, Item 20, *PSC PH LGE KU Attach to Q20 - Attach 1 LOLE EUE PVRR of Alternative Portfolios – CONFIDENTIAL.xlsx* (which shows the LOLE, LOLH, EUE for both portfolios).

[353] *See* LG&E/KU's Response to Post-Hearing Request, Item 20, *PSC PH LGE KU Attach to Q20 - Attach 1 LOLE EUE PVRR of Alternative Portfolios – CONFIDENTIAL.xlsx*.

[354] *See* LG&E/KU's Response to Post-Hearing Request, Item 20, *PSC PH LGE KU Attach to Q20 - Attach 1 LOLE EUE PVRR of Alternative Portfolios – CONFIDENTIAL.xlsx*.

LG&E/KU accounted for correlated outages but does generally believe that LG&E/KU's modeling of the reliability of the NGCC units was reasonable. Specifically, LG&E/KU assumed an unforced capacity value for the new NGCC units of about 93.4 percent, which would indicate a forced outage rate of over 6 percent.[355] Conversely, LG&E/KU's only current NGCC unit, Cane Rune 7, has had an equivalent forced outage rate of 0.74, 1.04, 1.60, 0.34 and 5.38 in each of the last 5 years.[356] Further, while fuel assurance issues will not be reflected in the equivalent forced outage rate, LG&E/KU indicated that the pipeline issue caused by Winter Storm Elliot has never happened before[357] and that such an incident would have had an limited effect on its equivalent forced outage rate.[358] Thus, a forced outage rate of over 6 percent was likely overstated if anything.

While correlated outages, for instance due to a cold weather event, may not be reflected in the way that LG&E/KU modeled reliability, because it was based on the outage rates of individual units, the evidence regarding outages during Winter Storm Elliot indicated that correlated outages associated with extreme weather events can affect units of all fuel types. Further, the Commission notes that with the retirement of Mill Creek 1 and 2 and the addition of Mill Creek 5, LG&E/KU's coal units will still make up the majority of their generation fleet. Thus, the Commission does not believe that risk of correlated outages and LG&E/KU's treatment of the same in its modeling effected modeling of the reliability of Mill Creek 5, especially given the arguably overstated forced outage rate for

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[355] *See* LG&E/KU Response to Staff's First Request, Item 89(c), 13-PSC_DR1_LGE_KU_Attach_to_Q89(c)_-_ICAP_UCAP.pdf (providing the ICAP and UCAP capacity values); LG&E/KU Response to Staff's Second Request, Item 50.

[356] LG&E/KU Response to Post Hearing Requests for Information, Item 10.

[357] *See* LG&E/KU Response to Staff's Fourth Request, Item 8.

[358] *See* LG&E/KU Response to Post Hearing Requests for Information, Item 8.

Mill Creek 5, which would tend to disfavor it from a reliability perspective. Regardless of the modeling, in order to address the risk of fuel assurance, LG&E/KU shall take all reasonable measures to mitigate the cost of Mill Creek 5, while prioritizing the addition of dual fuel capability at the facility for no more than the most recent received quote for the costs of the entire facility. Dual fuel capability, at no incremental cost (in excess of the most recent bid) will cost-effectively further minimize any risk of limited fuel availability.

While the Commission does not believe that LG&E/KU would retire Ghent 2 and Brown 3 without obtaining a CPCN for Brown 12 or some other replacement generation capacity, the Commission notes that LG&E/KU could not maintain reliability and resilience of the electric transmission grid without Ghent 2 and Brown 3 without other material changes to their systems. As noted above, LG&E/KU's system is marginally more reliable with Mill Creek 5. However, if only Brown 3 were retired without additional replacement generation, the reliability of LG&E/KU's system would drop significantly without the addition of generation capacity or a material reduction in demand, and would be lower than the status quo even with the addition of LG&E/KU's proposed owned solar and solar PPAs.[359] Further, while a portfolio that retires Brown 3, Mill Creek 1 and 2, Haefling 1 and 2, and Paddy's Run 12 and adds Mill Creek 5, owned solar, solar PPAs, and Brown BESS could achieve the same reliability as the status quo portfolio,[360] Brown 3 is necessary to support Ghent 2 in the event that SCR cannot be added in time if it is

[359] *See* LG&E/KU's Response to Post-Hearing Request, Item 20, *PSC PH LGE KU Attach to Q20 - Attach 1 LOLE EUE PVRR of Alternative Portfolios – CONFIDENTIAL.xlsx* (Portfolios l, m, and n show the reliability of the portfolio discussed above without Brown Unit 3).

[360] *See* LG&E/KU's Response to Post-Hearing Request, Item 20, *PSC PH LGE KU Attach to Q20 - Attach 1 LOLE EUE PVRR of Alternative Portfolios – CONFIDENTIAL.xlsx* (Portfolios o shows the reliability of this portfolio).

deemed needed. Thus, the Commission finds that LG&E/KU failed to establish that it can maintain reliability without Brown 3 and Ghent 2, and therefore, finds that their application to retire those units should be denied.

Maintains the Minimum Reserve Capacity Requirement

Kentucky Coal Association argued that LG&E/KU failed to present evidence regarding the reserve capacity requirement established by their reliability coordinator. LG&E/KU stated that they have contracted with TVA to be their reliability coordinator and that TVA has not established a minimum reserve capacity requirement. LG&E/KU argued that by presenting evidence that there is no minimum reserve capacity requirement applicable to them that they have presented evidence that they have complied with the minimum reserve capacity requirement.

The Commission agrees with LG&E/KU that they indicated that their reliability coordinator has not established a minimum reserve margin requirement.[361] If a utility's reliability coordinator has not established a minimum reserve margin, then any replacement capacity would meet the minimum reserve margin, because it is zero or nonexistent. An alternative reading that a utility could never satisfy KRS 278.264(2)(a)3 if its reliability coordinator does not establish a minimum reserve margin would prohibit such utilities from ever retiring generation. Thus, the Commission finds that LG&E/KU satisfied the requirements of KRS 278.264(2)(a)3 by indicating that their reliability coordinator has not established a minimum reserve margin requirement, though as noted above a portfolio that retires Mill Creek 1 and 2, Haefling 1 and 2, and Paddy's Run 12

[361] *See* Wilson 2023-00122 Testimony, Exhibit SB4-1 at 16-17.

and adds Mill Creek 5, would have an LOLE of 0.70, which is lower than the LOLE that both MISO and PJM use to establish their minimum reserve margin requirements.

Harm to Ratepayers and Cost Savings

To rebut the presumption against the retirement of a fossil fuel generating plant, KRS 278.264(2)(b) requires a utility to establish that:

> The retirement will not harm the utility's ratepayers by causing the utility to incur any net incremental costs to be recovered from ratepayers that could be avoided by continuing to operate the electric generating unit proposed for retirement in compliance with applicable law;

Similarly, KRS 278.264(3) states that:

> The utility shall at a minimum provide the commission with evidence of all known direct and indirect costs of retiring the electric generating unit and demonstrate that cost savings will result to customers as a result of the retirement of the electric generating unit.

Nearly every party to this case argued that LG&E/KU met these burdens, in whole or in part, by establishing that their preferred portfolio, or some variation thereof, had a lower PVRR than the status quo portfolio. However, Kentucky Coal Association argued that KRS 278.264(2)(b) requires a rate impact analysis to establish that there is no harm to ratepayers, that PVRR improperly excludes sunk costs from the cost of new generation by including the cost in the PVRR for the new portfolio and the status quo portfolio, and that KRS 278.264(3) requires LG&E/KU to include costs other than those that affect the rates of customers such as the loss of tax base, jobs at companies that supply the plants, and other local and State economic losses.

The Commission notes that KRS 278.264(2)(b) essentially defines harm to ratepayers as "causing the utility to incur any net incremental costs to be recovered from ratepayers that could be avoided by continuing to operate the electric generating unit proposed for retirement in compliance with applicable law." Importantly, KRS 278.264(2)(b) does not prohibit a utility from incurring any new costs as a result of the retirement, because such a requirement would effectively prohibit a utility from retiring any generation regardless of its age, reliability, or cost.[362] Rather, KRS 278.264(2)(b) prohibits a utility from incurring any "net incremental costs to be recovered from ratepayers" due to the retirement. Thus, the Commission reads KRS 278.264(2)(b) as requiring it to measure harm to customers based on the difference between the cost to customers of providing service with and without the proposed retirement, i.e., a portfolio that can provide adequate service and reliable service with the retired units and a portfolio that can provide adequate service and reliable service without the retired units.

The Commission also does not conclude that KRS 278.264(3) requires an additional cost-benefit analysis that considers costs other than those that would be paid by customers in rates. First, KRS 278.264(3) explicitly states that a utility must demonstrate that "that cost savings will result to customers." On its face, that language indicates that the concern being addressed by KRS 278.264(3) is that additional costs would be passed on to customers through rates. Further, pursuant to KRS 278.040, the Commission's jurisdiction is limited to the rates and services of utilities, so absent a clear directive, it would be illogical to assume that a statute requiring a utility to demonstrate

[362] Since KRS 278.264(a) requires that a retired electric generating unit be replaced with new electric generating capacity, there will always be a new cost incurred with a utility retires an electric generating unit. Thus, a corresponding requirement that a retirement not result in new costs, as opposed to net incremental costs as the statute plainly says, would effectively result in a prohibition against the retirement of any electric generating units, which the legislature clearly did not intend.

savings to customers was intended to require the Commission to look at anything other than the rate effects of retirement decisions.

In fact, KRS 278.264(3) appears to be indicating what a utility must file to meet the requirements of KRS 278.264(2)(b). KRS 278.264(2) establishes a presumption against the retirement of electric generating units and states that the presumption may rebutted by evidence sufficient for the Commission to find that the requirements of KRS 278.264(2)(a), (b), and (c) are met. Conversely, KRS 278.264(3) establishes a procedural requirement not a substantive requirement for rebutting the presumption. Thus, KRS 278.264(3), in stating that a utility must provide evidence of direct and indirect costs of retiring an electric generating unit and demonstrate cost savings, is further explaining the requirement in KRS 278.264(2)(b) that the retirement not harm the utility's ratepayers by causing the utility to incur any net incremental costs to be recovered from ratepayers.

LG&E/KU, as well as most of the Intervenors, relied on PVRR to establish that their preferred portfolio would be lowest cost to customers. PVRR is calculated by identifying known costs of various portfolios over a planning period and determining the revenue requirement effect of those costs in each year of a planning period and then discounting future years to account for the time value of money. The revenue requirement is the amount that all customers will be charged as a result of costs incurred by a utility. Calculating the PVRR for various portfolios over a long period of 20 to 30 years allows utilities and the Commission to compare the overall cost of those portfolios on all customers through periods that correspond more closely to the lives of the assets involved. This method of determining the cost of a portfolio to customers has been used the Commission for decades, including in numerous cases in which the Commission approved upgrades to coal plants in lieu of gas units with higher PVRRs, and was supported by LG&E/KU and Joint Intervenors' modeling witnesses (along with nearly every party in this case).

Kentucky Coal Association argued that utilities should perform rate impact analyses to establish that replacement generation capacity will not harm ratepayers. However, the first step of setting rates is the determination of the revenue requirement, which is the total amount that the utility will recover from all customers through the rates being established. The revenue requirement is then allocated among customer classes based on the cost of service, i.e., the cost to provide service to a particular customer class, and rates are designed based on that allocation to allow the utility to recover its full revenue requirement. A rate impact analysis would be difficult over the timeframes that it makes sense to use when looking at generation resources, because cost of service would have to be estimated in each year, and it ultimately would show the same effect on customers overall as simply looking at revenue requirement. Thus, the Commission finds that PVRR is the appropriate method for measuring the cost of portfolios to LG&E/KU's ratepayers, and therefore, whether the retirement and resulting replacement generation will result in net incremental costs to ratepayers.[363]

[363] Kentucky Coal Association's witness indicated that a rate impact analysis will show the return on and return of the capital investments made for the new generation as well as the effect of sunk costs. Aug. 29, 2023 HVT at 09:12:54-09:15:54. However, a major component of the revenue requirement, and therefore, a major component of a PVRR, is the return on and return of the capital investment. Further, the sunk costs, such as the undepreciated value of existing plant, are considered as part of a PVRR analysis, because it assumes that the sunk costs will be paid if the existing plant remained in service and if the existing plant is taken out of service such that a new plant will only be considered to be cost effective if the additional costs from the new plant and the sunk costs from the old plant are lower than the cost of operating the old plant. Including the sunk costs in that manner actually disfavors the new generation resource, as it should if the sunk costs will be paid even if the new generation resource is built and the old resource is retired.

To compare the PVRR of various portfolios, LG&E/KU conducted an extensive analysis of cost of various portfolios both in their applications and in response to extensive requests for information, as well as across six days of an evidentiary hearing. The Commission finds that LG&E/KU presented all known costs of its proposed retirements and replacement portfolios as part of that analysis and noted risks and uncertainties about such costs where appropriate. As discussed in more detail above, the Commission finds based on the evidence presented that a portfolio that retires Mill Creek 1 and 2, Haefling 1 and 2, and Paddy's Run 12 and replaces them with Mill Creek 5 has a lower PVRR than the status quo in the most likely future scenarios. As noted by LG&E/KU, the cost-effectiveness of Mill Creek 5 as compared to those resources is illustrated by the support of representatives of LG&E/KU's largest customers, KIUC and Walmart, both of which have a significant interest in LG&E/KU's rates and support the retirement of those units and the construction of Mill Creek 5. Thus, the Commission finds that the retirements of Mill Creek 1 and 2, Haefling 1 and 2, and Paddy's Run 12 will result in cost savings and will not result in harm to the ratepayers by causing the utility to incur any net incremental costs to be recovered from ratepayers that could be avoided by continuing to operate the electric generating unit proposed for retirement in compliance with applicable law.

Retirement Decision Not Result of Financial Incentives or Benefits

To rebut the presumption against the retirement of a fossil fuel generating unit, KRS 278.264(2)(b) requires a utility to present sufficient evidence for the Commission to find that "[t]he decision to retire the fossil fuel-fired electric generating unit is not the result of any financial incentives or benefits offered by any federal agency." The evidence in this case indicated that the decisions to retire Mill Creek 1 and 2, Haefling 1 and 2, and

Paddy's Run 12, and the decision to build Mill Creek 5 were not the result of any financial incentives or benefits offered by any federal agency. The evidence simply indicates that retiring Mill Creek 1 and 2, Haefling 1 and 2, and Paddy's Run 12, and building Mill Creek 5 is likely to be the most cost-effective way to serve load through the planning period. Further, rather than being financially incentivized by a federal agency, NGCC units have been subject to proposed regulations intended to increase their costs and reduce their emissions much like, though to a lesser extent than, coal units.

The only argument that was made in this matter to support a finding that the decision was a result of financial incentives or benefits offered by any federal agency was KCA's argument that LG&E/KU's decision was supported by solar resources that received tax credits from the federal government that reduced their costs. However, given the General Assembly's concern about the cost of rates, the Commission questions whether including cost savings for a new generation resource that will be passed on to customers in a cost-benefit analysis to assess the lowest cost portfolio for serving customers would be considered a financial incentive or benefit that resulted in the decision to retire a fossil fuel-fired electric generating unit.[364] Though, it is unnecessary to resolve that issue in this case, because the cost of solar resources are not necessary to establish that a portfolio in which Mill Creek 5 replaces Mill Creek 1 and 2, Haefling 1 and 2, and Paddy's Run 12 is least-cost. Thus, the Commission finds that the decision to retire the fossil fuel-fired electric generating unit is not the result of any financial incentives or benefits offered by any federal agency.

