COMMONWEATH 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**

SIERRA CLUB'S POST-HEARING BRIEF

Contents

Cases

Statutes

Other Authorities

Regulations

INTRODUCTION

The four coal-fired units at issue in this proceeding—Mill Creek 1, Mill Creek 2, Ghent 2, and E.W. Brown 3—are uneconomic on a going-forward basis. This is plain on LG&E/KU's own analysis, and it is even more obvious in examining the "litany" of proposed and final environmental regulations that impact the units on a going-forward basis. The Good Neighbor Plan alone will require the installation of major pollution controls at Mill Creek 1, Mill Creek 2, and Ghent 2 costing an eye-popping $110 million - $126 million *per unit*. A range of other proposed and possible clean air regulations of ozone, haze, and fine particulate matter would require the installation of those same pollution controls, even in the absence of the Good Neighbor Plan. Existing clean air regulation has the potential to impose $4.5 million per year in costs, each, for Mill Creek 1, Mill Creek 2, and Ghent 2. Clean Water Act regulations also risk costs for these units in the millions of dollars. And proposed and potential future carbon regulations pose severe risks to continued economic and legal operation of all four units. Retiring Mill Creek 1 and 2, Ghent 2, and Brown 3 is the least-cost, *least-risk* option for LG&E/KU customers.

Further, these coal-fired units are not a solution to LG&E/KU's reliability concerns. Coal-fired power failed to keep the lights on for LG&E/KU customers during Winter Storm Elliott: roughly as many megawatts of coal power were offline due to forced outages when LG&E/KU implemented rolling blackouts as megawatts of gas-fired generation. The amount of coal generation offline was 2.5 times what was needed to provide power to all LG&E/KU's customers. One of the units that failed customers at the time of greatest need, Brown 3, is a unit that LG&E/KU seeks to retire here. Roughly 20% of LG&E/KU's coal-fired generation was unavailable at the utility's time of greatest need.

The solution to prevent future rolling blackouts is not to hope, contrary to the observed facts of Winter Storm Elliott, that in future LG&E/KU will not experience correlated outages of coal-fired units and to retain coal generation. The solutions are to accurately forecast and plan for correlated outages of coal-fired and gas-fired units, including during extreme weather, and ultimately to increase portfolio diversity, geographic diversity, and load diversity to protect against events that severely impact thermal generation and that have a high likelihood of concentration in a specific area. LG&E/KU's peer utilities that are part of regional transmission organizations (RTOs) did not experience rolling blackouts. LG&E/KU, meanwhile, was rebuffed when it as a non-member sought power from an RTO during its time of greatest need. Simply put, if Kentucky is experiencing severe weather, LG&E/KU customers would be better protected by being part of an RTO and being able to draw on pooled supply resources across many states that are not experiencing the exact same weather at the same time.

In this proceeding, LG&E/KU has demonstrated that retirement of the coal-fired units, and all the units at issue, is warranted. LG&E/KU has put forward a portfolio that meets the requirements of K.R.S. § 278.264, that would build two 621-MW NGCCs, secure 877 MW of solar power for LG&E/KU customers, build a 125-MW battery, 4-hour battery. Joint Intervenor Witness Sommer has also put forward a portfolio that meets these requirements, that builds only one NGCC and provides for more DSM/EE resources. Either portfolio meets the requirements of § 278.264, showing that retirement is warranted. Further, an alternative portfolio that substitutes joining the regional transmission organization PJM for construction of the two NGCCs likely satisfies § 278.264 (depending on Commission interpretation) under the current PJM model, further supporting retirement.

LG&E/KU has shown that CPCNs for solar power and battery storage and declaratory orders for the solar PPAs in this case are necessary and beneficial for LG&E/KU customers. Approval of DSM/EE with the modifications proposed by the Joint Intervenors is also warranted. LG&E/KU has not, however, demonstrated that CPCNs approving two NGCCs are warranted.

First, *two* NGCCs is a severe overbuild: LG&E/KU's own modeling demonstrates that 40% of one NGCC is all that is needed to meet the Companies' energy demand. Second, LG&E/KU has not thoroughly evaluated all alternatives in concluding that two NGCCs, rather than zero or one NGCC and joining PJM, are the optimal solutions to the Companies' capacity needs. LG&E/KU's own RTO study was deeply flawed, and one of its key conclusions was based on a $200 million typo. Lexington/Louisville and Sierra Club Witness Levitt, by contrast, concluded that RTO membership is likely to provide significant net benefits for LG&E/KU customers. The Commission should deny at least one CPCN for one NGCC outright. As to the other, the Commission should either deny the CPCN or, at minimum, defer a decision until reasonable evaluation as to whether joining an RTO is a reasonable alternative that will provide for capacity savings that eliminates the need for a second NGCC and otherwise provide net benefits for LG&E/KU customers.

This matter has also raised serious questions about LG&E/KU's approach to planning for correlated outages, the Companies' transparency and accuracy regarding challenges and failures, and the quality of past decision-making as to whether joining an RTO is in the best interest of LG&E/KU customers. For these reasons independent of the CPCN analysis, the Commission should open an investigation into LG&E/KU's status as a non-member of an RTO—either as a condition of approving retirements, or on its own motion. A full and robust investigation into whether joining an RTO would benefit LG&E/KU customers is needed to ensure that customers are receiving the best possible service in terms of affordability and reliability. This investigation should *begin* immediately. RTOs are changing, in efforts to proactively respond to the energy transition. The Commission's past inquiry into LG&E/KU's then-membership in MISO lasted for years. Beginning an investigation now will ensure that the Companies and Commission are well poised to determine quickly what is in the best interest of LG&E/KU customers as soon as new RTO constructs clarify.

I. Legal Standard

This consolidated matter involves two separate proceedings. First, LG&E/KU seek Commission approval for the retirement of seven fossil fuel-fired units: E.W. Brown 3, Ghent 2, Mill Creek 1, Mill Creek 2, Haefling 1, Haefling 2, and Paddy's Run 12.[1] Second, LG&E/KU seek Commission approval for certificates of public convenience and necessity ("CPCN") for two 621 MW natural gas combined cycle combustion turbine ("NGCC") units located at Brown and Mill Creek, including on-site gas and electric transmission construction; a CPCN to build a 120 MW solar facility; a CPCN to acquire a second 120 MW solar facility; a CPCN to build a 125 MW, 4-hour battery at the Brown Generating Station; a declaratory order that entry into power purchase agreements for 637 MW of solar generation does not require Commission approval; and approval of a demand-side management and energy efficiency ("DSM/EE") plan.[2]

The legal standard for the CPCN proceeding is straightforward and has been in place since the 1950s. K.R.S. § 278.020 requires that a utility obtain a CPCN for "the construction of any plant, equipment, property, or facility" with limited exceptions, such as "[o]rdinary extensions of existing systems in the usual course of business." § 278.020(a). To receive a CPCN, the utility must show (1) a need for the construction and (2) an absence of wasteful duplication.[3] Demonstrating need requires "a showing of a substantial inadequacy of existing service."[4] Wasteful duplication is "an excess of capacity over need" and "an excessive investment in relation to productivity or efficiency, and an unnecessary multiplicity of physical properties."[5] Demonstrating an absence of wasteful

[1] Case No. 2023-122, Joint Application of Ky. Utils. Co. & Louisville Gas & Elec. Co. for Fossil Fuel-Fired Electric Generating Unit Retirements at 1.
[2] Case No. 2022-402, Joint Application at 1-2.
[3] *Ky. Utils. Co. v. Pub. Serv. Comm'n*, 252 S.W. 2d 885, 890 (Ky. 1952); *In re Elec. Application of Ky. Power Co. for a Certificate of Pub. Convenience & Necessity to Build the Wooton-Stinnett Portion of the Hazard-Pineville 161 KV Line in Leslie Cty., Ky.*, Case No. 2022-00118 (Ky. P.S.C. 2022) at 16-17.
[4] *In re Elec. Application of Ky. Power Co. for a CPCN*, Case No. 2022-00118 (Ky. P.S.C. 2022) at 16 (quoting *Ky. Utils. Co. v. Pub. Serv. Comm'n*, 252 S.W. 2d at 890).
[5] *Id.* (quoting *Ky. Utils. Co. v. Pub. Serv. Comm'n*, 252 S.W. 2d at 890).