[364] Joint Intervenors' Post-Hearing Brief at 58.

For the reasons discussed above, the Commission finds that LG&E/KU presented sufficient evidence to rebut the presumption against retirement for Mill Creek 1 and 2, Haefling 1 and 2, and Paddy's Run 12, and therefore, finds that LG&E/KU's request to retire the units should be approved. Conversely, the Commission finds that LG&E/KU failed to rebut the presumptions with respect to Ghent 2 and Brown 3, and therefore, finds that LG&E/KU's request to retire Ghent 2 and Brown 3 should be denied.

As discussed above, LG&E/KU's retirement of Mill Creek 1 and 2, Haefling 1 and 2, and Paddy's Run 12 is based on, in part, their plan to replace the units, particularly Mill Creek 1 and 2, with Mill Creek 5. However, the Commission recognizes that LG&E/KU intends to retire Mill Creek 1 at the end of 2024 as it has planned to do since 2020 and that they intends retire Haefling 1 and 2, and Paddy's Run 12, which together account for 47 MW of summer capacity and 55 MW of winter capacity, only if they suffer a significant mechanical issue, which they expect to occur in 2025 based on their history with similar units. Conversely, LG&E/KU is planning to place Mill Creek 5 in service in 2027. While the Commission understands that it would not be economic or necessary to serve load[365] to invest in Mill Creek 1 to keep it open until 2027 or to invest in Haefling 1 and 2, and Paddy's Run 12, LG&E/KU should not proceed with the retirement of Mill Creek 1, Haefling 1 and 2, and Paddy's Run 12 if circumstances change such that the timing of Mill Creek 5 is expected to be materially delayed, including if the permit for Mill Creek 5 is denied, and regardless of the timing of Mill Creek 5, LG&E/KU should not proceed with

[365] As noted above, Mill Creek 1, which generally cannot operate with Mill Creek 2 in the summer, was planned to be retired in the 2024, in part, because the capacity was noted needed at that time. With BlueOval's load, LG&E/KU likely needs either Mill Creek 1 or replacement capacity. However, LG&E/KU is not expected to have to serve BlueOval's full load until at least 2027 at which time it expects Mill Creek 5 to be online.

the retirement of Haefling 1 and 2, and Paddy's Run 12 unless they experience a material mechanical issue that makes them uneconomical to repair. LG&E/KU should also not proceed with the retirement of Mill Creek 2 until construction of Mill Creek 5 is completed.

3. DECLARATORY ORDER AND COST RECOVERY FOR SOLAR PPAS

LEGAL STANDARD

Declaratory Order and Applicability of Commission Precedent

LG&E/KU requested a declaratory order that the Solar PPAs did not require prior Commission approval. Under 807 KAR 5:001, Section 19, the Commission has the authority to issue a declaratory order with respect to the jurisdiction of the Commission and the applicability to a person, property or state of facts or meaning and scope of an order, an administrative regulation of the Commission, or provisions of KRS Chapter 278.

Regarding the standard of review of the Solar PPAs, it is well settled that the Commission reviews a request to approve a PPA as an evidence of indebtedness under KRS 278.300.[366] When the purpose and use of a PPA is to acquire new generation, the Commission will review the agreement pursuant to the CPCN statute, KRS 278.020.[367] The review under KRS 278.300 arises from the financial impact on ratepayers; the review under KRS 278.020 arises from the operational impact on ratepayers.

[366] Case No. 2009-00545, *Application of Kentucky Power Company for Approval of Renewable Energy Purchase Agreement for Wind Energy Resources Between Kentucky Power Company and FPL Illinois Wind, LLC* (Ky. PSC June 28, 2010); Case No. 2013-00144, *Application of Kentucky Power Company for Approval of the Terms and Conditions of the Renewable Energy Purchase Agreement for Biomass Energy Resources Between the Company and ecoPower Generation-Hazard LLC; Authorization to Enter into the Agreement; Grant of Certain Declaratory Relief; and Grant of All Other Required Approvals and Relief* (Ky. PSC Oct. 10, 2013).

[367] *Ky. Utilities Co. v. Public Service Comm'*n, 252 S.W.2d at 890.

Three elements must be met for the Commission to approve a PPA as an evidence of indebtedness under KRS 278.300(3):

1. The PPA is for some lawful object within the corporate purposes of the utility purpose, with the lawful object deemed as the acquisition of new generation;[368]

2. The PPA is necessary or appropriate for or consistent with the proper performance by the utility of its service to the public and will not impair its ability to perform that service; and

3. The PPA is reasonably necessary and appropriate for such purpose.

Under KRS 278.020(1), a utility must establish a need for additional generation and the absence of wasteful duplication.

Relevant to this matter, in Case No. 2020-00016, the Commission found that certain solar PPAs did not require Commission approval under KRS 278.300 or KRS 278.020.[369] In discussing the applicable standard and whether KRS 278.300 applied, the Commission reviewed relevant precedent. In Administrative Case No. 350, the Commission encouraged, but did not require, utilities to file long-term PPAs for pre-approval pursuant to KRS 278.300, stating:

> In addition, these contracts may well require prior approval under KRS 278.300 if they constitute evidence of indebtedness. In particular, the inclusion in such contracts of minimum payment obligations or take/pay provisions may necessitate prior approval.[370]

[368] Case No. 2009-00545, June 28, 2010, Order at 6.

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

[370] Administrative Case No. 350, *The Consideration and Determination of the Appropriateness of Implementing a Ratemaking Standard Pertaining to the Purchase of Long-Term Wholesale Power by*

In subsequent reviews of PPAs, the Commission affirmed that the KRS 278.300 standard of review applied when the agreements included minimum obligation or take/pay provisions. In Case No. 2014-00321 the Commission explained that:

> The minimum payment obligations in the form of fixed capacity and O&M charges and the requirement that [LG&E/KU] take a minimum amount of production over the term of the Agreement constitute long-term financial obligations that are appropriate for Commission review and approval under KRS 278.300.[371]

In Case No. 2020-00016, the Commission determined that the facts presented were substantively different from precedential cases and that neither KRS 278.300 nor KRS 278.020 applied.[372] First, the solar PPA in Case No. 2020-00016 did not include a minimum obligation or take/pay provision.[373] Further, the solar PPA in Case No. 2020-00016 was for nonfirm energy only and included no capacity.[374] LG&E/KU's contractual obligation to pay was based upon the actual receipt of output at a specified point of delivery and the payment amount was determined by the amount of output delivered.[375] Additionally, the price that LG&E/KU paid for the output was the same price that LG&E/KU would receive from commercial customers with a contract to purchase 75 percent of the output, so LG&E/KU would recover the cost for 75 percent of output directly from those

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Electric Utilities as Required in Section 712 of the Energy Policy Act of 1992 (Ky PSC. Oct. 25, 1993), Order at 8–9.

[371] Case No. 2014-00321, *Application of Louisville Gas and Electric Company and Kentucky Utilities Company for a Declaratory Order and Approval Pursuant to KRS 278.300 for a Capacity Purchase and Tolling Agreement* (Ky. PSC Nov. 4, 2004), Order at 6–7.

[372] Case No. 2020-00016, May 8, 2020 Order at 11–12.

[373] Case No. 2020-00016, May 8, 2020 Order at 12.

[374] Case No. 2020-00016, May 8, 2020 Order at 12.

[375] Case No. 2020-00016, May 8, 2020 Order at 12.

customers.[376] Regarding the 25 percent of energy from the solar PPA allocated to native load, LG&E/KU proposed to pass any costs, offset by REC sale revenue associated with that 25 percent of energy, through LG&E/KU's FAC, which is subject to scrutiny in periodic reviews.[377] The Commission concluded that the solar PPA approved in Case No. 2020-00016 did not constitute an evidence of indebtedness because the 75 percent of output would be recovered directly from two industrial customers that the PPA was obtained to serve, and the costs of the 25 percent allocated to native load will be scrutinized through periodic FAC proceedings.[378] For those same reasons, the Commission concluded that the solar PPA would not have the same operational impact on LG&E/KU ratepayers as the construction of new generation and thus declined to apply KRS 278.020(1) as a standard of review for the PPA in that proceeding.[379]

Recovery of Solar PPA Costs

LG&E/KU requested to recover the costs for the solar PPAs in FAC proceedings, which is the manner approved in Case No. 2020-00016 for recovery of the costs of that solar PPA.

Pursuant to Commission regulation 807 KAR 5:056, Section 1(3), net energy costs for economy energy purchases, exclusive of capacity or demand charges, may be recovered in FAC proceedings when economy energy is purchased on an economic dispatch basis. In a 2002 decision, the Commission defined economy energy purchases

[376] Case No. 2020-00016, May 8, 2020 Order at 12.

[377] Case No. 2020-00016, May 8, 2020 Order at 12.

[378] Case No. 2020-00016, May 8, 2020 Order at 12.

[379] Case No. 2020-00016, May 8, 2020 Order at 12.

recoverable through FAC review as "purchases that an electric utility makes to serve native load, that displace its higher cost of generation, and that have an energy cost less than the avoidable variable generation cost of the utility's highest-cost generating unit available to serve native load during that FAC expense month."[380]

In contrast, the Commission defined non-economy energy purchases as "purchases made to serve native load that have an energy cost greater than the avoided variable cost of the utility's highest cost generating unit available to serve native load during that FAC expense month."[381] The Commission has consistently held that an electric utility can recover through the FAC review "only the lower of the actual energy cost of the non-economy purchased energy or the fuel cost of its highest cost generating unit available to be dispatched to serve native load during the reporting expense month."[382]

LG&E/KU'S REQUEST FOR A DECLARATORY ORDER AND COST RECOVERY

LG&E/KU requested a declaratory order that four Solar PPAs do not require Commission approval under KRS 278.300 or KRS 278.020, and that LG&E/KU can recover the cost of the Solar PPAs through their FAC mechanism under the same "highest cost unit calculation" approach approved in Case No. 2020-00016.[383] LG&E/KU

[380] Case No. 2000-00495-B, *An Examination by the Public Service Commission of the Application of the Fuel Adjustment Clause of American Electric Power Company from May 1, 2001 to October 31, 2001* (Ky. PSC May 2, 2002), Order at 4.

[381] Case No. 2000-00495-B, May 2, 2002 Order at 4.

[382] Case No. 2000-00495-B, May 2, 2002 Order at 5. *See also* Case No. 2016-00003, *An Examination of the Application of the Fuel Adjustment Clause of Kentucky Utilities Company from May 1, 2015 through October 31, 2015* (Ky. PSC July 7, 2016), Order at 2; and Case No. 2016-00004, *An Examination of the Application of the Fuel Adjustment Clause of Louisville Gas & Electric Company from May 1, 2015 through October 31, 2015* (Ky. PSC July 7, 2016), Order at 2.

[383] Application at 32.

proposed to enter into four nonfirm energy only PPAs for output of four solar facilities with combined capacity of 637 MW. The Solar PPAs are more specifically described as (1) a 138 MW 30-year PPA with ibV Energy Partners for a solar facility to be built in Hopkins County, Kentucky, and named Grays Branch; (2) a 280 MW 30-year PPA with ibV Energy Partners for a solar facility to be built in Hardin County, Kentucky and named Nacke Pike; (3) a 104 MW 20-year PPA with Clearway Energy for a solar facility to be built in Ballard County, Kentucky, and named Song Sparrow; and (4) a 115 MW 20-year PPA with BrightNight LLC for a solar facility to be built in Ballard County, Kentucky, and named Gage Solar.

LG&E/KU asserted that the Solar PPAs are identical to the solar PPAs approved in Case No. 2020-00016 because they are for non-firm energy only, and not for firm energy or capacity; LG&E/KU will not have capital, operating, or maintenance obligations associated with the PPAs; and LG&E/KU will not have a minimum purchase obligation.[384] LG&E/KU explained that they will purchase nonfirm energy under the Solar PPAs as available output at a fixed price per MWh.[385]

Of the four Solar PPAs, three contain a 60-day price re-opener clause that allow LG&E/KU or the solar PPA seller, or both, to reopen the PPA terms if solar energy prices increase or decrease above the contractual terms.[386] If the parties cannot agree on a new price within a specified period, the original PPA price remains in place and either

[384] Application at 31; Direct Testimony of Charles R. Schram (Schram Direct Testimony) (filed Dec. 15, 2023) at 7–8.

[385] Application at 31; Schram Direct Testimony at 7–8.

[386] Schram Direct Testimony at 8; Executed Solar PPAs (filed Mar. 1, 2023); LG&E/KU Motion for Reconsideration (filed Sept. 22, 2023).

party would have 30 days to terminate the PPA.[387] LG&E/KU explained that rising interest rates and rising costs of solar components increase the risk that the solar facilities may not be constructed.[388] LG&E/KU maintained that the price re-opener clause manages the solar execution risk that the facilities would not be built due to pricing and financing concerns.[389]

LG&E/KU asserted that the Solar PPAs are not, and should not be evaluated as, replacement generation under KRS 278.264.[390] LG&E/KU argued that the Solar PPAs are not dispatchable for KRS 278.264 purposes because LG&E/KU will not have the right to control the facilities output.[391] However, LG&E/KU included the output of the Solar PPAs in their reliability analysis, based upon LOLE, [392] and in the reserve margin analysis, conducted pursuant to KRS 278.264.[393] LG&E/KU also considered the cost of purchased power in their KRS 278.264 analysis of direct and indirect costs of unit retirements[394] and cumulative PVRR changes.[395]

In post-hearing briefing, LG&E/KU changed its position and requested to recover the Solar PPA costs through a rider, which is discussed below.

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[387] Schram Direct Testimony at 8.

[388] Direct Testimony of David Sinclair (Sinclair Direct Testimony) (filed Dec. 15, 2022) at 19–21.

[389] Sinclair Direct Testimony at 21–22.

[390] Direct Testimony of Lonnie Bellar (Bellar May 10, 2023 Direct Testimony) (filed May 10, 2023) at 10–11.

[391] Bellar May 10, 2023 Direct Testimony at 10–11.

[392] Bellar May 10, 2023 Direct Testimony at 14, Table 4.

[393] Bellar May 10, 2023 Direct Testimony at 14, Table 5.

[394] Bellar May 10, 2023 Direct Testimony at 20, Table 7.

[395] Bellar May 10, 2023 Direct Testimony at 21, Table 8.

INTERVENORS ARGUMENTS – SOLAR PPAS

Attorney General

The Attorney General did not file witness testimony. In briefing, the Attorney General argued that the Solar PPAs should be rejected because they do not satisfy the requirements for generation that replaces a retiring fossil fuel-fired generating unit established in KRS 278.264. The Attorney General asserted that the Solar PPAs do not satisfy the requirement established in KRS 278.264(2)(a)(1) that generation replacing a retired generating facility be dispatchable.[396] The Attorney General further asserted that the Solar PPAs will receive federal incentives, and thus must be rejected under KRS 278.246(2)(c), which states that the decision to retire a fossil fuel-fired electric generating unit is not the result of any financial incentives offered by any federal agency.[397] The Attorney General cited to a public comment filed into the record by Kentucky Senate President Robert Stivers that questioned whether LG&E/KU were receiving federal incentives or benefits to "provide solar power as a replacement for a portion of the power provided by fossil fuel-fired electric generating units," which is contrary to the provisions of KRS 278.264.[398]

The Attorney General argued that the Solar PPAs should be considered on their own merits and not as replacement generation.[399] The Attorney General maintained that, if the Commission approves the Solar PPAs, that the expense should not be recovered

[396] Attorney General's Post-Hearing Brief at 35.