duplication requires showing that "a thorough review of all reasonable alternatives has been performed."[6] The proposal selected need not be the absolute least cost, but "[t]he fundamental principle of reasonable least-cost alternative is embedded in [the] analysis."[7]

By contrast, retirement proceedings are new: this is the first case in which the Commission will determine whether retirement is warranted under Kentucky's new structure for Commission approval of the retirement of fossil fuel-fired generating units. The procedure for retirement proceedings is provided in K.R.S. § 278.264. Section 278.262 is the definitional section for the retirement proceeding statute.[8] Because application of §§ 278.262 and 278.264 is an issue of first impression for the Commission, Sierra Club provides below arguments for how the Commission should interpret these statutory provisions, as well as how it should apply that statutory interpretation in this matter.

II. Statutory Interpretation of K.R.S. §§ 278.262 and 278.264 (SB4)

Because this is a case of first impression regarding K.R.S. §§ 278.262 and 278.264 ("retirement proceeding statutes"), it necessarily involves novel questions of statutory interpretation. Below we expand on the interpretation of specific statutory requirements in greater detail and, finally, on the bedrock grounding in fundamental principles of Kentucky utility regulation—affordability, reliability, and reasonableness—that is key to understanding and applying the retirement proceeding statutes. Fundamentally, the retirement proceeding statutes create a new proceeding that is the mirror image of a CPCN and reallocate decisional authority for retirement from the utilities alone to the Commission. But they are best understood as in line with, rather than a departure from, the ordinary analysis that the Commission regularly conducts to ensure that Kentucky utility customers benefit from just, reasonable, and affordable rates and reliable electricity.

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[6] *Id.*
[7] *Id.* at 16-17.
[8] These statutes have been colloquially referred to throughout these proceedings as "SB4," the bill number at the Kentucky legislature.

A. Section 278.264(2)(a): Replacement

Section 278.264(2)(a) requires that a utility demonstrate that it "will replace the retired electric generating unit with new electric generating capacity." Crucially, "replace[ment]" of a retired electric generating unit need not be 1:1—that is, megawatt for megawatt—under the statute. In other words, the retirement of a 400 MW unit (whether nameplate or discounted for ELCC-type purposes) need not be replaced with precisely 400 MW of equivalent generating capacity. This fact is evident from the statutory text.

Section 278.264(2)(a)(3) requires that replacement generating capacity "[m]aintains the minimum reserve capacity requirement established by the utility's reliability coordinator." If replacement capacity needed to be the same amount as the capacity of the retiring unit, this statutory requirement would be straightforwardly superfluous. That's because a replacement of equivalent capacity would always maintain the minimum reserve capacity requirement. In Kentucky statutory interpretation, "[a]ll parts of the statute must be given equal effect so that no part of the statute will become meaningless or ineffectual." *Ky. Dep't of Corr. v. Dixon*, 572 S.W. 3d 46, 49 (Ky. 2019) (quoting *Lewis v. Jackson Energy Co-op. Corp.*, 189 S.W. 3d 87, 92 (Ky. 2005); *see also Ky. Heritage Land Conservation Fund Bd. v. Louisville Gas & Elec. Co.*, 648 S.W. 3d 76, 86 (Ky. Ct. App. 2022) ("Under the principles of statutory interpretation, no subsection of a law should be interpreted so as to render it meaningless ....This Court cannot endorse an interpretation that simply ignores a portion of the statutory text."); *Travelers Indemnity Co. v. Armstrong*, 565 S.W. 3d 550, 563 (Ky. 2018) ("One of the most basic interpretative canons of statutory interpretation is that a statute should be construed so that effect is given to all its provisions, so that not part will be inoperative or superfluous, void or insignificant."). If replacement capacity needed to be 1:1 with retiring capacity, section 278.264(2)(a)(3) would be meaningless. Therefore, this cannot be the case.

Further, "replace[ment]" of a retired unit need not be with another fossil fuel-fired unit, as is likewise clear from the language of the statutory scheme. Section 278.264(2)(a) requires evidence that "[t]he utility will replace the retired *electric generating unit* with new electric generating *capacity*." *Id.* (emphasis added). The differential use of "electric generating unit" and "electric generating capacity" carries significance. Section 278.262(1) defines "electric generating unit" as "one (1) or more fossil fuel-fired combustion or steam generating sources used for generating electricity that deliver all or part of their power to the electric power grid for sale." In other words, "electric generating unit" is a defined term of art.

The statutory scheme does not, however, define "electric generating capacity." In the absence of such definition, "words of a statute [carry] their normal, ordinary, everyday meaning." *Stephenson v. Woodward*, 182 S.W. 3d 162, 170 (Ky. 2005). "Capacity" is possibly not an "everyday" word for most individuals, but it carries a "normal" and "ordinary" meaning in the public utility context. This is evident from the plain text of Section 278.264, which refers to "capacity" repeatedly. *E.g.*, K.R.S. § 278.264(4)(a) (requiring a Commission report on "the nameplate capacity" of electric generating units for which retirement was requested), § 278.264(4)(b)(3) (similarly requiring a Commission report on the effect of approved retirement on any "[n]eed for capacity additions or expansions"). Evaluation of "capacity" is also a familiar aspect of the Commission's decisions and orders, particularly in the CPCN context. In fact, an applicant for a CPCN must demonstrate that there Is not "an excess of capacity over need," in order to show "the absence of wasteful duplication."[9]

Crucially, unlike the term "electric generating unit" as defined in the statutory scheme, the word "capacity"—in its ordinary meaning, as regularly used in the public utility context—is not limited in application to fossil fuel-fired sources of generation. This is apparent both from Kentucky

[9] *See, e.g.*, *In re Elec. Application of E. Ky. Power Coop., Inc. for a (1) Certificate of Pub. Convenience & Necessity for the Constr. of Transmission Facilities in Madison Cty., Ky.; & (2) Declaratory Order Confirming that a Certificate of Pub. Convenience & Necessity Is Not Required for Certain Facilities*, No. 2022-00314, 2023 WL 2259498, at *5 (Feb. 23, 2023).

statute and from decisions of this Commission. K.R.S. § 278.466(1) refers to "the cumulative generating capacity of net metering systems." Under Kentucky law, net metering systems can only be solar, wind, biomass or biogas, or hydro generation. § 278.465(2)(b) (listing permissible electric generating facilities for net metering). None of these, obviously, are fossil fuel-fired generation—and yet Kentucky law contemplates them all as providing "generating capacity." Similarly, the Commission regularly discusses and refers to "capacity" with respect to non-fossil fuel-fired units.[10]

The use of the two different terms, "electric generating unit" with respect to retirements and "electric generating capacity" with respect to replacement capacity, therefore matters. *See Ky. Heritage Land Conservation Fund Bd.*, 648 S.W. 3d at 86 ("This Court cannot endorse an interpretation that simply ignores a portion of the statutory text."). Only one, "electric generating unit," is a term of art defined by statute as limited only to fossil fuel-fired generation. The requirement of replacement "generating capacity" broadly speaking, without any specification that it be fossil fuel-fired, must have statutory meaning. *See Farley v. P&P Construction, Inc.*, _ S.W. 3d _, 2023 WL 5444615 at *7 (Ky. 2023) (explaining that "we assume that the Legislature meant exactly what it said, and said exactly what it meant"). If the legislature intended to require replacement of fossil fuel-fired units with other fossil fuel-fired generation, it knew how to say so. *See Rubin v. Islamic Republic of Iran*, 138 S. Ct. 816, 826 (2018) (if Congress intended statute to rescind immunity, "it knew how to say so"); *Caraco Pharmaceutical Labs., Ltd. V. Novo Nordisk A/S*, 566 U.S. 399, 416 (2012) (where Congress used "not