[397] Attorney General's Post-Hearing Brief at 35–36.

[398] Attorney General's Post-Hearing Brief at 36. *See also* Senate President Robert Stivers Public Comment (filed Aug. 18, 2023).

[399] Attorney General's Post-Hearing Brief at 36.

through the FAC, but instead through a methodology proposed by KIUC's witness, Lane Kollen, which is discussed below.[400]

KIUC

In briefing, KIUC explained that, although it originally opposed the Solar PPAs as not being in compliance with KRS 278.264, based on LG&E/KU's rebuttal testimonies, KIUC agreed that the Solar PPAs are not considered replacement generation subject to KRS 278.264.[401] KIUC also pointed to evidence in the record that under current PPA pricing the Solar PPAs will lower costs for ratepayers under five of six fuel cost scenarios.[402] Based on the changed position, KIUC stated that it does not oppose approval of the Solar PPAs.[403]

KIUC maintained that LG&E/KU should not recover costs of the Solar PPAs through the FAC process, but instead through a new Solar PPA rider.[404] KIUC argued that FAC recovery is entirely energy based, and thus is an appropriate mechanism for variable fuel costs, but inappropriate for recovery of Solar PPA costs because such costs are wholly fixed costs and do not include a variable cost component.[405] KIUC asserted that recovering demand-related fixed costs on an energy basis would burden high load

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[400] Attorney General's Post-Hearing Brief at 36.

[401] KIUC's Post-Hearing Brief (filed Sept. 22, 2023) at 2, 16–19.

[402] KIUC's Post-Hearing Brief at 16. *See also* Rebuttal Testimony of David S. Sinclair (Sinclair Rebuttal Testimony) (filed Aug. 9, 2023) at 11 and Exhibit DSS-2 at 1.

[403] KIUC's Post-Hearing Brief at 2, 16–19.

[404] Direct Testimony of Lane Kollen (Kollen Direct Testimony) (filed July 14, 2023) at 20-22; Aug. 28, 2023 Hearing Video Testimony (HVT) at 9:31:51 and 934:17; KIUC's Post-Hearing Brief at 16–19.

[405] Kollen Direct Testimony at 20-22; Aug. 28, 2023 Hearing Video Testimony (HVT) at 9:31:51 and 934:17; KIUC's Post-Hearing Brief at 16–19.

factor customers such as the KIUC members.[406] KIUC and its witness, Lane Kollen, recommended that Solar PPA costs be recovered through a rider mechanism, which would align with cost-of-service principles and results in a better regulatory review process.[407]

Walmart

Walmart did not file witness testimony. In briefing, Walmart supported approving the Solar PPAs but urged the Commission to deny recovery of Solar PPA costs through the FAC and instead approve recovery of costs in a manner that recognizes both the energy and capacity benefits of the Solar PPAs.[408] Walmart stated that it was not opposed to the mechanism rider proposed by KIUC, explaining that while generally opposed to riders, Walmart concluded that the benefits of appropriate cost allocation under a rider outweighed Walmart's general opposition to riders.[409]

Sierra Club

In briefing, Sierra Club argued that LG&E/KU had demonstrated that the Solar PPAs are necessary and beneficial for LG&E/KU ratepayers, and thus recommended that the Commission should approve the Solar PPAs.[410] Also in briefing, Sierra Club agreed with Joint Intervenors' witness, John Wilson, that the Inflation Reduction Act, which

[406] KIUC's Post-Hearing Brief at 16.

[407] Kollen Direct Testimony at 21–22; Aug. 28, 2023 HVT at 9:27:35 and 9:28:52; KIUC's Post-Hearing Brief at 17–19.

[408] Walmart Post-Hearing Brief (filed Sept. 22, 2023) at 2, 18.

[409] Walmart Post-Hearing Brief at 2, 18–19.

[410] Sierra Club's Post-Hearing Brief (filed Sept. 22, 2023) at 8, 109; Sierra Club's Post-Hearing Reply Brief (filed Oct. 4, 2023) at 27.

includes tax credits for solar projects and was enacted after LG&E/KU filed their application, was unlikely to have resulted in LG&E/KU pursuing the Solar PPAs.[411]

Louisville Metro and LFUGC

In briefing, Louisville Metro and LFUCG stated that they do not oppose a finding that Commission approval is not required for the Solar PPAs and cost recovery through the FAC based on Commission precedent in Case No. 2020-00016.[412]

Joint Intervenors

Joint Intervenors' witness, John Wilson, disputed whether federal incentives played a role in LG&E/KU's decision to obtain Solar PPAs, noting that LG&E/KU filed its application before the Inflation Reduction Act was enacted, and thus tax credits included in the Inflation Reduction Act are unlikely to have resulted in LG&E/KU pursuing the Solar PPAs.[413] Regarding dispatchability of the Solar PPAs, Mr. Wilson recommended that LG&E/KU include provisions for the right to curtail Solar PPA facilities in future contract negotiations.[414]

In briefing, Joint Intervenors stated their support for the Solar PPAs but, due to limited time and the number of contested issues, did not further address the issue.[415]

[411] Direct Testimony of John Wilson (John Wilson Direct Testimony) (filed July 14, 2023) at 35–36.

[412] Louisville Metro and LFUGC's Post-Hearing Brief (filed Sept. 22, 2023) at 8; Louisville Metro and LFUGC's Post-Hearing Reply Brief (filed Oct. 4, 2023) at 2.

[413] John Wilson Direct Testimony at 35–36.

[414] John Wilson Direct Testimony at 12.

[415] Joint Intervenors' Post-Hearing Brief (filed Sept. 22, 2023) at 2.

Kentucky Coal Association

In written testimony, Kentucky Coal Association's witness, Emily Medine, raised concerns regarding the lack of a guarantee of performance at a specified price, must-take requirements, and the lack of a buy-out option in the Solar PPAs.[416] Ms. Medine argued that, given these issues, reliance on long-term PPAs was a high risk if the Solar PPAs became uneconomic.[417] Ms. Medine recommended that the Solar PPAs be rejected in their current form unless the contracts were revised to address concerns raised by Ms. Medine.[418]

In briefing, Kentucky Coal Association argued that the Solar PPAs, along with proposed LG&E/KU-owned solar facilities and Brown BESS, are not generating resources and should not be considered in an analysis of reliability of replacement generation under KRS 278.264.[419]

Mercer County Government

Mercer County Government intervened for the sole purpose of addressing the Mercer County property that is the subject of the stipulation discussed above. Mercer County Government took no position on this issue.

LG&E/KU RESPONSE TO INTERVENORS' ARGUMENTS – SOLAR PPAS

In rebuttal testimony and briefing, LG&E/KU disputed that they held out the Solar PPAs as replacement generation under KRS 278.264, rejecting the arguments of some

[416] Medine Direct Testimony at 50–52.

[417] Medine Direct Testimony at 34.

[418] Medine Direct Testimony at 52.

[419] Kentucky Coal Association's Post-Hearing Brief (filed Sept. 22, 2023) at 9; Kentucky Coal Association's Post-Hearing Reply Brief (filed Oct. 4, 2023) at 4.

Intervenors that the Solar PPAs are replacement generation under KRS 278.264.[420] LG&E/KU also rejected the objections to the Solar PPAs' contract terms by Kentucky Coal Association witness, Ms. Medine, arguing that implementing Ms. Medine's recommendations would likely result in the solar facilities never being built.[421]

LG&E/KU alleged that not entering into the Solar PPAs would have three adverse impacts: (1) the PVRR would be increased between $69 million and $734 million, depending upon the price of natural gas and pending EPA rules, without the Solar PPAs; (2) for every $1/REC, customers would save approximately $1.5 million annually with the Solar PPAs; and (3) without the Solar PPAs, carbon emissions increase by 1.4 million tons annually.[422] LG&E/KU asserted that the Solar PPAs would help mitigate the risks of the summer ozone season, during which certain coal-fired generating units cannot operate.[423]

In briefing, LG&E/KU asserted that there is "clear evidence" that the Solar PPAs have value as a hedge against fuel price and greenhouse gas cost risks, while noting there are risks that the PPA solar facilities will not be constructed due to increased interest rates and solar component costs.[424]

In rebuttal testimony regarding cost recovery, LG&E/KU indicated that Mr. Kollen's proposal to establish a rider to recover Solar PPA costs "may have merit as an alternative

[420] Rebuttal Testimony of Lonnie E. Bellar (Bellar Rebuttal Testimony) (filed Aug. 9, 2023) at 11–12; LG&E/KU Post-Hearing Brief at 34.

[421] LG&E/KU Post-Hearing Brief at 46–47.

[422] Sinclair Rebuttal Testimony at 11–12.

[423] Sinclair Rebuttal Testimony at 12.

[424] LG&E/KU Post-Hearing Brief at 28.

means of cost recovery," but specific details are needed considering the impact on the FAC, After-the-Fact billing, and Off-System Sales adjustment clause.[425] In briefing, LG&E/KU revised their request to ask that the Commission to approve a PPA rider rather than recovery through the FAC based on KIUC's witness Lane Kollen's written and hearing testimony.[426]

As a basis for the changed position, LG&E/KU argued for a PPA rider similar to their existing Environmental Cost Recovery (ECR) and Retired Asset Recovery (RAR) riders, which includes rate scheduled divided into Group 1 or Group 2.[427] As a basis for the changed position, LG&E/KU agree that a rider would provide the Commission with the opportunity to assess and approve cost recovery for the PPAs before the cost is incurred rather than after the cost is incurred; would reduce risk to LG&E/KU that their costs are not fully recovered under the FAC; and would utilize the Group 1/Group 2 cost recovery methodology already in use for the ECR and RAR riders.[428] LG&E/KU agreed with Mr. Kollen that a rider better reflects that Solar PPAs provide "not only energy but also capacity" and result from fixed-cost investments by the developer even though PPA charges are stated in volumetric basis of price per kWh.[429] LG&E/KU pointed to Mr.

[425] Rebuttal Testimony of Robert M. Conroy (Conroy Rebuttal Testimony) (filed Aug. 9, 2023) at 3.

[426] LG&E/KU's Post-Hearing Brief at 43.

[427] Group 1 includes customer classes residential service, residential time of day-energy service, residential time of day-demand service, volunteer fire department service, lighting service, restricted lighting service, lighting energy service, and traffic energy service. Group 2 includes customer classes general service, general time of day-energy service, general time of day-demand service, power service, time of day secondary service, time of day primary service, retail transmission service, fluctuating load service, electric vehicle supply equipment, electric vehicle charging service-level 2, electric vehicle fast charging service, and outdoor sports lighting service.

[428] LG&E/KU's Post-Hearing Brief at 43–44.

[429] LG&E/KU's Post-Hearing Brief at 44.

Kollen's hearing testimony that a rider removes disincentives for utilities to use PPAs that would otherwise be in the best interest of customers because of the risk to the utilities that full costs might not be recovered through the FAC.[430] LG&E/KU agreed with Mr. Kollen that using a PPA rider would remove price volatility through the FAC with the certainty of PPA costs on a total bill basis.[431] LG&E/KU asserted that customers would derive benefits of net proceeds from the sale of renewable energy credits attributable to the Solar PPAs.[432]

LG&E/KU requested that the Commission approve the concept of Solar PPA cost recovery through a PPA rider, but that details of a PPA rider be addressed in a separate proceeding.[433]

DISCUSSION AND FINDINGS – SOLAR PPAS

Applicability of Precedent

The Commission grants LG&E/KU's request for a declaratory Order and, based on the case record and being otherwise sufficiently advised, the Commission finds that the Solar PPAs are subject to the Commission's jurisdiction and require prior Commission approval under KRS 278.300 given the financial impact on customers and for the reasons discussed below. It has not escaped the Commission's notice that despite denying that the Solar PPAs provide capacity, LG&E/KU now acknowledges, in briefing and hearing testimony, that the Solar PPAs "provide not only energy but also capacity."[434] The record

[430] LG&E/KU's Post-Hearing Brief at 44. *See also* Aug. 29, 2023 HVT at 14:36:18.

[431] LG&E/KU's Post-Hearing Brief at 44.

[432] LG&E/KU's Post-Hearing Brief at 44.

[433] LG&E/KU's Post-Hearing Brief at 44.

[434] LG&E/KU's Post-Hearing Brief at 44.

is replete with references that LG&E/KU included the Solar PPAs' 637 MW in their economic analysis, LOLE reliability analysis, and target reserve margins to meet customer needs throughout the year.[435]

In addition to the above, the Solar PPAs at issue here represent a financial obligation that impact customers similar to the construction of new generation. The second prong of the legal standard established in KRS 278.300(3) is that the PPA must be necessary or appropriate for or consistent with the proper performance by the utility of its service to the public and will not impair its ability to perform that service. Until *In re PG&E Corporation*,[436] which allowed a utility to terminate an executory wholesale PPA through bankruptcy, the Commission is unaware of any instance in which a utility was able to default on a PPA. The financial impact of the Solar PPAs is greater than the Rhudes Creek Solar PPA at issue in Case No. 2020-00016. In the PPA at issue in Case No. 2020-00016 was a 100 MW solar PPA with the cost for 75 MW recovered from two industrial customers through a separate contract and only 25 MW recovered from customers through the FAC, net of RECs, and thus unlikely to impair LG&E/KU's ability to perform their service to the public. Here, the PPAs are for 647 MW, in the aggregate, between 20 and 30 years. If the Solar PPAs are executed, there is a significant financial risk that impacts ratepayers because, even if LG&E/KU cannot recover the costs, the costs remain on the books and impact LG&E/KU's financial performance. The Commission's statutory authority to ensure that PPAs will not impair a utility's ability to

[435] *See* Bellar May 10, 2023 Direct Testimony at 14, Tables 4 and 5, at 20, Table 7, and at 21, Table 8.

[436] *In re PG&E Corporation*, 603 B.R. 471 (Bankr. N.D. Cal. 2019), order vacated, appeal dismissed sub nom. Pacific Gas & Electric Company v. FERC, 829 Fed. Appx. 751 (9th Cir. 2020) (rendered moot upon entry of bankruptcy court order confirmed a Chapter 11 plan).

perform its service to the public is fundamental to the Commission's exclusive and plenary authority under KRS 278.040.

Additionally, PPAs specific to an asset, especially when a balancing authority such as LG&E/KU has control over the ultimate dispatch of that asset, has effectively the same impact on a utility's balance sheet as a capital lease. Here, LG&E/KU is under a contractual obligation to pay so long as they receive energy through the Solar PPAs. Given the size of the 637 MW Solar PPAs and the 20- to 30-year duration, LG&E/KU's obligation to pay creates a risk for their retail customers.

For these reasons, and based upon the case record, the Commission finds that the Solar PPAs must receive prior Commission approval under KRS 278.300. The Commission further finds that LG&E/KU presented sufficient evidence to satisfy their burden of proof under KRS 278.300. LG&E/KU demonstrated that the PPAs are for a lawful object within the corporate purposes of the utility purpose, with the lawful object deemed as the acquisition of new generation. As discussed above, LG&E/KU provided evidence that the Solar PPAs will be utilized to meet customer needs throughout the year and were included in LG&E/KU's economic analysis, LOLE, and target reserve margin. For the same reason, the evidence of record supports the conclusion that the Solar PPAs are appropriate for or consistent with the proper performance by LG&E/KU of their service to the public and will not impair their ability to perform that service based upon cost recovery discussed below. Finally, the Solar PPAs are reasonably necessary and appropriate for such purpose of providing adequate service to LG&E/KU's customers, as customers require affordable energy for retail use. For these reasons, LG&E/KU's request for approval of the Solar PPAs is granted contingent on the price of the Solar

PPAs not exceeding 5 percent of the price as filed. If any of the Solar PPAs' price exceeds 5 percent of the price as filed, LG&E/KU must notify the Commission within ten days.

However, the Commission is not convinced that the Solar PPAs will have the same degree of operational impact on customers as they have financial impact, and thus declines to address the applicability of KRS 278.020 under the facts presented.

The Commission disagrees with LG&E/KU's assessment that the Solar PPAs at issue are not dispatchable under a plain reading of KRS 278.264. In hearing testimony, LG&E/KU confirmed that, as the balancing authority in their service area, they have the option and authority to curtail any generator due to safety, reliability, or voltage issues whether the generator was owned by LG&E/KU or another entity.[437] Regardless, as previously noted, since the Solar PPAs are not necessary to ensure compliance with KRS 278.264, the Commission need not make a definitive determination regarding the facilities' dispatchability.

Cost Recovery

Based on the evidence of record, the Commission concludes that it is premature to enter a decision on the method of cost recovery of the Solar PPAs. First, LG&E/KU requested to revise the cost recovery mechanism despite testimony that the specifics of the rider and the implications to the FAC should be considered[438] and proposed to use a capacity-based recovery mechanism after arguing that the Solar PPAs are energy only, and not capacity. Second, the Commission notes that the underlying solar facilities have not yet submitted applications for construction certificates with the Kentucky State Board

[437] Aug. 22, 2023 HVT at 1:51:50–1:57:48.

[438] Conroy Rebuttal Testimony at 3-4.

on Electric Generation and Transmission Siting, much less received all regulatory approvals. For these reasons, the Commission declines to address the specific method of cost recovery of the Solar PPAs at this time.

4. SITE COMPATIBILITY CERTIFICATES

LEGAL STANDARD

KRS 278.216 states that a utility cannot begin the construction of an electric generation facility capable of generating more than 10 MWs in the aggregate without first obtaining a site compatibility certificate from the Commission. The utility must submit a site assessment report (SAR) as prescribed in KRS 278.708(3) and (4), except that a utility that proposes to construct a facility on a site that already contains facilities capable of generating 10 MW or more of electricity shall not be required to comply with setback requirements established pursuant to KRS 278.704(3).

KRS 278.708(3) requires a SAR to include the following:

> (1) A description of the proposed facility that shall include a proposed site development plan that describes:
> a. Surrounding land uses for residential, commercial, agricultural, and recreational purposes;
> b. The legal boundaries of the proposed site;
> c. Proposed access control to the site;
> d. The location of facility buildings, transmission lines, and other structures;
> e. Location and use of access ways, internal roads, and railways; existing or proposed utilities to service the facility;
> f. Compliance with applicable setback requirements as provided under KRS 278.704(2), (3), (4), or (5); and
> g. Evaluation of the noise levels expected to be produced by the facility;
> (2) An evaluation of the compatibility of the facility with scenic surroundings;
> (3) The potential changes in property values and land use resulting from the siting, construction, and operation of the proposed facility for property owners adjacent to the facility;

> (4) Evaluation of anticipated peak and average noise levels associated with the facility's construction and operation at the property boundary; and
> (5) The impact of the facility's operation on road and rail traffic to and within the facility, including anticipated levels of fugitive dust created by the traffic and any anticipated degradation of roads and lands in the vicinity of the facility.

KRS 278.708(4) states that the SAR shall also suggest any mitigating measures to be implemented by the applicant to minimize or avoid adverse effects identified in the SAR.

KRS 278.216(3) states that the Commission may require mitigation of certain impacts disclosed in the SAR but "shall, in no event, order relocation of the facility."

KRS 278.216 does not limit a utility's exemption under KRS 100.324, which exempts utilities' subject to the Commission's jurisdiction are not required to obtain approval of a planning unit for the location of a utility's service facilities.

PROPOSED SITE COMPATIBILITY CERTIFICATES

LG&E/KU requested that the Commission grant site compatibility certificates pursuant to KRS 278.216 for the two NGCC units, Mill Creek 5 and Brown 12, both of which will be constructed on property at an existing power site owned by LG&E/KU at the Mill Creek Station and Brown Station, respectively. LG&E/KU explained that it was not requesting a site compatibility certificate for the Mercer County solar facility at this time but that, once the SAR was prepared, LG&E/KU will file an application in the future for a site compatibility certificate for that facility.[439] LG&E/KU asserted that the Brown BESS did not require a compatibility certificate because KRS 278.216 applies to generation

[439] Direct Testimony of Robert M. Conroy (Conroy Direct Testimony) (filed Dec. 15, 2022) at 5.

facilities and, according to LG&E/KU, Brown BESS is not a generation facility.[440] LG&E/KU explained that the Marion County solar facility is being built by a third party and not LG&E/KU, and thus LG&E/KU is not required to file a site compatibility certificate for that facility.

Pursuant to KRS 278.216(2), LG&E/KU submitted SAR for Mill Creek 5 and Brown 12. The SARs provided a detailed description of both facilities. Mill Creek 5 will be located at the existing Mill Creek Station in southwest Jefferson County, Kentucky, on a site currently occupied by an existing facility that will be demolished prior to constructing Mill Creek 5.[441] Mill Creek 5 will consist of (1) one natural gas-fired gas combustion turbine; (2) a steam turbine; (3) one heat recovery steam generator, with natural gas-fired duct burners arranged in a one-on-one configuration; and (4) ancillary support equipment, including one natural gas-fired boiler, one pipeline fuel gas heater, one 2 MW emergency generator with diesel-fired engine, one emergency diesel-driven fire pump, and one 8-cell mechanical draft cooling tower.[442] LG&E/KU will install a new natural gas pipeline to serve Mill Creek 5.[443] The area north and east of Mill Creek 5 is zoned for residential land use, much of which is undeveloped; the area to the south is zoned for industrial use and is occupied by a cement facility; the Ohio River lies to the west of Mill Creek 5.[444] The SAR indicated that Mill Creek 5 will utilize a single stack for exhaust emissions that is located more than 1,000 feet from the nearest property boundary and more than 2,000

[440] Conroy Direct Testimony at 5.

[441] Application, Exhibit 5 at 1-1.

[442] Application, Exhibit 5 at 1-6–1-7.

[443] Application, Exhibit 5 at 1-7.

[444] Application, Exhibit 5 at 2-4.

feet from the nearest residential neighborhood boundary.[445] The SAR further indicated that two residential parcels occur within the 2,000-foot setback requirement; however, the parcels do not meet the KRS 278.700(6) definition of a residential neighborhood because they are below five total acres.[446] LG&E/KU stated that no additional setback requirements were identified for Mill Creek 5.[447] The SAR identified no significant effects or complications on surrounding infrastructure or nearby residents, including viewshed impairments, property values, excessive noise, fugitive dust, and transportation.[448] The SAR also identified that Mill Creek 5 will contribute air emissions that are subject to environmental regulations, but that there will be a net decrease of emissions and thus Mill Creek 5 will have no significant impact on the air quality resource.[449] According to the SAR, Mill Creek 5 will not have a significant impact on the water resource.[450]

Brown 12 will be located at the existing Brown Station in Mercer County, Kentucky on a site with an existing facility that will be demolished.[451] Brown 12 will consist of (1) one natural gas-fired gas combustion turbine; (2) a steam turbine; (3) one heat recovery steam generator, with natural gas-fired duct burners arranged in a one-on-one configuration; (4) and ancillary support equipment, including one natural gas-fired boiler, one pipeline fuel gas heater, one 2 MW emergency generator with diesel-fired engine,

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[445] Application, Exhibit 5 at 2-8.

[446] Application, Exhibit 5 at 2-8.

[447] Application, Exhibit 5 at 2-8.

[448] Application, Exhibit 5 at 3-3–3.35.

[449] Application, Exhibit 5 at 4-1.

[450] Application, Exhibit 5 at 4-2–4.4.

[451] Application, Exhibit 6 at 1-1.

one emergency diesel-driven fire pump, and one 8-cell mechanical draft cooling tower.[452] LG&E/KU will tap into an existing natural gas pipeline to serve Brown 12.[453] The surrounding area is zoned for residential use to the south and east, and zoned for agricultural and rural residential use to the northwest and west.[454] The SAR indicated that Brown 12 will utilize a single stack for exhaust emissions that is located more than 1,000 feet from the nearest property boundary and more than 2,000 feet from the nearest residential neighborhood, school, hospital, or nursing home facility.[455] The SAR further indicated that no additional setback requirements were identified.[456] The SAR identified no significant effects or complications on surrounding infrastructure or nearby residents, including viewshed impairments, property values, excessive noise, fugitive dust, and transportation.[457] The SAR also identified that Brown 12 will contribute air emissions that are subject to environmental regulations, but that there will be a net decrease of emissions and thus Brown 12 will have no significant impact on the air quality resource.[458] According to the SAR, Brown 12 will not have a significant impact on the water resource.[459]

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[452] Application, Exhibit 6 at 2-1.

[453] Application, Exhibit 6 at 2-1.

[454] Application, Exhibit 6 at 2-3.

[455] Application, Exhibit 6 at 2-6.

[456] Application, Exhibit 6 at 2-6.

[457] Application, Exhibit 6 at 3-1–3.28.

[458] Application, Exhibit 6 at 4-1.

[459] Application, Exhibit 6 at 4-2–4.4.

INTERVENORS' ARGUMENTS – SITE COMPATIBILITY CERTIFICATES

In witness testimony and briefing, none of the intervening parties took a position on the site compatibility certificates. The Commission notes that, as discussed above, some of the intervening parties are opposed to granting a CPCN to construct Mill Creek 5 and Brown 12.

DISCUSSION AND FINDINGS – SITE COMPATIBILITY CERTIFICATES

Having reviewed the record and being otherwise sufficiently advised, the Commission finds that the LG&E/KU have satisfied the requirements of KRS 278.216 for the issuance of a site compatibility certificate for Mill Creek 5. This is because the evidence demonstrates that Mill Creek 5, which will be constructed on property owned by LG&E/KU and located at an existing power site, would not harm local property values, unduly increase traffic or noise, or materially change the visual impact of the facility. For these reasons, the Commission finds that a site compatibility certificate should be issued for the construction of Mill Creek 5.

Because the Commission denied LG&E/KU's request for a CPCN to construct Brown 12 at this time, the issue of a site compatibility certificate for Brown 12 is moot. The Commission reiterates that the denial of the CPCN for Brown 12 is wholly based on the Commission's finding that the construction of Brown 12 should be deferred with the construction beginning on a date that provides for an in-service date in 2030.

Regarding Brown BESS, the Commission disagrees with LG&E/KU's argument that Brown BESS stores but does not generate electricity, and thus no site compatibility certificate is required. The Commission finds that, because battery energy storage systems convert electricity into other forms of energy, and then are able to produce electricity from converting the energy again, they do not store electricity, but instead generate it. Thus, battery energy storage systems are a generation source of electricity. With the finding that Brown BESS is generation and, with four-hour, 125 MW capacity, exceeds the 10 MW threshold established in KRS 278.216, the Commission finds that LG&E/KU must file an application in a separate proceeding requesting a site compatibility certificate for Brown BESS.

5. REGULATORY ASSET

LEGAL STANDARD

KRS 278.220 provides that the Commission may establish a uniform system of accounts (USoA) for utilities and in LG&E/KU's case, that the system of accounts shall conform as nearly as practicable to the system adopted or approved by the Federal Energy Regulatory Commission (FERC). The FERC USoA provides for regulatory assets, or the capitalization of costs that would otherwise be expensed but for the actions of a rate regulator. It must be probable that the utility will recover approximately equal revenue through the inclusion of these costs for ratemaking purposes, with the intent to recover the previously incurred cost not a similar future cost.

The Commission has established parameters for expenses that qualify for regulatory asset treatment; the Commission has approved regulatory assets when a utility has incurred (1) an extraordinary, nonrecurring expense which could not have reasonably been anticipated or included in the utility's planning; (2) an expense resulting from a statutory or administrative directive; (3) an expense in relation to an industry sponsored initiative; or (4) an extraordinary or nonrecurring expense that over time will result in a saving that fully offsets the cost.[460] Additionally, the Commission has established a requirement that utilities seek Commission approval before recording regulatory assets,[461] and requirements regarding the timing for applications seeking such approval.[462] Outside of the prescribed categories of expenses that qualify for regulatory asset treatment, utilities have established regulatory assets for certain timing and accounting differences, such as over- or under-recoveries for riders.

PROPOSED REGULATORY ASSET

LG&E/KU requested Commission approval to establish a regulatory asset to defer certain costs associated with the construction of Mill Creek 5, Brown 12, Mercer County Solar Facility, and Brown BESS. LG&E/KU proposed to record their investment in these four facilities as Construction Work In Progress (CWIP) and accrue an allowance for funds used during construction (AFUDC) using the methodology approved by the Federal Energy Regulatory Commission (FERC).[463] LG&E/KU further proposed to record a regulatory asset during the approximately four-year construction period for the difference between AFUDC accrued at LG&E/KU's weighted average cost of capital (WACC) and AFUDC accrued using the FERC methodology.[464] LG&E/KU argued that, under this

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[460] Case No. 2008-00436, *Application of East Kentucky Power Cooperative, Inc. for an Order Approving Accounting Practices to Establish a Regulatory Asset Related to Certain Replacement Power Costs Resulting from Generation Forced Outages* (Ky. PSC Dec. 23, 2008), Order at 3–4.

[461] Case No. 2016-00180, *Application of Kentucky Power Company for an Order Approving Accounting Practices to Establish Regulatory Assets and Liabilities Related to the Extraordinary Expenses Incurred by Kentucky Power Company in Connection with the Two 2015 Major Storm Events* (Ky. PSC Nov. 3, 2016), Order at 9.

[462] Case No. 2016-00180, Order (Ky. PSC Dec. 12, 2016) at 5.

[463] Conroy Direct Testimony at 3. FERC requires utilities recording AFUDC to use short-term debt first and then the weighted average of long-term debt and equity for the remainder of the balance. This approach implies that projects are primarily financed with short-term debt during construction.

[464] Conroy Direct Testimony at 3.

proposed methodology, they would recover only their "actual cost of capital, no more or no less."[465] LG&E/KU explained that the AFUDC and regulatory asset accruals would end as each asset is placed in service and that the request for AFUDC treatment is only for these four facilities.[466] LG&E/KU asserted that their proposal allows LG&E/KU to construct these facilities over a four-year period without impacting the bills of customers until actual costs are known and the projects are in-service while accruing the financing costs incurred related to the four projects.[467] LG&E/KU maintained that they would record only CWIP for all other new construction projects, explaining that the other projects are smaller in scale and have a shorter construction time period than Mill Creek 5, Brown 12, Mercer County Solar Facility, and Brown Bess.[468] LG&E/KU stated that they will finance the four projects with the same capital structure used in their 2020 base rate cases during the construction period and beyond because they do not engage in project financing.[469]

INTERVENORS' ARGUMENTS – REGULATORY ASSET

KIUC was the only party to address the issue of the regulatory asset in witness testimony. In his direct testimony, KIUC's witness, Lane Kollen, stated that he did not

[465] Conroy Direct Testimony at 3.