[10] *E.g.*, *In re: Elec. App. of Big Rivers Elec. Corp. for Approval of Amend. To Power Purchase Agreement*, No. 2022-00296, 2023 WL 4405087, at *2 (June 13, 2023) ("the Commission approved a total of three solar contracts Under [one] PPA, BREC would receive all of the *capacity*, energy, ancillary services, and environmental attributes of a 160 MW solar facility" (emphasis added)); *In re: Elec. App. of Duke Energy KY., Inc. for an Order Declaring the Constr. of Solar Facilities Is an Ordinary Extension of Existing Sys. in the Usual Course of Bus.*, No. 2020-00385, 2021 WL 832938, at *5 (Mar. 1, 2021) (company "currently only has 7 MW of solar capacity," and "most recent IRP indicated a need for an additional 10 MW solar generation capacity annually"); *see also In re: Elec. 2019 Integrated Resource Plan of E. Ky. Power Coop., Inc.*, No. 2019-00096, 2020 WL 6948785 at *2 (Staff Report Appendix explaining that cooperative had "implemented a community solar project .... The facility has a capacity of 8.5 MW and consists of a 60-acre farm with 32,300 solar panels.").

any" construction in a different statutory subclause enacted simultaneously, "Congress knew how to say 'not any' when it meant 'not any'"). The statutory choice to require replacement with "electric generating capacity" broadly speaking, without any limit to fossil fuel-fired generation, means what it says—that replacement generating capacity under § 278.264 need not be provided by fossil fuel. *See id.* (holding that where unambiguous plain language did not limit the application of a deadline to certain circumstances, that deadline applied in all circumstances).

B. Section 278.264(2)(a)(1): Dispatchability

Section 278.264(2)(a)(1) requires that new electric generating capacity be "dispatchable by either the utility or the regional transmission organization or independent system operator responsible for balancing load within the utility's service area." A shorter version of this statutory provision—one that would not contain the level of specificity in the version that the legislature chose—is that the capacity must be dispatchable by the grid operator. As the U.S. Department of Energy explains:

> One key player [in the reliable provision of electricity to customers] is the balancing authority, which manages the operation of the electric system within a specific geographic area. There are more than 60 balancing authorities in the U.S., and they are typically either utilities, Power Marketing Administrations (PMAs),[11] or a group of utilities that have formed regional entities called regional transmission organizations (RTOs) and independent system operators (ISOs). [¶] A balancing authority ensures that power system demand and supply are always balanced, which maintains safe and reliable operation of the power system. . . . Balancing authorities function as grid operators that dispatch electric generators to provide reliable power at the lowest cost. Because each generator has differing variable costs, generation is dispatched using the least costly generator first, in a way that is consistent with the relevant constraints of the transmission system and reliability requirements. Traditional utilities that are balancing authorities manage economic dispatch within their service areas, while ISOs and RTOs determine economic dispatch using bid-based markets where buyers and sellers bid for or offer generation.[12]

[11] PMAs are federal entities that sell power generated by hydroelectric dams that are federally owned and operated. U.S. Dep't of Energy, Office of Enterprise Assessments, *Power Marketing Administrations*, https://www.energy.gov/ea/power-marketing-administrations.

[12] U.S. Dep't of Energy, Office of Cyber Security, Energy Security, & Emergency Response, *How It Works: The Role of a Balancing Authority*, https://www.energy.gov/sites/default/files/2023-08/Balancing%20Authority%20Backgrounder_2022-Formatted_041723_508.pdf.

In other words, a utility, a regional transmission organization, or an independent system operator may perform the role of the balancing authority—the entity that operates the grid in a particular area. With this basic backdrop of the United States electric system in mind, it is clear that, in § 278.264(2)(a)(1), "responsible for balancing load within the utility's service area" modifies the entire phrase "either the utility or the regional transmission organization or independent system operator." The statutory provision specifically lists the different entities that may operate the grid—clarity that makes sense in a state with multiple RTOs, and in which the largest utility is not part of an RTO. But at bottom, the statute means "dispatchable by the entity doing the dispatching"—whichever entity that is among the various options for various Kentucky utilities.

The Commission may consider these basic facts about how the electric grid operates in interpreting the dispatchability requirement. In statutory interpretation, courts and administrative bodies may take notice of "legislative facts"—that is, facts that "do not usually concern the immediate parties but are general facts which help the tribunal decide questions of law and policy and discretion." *McKinstry v. Wells*, 548 S.W. 2d 169, 173 (Ky. Ct. App. 1977); *see also* Fed. Prac. & Procedure (Wright & Miller) § 5103.2. As the Kentucky Supreme Court has explained, "the court is not required to act in a vacuum when determining the purpose of legislation" and "may take judicial notice of the historical settings and conditions out of which the legislation was enacted." *Commonwealth v. Howard*, 969 S.W. 2d 700, 705 (Ky. 1998). Courts are "entitled to recognize matters of common knowledge, and to give consideration to contemporaneous circumstances throwing light on the legislature's intent." *Hamilton v. Int'l Union of Operating Eng'rs*, 262 S.W. 2d 695, 699 (Ky. Ct. App. 1953). For example, the Kentucky Supreme Court has taken notice of Kentucky's high rate of teenage deaths in car accidents, *Howard*, 969 S.W. 2d at 705, and that "alcohol (or other substances) *may* impair driving ability," *Bridges v. Commonwealth*, 845 S.W. 2d 541, 542 (Ky. 1993).

The Commission Chair noted that the meaning of dispatchability with respect to utility, balancing authority, and RTO had been "equated" in witness observations, and observed that "it may be a question of law, whether that makes a difference as to the definition and determination of dispatchability."[13] Because this is a question of statutory interpretation, rather than a question contingent on the application of the specific facts of this case, it is the type of "question of law" where the Commission and any reviewing court can take notice of the underlying backdrop of ordinary electric grid practices against which the Legislature enacted the statute. In that context, it is clear that the dispatchability requirement applies equally to whichever entity is "responsible for balancing load within the utility's service area." § 278.264(2)(a)(1). As a result, behind the meter systems, such as distributed solar generation at residences, would not fall within § 278.264(2)(a)(1) because they do not create generation that is dispatchable in the broader electric grid. But generation that *is* dispatchable in the broader grid by the grid operator fits the criterion of § 278.264(2)(a)(1). It does not matter whether that grid operator is a utility or an RTO—the question is merely whether that generation can be dispatched by that grid operator, whatever entity it may be.