[466] Conroy Direct Testimony at 3.

[467] Conroy Direct Testimony at 3.

[468] Conroy Direct Testimony at 3−4.

[469] Conroy Direct Testimony at 4. In their last base rate cases, LG&E's capital structure was 1.53 percent short-term debt, 45.34 percent long-term debt, and 53.13 percent common equity and KU's capital structure was 2.46 percent short-term debt, 44.41 percent long-term debt, and 53.14 percent common equity. *See* Case No. 2020-00349, Application, Tab 63, Schedule J-1 at 1; Case No. 2020-00350, Application, Tab 63, Schedule J-1 at 1.

oppose the requested regulatory asset.[470] KIUC did not take a position on this issue in its post-hearing briefs.

No other party took a position on this issue in witness testimony or post-hearing briefs.

DISCUSSION AND FINDINGS – REGULATORY ASSET

LG&E/KU have historically included CWIP in rate base during their base rate cases, which allows them to recover financing costs as construction occurs, instead of capitalizing the construction costs as AFUDC and recovering them over the life of the asset. The Commission allowed LG&E/KU to record AFUDC and defer the difference between the AFUDC accrued at LG&E/KU's WACC and AFUDC accrued using the methodology approved by the FERC for advanced metering infrastructure, due to the long construction period and significant expenditure.[471] Having reviewed the record and being otherwise sufficiently advised, the Commission finds that LG&E/KU's request for authorization to establish deferral accounting for the difference between AFUDC accrued at LG&E/KU's WACC and AFUDC accrued using the methodology approved by the FERC during the construction period of Mill Creek 5, Mercer County Solar Facility, and Brown BESS is an acceptable treatment for the financing costs during construction, given LG&E/KU's actual financing plans, the long construction period, and the significant expenditure. Accordingly, the Commission finds that LG&E/KU should be authorized to establish, for accounting purposes only, regulatory assets based on the difference between AFUDC accrued at LG&E/KU's WACC and AFUDC accrued using the

[470] Kollen Direct Testimony at 5-6.

[471] Case No. 2020-00349, June 30, 2021 Order at 13 and Appendix A at 11; Case No. 2020-00350, June 30, 2021 Order at 15 and Appendix A at 11.

methodology approved by the FERC during the construction period of Mill Creek 5, Mercer County Solar Facility, and Brown BESS.

Because the Commission denied LG&E/KU's request for a CPCN to construct Brown 12 at this time, the issue of a regulatory asset for deferred construction costs for Brown 12 is moot. The Commission reiterates that the denial of the CPCN for Brown 12 is wholly based on the Commission's finding that the construction of Brown 12 should be deferred with the construction beginning on a date that provides for an in-service date in 2030.

The Commission's approval of the regulatory asset is not a finding that LG&E/KU can recover construction costs in rates. Approval of the establishment of a regulatory asset by the Commission does not direct or imply approval of any expenses that the utility defers to the regulatory asset. That will occur in the case where LG&E/KU seek recovery of costs related to the regulatory asset and the Commission will thoroughly review the reasonableness of the deferred construction financing costs in a future rate case.

6. DSM-EE PLAN AND TARIFF

LEGAL STANDARD

KRS 278.285(1) authorizes the Commission to review and approve the reasonableness of DSM-EE programs proposed by any utility under its jurisdiction. The statue lists multiple factors the Commission can consider when determining the reasonableness of the DSM-EE programs. The listed factors in KRS 278.285(1) are:

> (a) The specific changes in customers' consumption patterns which a utility is attempting to influence;
>
> (b) The cost and benefit analysis and other justification for specific demand-side management programs and measures included in a utility's proposed plan;

(c) A utility's proposal to recover in rates the full costs of demand-side management programs, any net revenues lost due to reduced sales resulting from demand-side management programs, and incentives designed to provide positive financial rewards to a utility to encourage implementation of cost-effective demand-side management programs;

(d) Whether a utility’s proposed demand-side management programs are consistent with its most recent long-range integrated resource plan;

(e) Whether the plan results in any unreasonable prejudice or disadvantage to any class of customers;
(f) The extent to which customer representatives and the Office of the Attorney General have been involved in developing the plan, including program design, cost recovery mechanisms, and financial incentives, and if involved, the amount of support for the plan by each participant, provided however, that unanimity among the participants developing the plan shall not be required for the commission to approve the plan;

(g) The extent to which the plan provides programs which are available, affordable, and useful to all customers; and

(h) Next-generation residential utility meters that can provide residents with amount of current utility usage, its cost, and can be capable of being read by the utility either remotely or from the exterior of the home.

KRS 278.285(1) also states the factors listed are not exhaustive; the Commission can consider anything that will help determine whether the programs are reasonable.

CURRENT DSM-EE PROGRAM PORTFOLIO

LG&E/KU's 2019-2025 DSM-EE program portfolio includes the following programs, as approved by the Commission in Case No. 2017-00441[472] and modified in Case No. 2019-00105.[473]

1. Residential and Small Nonresidential Demand Conservation Program
2. Low Income Weatherization Program (WeCare)
3. Residential Advanced Metering System Incentive
4. Residential and Small Nonresidential Demand Conservation Program
5. Large Nonresidential Demand Conservation Program
6. Nonresidential Rebates Program
7. Nonresidential Advanced Metering System Incentive

PROPOSED DSM-EE PROGRAM PORTFOLIO

Modifications to Current DSM-EE Plan

In the 2024−2030 DSM-EE plan, LG&E/KU proposed 14 DSM-EE programs that, according to LG&E/KU, would result in an increase in peak cumulative demand savings from 296 MW to 377 MW by 2030. Through October 2022, LG&/E/KU's DSM-EE programs have produced cumulative energy savings of approximately 1,566 GWh and gas savings of approximately 7.5 million Ccf. LG&E/KU are estimating to achieve additional peak cumulative energy and gas savings of 878 GWh and 170,000 Mcf by 2030

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

[473] Case No. 2019-00105, *Electronic Demand Side Management Filings of Louisville Gas and Electric Company and Kentucky Utilities Company* (Ky. PSC Aug. 19, 2019) (modifying the DSM balancing adjustment and DSM capital cost recovery component for residential service and general service rate customers).

if the DSM-EE Program Plan is approved as filed. LG&E/KU also proposed to increase the total DSM budget from approximately $98 million to $341 million by 2030. LG&E/KU proposed that the DSM-EE plan and new tariff sheets to be effective as of January 1, 2024.

LG&E/KU explained that due to the limited remaining economic life of coal generation, combined with market-wide electric demand growth, they indicated a significant increase in their baseload demand projections over the next several years. LG&E/KU explained concern with the historic economic conditions over the past 32 months. LG&E/KU stated that the immediate concerns surrounding the COVID-19 pandemic are receding, the effects of it are still persisting in terms of continuing financial hardship, supply chain issues, labor shortages, and higher costs for raw materials and products.[474] LG&E/KU also stated that while the cumulative near-term economic impacts affect both LG&E/KU's costs and their customers' ability to invest in energy efficiency, the potential effect on LG&E/KU's ability to achieve their DSM-EE goals are unknown.[475] Additionally, through ongoing collaboration with stakeholders, LG&E/KU recognizes a growing need for solutions aimed at helping reduce customers' energy burden, improving indoor health and comfort, addressing environmental concerns, and contributing to workforce development and economic growth for the state of Kentucky. Therefore, those factors prompted LG&E/KU to file a new DSM-EE Plan to request approval for additional budget and programs to support a substantive increase in their portfolio offerings that will

[474] Direct Testimony of John Bevington (Bevington Direct Testimony) (filed Dec. 15, 2022), Exhibit JB-1, Appendix A, at 6.

[475] Bevington Direct Testimony, Exhibit JB-1, Appendix A, at 7.

make more comprehensive energy efficiency and demand response opportunities available to a broader customer population.

LG&E/KU and Cadmus formulated the proposed 2024-2030 DSM-EE Program Plan by beginning with a pool of 39 possible programs that were developed by researching and reviewing successful programs other utilities across the nation have implemented. LG&E/KU and Cadmus used a customized scoring rubric using 12 key objective criteria such as the program's ability to generate energy savings and demand reduction, be cost-effective, and benefit disadvantaged communities. LG&E/KU and Cadmus then narrowed the pool down to 14 programs due to some programs not passing the scoring rubric.[476] The 14 programs then went through a cost-benefit analysis in which LG&E/KU and Cadmus evaluated whether the programs were cost-effective; the cost-benefit analysis is discussed in detail below. LG&E/KU explained that it shared and discussed the results from the cost-benefit analysis with the DSM-EE Advisory Group and solicited input through frequent formal and informal communications with multiple parties. LG&E/KU then calculated program savings as the sum of each measure's annual energy-savings estimate and expected participation over the 2024-2030 period. Using the costs, savings, and avoided benefits and costs estimates for each measure, LG&E/KU then computed the programs' cost-effectiveness. Based on the results of the final round of cost-benefit analyses and discussions with the DSM-EE Advisory Group, LG&E/KU finalized the proposed 2024-2030 DSM-EE Program Plan.

In their current application, LG&E/KU propose the following DSM-EE programs:

[476] Bevington Direct Testimony at 8.

Income Qualified Solutions. The proposed Income-Qualified Solutions consists of two programs: Low-Income Weatherization, formerly known as We Care, and Whole-Building Multifamily.

Low-Income Weatherization is an education and weatherization program designed to reduce energy consumption of income-qualified customers. The program provides energy audits, energy education, and installation of weatherization and energy conservation measures in qualified single-family homes. This program is available to residential customers who qualify for Federal Low Income Weatherization Assistance Program or Low-Income Home Energy Assistance Program (LIHEAP) services or those who are at or below 300 percent of the federal poverty level. In the proposed DSM-EE plan, LG&E/KU raised the eligibility threshold from 200 percent to 300 percent of the federal poverty level.

Whole-Building Multifamily is a new education and weatherization program designed as a service for increasing the efficiency of property managers' and owners' income-qualified properties' common areas and tenant units. This program provides installation of energy-saving devices to help reduce energy use in residents' living units and in common areas, incentives to property managers and owners who purchase high-efficiency equipment to retrofit the property as a whole rather than individual units, and energy usage and conservation education.

Appliance Recycling. LG&E/KU proposed an effective date of January 1, 2026, for this program, which provides a one-time incentive for residential customers to dispose of and recycle inefficient appliances. LG&E/KU explained that the program targets removal and recycling of refrigerators, freezers, room air conditioners, and dehumidifiers, with free pick-up and a $50 incentive per eligible, recycled refrigerator or freezer, and free pick up only for room air conditioners and dehumidifiers. LG&E/KU further explained that it will work with an independent third-party vendor to collect and transport working but inefficient appliances to a recycling center.

Similarly, LG&E/KU previously had the Residential Refrigerator Removal Program, where LG&E/KU offered a $50 incentive to remove older, less efficient refrigerators and freezers from participants' homes. LG&E/KU partnered with Appliance Recycling Centers of America and promoted the program to retailers. However, the declining age in the removed appliances made this program no longer cost-effective and in 2018, LG&E/KU discontinued the program.

Residential online audit. LG&E/KU proposed an effective date of January 1, 2025, for this program, which is a web-based, self-guided assessment of a residential customer's home designed to achieve feedback on disaggregated energy use, and energy conservation education. After the audit is completed, participants are mailed a kit with energy efficiency measures for self-installation. The kit will include a low-flow bathroom faucet aerator, a low-flow kitchen faucet aerator, a low-flow showerhead, water heater pipe insulation, weatherstripping, caulking, spray foam, and an advanced power strip. In addition, residential customers who complete the audit gain access to prescriptive rebates for deeper energy efficiency retrofits, include a $300 rebate for a heat pump water heater, $300 rebate for a central air conditioner, $400 rebate for a ductless heat pump. $400 rebate for an air source heat pump, and $250 rebate for a 95 percent annual fuel utilization efficiency (AFUE) furnace.

Business Solutions. The proposed Business Solutions consists of three programs: Nonresidential Rebates, Small Business Audit and Direct Install, and Nonresidential Midstream Lighting.

Nonresidential Rebates provides nonresidential customers with financial incentives to help replace aging and inefficient equipment. This program includes prescriptive incentives for energy audits and high-efficiency equipment such as lighting, motors, pumps, variable frequency drives, and air conditioning retrofits installed in existing buildings; custom incentives for eligible customers to implement energy-efficient technologies not covered in the prescriptive component of the program; and custom retrofit projects in existing buildings. The incentives are based upon achieved first-year energy (kWh) savings and demand (kW) reductions. New construction incentives are performance-based and intended for constructing new, efficient nonresidential facilities that exceed current state building energy code requirements, with bonus incentives for LEED certification. Industrial customers that participate in this program may not use their statutory opt-out.

The Small Business Audit and Direct Install program provides free energy audits conducted by a third-party contractor to small businesses and allows for direct installation of high-efficiency equipment, including nonresidential LED bulbs and fixtures, faucet aerators, low-flow showerheads, and pre-rinse spray valves.

LG&E/KU proposed a January 1, 2026 effective date for the Nonresidential Midstream Lighting program, which provides incentives to lighting distributors to stock and sell high-efficiency equipment, with the bulk of the incentives pass through to customers who purchase the equipment. Because purchasers don’t have to submit rebate applications, the program is designed to reduce participation barriers for customers and contractors.

Connected Solutions. The proposed Connected Solutions demand response program consists of four programs: Residential and Small Nonresidential Demand Conservation; Bring Your Own Device; Optimized Charging; and Online Transactional Marketplace. LG&E/KU retain the right to limit participation in multiple programs to prevent customers receiving compensation more than once for the same demand reduction.

Residential and Small Nonresidential Demand Conservation utilizes switches in homes and small businesses to assist in reducing the demand for electricity during peak times. The program communicates with the switches to cycle central air conditioning units, heat pumps, electric water heaters, and pool pumps off and on through a predetermined sequence. As of January 14, 2023, no additional switches will be installed under this program. Customers currently enrolled in this program will be allowed to continue to participate until their switch fails. The compensation for this demand reduction is:

- Single-family air conditioning and heat pump switches receive $5 per event per device up to 20 events per year.
- Single-family water heater and pool pump switches receive $4 per event per device, up to 20 events per year.
- Multifamily air conditioning and heat pump switches receive $2 per event per device for tenants and $2 per event per device for property owners/managers, up to 20 events per year.

- Multifamily water heater and pool pump switches receive $4 per event per device for tenants and $4 per event per device for property owners/managers, up to 20 events per year.
- Small business air conditioning switches receive $5 per summer month, up $20 annually. per device for each central air conditioning unit or heat pump system weighing up to five tons, plus an additional $1 per month for every additional ton.
- Small business water heater switches receive $4 per month, up to $16 annually, per device.

Bring Your Own Device is an event-based, load control demand response program in which LG&E/KU can directly manage summer and winter loads during hours of peak demand through smart thermostats and other devices without the need for switches. Participants receive an incentive for enrolling and another incentive for each event their device participates in. Beginning in 2024, LG&E/KU will offer customers an incentive of up to $50 for enrolling a smart thermostat and up to $10 for each event in which their device participates, up to 25 events per year. In 2026, LG&E/KU will offer customers an incentive of up to $50 for enrolling a smart water heater and up to $10 for each event in which their device participates, up to 25 events per year. Participants are limited to a maximum incentive of $300 per device in the first year of participation and $250 per device in the second and subsequent years.

Optimized Charging targets electric vehicle (EV) charging to provide demand response and load shifting. LG&E/KU will issue signals to qualifying electric vehicles and qualifying electric vehicle supply equipment to affect the timing and level of charging for electric vehicles within parameters set by participants. The program requires no action from the customer after enrollment aside from plugging in the vehicle. LG&E/KU will offer an incentive for enrolling in the program and a monthly incentive for continuing LG&E/KU's access to optimize charging for the vehicle. LG&E/KU will offer customers a one-time incentive upon enrollment of up to a $50 per vehicle and up to $5 per month for optimized charging per vehicle. Participants are limited to a maximum incentive of $110 per vehicle in the first year of participation and $60 per vehicle in the second and subsequent years.

The Online Transactional Marketplace program offers instant incentives through price markdowns to customers who purchase qualified products. Customers who purchase a new smart thermostat from the Online Transactional Marketplace will be automatically enrolled in the BYOD program subcomponent. LG&E/KU will offer a discount of up to $75 on smart thermostats and up to $10 on smart plugs. Beginning in 2026, LG&E/KU will offer a discount of up to $50 on smart water heaters. LG&E/KU will continue to monitor cost-effective opportunities for new measure offerings to be added to the Online Transactional Marketplace.

Peak time rebates. LG&E/KU proposed an effective date of January 1, 2025, for this program, which is a voluntary, event-based demand response resource that pays customers to reduce their electric consumption during times of high demand all year round. LG&E/KU would notify customers in advance of peak demand events and educate customers on ways to save and shift energy consumption during events. Customers' savings will be calculated by comparing their metered consumption with an estimate of their baseline consumption during events. LG&E/KU will offer incentives based on a pay-for-performance model. Customers participating in Peak Time Rebates will earn up to $2 for every kWh of savings achieved during an even relative to their baseline energy consumption. Customers will be eligible for up to a $15 annual participation bonus for each year that they remain enrolled in the program and actively participate. LG&E/KU anticipates up to 25 events per year.

Nonresidential Demand Response. The proposed Nonresidential Demand Response program employs, as needed, interfaces to customer equipment to help reduce the demand for electricity during peak times by cycling power on the equipment. LG&E/KU will notify customers in advance of peak demand events. This program has an approved flexible incentive structure with an incentive rate of $75 per kW curtailed. The incentive amount that a participant receives will continue to be calculated based on the actual demand reduction achieved by the participant over the entire year's events. Curtailable Service Rider (CSR) participants are not eligible for participation in this program.

Tariff Revisions

LG&E/KU proposed to adjust the return on equity (ROE) component for the DSM capital cost recovery portion of the DSM mechanism formula. This adjustment is a decrease from the current 10.2 percent ROE for DSM-EE related capital to 9.925 percent ROE. The 9.925 percent ROE includes the most recently awarded base-rate ROE in Case Nos. 2020-00349 and 2020-00350,[477] 9.425 percent, plus a 50-basis-point

[477] Case No. 2020-00349, *Electronic Application of Kentucky Utilities Company for an Adjustment of Its Electric Rates, A Certificate of Public Convenience and Necessity to Deploy Advanced Metering Infrastructure, Approval of Certain Regulatory and Accounting Treatments, and Establishment of a One-Year Surcredit* (Ky. PSC June 30, 2021); Case No. 2020-00350, *Electronic Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Rates, A Certificate of Public Convenience and Necessity to Deploy Advanced Metering Infrastructure, Approval of Certain Regulatory and Accounting Treatments, and Establishment of a One-Year Surcredit* (Ky. PSC June 30, 2021).

incentive. LG&E/KU explained that the incentive is based upon KRS 278.285, which includes language regarding incentives that are designed to provide positive financial rewards to a utility to encourage implantation of cost-effective DSM-EE. LG&E/KU further explained that the 50-basis-point incentive is consistent with past DSM-EE capital cost recovery approvals.[478]

DSM-EE PROGRAM COST-EFFECTIVENESS AND ENERGY SAVINGS

Prior to the approval of the current DSM suite of programs in Case No. 2017-00441[479], LG&E/KU had avoided capacity costs that were greater than $0, which contributed to a more robust DSM programming due to programs being more cost-effective. LG&E/KU explained that, at that time, the avoided capacity costs were based in part on declining load growth projections, very low fuel costs, and, consequently, low production costs, and those factors were compounded by an annual 30-year demand and energy forecast and resource plans that projected relatively flat demand and sufficient generating capacity.[480] LG&E/KU state that they increased the pace of the DSM-EE Program Plan development because they are proposing to retire large amounts of coal-fired generation capacity in this case, and the avoided cost of capacity has significantly increased since LG&E/KU's most recent DSM-EE Program Plan filing. However, LG&E/KU stated that the avoided cost change positively impacts the cost-effectiveness

[478] Conroy Direct Testimony, at 7-8. *See also* Case No. 2017-00441, Oct. 5, 2018 Order at 4.

[479] Case No. 2017-00441, Oct. 5, 2018 Order.

[480] Bevington Direct Testimony, Exhibit JB-1, at 4.

of certain DSM-EE programs and allows LG&E/KU to propose an expanded DSM-EE Program Plan that is cost-effective.[481]

LG&E/KU analyzed the proposed DSM-EE programs using the four California Standard Practice Manual tests that the Commission requires for DSM-EE programs evaluations.[482] The following table shows the result of the cost-effectiveness test as provided by LG&E/KU:[483]

DSM Program Portfolio	TRC	PCT	RIM	PAC
Program Development and Administration	0.00	N/A	0.00	0.00
Income-Qualified Solutions	0.27	N/A	0.13	0.27
Appliance Recycling Program	1.02	N/A	0.20	0.81
Residential Online Audit Program	0.74	5.10	0.19	1.06
Business Solutions	1.84	7.40	0.27	7.93
Connected Solutions	3.52	12.65	0.94	1.17
Peak Time Rebates	2.62	N/A	0.40	0.40
Nonresidential Demand Response Program	1.68	1.36	1.34	1.37
Overall Portfolio	1.54	7.53	0.32	1.83

[481] Bevington Direct Testimony at 5.

[482] The four tests are the Total Resource Cost (TRC), Participant Cost Test (PCT), Ratepayer Impact Measurement Test (RIM), and Program Administrator Cost Test (PAC).

[483] Bevington Direct Testimony, Exhibit JB-1 at 19, Table 1-4.

The Commission has traditionally evaluated DSM effectiveness by focusing on the Total Resource Cost (TRC) results. A TRC score of less than one indicates that the cost of the program outweighs the measured benefits. LG&E/KU explained that although the Income-Qualified Solutions does not pass the cost-effectiveness threshold, LG&E/KU included it in the portfolio to address a critical need for energy efficiency services among their most vulnerable customers and because it was important to the DSM Advisory Group's stakeholders. Additionally, the Residential Online Audit is also not cost-effective, but LG&E/KU explained that it provides both education and incentives for energy efficiency equipment intended for energy savings to their customers.[484]

LG&E/KU stated that in order to meet customer needs and fulfill resource obligations, they will need to offer a more comprehensive portfolio of energy efficiency and demand response programs that aim to capture a larger share of available energy savings potential and increase access to firm, dispatchable load reduction benefits.[485] LG&E/KU provided the annual and total demand, energy, and gas savings per program from 2024-2030. The following table shows the total savings results of the 2024-2030 DSM-EE Program Plan:[486]

Program	Total Energy Savings (MWh)	Total Demand Savings (MW)	Total Gas Savings (Ccf)
Income Qualified Solutions	30,833	2.59	927,071
Appliance Recycling	28,013	3.30	0
Residential Online Audit	23,270	1.90	63,163
Business Solutions	776,406	162.20	24,887

[484] Direct Testimony of Lana Isaacson (Isaacson Direct Testimony) (filed Dec. 15, 2022) at 8.

[485] Bevington Direct Testimony, Exhibit JB-1, Appendix A at 5.

[486] Bevington Direct Testimony, Exhibit JB-1, Appendix A at 54–56.

Connected Solutions	16,061	68.30	684,562
Peak Time Rebates	0	30.8	0
Nonresidential Demand Response	782	78.7	0
Total	875,365	347.79	1,699,683

LG&E/KU explained that the relationship between the DSM-EE costs and savings is not entirely linear and that when economic and market factors are introduced that the potential for demand and energy savings declines. LG&E/KU stated that in order for DSM to serve as a reliable generation planning resource, it is imperative that the DSM-EE programs and savings goals account for the realistic conditions of the market.[487]

DSM-EE PROPOSED RATES

LG&E/KU explained that when developing the DSM-EE Program Plan, they sought to maximize the impacts that the DSM-EE Program Plan can provide to their service territories while ensuring that program benefits outweigh program costs. LG&E/KU provided the annual and total Utility Program Costs from 2024-2030. The following table shows the total portfolio and program costs of the 2024-2030 DSM-EE Program Plan:[488]

Program	Total Program Cost
Program Development and Administration	$ 21,336,000
Income Qualified Solutions	$ 70,902,000
Appliance Recycling	$ 8,880,000
Residential Online Audit	$ 8,904,000

[487] Bevington Direct Testimony, Exhibit JB-1, Appendix A at 2.

[488] Bevington Direct Testimony, Exhibit JB-1, Appendix A at 21.

Business Solutions	$ 48,899,000
Connected Solutions	$ 100,739,000
Peak Time Rebates	$ 41,562,000
Nonresidential Demand Response	$ 38,520,000
Total Portfolio Costs	$ 340,742,000

LG&E/KU explained that they will ensure that the DSM-EE programs will remain effective once they are approved because they currently use a third-party contractor to examine program design, delivery, impacts, and processes. The contractor then ensures quality and effectiveness of the programs, optimal use of resources, and responsiveness to customers' needs. LG&E/KU stated that they will use the results and guidance to ensure that all of the programs contained in the Program Plan demonstrate continuous improvement and remain a good application of customer dollars.[489] The average monthly bill impacts with the proposed DSM-EE programs are[490] (1) Electric: $0.54 per month for LG&E customers; $0.55 per month for KU customers; and (2) Gas: $0.15 per month for LG&E customers.

INTERVENORS' ARGUMENTS – DSM-EE PLAN AND TARIFF

Attorney General

The Attorney General did not file witness testimony. In its post-hearing brief, the Attorney General recommended that the Commission approved the proposed DSM-EE plan, subject to annual reporting on the DSM-EE plans continuing cost-effectiveness, and

489 Isaacson Direct Testimony at 16.

490 Application at 18–19.

an annual true-up of actual costs and amounts collected through the DSM-EE cost recovery mechanisms.[491] The Attorney General also recommended that the Commission require LG&E/KU to include updates on avoided capacity costs with LG&E/KU's annual DSM-EE update given the potential uncertainty of avoided capacity costs over the seven-year duration of the DSM-EE plan.[492]

The Attorney General disagreed with LG&E/KU's proposal to modify the eligibility for the Income Qualified Solutions program to include participants with a household income up to 300 percent of the federal poverty level instead of capping eligibility at 200 percent of the federal poverty level. The Attorney General asserted that it would be more appropriate to allow participants with household income between 201 and 300 percent of the federal poverty level to participate if funds remain after serving applicants with incomes up to 200 percent of the federal poverty level.[493] However, the Attorney General agrees with one commenter who proposed that LG&E/KU track the income level of participants on an annual basis and report the aggregate numbers to the Commission to ensure the income qualified solutions serves primarily customers at lower income levels.[494]

KIUC

KIUC sponsored testimony from its witness, Lane Kollen, who stated that he did not oppose LG&E/KU's proposed DSM-EE plan and tariffs.[495] In its post-hearing brief,

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[491] Attorney General's Post-Hearing Brief at 39.

[492] Attorney General's Post-Hearing Brief at 39−40.

[493] Attorney General's Post-Hearing Brief at 39–40.

[494] Attorney General's Post-Hearing Brief at 39.

[495] Kollen Direct Testimony at 5.

KIUC asserted that the DSM-EE programs, especially those for low-income residential customers, are reasonable, citing the projected cumulative peak demand savings of 377 MW, energy savings of 878 GWh, and 170,000 Mcf gas savings by 2023 at a cost of $341 million.[496]

Walmart

Walmart did not file witness testimony. In its post-hearing briefs, Walmart recommended that the Commission approve LG&E/KU's DSM-EE plan and tariff.[497] Walmart further recommended that the Commission require LG&E/KU to take steps to "better engage" commercial and industrial customers in the DSM-EE Advisory Group process.[498] Walmart pointed to the evidence of record that the majority of DSM-EE Advisory Group meeting participants represent residential and low-income customer interests.[499] Walmart asserted that because the DSM-EE Advisory Group meetings dominated by residential and low-income customer issues, it is difficult to engage commercial and industrial customers on DSM-EE issues, especially given limited time and resources of commercial and industrial customers.[500] Walmart rebutted an LG&E/KU's witness statement that commercial and industrial customers can discuss issues one-on-one with LG&E/KU representatives, arguing that one-on-one conversations are not a substitute for a group collaborative process such as the DSM-EE

[496] KIUC's Post-Hearing Brief at 11.

[497] Walmart's Post-Hearing Brief at 2; Walmart's Post-Hearing Reply Brief (filed Oct. 4, 2022) at 12.

[498] Walmart's Post-Hearing Brief at 2; Walmart's Post-Hearing Reply Brief at 12

[499] Walmart's Post-Hearing Brief at 16.

[500] Walmart's Post-Hearing Brief at 16−17.

Advisory Group.[501] Walmart argued that, without the opportunity for group collaboration for commercial and industrial customers, opportunities for commercial and industrial DSM-EE programs and the corresponding benefit to LG&E/KU are being missed.[502]

For the above reasons, Walmart requested the Commission to require LG&E/KU to take steps to better evaluate commercial and industrial customer DSM-EE programs. Walmart suggested the LG&E/KU could be required to hold separate DSM-EE Advisory Group meetings devoted to commercial and industrial customers and requiring LG&E/KU to contact larger customers, particularly those that are prohibited by statute from opting out of utility-sponsored DSM-EE, to notify such customers of the opportunity to participate in a DSM-EE Advisory Group.[503]

Sierra Club

Sierra Club did not file testimony that took a position on LG&E/KU's proposed DSM-EE plan and tariff. In its post-hearing brief, Sierra Club referenced dispatchable DSM-EE as part of the portfolios analyzed but did not expressly take a position whether to grant or deny LG&E/KU's proposed DSM-EE plan and tariff.[504]

Louisville Metro and LFUGC

Louisville Metro and LFUGC filed joint witness testimony with Sierra Club that did not take a position on LG&E/KU's proposed DSM-EE plan and tariff. In their joint post-hearing briefs, Louisville Metro and LFUCG stated that they generally support the

[501] Walmart's Post-Hearing Brief at 17.

[502] Walmart's Post-Hearing Brief at 17.

[503] Walmart's Post-Hearing Brief at 17−18.