Sierra Club agrees with Joint Intervenor Witness Wilson's definition of dispatchability to encompass storage resources, including batteries.[14] With that caveat, Sierra Club agrees with a definition of dispatchability as "capable of following dispatch instructions between economic minimum and economic maximum when (i) the . . . unit is physically capable of producing electricity and (ii) the unit's power source is available."[15]

C. Section 278.264(2)(a)(2): Reliability and Resilience

Section 278.264(2)(a)(2) requires that replacement capacity "[m]aintains or improves the reliability and resilience of the electric transmission grid." For purposes of § 278.264, the statutory

[13] Hr. Video (Aug. 29, 2023) at 8:05:50 (16:28:45 PM).
[14] John Wilson Dir. Test. at 6:4-21.
[15] Case No. 2023-00122, Stuart A. Wilson Dir. Test., Exh. SB4-1 at 11 (with removal of the word "generating" from (i) to encompass battery storage).

scheme defines "reliability" as "having adequate electric generation capacity to safely deliver electric generation in the quantity, with the quality, and at a time that the utility customers demand." § 278.262(2). In other words, reliability is established at a threshold minimum: the grid has reliability or is reliable where it has adequate electric generating capacity to meet demand as needed. An unreliable grid does not have adequate capacity to do so. "Resilience," under the statutory scheme, "means having the ability to quickly and effectively respond to and recover from events that compromise grid reliability." § 278.262(3). Like reliability, resilience has a threshold minimum: the grid has resilience or is resilient where it can quickly and effectively deal with events compromising grid reliability. An unreliable grid cannot quickly and effectively deal with such events. It is possible to speak of more reliable or less reliable electric grids, or more resilient or less resilient. But the grid either crosses the thresholds of reliability and resilience as defined in § 278.262—it has the qualities provided for in statute, or in other words meets the statutory requirements—or it does not. Both reliability and resilience have a minimum or binary character due to the language of the definitions in § 278.262. A utility's grid is reliable and resilient, or it is not. Another way of putting it: A grid may be *more* reliable or resilient—say an A+ grid versus a C—but to be called reliable or resilient at all, it must obtain a passing grade by meeting the minimum provided for in the statutory definition.

At the hearing in this matter, the Commission Chair asked whether, if the Companies create a more reliable system, "Doesn't that effectively raise the bar" from the Companies' target LOLE to any new actual LOLE that is more reliable than the target LOLE, with respect to reliability and resilience in § 278.264?[16] The Commission Chair asked whether the new, actual LOLE emerging from the case would be "the new reliability bar that you have to meet going forward for retirements."[17] Because of the way that the statutory definitions in § 278.262 create a pass-or-flunk

[16] Hr. Video (Aug. 22, 2023) at 9:17:00 (6:18 PM) (Commission Chair questioning of Mr. Bellar).
[17] *Id.*

system for reliability and resilience, the answer to that question is no. The baseline is the minimum of reliability and resilience as defined in § 278.262. For example, typically utilities use a one-in-ten standard for LOLE.[18] If the Commission agrees that one-in-ten is the appropriate standard for reliability, then "maintains reliability" means that the utility continues to meet that standard. This interpretation also avoids the absurd result of a utility being required to pile on ever greater reliability and resilience, regardless of how closely the utility approaches perfection. "A statute should not be interpreted so as to bring about an absurd or unreasonable result." *Ky. Indus. Util. Customers, Inc. v. Ky. Utils. Co.*, 983 S.W. 2d 493, 500 (Ky. 1998). And, relatedly, it guards against disincentivizing utilities from seeking the greatest possible reliability: if a utility knew that building to an extremely reliable LOLE standard would require it to always build to that standard in future, it might opt for a less reliable LOLE to avoid being locked in to a very high (possibly even impracticable) standard for the long term.

Two final important points: First, "adequate" capacity for reliability purposes cannot possibly mean capacity that will certainly, no question, be sufficient for customers in all possible circumstances. As was discussed extensively throughout these proceedings, utility planning is an inherently probabilistic endeavor that involves some degree of risk. The automobile industry provides a good analogy in this context. No car manufacturer or governmental vehicle regulator can guarantee that an accident will pose *no* risk to vehicle occupants. The same is true in the medical field: no surgeon can guarantee no complications, and no pharmacist can guarantee no side effects from a drug. But governmental regulation minimizes those harms to the extent practicable by determining the acceptable boundaries of risk. Just so for utility planning and utility regulation. It is impossible to guarantee that LG&E/KU's plants will not experience generation failures due to a tornado outbreak or extreme flooding, for example. And it is likely—in fact, virtually guaranteed—

[18] Levitt Dir. Test. 14:167-168.

that units will malfunction for mechanical or other reasons at some point. As LG&E/KU Witness Bellar explained in these proceedings, "When we design our system, we don't expect every unit to operate perfectly 8,760 hours a year."[19] Inherent in the LOLE analysis that utilities perform is the underlying idea of risk: that there will be a loss of load event on exceedingly rare occasions.[20] The reliability and resilience requirements in § 278.262 therefore cannot be perfect guarantees—that would be impossible.

Second, and relatedly, the reliability and resilience requirements are a mechanism of shifting responsibility for reliability regulation in the context of fossil fuel-fired unit retirements from the utility to the Commission. As described in greater detail *infra*, the key function of the new retirement proceeding is to provide a regulatory check on utilities' retirement decisions. As in other aspects of utility planning, the Commission is now the decisionmaker as to what constitutes adequate reliability and resilience—meeting the statutory thresholds such that retirement is permissible. LG&E/KU's understanding of the regulatory baseline, as expressed at the hearing, is inaccurate. In the Companies' view, the baseline for assessing compliance with reliability and resilience in § 278.264 is the Companies' current system, and the new law asks whether the Companies are dropping below that existing baseline.[21] This interpretation, however, is not supported by the statutory definitions in § 278.262, which make no reference to the utilities' preexisting levels of reliability and resilience. Instead, these definitions focus on objective standards assessable by neutral criteria and a disinterested observer. At best, the language of § 278.264(2)(a)(2)—which requires that new capacity

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[19] Hr. Video (Aug. 22, 2023) at 5:52:39 (2:45 PM) (Sierra Club cross-examination of Mr. Bellar); *see also* Hr. Video (Aug. 23, 2023) at 6:10:00 (2:25 PM) (Sierra Club cross-examination of Mr. Stuart Wilson) ("We manage a portfolio of generating units . . . no one I don't think expects them all to operate perfectly........In fact almost every day you're going to have minor issues, at least, with units in your generation portfolio.").
[20] *See* Hr. Video (Aug. 29, 2023) at 2:41:00 (Commission Chair questioning of Mr. Levitt) (describing the meaning of various LOLEs in light of the PJM clearing price).
[21] Hr. Video (Aug. 22, 2023) at 9:17:00 (6:08 PM) (Commission Chair questioning of Mr. Bellar).

"maintains or improves the reliability and resilience of the electric transmission grid"—assumes, in the word "maintains," that the utilities already cross the threshold of reliability and resilience.

Given the function of the new proceeding in reallocating retirement decisional authority from the utilities to the Commission, it would be surprising if the reliability and resilience requirement rested ultimately on a threshold set by the utilities themselves. The plain language of the statute demonstrates the contrary: that reliability and resilience are objective requirements outside of the utilities. It is consistent with the statute that whether a utility meets requisite minimum reliability and resilience requirements is determined not by the utility but by the Commission.

1. *Loss of Load Expectation, Not Reserve Margin, As Reliability Standard*

Sierra Club urges the Commission to adopt loss of load expectation ("LOLE"), not the reserve margin, as the appropriate reliability standard. LOLE is a straightforward reliability standard that is regularly used by NERC.[22] Reserve margin is then typically, but not always, derived from LOLE.[23]

There are key advantages to using the objective LOLE standard rather than the reserve margin as the determination of system reliability. First, LOLE is a more standardized metric with a more objective threshold: ordinarily, it is set at a one-in-ten standard as a sort of industry-accepted best practice.[24] Second, and relatedly, LOLE can be measured and is a function of the properties of units. Even where reserve margin depends on LOLE, it involves an additional interpretive step, of translating LOLE to the amount of excess capacity needed. And a reserve margin used by a utility

[22] *See* Levitt Dir. Test. at 14:173-174.
[23] Levitt Dir. Test. at 14:167-170 (explaining that "[t]arget reserve margins in the United States are commonly set to yield a modeled LOLE metric of 1-in-10" and that "when different regions target the same reliability metric, the resulting reserve margins can differ significantly based on the circumstances").
[24] Levitt Dir. Test. at 14:167-168 & n.23.

does not necessarily depend on, or depend solely on, LOLE. In this proceeding, LG&E/KU has put forward a range of possible reserve margins: a reserve margin predicated on a one-in-ten loss of load expectation (updated later in these proceedings), a reserve margin predicated on economics, and a third reserve margin used in planning.[25]

In other words, reserve margin requires a judgment call by the utility or system operator, and it is discretionarily set (pursuant to that judgment call) by the utility or system operator. Setting the reliability standard as meeting the utility's reserve margin, rather than making it an objective metric outside the utility's discretion, therefore risks making the reliability standard a paper tiger. It is also more commensurate with the statutory language and with the purpose of the retirement proceeding—Commission determination as to whether reliability will in fact be maintained or improved by retirement—to adopt an objective standard outside the utility's judgment. *See* § 278.262(2) (definition of reliability); § 278.264(2)(a)(2) (Commission's reliability determination in retirement proceedings).