[504] Sierra Club's Post-Hearing Brief.

proposed DSM-EE plan and tariff, but argued that the plan should be more robust.[505] Louisville Metro and LFUCG pointed to recommendations to improve LG&E/KU's DSM-EE plan presented in Joint Intervenors' witness Jim Grevatt's testimony.[506] Louisville Metro and LFUCG asserted that LG&E/KU should improve their coordination and cooperation with the DSM-EE Advisory Group and better engage commercial and industrial customers in the DSM-EE Advisory Group.[507] Louisville Metro and LFUCG also raised their concern that DSM-EE Advisory Group members are not sufficiently included in the DSM-EE planning process.[508]

Joint Intervenors

In witness testimony sponsored by Joint Intervenors and in Joint Intervenors' post-hearing briefs, Joint Intervenors recommended that the proposed DSM-EE plan be approved, but with modifications put forth in Mr. Grevatt's written testimony.[509] In their briefs, Joint Intervenors contended that LG&E/KU's DSM-EE proposal is reasonable given that it triples LG&E/KU's annual investment in DSM-EE, increases the seven-year cumulative energy savings from 112 MW to 170 MW, and increases the demand response savings from 86 MW to 207 MW, but also contended that LG&E/KU could pursue greater levels of energy savings.[510]

[505] Louisville Metro and LFUCG's Post-Hearing Brief at 8.

[506] Louisville Metro and LFUCG's Post-Hearing Brief at 8.

[507] Louisville Metro and LFUCG's Post-Hearing Brief at 9; Louisville Metro and LFUCG's Post-Hearing Reply Brief at 2.

[508] Louisville Metro and LFUCG's Post-Hearing Brief at 9.

[509] Supplemental Errata Filing of the Direct Testimony of Jim Grevatt (Grevatt Direct Testimony) (filed Aug. 29, 2023); Joint Intervenors' Post-Hearing Brief at 3; Joint Intervenor's Post-Hearing Reply Brief (filed Oct. 4, 2023) at 1.

[510] Joint Intervenors' Post-Hearing Brief at 7; Joint Intervenor's Post-Hearing Reply Brief at 4.

Joint Intervenors contended that LG&E/KU should expand DSM-EE programs to achieve savings equal to at least one percent of LG&E/KU's 2021 MWh sales by 2027, with a balance between residential and non-residential savings.[511] Joint Intervenors requested that the Commission direct LG&E/KU to re-evaluate and revise their DSM-EE programs so that LG&E/KU can achieve Joint Intervenors' proposed savings goal.[512]

Joint Intervenors and their witness raised concerns regarding the validity of measure characteristics, avoided capacity costs, avoided fuel costs, and related assumptions LG&E/KU used in developing the proposed DSM-EE programs.[513] Joint Intervenors recommended that that Commission require LG&E/KU to revise the study used to develop the proposed DSM-EE programs, focusing on the economic potential of DSM-EE plans using avoided energy and capacity costs that reflect LG&E/KU's future needs.[514]

Regarding the Income Qualified Solutions program, Joint Intervenors and their witness asserted that the Commission should deny LG&E/KU's proposed increase in the income eligibility requirement from 200 percent of the federal poverty level to 300 percent of the federal poverty level to ensure that LG&E/KU's "highest need" and "most economically vulnerable customers" are served by the income qualified solutions program.[515] Joint Intervenors further asserted that, whether the Commission approves or

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[511] Grevatt Direct Testimony at 7, 41−47, and 60−61; Joint Intervenors' Post-Hearing Brief at 7−9; Joint Intervenors' Post-Hearing Reply Brief at 6.

[512] Grevatt Direct Testimony at 5–7, 48; Joint Intervenors' Post-Hearing Brief at 33–34.

[513] Grevatt Direct Testimony at 4, 25−34, and 59; Joint Intervenors' Post-Hearing Brief at 17−21.

[514] Grevatt Direct Testimony at 59; Joint Intervenors' Post-Hearing Brief at 17−21.

[515] Grevatt Direct Testimony at 12−17, and 19; Post-Hearing Joint Intervenors' Brief at 26−27.

denies the proposed income eligibility increase for the income qualified solutions program, the Commission should require LG&E/KU to conduct a low-income market characterization study to design DSM-EE programs to meet the needs of low-income customers and should track and report on an annual basis the income of income qualified solutions participants to monitor that the program serves customers most in need of the program.[516]

Joint Intervenors and their witness argued that LG&E/KU failed to conduct a robust analysis of an on-bill financing program, known as PAYS, and recommended that the Commission require LG&E/KU to reassess offering an on-bill financing program in their DSM-EE programs.[517]

Joint Intervenors requested that the Commission require LG&E/KU to include non-energy benefits in the DSM-EE cost/benefit analysis.[518] Joint Intervenors alleged that "there is no jurisdictional or other barrier" that prevents the Commission from considering public health, environmental, and non-energy benefits in a DSM-EE cost-benefit analysis and therefore the Commission should "[c]orrect past conflations of jurisdiction" and apply a broad discretion to hear evidence on non-energy benefits in analyzing DSM-EE programs.[519]

Joint Intervenors and their witness asserted that, if the Commission approves the DSM-EE plan and tariff as filed, then the Commission should require LG&E/KU to conduct

[516] Grevatt Direct Testimony at 6, 17−18, and 59−60; Joint Intervenors' Post-Hearing Brief at 27.

[517] Grevatt Direct Testimony at 6, 49−53, and 60; Joint Intervenors' Post-Hearing Brief at 28.

[518] Joint Intervenors' Post-Hearing Brief at 30−33.

[519] Joint Intervenors' Post-Hearing Brief at 30−33.

a mid-plan review to update avoided costs and re-calculate cost-effectiveness, along with identifying opportunities to develop more robust programs.[520]

In their brief, Joint Intervenors claimed that LG&E/KU did not pursue increased energy savings through DSM-EE in lieu of building replacement generation for retiring units or involve the DSM-EE Advisory Group in developing and evaluating the DSM-EE plan, and therefore should be directed to improve the DSM-EE planning process.[521]

Kentucky Coal Association

Kentucky Coal Association filed witness testimony that did not take a position on LG&E/KU's proposed DSM-EE plan and tariff. In its post-hearing briefs, Kentucky Coal Association referenced the attributes of DSM-EE as part of the portfolios analyzed but did not expressly take a position whether to grant or deny LG&E/KU's proposed DSM-EE plan and tariff.[522]

Mercer County Government

Mercer County Government filed witness testimony and a brief that did not take a position on LG&E/KU's proposed DSM-EE plan and tariff.[523]

LG&E/KU RESPONSE TO INTERVENORS' ARGUMENTS – DSM-EE PLAN AND TARIFF

In rebuttal testimony, LG&E/KU addressed Joint Intervenors' witness Mr. Grevatt's criticisms of the proposed DSM-EE plan regarding the program selection process, the

[520] Grevatt Direct Testimony at 61−62; Joint Intervenors' Post-Hearing Brief at 33−34.

[521] Joint Intervenors' Post-Hearing Brief at 34−41.

[522] Kentucky Coal Association's Post-Hearing Brief at 6, 8–9, 17, 25; Kentucky Coal Associations Post-Hearing Reply Brief at 6, 8–9, 17, and 25.

[523] Mercer County Government's Post-Hearing Brief (filed Sept. 22, 2023).

income eligibility increases to the income qualified solutions program, and balance of programs between residential customers, and commercial and industrial customers, among other things. LG&E/KU noted that Mr. Grevatt did not calculate the cost-effectiveness of his proposed modifications to the DSM-EE portfolio and did not address that different states have different DSM-EE cost-effectiveness inputs when Mr. Grevatt based his recommendations on a study prepared for another state.[524] LG&E/KU disputed that the DSM-EE Advisory Group was not included in DSM-EE program selection and that only LG&E/KU and their DSM-EE consultant participated in the program selection process.[525]

Regarding the income qualified solutions, LG&E/KU argued that the increase in the eligibility was the result of feedback from the DSM-EE Advisory Group, asserting that the program as proposed will increase the number of participants along with expanded eligibility from 200 percent of the federal poverty line to 300 percent of the federal poverty line.[526] In their brief, LG&E/KU stated that it sought to make the program available to more customers by increasing the income level for eligible participants, but would not object to retaining the eligibility level of 200 percent of the federal poverty level for that program.[527] LG&E/KU challenged Mr. Grevatt's recommendation that LG&E/KU conduct a low-income DSM-EE study, arguing that LG&E/KU proposed a similar study as part of

[524] Rebuttal Testimony of Lana Isaacson (Isaacson Rebuttal Testimony) (filed Aug. 9, 2023) at 4; LG&E/KU's Post-Hearing Brief at 52–53; LG&E/KU's Post-Hearing Reply Brief (filed Oct. 4, 2023) at 34–35.

[525] Isaacson Rebuttal Testimony at 6; LG&E/KU's Post-Hearing Brief at 48–50; LG&E/KU's Post-Hearing Reply Brief at 29–31.

[526] Isaacson Rebuttal Testimony at 8; LG&E/KU Post-Hearing Reply Brief at 36.

[527] LG&E/KU Post-Hearing Reply Brief at 36.

the DSM-EE plan to identify households with high need for whole-building retrofits such as HVAC and weatherization.[528] LG&E/KU further argued that the study, as proposed by Mr. Grevatt, would increase charges to all residential customers through the DSM-EE mechanism without providing a demonstrative benefit.[529]

LG&E/KU asserted that their 2024–2030 DSM-EE plan was developed to allow all customers to meaningfully participate but that, in the balance, the proposed DSM-EE plan favors residential and small commercial customers.[530] LG&E/KU argued that the proposed DSM-EE plan allocated 69 percent of the program costs plus incentives to residential and small commercial customers and 25 percent to large commercial and industrial customers.[531] LG&E/KU also argued that the programs are expected to provide 11.5 percent of the total plan energy savings from residential and small customers, and 88.5 percent of the total plan energy savings from large commercial and industrial customers, with forecasted peak capacity reduction of 62 percent from residential and small customers, and 38 percent from large commercial and industrial customers.[532]

In their post-hearing brief, LG&E/KU noted that no Intervenors other than the Joint Intervenors took issue with the DSM-EE plan and that Joint Intervenors supported the plan while arguing that more savings were achievable.[533] LG&E/KU further noted that Joint Intervenors did not propose specifics for additional programs or calculate cost-

[528] Isaacson Rebuttal Testimony at 8–9; LG&E/KU Post-Hearing Reply Brief at 36.

[529] LG&E/KU Post-Hearing Reply Brief at 36.

[530] Isaacson Rebuttal Testimony at 9–10.

[531] Isaacson Rebuttal Testimony at 9–10.

[532] Isaacson Rebuttal Testimony at 10.

[533] LG&E/KU Post-Hearing Brief at 48.

effectiveness of their recommendations.[534] Also in their brief, LG&E/KU walked through the steps of the DSM-EE program planning and selection to support their position that the DSM-EE Advisory Group members fully participated in the planning and selection process.[535] LG&E/KU asserted that, as circumstances change, they will perform a mid-plan revision of the DSM-EE portfolio, as it has done in the past.[536]

DISCUSSION AND FINDINGS – DSM-EE PLAN AND TARIFF

In making our findings in this case, the Commission recognizes that, unlike the prior LG&E/KU DSM case in which it projected a capacity surplus, resulting in an avoided capacity cost of zero, LG&E/KU are projecting a capacity shortfall in the near future and are proposing avoided costs greater than zero. The Commission agrees with the avoided costs that LG&E/KU used to determine the cost-effectiveness of the DSM-EE Program Plan. Furthermore, the Commission has traditionally evaluated DSM effectiveness by primarily focusing on the TRC results. Therefore, when discussing LG&E/KU's low-income programs, such results are not uncommon for low-income programs to not be cost-effective. The Commission has found that such DSM programs assist low-income customers in lowering their energy bill as well as the impact these programs have on LG&E/KU's generation load. The Commission notes that LG&E/KU should be vigilant in their scrutiny of the results of each DSM program measure's cost-effectiveness test and provide those results in future DSM cases along with detailed support for future DSM program expansions and additions. Additionally, the Commission finds that LG&E/KU will

[534] LG&E/KU Post-Hearing Brief at 48.

[535] LG&E/KU Post-Hearing Brief at 48–50.

[536] LG&E/KU Post-Hearing Brief at 50–52.

include updated TRC scores and any changes to the programs or the program costs during their annual DSM-EE filings with the Commission.

The Commission notes that while it recognizes the effort LG&E/KU took to meet with the DSM-EE Advisory Groups five times, the Commission has concern that these meetings were not as constructive as they could have been. The Commission has an understanding that these meetings should be more than informational and, instead, should entail fluid dialog among all vested parties. The Commission notes Walmart's request for either a separate DSM-EE Advisory Group for commercial and industrial representatives, or designation of a portion of the DSM-EE Advisory Group meeting that focuses on commercial and industrial representatives. The Commission notes that the development of a DSM-EE plan requires full involvement of all groups, with opinions and ideas incorporated through shared decision-making. The Commission would encourage LG&E/KU to integrate opinions and discussion results more fully and formally from collaboratives and advisory groups. Therefore, the Commission finds that LG&E/KU should establish separate Advisory Group meetings for the commercial and industrial representatives, with a representative from the Office of the Attorney General, to allow a more fluid and constructive meeting with both residential customer representatives, and commercial and industrial representatives.

The Commission would also like to note that there have been multiple comments and concerns regarding LG&E/KU's recent IRP filing. The Commission refers to the 2021 IRP Staff Report in which the Commission provided recommendations for LG&E/KU's next IRP filing. The Commission finds that LG&E/KU are actively working towards achieving those recommendations and that the 2024-2030 DSM-EE Program Plan is a more robust and expanded plan from the 2019-2025 DSM-EE Program Plan that includes cost-effective options, programs that shift load, and programs that achieve actual dollar savings and demand and energy savings. However, the Commission finds that the recommendations listed in the 2021 IRP Staff Report must be considered for future planning and that LG&E/KU should always continue to evaluate their DSM-EE Program Plan.

Additionally, the Commission finds that the factors listed in KRS 278.285(1) are supported considering LG&E/KU are attempting to alter usage patterns and lower energy and peak consumption; LG&E/KU provided a cost-benefit analysis based upon the California Tests, provide support for recovery of all program costs, lost revenues, and incentives; LG&E/KU include all DSM in their IRP flings, including the current filing;[537] the proposed programs are available to qualifying customers; the DSM-EE Advisory Group includes the Attorney General; LG&E/KU ensure that the programs are available, affordable, and educational with customer service representatives (CSRs); and LG&E/KU were granted a Certificate of Convenience and Public Necessity for full deployment of AMS meters in their 2020 rate cases and have commitments to provide an on-line platform accessible to the customer and to CSRs for usage, costs, and meter readings. Furthermore, there is near universal support for LG&E/KU's programs. The Commission also approves LG&E/KU's request for a 50-basis point addition to the ROE and the DSM rates for electric and gas service as set forth in the Appendix to this Order are reasonable and should also be approved.

[537] See Case No. 2021-00393*, Electronic 2021 Joint Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company* (Ky. PSC filed Oct. 19, 2021).

SUMMARY OF FINDINGS

As set forth above, the Commission finds that:

1. LG&E/KU's request to retire Mill Creek 1 and Mill Creek 2 should be granted, with the retirement of Mill Creek 2 conditioned on LG&E/KU constructing Mill Creek 5.

2. LG&E/KU's request to retire Haefling 1 and 2, and Paddy's Run 12 should be granted.

3. LG&E/KU's request to retire Ghent 2 and Brown 3 should be denied.

4. LG&E/KU's request for CPCNs to construct Mill Creek 5, Mercer County Solar Facility, and Brown BESS should be granted.

5. LG&E/KU's request for a CPCN to acquire Marion County Solar Facility should be granted.

6. LG&E/KU's request for a CPCN to construct Brown 12 should be denied.

7. LG&E/KU's request for a site compatibility certificate for Mill Creek 5 should be granted.

8. LG&E/KU's request for a site compatibility certificate for Brown 12 should be denied.

9. LG&E/KU should be required to file an application for a site compatibility certificate for Brown BESS.

10. LG&E/KU's request to enter into four Solar PPAs should be granted pursuant to KRS 278.300.

11. LG&E/KU's request to recover the costs of the Solar PPAs through the FAC or a PPA rider should be denied, with leave to subsequently file an application for cost recovery of the Solar PPAs in the future.

12. LG&E/KU's request for approval of the change in ownership of assets pursuant to KRS 278.218 and stipulation regarding the sale of the Mercer County property described in this Order should be granted.

13. LG&E/KU's request to establish a regulatory asset for the difference between AFUDC accrued at LG&E/KU's weighted average cost of capital and AFUDC accrued using the methodology approved by the FERC during the construction period of Mill Creek 5, Mercer County Solar Facility, and Brown BESS should be granted.

14. LG&E/KU's request to establish a regulatory asset for the difference between AFUDC accrued at LG&E/KU's weighted average cost of capital and AFUDC accrued using the methodology approved by the FERC during the construction period of Brown 12 should be denied.

15. LG&E/KU should take all reasonable measures to mitigate the cost of Mill Creek 5, while prioritizing the addition of dual fuel capability at the facility for no more than the most recent received quote for the costs of the entire facility.

16. LG&E/KU's request for approval of the DSM-EE plan and tariff should be approved

17. LG&E/KU's motion for the Commission to take administrative notice of their Hearing Exhibit 1, Joint Comment ERCOT, MISO, PJM, and SPP in EPA Docket No. EPA-HQ-OAR-2023-0072, New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating

Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule should be granted.

SUMMARY OF CONCLUSIONS

This case is fundamentally about the adequacy, reliability and cost of LG&E/KU's generation facilities. Importantly, the only immediate rate impact of this proceeding relates to the demand-side management and energy efficiency measures, otherwise known and DSM-EE, approved in this Order. Those programs are permitted by statute, and utilities, such as LG&E/KU, charge line-item rates to recover the costs of the programs. DSM-EE programs are intended to provide either demand reductions that can be used to reduce the overall needs of the system, or energy savings that in aggregate, reduce the total amount of electricity used by customers. Other than targeted low-income programs designed specifically to reduce the energy burden of those customers least able to afford their bills, DSM-EE programs are cost-effective in reducing demand and energy. Said differently, every dollar spent on DSM-EE programs returns benefits to customers in excess of a dollar. Given their cost-effectiveness, customers rates over time are lower with DSM-EE programs than they would have been without them.

None of the resource decisions made in this Order immediately impact rates. With the passage of Senate Bill 4 in the 2023 session of the General Assembly, for the first time this Commission was given the explicit authority to grant or deny requests to approve the retirement of utilities' generating facilities. Furthermore, Senate Bill 4, codified as KRS 278.262 and 278.264, added reliability as a specific statutory standard for the Commission to apply in regulating electric utilities, in addition to the primary requirements of service, that service be adequate, efficient and reasonable. In recognition of the General Assembly's clear concern for the Commonwealth's electric transmission system, and the statute's dictate that the Commission ensure retirements are economic and do not negatively impact bulk grid reliability, this Order attempts to maximize the reliability of those dollars that will be spent on generation and transmission facilities, while minimizing the risk of burdensome rates and stranded costs.

In this matter, LG&E/KU requested to retire four coal-fired generating units, in order of size from smallest to largest: Mill Creek 2, 297 MW; Mill Creek 1, 300 MW; Brown 3, 412 MW; and Ghent 2, 485 MW. LG&E/KU also requested to retire three natural gas-fired units: Haefling 1 and 2, and Paddy's Run 12. The three natural gas-fired units combined have 47 MW of summer capacity and 55 MW of winter capacity, or about one-sixth the capacity of LG&E/KU's smallest coal-fired plant at issue in the proceeding. LG&E/KU proposed to replace those facilities, and add new generation, with a suite of varied facilities, including large natural gas plants, a number of solar generators (both owned and contracted), and a large battery.

In accordance with the law, this Order approves the retirement of the two smallest coal plants, Mill Creek 1 and 2, as well as the three small natural gas-fired units, Haefling 1 and 2, and Paddy's Run 12. This Order gives defined retirement dates for Mill Creek 1 and 2, as long as certain conditions are met, and approves LG&E/KU to retire the small natural gas-fired units when they break and the cost to fix or maintain them exceeds their value. In approving the retirement of those five units, the Commission also approves a certificate to build a large natural gas-fired generator, called Mill Creek 5, at the Mill Creek Station in Jefferson County, Kentucky. Replacing those five retiring units with Mill Creek

5 is cheaper than the cost of maintaining and upgrading those units, based on known, likely, and expected expenses. The Commission's Order herein also finds that replacement of those five retiring units with Mill Creek 5 will make the system more reliable than it is today, reducing the likelihood that LG&E/KU's system will not have enough energy to serve customers when they demand it, as compared to a system that keeps all five generators and makes the necessary upgrades to fully operate them. Importantly, no other proposed facility, including the solar and battery facilities, is necessary for the Commission's findings regarding the cost-effectiveness of the retirement and replacement, or the finding regarding enhanced reliability with the addition of Mill Creek 5.

The Commission denies LG&E/KU's request for a certificate to build another large natural gas-fired generator, Brown 12, because it is not needed now. Herein, the Commission finds that the retirement of Ghent 2 and Brown 3, two large coal-fired units, is premature given the timing of overhaul costs and uncertainty surrounding environmental compliance. The Commission finds there are material distinctions between Mill Creek 1 and 2, and Brown 3 and Ghent 2 that support the Mill Creek unit retirements, while finding the retirement of Ghent 2 and Brown 3 is premature. There are a number of differences, including a number of local air quality issues in Jefferson County that increase the likelihood Mill Creek 1 and 2 will be forced to retire or will certainly need to make expensive upgrades, as well as the fact that Mill Creek 1 has been operated and maintained since 2020 in ways that anticipated its retirement in 2024. Regardless, in the event LG&E/KU have trouble timely constructing Mill Creek 5, the Commission finds that given their need for adequate generation, LG&E/KU should not retire Mill Creek 2 without sufficient replacement.

LG&E/KU also proposed to own, as well as contract for, solar generation. In nearly every scenario studied the proposed solar reduced the total cost for customers by providing cheap energy at the times the facilities produce it. Given the significant savings the proposed solar provides for customers, the Commission approves it as an additive source of generation to help supplement LG&E/KU's needs. The Commission also approves a certificate to build the proposed energy storage system, or BESS, as it will give LG&E/KU a significant insight into the operation and integration of large-scale storage in meeting customer demand. Given the expected resource constraints in the future, not the least of which are increased environmental regulation and difficulty in the siting of energy infrastructure, both of which were discussed at lengths in this matter, it is imperative LG&E/KU are not caught unprepared in understanding the facilities that will be necessary to keep the lights on over the coming decades. Building, owning and operating the proposed battery as soon as practical will provide LG&E/KU with invaluable knowledge necessary to mitigate reliability and cost impacts in a changing resource environment.

A number of other items are addressed herein, including concerns around LG&E/KU's load forecast, proposals to join wholesale power markets in lieu of building or buying generation, and questions around the resource mix after this case is decided. Given the denial of the retirement of Ghent 2 and Brown 3, particularly until further environmental compliance is clearer, as well as the denial of the CPCN for Brown 12, the Commission finds that parties' concerns surrounding a sudden shift in the

Commonwealth's generation resource mix are overstated. Following this Order, LG&E/KU's reliance on gas as opposed to coal is only marginally shifted, and the addition of a battery and solar, the latter of which will materially contribute to reliability during the LG&E/KU's summer peaks, improve the system's reliability. As noted above, without the addition of the solar and battery, and only with the replacement of the retiring generators with Mill Creek 5, the reliability of the system going forward is higher than the status quo.

With regard to joining an RTO, the Commission finds that joining a market to address generation retirement is not in conformity with the law, and places customers at significant risk of unmitigable costs and reliability concerns. As this body has said in other proceedings, "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."[538] If LG&E/KU are retiring generation, and customer demand requires replacement generation, this Commission expects LG&E/KU to own or contract for the necessary resources, not depend on a capacity market where someone else is in charge of weatherization, maintenance and fuel assurance of those resources. Regardless, the Commission uses this opportunity to reiterate its interest in LG&E/KU continuing to seriously study the costs and benefits of RTO membership, in order to maximize LG&E/KU's investments for the benefit of its customers, and to take advantage of the reliability benefits of being in a larger system.

As it relates to measuring generation and demand for purposes of resource planning, given the uncertainty around financing, environmental regulations and the ability

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[538] Case No. 2021-00198, *Electronic Tariff Filing of East Kentucky Power Cooperative, Inc. and Its Member Distribution Cooperatives for Approval of Proposed Changes to Their Qualified Cogeneration and Small Power Production Facilities Tariffs* (Oct 26, 2021) at 5, Footnote 10.

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.

IT IS THEREFORE ORDERED that:

1. LG&E/KU's request to retire Mill Creek 1 and Mill Creek 2 is approved, with the retirement of Mill Creek 2 conditioned on LG&E/KU constructing Mill Creek 5.

2. LG&E/KU's request to retire Haefling 1 and 2, and Paddy's Run 12 is approved, with the conditions expressed herein.

3. LG&E/KU's request to retire Ghent 2 and Brown 3 is denied.

4. LG&E/KU's request for CPCNs to construct Mill Creek 5, Mercer County Solar Facility, and Brown BESS are granted.

5. LG&E/KU's request for a CPCN to acquire Marion County Solar Facility is granted.

6. LG&E/KU's request for a CPCN for Brown 12 is denied.

7. LG&E/KU shall obtain approval from the Commission prior to performing any additional construction not expressly authorized by this Order.

8. LG&E/KU shall provide written notice to the Commission one week prior to the actual start of construction of Mill Creek 5.

9. LG&E/KU shall provide written notice to the Commission one week prior to the actual start of construction of Mercer County Solar Facility.

10. LG&E/KU shall provide written notice to the Commission one week prior to the actual start of construction of Brown Bess.

11. LG&E/KU shall file written notice with the Commission of any increase to the cost of construction of Mill Creek 5, Mercer County Solar Facility, or Brown Bess that exceeds five percent of the costs as filed.

12. LG&E/KU shall file with the Commission documentation of the total costs of the construction of Mill Creek 5, Mercer County Solar Facility, and Brown BESS, including the cost of construction and all other capitalized costs (e.g., engineering, legal, and administrative), within 60 days of the date that the construction of each facility is substantially completed. Construction costs shall be classified into appropriate plant accounts in accordance with the USoA for electric utilities prescribed by the Commission.

13. LG&E/KU shall file with the Commission documentation of the total costs of acquiring Marion County Solar Facility within 60 days of the date that LG&E/KU acquires the facility.

14. LG&E/KU are authorized to enter into the four Solar PPAs, as filed, contingent on the respective Solar PPAs' costs not exceeding five percent of the costs as filed.

15. LG&E/KU shall file written notice within ten days of an increase that exceeds five percent of any of the Solar PPAs' costs as filed.

16. LG&E/KU's request to recover the costs of the Solar PPAs through the FAC or a PPA rider is denied, with leave to refile an application for cost recovery of the Solar PPAs in the future.

17. LG&E/KU are authorized to establish a regulatory asset for the difference between AFUDC accrued at LG&E/KU's weighted average cost of capital and AFUDC

accrued using the methodology approved by the FERC during the construction period of Mill Creek 5, Mercer County Solar Facility, and Brown BESS is granted.

18. The regulatory asset account established in this case are for accounting purposes only.

19. The amount, if any, of the regulatory asset approved in this Order that is to be amortized and included in rates shall be determined in LG&E/KU's next base rate case.

20. LG&E/KU are granted a site compatibility certificate to construct Mill Creek 5 at the Mill Creek Generating Station in Jefferson County, Kentucky.

21. LG&E/KU's request for a site compatibility certificate to construct Brown 12 at the Brown Generating Station is denied.

22. LG&E/KU shall file an application for a site compatibility certificate to construct Brown BESS at the Brown Generating Station in a separate proceeding.

23. KU's request to sell property owned in Mercer County to Mercer County Government and the city of Harrodsburg is granted.

24. The stipulation as filed by KU and Mercer County Government is approved.

25. LG&E/KU's DSM-EE programs and associated costs as filed in their January 6, 2023 application are approved effective January 1, 2024.

26. The rates for LG&E/KU's DSM-EE programs set forth in Appendices A and B to this Order are approved.

27. Within 20 days of the date of this Order, LG&E/KU shall file with this Commission, using the Commission's electronic Tariff Filing System, revised tariff sheets

setting out the rates approved in this Order and reflecting that they were approved pursuant to this Order.

28. LG&E/KU's motion for the Commission to take administrative notice of their Hearing Exhibit 1, Joint Comment ERCOT, MISO, PJM, and SPP in EPA Docket No. EPA-HQ-OAR-2023-0072, New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule is granted.

29. This case is closed and removed from the Commission's docket.

PUBLIC SERVICE COMMISSION

Kent Chandler

Chairman

Angie Hatton

Vice Chairman

Mary Pat Regan

Commissioner

ENTERED

NOV 06 2023 bsb

KENTUCKY PUBLIC SERVICE COMMISSION

ATTEST:

Linda C. Bridwell

Executive Director

APPENDIX A

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2022-00402 DATED NOV 06 2023

The following rates and charges are prescribed for the customers served by Louisville Gas and Electric Company. All other rates and charges not specifically mentioned herein shall remain the same as those in effect under the authority of this Commission prior to the effective date of this Order.

LG&E Electric Rate Classes

RS, RTOD-Energy, RTOD-Demand, VFD	$ 0.00196 per kWh
GS, GTOD-Energy, GTOD-Demand	$ 0.00256 per kWh
PS	$ 0.00659 per kWh
TODS, TODP, RTS, FLS, OSL	$ 0.00078 per kWh

LG&E Gas Rate Classes

RGS, VFD	$ 0.00722 per Ccf
CGS, IGS, AAGS, SGSS, FT	$ 0.00165 per Ccf

APPENDIX B

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2022-00402 DATED NOV 06 2023

The following rates and charges are prescribed for the customers served by Kentucky Utilities Company. All other rates and charges not specifically mentioned herein shall remain the same as those in effect under the authority of this Commission prior to the effective date of this Order.

KU Electric Rate Classes

RS, RTOD-Energy, RTOD-Demand, VFD	$ 0.00120 per kWh
GS, GTOD-Energy, GTOD-Demand	$ 0.00156 per kWh
AES	$ 0.00849 per kWh
PS, TODS, TODP, RTS, FLS, OSL	$ 0.00198 per kWh

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