D. Section 278.264(2)(a)(3): Minimum Reserve Capacity

Section 278.264(2)(a)(3) requires that the new replacement generation "maintains the minimum reserve capacity requirement established by the utility's reliability coordinator." "Reliability coordinator" appears in no other Kentucky statute. It is a term of art in the public utility context: utilities have "reliability coordinators" that perform "reliability coordination services." The 2006 Commission order that authorized LG&E/KU to withdraw from MISO discussed the role of the reliability coordinator, which is certified by the North American Electric Reliability Corporation. In that case, LG&E/KU explained to the Commission the Companies' plans for reliability coordination on exiting MISO:

> LG&E and KU state that upon exiting MISO they will operate their transmission system in accordance with the requirements specified in applicable ECAR documents and the NERC Operating Manual. They assert that any NERC-certified reliability coordinator, not just

[25] *See* Levitt Dir. Test. 18:239-249, Table 5, and 28:386-389.

> MISO, is required to have a 'wide area view' of its reliability coordination area and of those areas surrounding it. NERC standards also require reliability coordinators to have agreements in place to direct generation redispatch, transmission reconfiguration, or reduce load to return the transmission system to a reliable state........ At all times, according to LG&E and KU, they will have the services of a NERC-certified reliability coordinator . . . . LG&E and KU contend that the Commission can have confidence that their reliability will not suffer if they exit MISO and choose to contract with another reliability coordinator.[26]

Upon exiting MISO, LG&E/KU contracted with TVA as the Companies' reliability coordinator.[27] TVA remains LG&E/KU's reliability coordinator.[28] PJM, TVA, and MISO all function as reliability coordinators.[29] EKPC's emergency procedures, appended to a settlement agreement before the Commission in 2009, provide further detail on the role of the reliability coordinator and its interaction with the balancing authority:

> The Balancing Authority and the Reliability Coordinator have the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its respective area and to exercise specific authority to alleviate capacity and energy emergencies. . . . The Balancing Authority experiencing an operating capacity or energy emergency will communicate its current and future system conditions to the Reliability Coordinator and neighboring Balancing Authorities. A Balancing Coordinator that has any Balancing Authority within its Reliability Coordinator Area experiencing a potential or actual Energy Emergency will initiate an Energy Emergency Alert......... The Reliability Coordinator will act to mitigate the emergency condition, including a request for emergency assistance if required.[30]

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[26] *In the Matter of: Investigation into the Membership of Louisville Gas & Elec. Co. & Ky. Utils. Co. in the Midwest Independent Transmission Sys. Operator, Inc.*, No. 2003-00266, 2006 WL 1685839 (Ky. P.S.C. 2006).
[27] *Id.* n. 15.
[28] *See* LG&E/KU Response to Sierra Club Question No. 3-4(a), Attachment (Amended and Restated Reliability Coordinator Agreement Between Louisville Gas & Elec. Co. & Ky. Utils. Co. & Tenn. Valley Authority).
[29] *See In the Matter of: App. of E. Ky. Power Cooperative, Inc. to Transfer Functional Control of Certain Transmission Facilities to PJM Interconnection, LLC*, No. 2012-00169, 2012 WL 6705962 (Ky. P.S.C. 2012) (Appendix, Art. 4, § 4.3).
[30] *In re E. Ky. Power Cooperative, Inc.*, No. 2008-00409, 2009 WL 1034507 (Ky. P.S.C. 2009) (Appendix, Exh. 2, EKPC Emergency Electric Procedures). At the time, before joining PJM, EKPC contracted with TVA as its reliability coordinator—as LG&E/KU does now. This description of the Balancing Authority and Reliability Coordinator functions references EOP-011-1, a NERC reliability standard that also applies to LG&E's relationship with TVA. *See* LG&E/KU Response to Joint Intervenors Question No. 4-4(b).

To reiterate, as is evident from these descriptions and from LG&E/KU's contract with TVA for reliability coordination services, "reliability coordinator" is a term of art or technical term used within the public utility industry to refer to an entity that takes on specific reliability coordination functions for a particular utility.

Technical terms in Kentucky statutes are given their technical meaning: "[T]echnical words and phrases . . . shall be construed according to such meaning." K.R.S. § 446.080(4); *see also City of Fort Wright v. Bd. of Trustees of Ky. Retirement Sys.*, 635 S.W.3d 37 (Ky. 2021) ("We interpret statutory terms based upon their common and ordinary meaning, *unless they are technical terms*." (quoting *Maupin v. Tankersley*, 540 S.W. 3d 357, 359 (Ky. 2018)) (emphasis added)). Accordingly, "reliability coordinator" in § 278.264(2)(a)(3) should be interpreted in accordance with its technical definition, to mean the entity performing "reliability coordinator" functions for a utility. For LG&E/KU, that is TVA.

With "reliability coordinator" established, the next interpretive question prompted by § 278.264(2)(a)(3) is how to determine the "minimum reserve capacity requirement established by the reliability coordinator." Joint Intervenors Witness John Wilson states, "It is unclear how this portion of the statute might be implemented if the utility's reliability coordinator does not have a minimum reserve capacity requirement."[31] There are two interpretive possibilities for the meaning of "minimum reserve capacity requirement": the "target reserve margin" set by the utility, and the "contingency reserve requirement" set in this case by LG&E/KU's "participation requirements in their Contingency Reserve Sharing Group."[32] In context, the best interpretation is that "minimum reserve capacity requirements' means "contingency reserve requirement." This interpretation

[31] John D. Wilson Dir. Test. at 26:22-27:2.
[32] *See* LG&E/KU Response to Sierra Club Question No. 2-15(e)-(f); LG&E/KU Response to Commission Staff Post-Hearing Data Request No. 14, Attachment ("TEE Contingency Reserve Sharing Group Agreement").

implicates the reliability coordinator function; it is more consistent with the language "minimum reserve capacity requirement," particularly in the context of the statute as a whole; and it does not lead to the absurd result of a utility being able to nullify this section of the statute by setting the reserve margin at whatever the utility wants it to be.

First, the legislature's use of "reliability coordinator" in the statute must carry weight. As discussed above, technical words and phrases of a statute are construed according to their meaning, and statutes are read to prevent any part from becoming meaningless or superfluous. If the target reserve margin—in which the utility or regional transmission organization plays a role, but in which the reliability coordinator plainly does not—were the relevant measure, the words "reliability coordinator" would be superfluous, contrary to interpretive principles. Additionally, if the legislature intended to say "utility" or "utility or the regional transmission organization or independent system operator"—the actors who set the target reserve margin—it knew how to do so. It used that exact phrase in § 268.264(a)(1). The use of "reliability coordinator" must have meaning. And a reliability coordinator's function only relates to a contingency reserve requirement—not to setting the target reserve margin. This is evident from LG&E/KU's discovery responses.[33]

Second, the phrase "minimum reserve capacity requirement" is more consistent with a "contingency reserve requirement" than with a "target reserve margin"—especially when juxtaposed with other statutory specification for new generation capacity. The use of "minimum" and "requirement" in both connotes an externally set floor, which is what a contingency reserve requirement is—not a "target" that a utility strives for. Further, the requirement that the new generating capacity also "[m]aintains or improves the reliability and resilience of the electric transmission grid" indicates that the next requirement in the statutory list, the "minimum reserve

[33] *Id.* (describing annual update of contingency reserve requirement and explaining, by contrast, that "[i]f by 'minimum reserve capacity' the question refers to summer and winter reserve margins, SERC and the Reliability Coordinator (TVA) play no role").

capacity requirement," is distinct from generic reliability considerations. The target reserve margin is set by the utility or regional transmission organization to promote reliability. But the contingency reserve requirement is a distinct obligation for the utility, separate and apart from general reliability considerations—as is evident from the fact that it is externally set due to commitments related to the reliability coordination function. It is more plausible that, separate from generic reliability considerations, the Kentucky legislature sought to ensure via a specific statutory requirement that Kentucky utilities would always meet those minimum requirements. That is particularly true in the context of the law's passage shortly after Winter Storm Elliott and the legislature's accompanying concern regarding future severe weather events.

Third, reading "minimum reserve capacity requirement" as "target reserve margin" would lead to an absurd result: the statutory text of § 278.264(2)(a)(3) would be functionally meaningless. This is because absent RTO membership a utility such as LG&E/KU controls the setting of its target reserve margin. If "minimum reserve capacity requirement" meant a requirement set by the utility, the utility could attempt to obviate § 278.264(2)(a)(3) by setting a very low target reserve margin that it knew it could reach. It's no answer to say that many utilities in Kentucky can't do this, because they are part of RTOs. LG&E/KU is the largest utility in the state. The legislature was surely aware of its existence and structure when it drafted the law. It is implausible that the legislature intended to render this statutory section a nullity by handing the keys for "minimum reserve capacity requirement" over to the utility if not part of an RTO—particularly since the point of the statute is to constrain utility discretion. This kind of unreasonable or absurd result is impermissible as a matter of statutory interpretation: "A statute should not be interpreted so as to bring about an absurd or unreasonable result." *Ky. Indus. Util. Customers, Inc. v. Ky. Utils. Co.*, 983 S.W. 2d 493, 500 (Ky. 1998).

Thus, at first blush "maintains the minimum reserve capacity requirement established by the utility's reliability coordinator" may *appear* ambiguous, as it did for Witness John Wilson (a non-lawyer). But in fact, for all these reasons—the technical meaning of "reliability coordinator," the meaning of "minimum reserve capacity requirement" in statutory context, and the avoidance of absurdity of results—application of the plain terms of the statute and logic demonstrates that in fact its meaning is plain. "Minimum reserve capacity requirement" means "contingency reserve requirement"—not "target reserve margin." For LG&E/KU, for example, that requirement is the Companies' share of the contingency reserves obligation within the TEE Contingency Reserve Sharing Group. The overall contingency reserves obligation is equal to the most severe single contingency, and LG&E/KU's share is determined by prorating the Companies' "coincident peak load MW amount for the preceding calendar year against the sum of the coincident peak load levels for each" member of the reserve sharing group "for the same year."[34] In 2009, for instance, the most severe single contingency was 1,270 MW, and LG&E/KU's share of the 1,270-MW contingency reserve was 201 MW.[35] Currently, LG&E/KU must carry 243 MW as its share of the most severe single contingency in the reserve sharing group.[36] For utilities that are not part of a reserve sharing agreement, NERC requires the maintenance of a level of contingency reserves equal to the most severe single contingency—and that is what "minimum reserve capacity requirement" would mean for any such utilities in Kentucky.[37]

E. Section 278.264(2)(b): No Harm to Utility Ratepayers

[34] LG&E/KU Response to Commission Staff Post-Hearing Data Request No. 14, Attachment, at 37.
[35] *Id.* at 54.
[36] Exh. SAW-1 (May 2023 update) at D-19-20. LG&E/KU sometimes refers to these reserves as "spinning reserves." Hr. Video (Aug. 22, 2023) at 10:01:00 (6:53 PM) (Commission Chair questioning of Mr. Bellar) (Mr. Bellar clarifying that "spinning reserves" are equal to the utility's share of the most severe single contingency for the reserve sharing group).
[37] Hr. Video (Aug. 22, 2023) at 10:01:30 (6:53 PM) (Commission Chair questioning of Mr. Bellar).

Section 278.264(2)(b) requires that the utility show that "[t]he 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." Sierra Club agrees with LG&E/KU that this provision may be satisfied by analysis of the present value of revenue requirements ("PVRR"). As Joint Intervenor Witness John Wilson notes, this interpretation is consistent with "the standard that has been applied in CPCN cases."[38]

F. Section 278.264(2)(c): Decision to Retire Is Not Result of Financial Incentives or Benefits Offered by Any Federal Agency

The requirement in Section 278.264(2)(c) that the retirement decision "is not the result of any financial incentives or benefits offered by any federal agency" implicates straightforward principles of legal causation. This provision does not bar the Commission from taking into account financial incentives or benefits regarding the specific type of replacement capacity. Instead, the question is whether the decision *to retire the unit*—the decision at issue in the retirement proceeding—is the *result* of federal financial incentives or benefits. The question of *which* replacement capacity is chosen is a separate question, the subject of the CPCN proceeding.

Further, a decision to retire the unit as the result of federal environmental regulation is different and does not trigger a bar on retirement pursuant to § 278.264(2)(c). This is because in economic terms, an environmental regulation is a stick, and Section 278.264(2)(c) only applies to carrots. This distinction is apparent, first, from the plain language of § 278.264(2)(c). An environmental regulation is a burden placed on the unit that either makes it less economic or bars the unit's operation altogether. That is not an "incentive" or "benefit," which are positive inducements to action. Moreover, the requirement that retirement decisions not be due to federal financial incentives must be read next to the no harm to ratepayers requirement. *See, e.g.*, *Lewis v.*

[38] John Wilson Dir. Test. at 28:12-13.

Jackson Energy Co-op Corp., 189 S.W. 3d 87, 92 (Ky. 2005) (directing that "the statute must be read as a whole"). The no harm to ratepayers requirement asks whether incremental costs "could be avoided by continuing to operate the electric generating unit proposed for retirement *in compliance with applicable law*." § 278.264(2)(b) (emphasis added). Unsurprisingly, the no harm to ratepayers requirement takes as a given that the unit must operate against the backdrop of "applicable law"—which, of course, includes federal environmental regulation. The choice to include this specific language in the preceding statutory subsection, evaluating the viability of the unit's continued operation under legal constraints, indicates that this subsection is not directing the Commission to ignore those same legal constraints.

Finally, Sierra Club agrees with LG&E/KU that federal tax credits "must be included in any reasonable PVRR analysis to appropriately reflect the cost of such generation supply alternatives" and that "[i]t would be unreasonable and unfair to customers to have such benefits eliminated from consideration when evaluating generation units."[39] It is neither practicable nor consistent with Kentucky utility regulation's deep-rooted commitment to affordability and reasonable rates to fail to take into account the entirety of the financial landscape in evaluating the long-term economic viability of various portfolios. *See* § 278.030(1) (utilities may collect only "fair, just and reasonable rates").

Joint Intervenor Witness John Wilson's efforts to evaluate the economics of various portfolios shows the impracticability of attempting to entirely disentangle the economics of federal financial incentives from economic analysis. As Witness Wilson points out, "There are several tax benefits that incentivize the use of coal by the Companies."[40] This includes federal excess depletion tax benefit that benefits mining companies.[41] The Companies do not know "[w]hether such tax

[39] Case No. 2023-122, Exh. SB4-1 at 21.
[40] John Wilson Dir. Test. 38:18.
[41] John Wilson Dir. Test. 39:4.

benefits are included in the price of fuel purchased by the Companies."[42] Thus, it is impossible to determine the extent to which this federal financial incentive affects the retirement decision. The same is true for tax benefits related to solar PPAs, for evaluating the economics of PPAs as compared to other sources of generation.[43] The analysis becomes even more tangled when Witness Wilson attempts to ascertain whether the economic value of avoided capacity in PJM derives, in an attenuated manner, from federal financial incentives. Witness Wilson assesses that "[i]t is impossible to analyze this question quantitatively due to the complexity of the PJM market."[44]

It is telling that the preceding statutory subsection, the no harm to ratepayers requirement, does *not* direct utilities to strip all federal financial incentives out of the economic analysis of incremental costs. Rather, the requirement that the retirement decision not be due to federal financial incentives is a *separate* statutory subsection. This drafting distinction indicates that LG&E/KU is correct, and that utilities need not strip out federal tax credits in their analyses—or undertake herculean efforts to attempt to disentangle the many ways that federal tax policies and federal incentives may affect the economics of utility regulation, however attenuated.

This approach is also consistent with basic principles of legal causation implicated by the question whether the retirement decision is the "result" of federal financial incentives. As the Kentucky Supreme Court recently explained, and as is a fundamental tenet of tort analysis:

> Causation consists of two distinct components: 'but-for' causation, also referred to as causation in fact, and proximate causation. 'Literally speaking there can never be only one 'cause' of any result. Every cause is a collection of many factors, some identifiable and others not, all determined by prior events ....' But-for causation requires the existence of a direct, distinct, and identifiable nexus ...... such that the event would not have occurred 'but for' the defendant's negligent or wrongful conduct in breach of duty. .... Proximate causation captures the notion that....... [conduct] is nevertheless too attenuated from the damages in time, place, or foreseeability to reasonably impose liability upon the defendant.

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[42] John Wilson Dir. Test. 39:4-6 (quoting LG&E/KU Resp. to Joint Intervenors Question No. 3-9(b)(iv), (v)).
[43] John Wilson Dir. Test. 39:4-6.
[44] John Wilson Dir. Test. 45:15-16.

Patton v. Bickford, 529 S.W. 3d 717, 730-31 (Ky. 2016). Attempting to directionally quantify all federal financial incentives and their influence on a retirement decision, no matter how attenuated, would be impracticable and inconsistent with Kentucky utility regulation's concern with the economics of decisions for ratepayers. Moreover, "a direct, distinct, and identifiable nexus" to the *retirement decision itself* is necessary. And as LG&E/KU points out, federal tax credits "inure completely to the benefit of customers."[45] Incorporating them into the economic analysis of retirement and/or replacement generation, alone—rather than having "a direct, distinct, and identifiable nexus" to the retirement decision—certainly cannot be sufficient for either but-for or proximate causation.

The best understanding of § 278.264(2)(c) in statutory context, in light of the underlying principles of affordability and reliability that guide Kentucky public utility regulation and basic legal tenets, is that federal financial incentives cannot be the "but-for" cause of retirement decisions: no direct causation. But attenuated effects of federal policies are not enough to trigger the bar.

G. Section 278.264(3): All Known Direct or Indirect Costs

Section 278.264(3) requires that the utility "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." Sierra Club urges the Commission, in analyzing this provision and the resulting cost savings to customers, to take into account evidence of cost savings due to the effect of retirement on customers' health. Quantified evidence of cost savings due to health benefits has not been provided in these proceedings.[46] Nevertheless, the Companies agree that retiring the coal-fired units would benefit air quality, that "better air quality has public health benefits," and that "those public health benefits also have economic benefits."[47] The Companies further recognize that "there are folks who try to make

[45] Exh. SB4-1 at 21
[46] *See* Hr. Video (Aug. 28, 2023) at 3:19:00 (1:27 PM) (Sierra Club cross-examination of Mr. Sinclair).
[47] Hr. Video (Aug. 28, 2023) at 3:18:00 (1:26 PM) (Sierra Club cross-examination of Mr. Sinclair).

those estimates" as to those economic benefits.[48] Directionally speaking, in these proceedings these cost savings counsel toward retirement of Brown 3, Ghent 2, and Mill Creek 1 and 2. More broadly, the Commission should make clear in this case of first impression that economic benefits due to improvements in public health from retirement are a cost saving for customers to be taken into account in the cost savings analysis.

H. Statutory Backdrop of Basic Utility Regulatory Principles

Fundamentally, the Commission's interpretation of § 278.264 does not take place in a vacuum. *See Howard*, 969 S.W. 2d at 705. In addition to the statutory interpretation principles already discussed, the Commission must interpret § 278.264 against the backdrop of longstanding principles enshrined in Kentucky public utility law: that utilities may only charge "fair, just and reasonable rates" and that "[e]very utility shall furnish adequate, efficient and reasonable service." § 278.030(1)-(2). There is no indication that the legislature intended to displace these basic tenets of public utility law in passing what is now § 278.264. To the contrary, the language of § 278.264 evinces concern for ensuring that Kentucky utility customers' rates are "fair, just and reasonable." Section 278.264(2)(b) requires a demonstration that there will be no "net incremental costs" as a result of the retirement "that could be avoided" and that will "harm the utility's ratepayers." Section 278.264(3) requires a showing "that cost savings will result to customers as a result of the retirement." And similarly, the statutory language shows a commitment to "adequate, efficient and reasonable service" not only in the requirement to demonstrate cost savings but also in the need to show that new capacity "maintains or improves the reliability and resilience of the electric transmission grid" and "[m]aintains the minimum reserve capacity requirement." § 278.264(2)(a)(2)-(3).

In other words, Section 278.264 is an outgrowth of, not a sea change in, the substance of Kentucky utility regulation. Its underlying commitments to reasonable and affordable rates and to a

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[48] *Id.*

reliable electric grid are longstanding mainstays of this vertically integrated state. *See, e.g.*, *Ky. Utils. Co. v. Pub. Serv. Comm'n*, 252 S.W. 2d 885 (Ky. 1952). Instead of changing substance, Section 278.264 changes Kentucky law by establishing a new *procedure*—requiring that the Commission verify that the retirement of certain generating units, those that are fossil fuel-fired, will in fact contribute to affordability and reliability. Previously, the Commission set depreciation schedules based on anticipated retirement dates, pursuant to the affordability, reliability, and reasonableness requirements in Kentucky law. But the ultimate retirement decision was up to "the discretion" of the utility.[49]

In removing that retirement discretion from the utility and instead requiring Commission approval, the Kentucky legislature has essentially created a new proceeding that is the mirror image of a CPCN proceeding. This new statute provides an additional layer of regulation of retirements, just as new investment decisions are regulated. The statute regarding retirements provides more statutory detail as to the Commission's decision-making parameters than the CPCN statute; for CPCNs, court opinions rather than the words of the statute constrain and guide the Commission's decision-making. *Compare* § 278.264(2) *with, e.g.*, *Ky Utils. Co.*, 252 S.W. 2d at 890 (setting the standard for "public convenience and necessity" as "a need for service" and "absence of wasteful duplication"). But the fundamental touchstones of the Commission's decisionmaking—which were already essential to setting depreciation schedules—are not different than in the Commission's other proceedings. The key question before the Commission in approving the retirement of fossil fuel-

[49] *E.g.*, *In re Electronic App. of Louisville Gas & Elec. Co. 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 & Acct. Treatments, & Establishment of a One-Year Surcharge*, No. 2020-00350 (Ky. P.S.C. June 30, 2021) ("The Commission finds that although LG&E has the discretion to determine when a generation unit should be retired, it is the Commission that is vested with the authority to determine the ratemaking treatment resulting from that retirement decision.").

fired generating units, as for approving new construction, is how best to ensure affordable, reliable, and reasonable utility service for Kentuckians.

III. Failure to Retire Mill Creek 1 and 2, Ghent 2, and Brown 3 Will Harm LG&E/KU Customers, Because Continued Operation Is Not Economically or Legally Viable.

The record makes clear that the continued operation of Mill Creek 1 and 2, Ghent 2, and E.W. Brown 3 is not economically or legally viable. EPA's Good Neighbor Plan 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 installs selective catalytic reduction ("SCR") equipment at each of the units or obtains sufficient nitrogen oxide ("NOx") emission credits to reduce its emissions by approximately 80%.[50] SCRs have significant capital costs: $110 million for each of the Mill Creek units and $126 million for Ghent 2.[51] Although not required to install new pollution control technology under the Good Neighbor Plan, E.W. Brown 3 is already "the Companies' coal unit with the highest operating costs and will require a $26 million overhaul in 2027 to operate safely beyond 2028."[52]

In response to those impending costs, the Companies evaluated nine different replacement or retrofit portfolios, under varying fuel price forecasts and three net carbon dioxide ("CO_2") compliance costs.[53] In all but one of those scenarios (the "high gas," "zero CO_2 price" future), retiring Mill Creek 1 and 2, Ghent 2, and E.W. Brown 3, rather than continuing to make capital investments in those resources was the least-cost option for Kentucky ratepayers.[54] And even in that high gas, zero carbon price scenario, retrofitting Ghent 2 was only slightly more favorable than

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[50] LG&E/KU Ex. SAW-1 at 4 of 104 (May 2023 Update) (Provided as Attachment 2 to LG&E/KU Resp. to JI-2 Question No. 60(a)); *see also* Ex. SC-6 (LG&E/KU Resp. to AG 1-1).
[51] LG&E/KU Ex. SAW-1 at 4 of 104 (May 2023 Update); *see also* Corrected LGE Ex. SB4-1 (filed Sept. 8, 2023) (reflecting stay open SCR capital costs for Mill Creek 1 and 2, and Ghent 2).
[52] LG&E/KU Ex. SAW-1 at 4 of 104 (May 2023 Update).
[53] *Id.* at 27-33 of 104.
[54] *Id.* at 32 of 104.

retiring it, while retiring Mill Creek 1 and 2 and E.W. Brown 3 remained more favorable even in this scenario.[55] Moreover, as LG&E/KU witness Mr. Imber confirmed, if any additional capital costs are required at Mill Creek 1 and 2, Ghent 2, or E.W. Brown 3, the retrofit and continued operation of those units would only be more unfavorable to customers, relative to retirement.[56] And, as explained below, all of these units face significant risks of further capital costs if they are not retired as proposed.

"Some things are difficult to predict, especially the future" costs of operating a coal plant.[57] But the record is clear that retiring Mill Creek 1 and 2, Ghent 2, and E.W. Brown 3 is the least-cost, *least-risk* option for Kentucky ratepayers, for several reasons. *First*, as noted, the Companies' scenario modeling overwhelmingly supports retiring these units. *Second*, despite the hopes of some, EPA's longstanding approach to regulating interstate ozone pollution, which has been upheld by the Supreme Court, is not going away. *Third*, even if parts of the rule are invalidated or delayed, Mill Creek 1 and 2, Ghent 2, and E.W. Brown 3 face additional, significant environmental compliance costs, independent of the Good Neighbor Plan, that would be avoided by retirement. And those costs cannot be avoided by operating Mill Creek or Ghent only in the non-ozone season. *Finally*, EPA's recently proposed CO_2 regulations for new and existing power plants, and the cost analyses supporting that rule, confirm that Mill Creek 1 and 2, Ghent 2, and Brown 3 cannot continue to operate without incurring significant costs.

A. EPA's Long-Standing Approach to Regulating Interstate Ozone Pollution Is Not Going Away.

[55] *Compare id.* at 28 with *id.* at 32 (indicating that retiring and replacing Mill Creek 1 and 2 with Mill Creek 5, adding SCR to Ghent 2, retiring EW Brown 3, and adding 637 MW of solar results in slightly lower costs than the Company's preferred alternative under a high gas, zero carbon future).
[56] Aug. 25, 2023 Hr'g Tr. at 3:00:57 - 3:01:10.(Imber Cross).
[57] Sinclair Rebuttal at 73 (quoting World War II veteran Yogi Berra).

To understand the Good Neighbor Plan, it is useful to understand the basic regulatory context under which EPA promulgated the rule. To protect public health and welfare, the Clean Air Act requires EPA to establish National Ambient Air Quality Standards that establish the maximum allowable ambient concentration of certain harmful air pollutants, like ozone or ground-level smog.[58] EPA must review and, if appropriate, revise those standards every five years.[59] And once EPA sets a standard, states must develop and implement pollution-reduction measures to achieve and maintain the standard within the state within statutorily mandated timelines.[60]

Many states, however, struggle to achieve air quality standards partly due to harmful cross-border pollution that blows from "upwind" states.[61] This interstate pollution imposes an unfair burden on "downwind" states, forcing them to incur additional public health costs and regulatory costs to further limit their own emissions to achieve national standards.[62] To remedy the problem, the "Good Neighbor Provision" of the Clean Air Act requires states (or, where the state fails to do so, EPA) to implement "adequate provisions ... prohibiting ... any source or other type of emissions activity within the State from emitting any air pollutant in amounts which will ... contribute significantly to nonattainment or interfere with maintenance" of the National Ambient Air Quality Standards ("NAAQS") in any other state.[63] If EPA determines that a state has not submitted a compliant plan, EPA must adopt a federal plan for the state to achieve compliance with the NAAQS in all areas of the country within the statutory deadline.[64]

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[58] 42 U.S.C. §§ 7408(a), 7409(b)(l).
[59] *Id.* § 7409(d).
[60] *Id.* § 7410(a).
[61] *EPA v. EME Homer City Generation, L.P.*, 572 U.S. 489, 496 (2014) ("*Homer II*").
[62] *See id.* at 496-97.
[63] 42 U.S.C. § 7410(a)(2)(D)(i)(I).
[64] 42 U.S.C. § 7410(c)(1), (k)(1)-(4); *Homer II*, 572 U.S. at 508.

EPA issued the Good Neighbor Rule after finding that many states, including Kentucky, failed to include any "permanent and enforceable emissions controls" to eliminate contribution to downwind ozone nonattainment. [65] To ensure downwind compliance with the 2015 ozone standard–a final regulation, upheld by the courts–the Rule revises and tightens the existing Cross-State Air Pollution NOx allowance trading program with revised emissions budgets for fossil fuel-fired power plants in 25 states, including Kentucky, beginning in the 2023 ozone season (May through September).[66] The rule initially assumes consistent operation of emissions controls already installed, but beginning in 2026, emissions budgets would assume installation of selective catalytic reduction ("SCR") controls at all coal-fired generating units, including Mill Creek 1 and 2 and Ghent 2. In addition, starting in 2027, the rule imposes a three to one emission surrender penalty for emissions exceeding the rate assumed with SCR technology. The rule 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 installs SCR equipment at each of the units, or obtains sufficient NOx emission credits to reduce its emissions by approximately 80% plus any allowances need to cover the 3 to 1 surrender penalty.[67]

As explained by LG&E/KU witness Imber, despite its apparent stringency, neither the Good Neighbor Rule nor Kentucky's obligation to reduce its ozone impacts to downwind states are likely to go away, for several reasons. First, EPA's Good Neighbor Plan is *not* a novel approach to dealing with the national problem of interstate air pollution.[68] Indeed, EPA has established and implemented similar interstate pollution trading programs for more than 25 years, including an

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[65] 88 Fed. Reg. 36,654 (June 5, 2023).
[66] Nitrogen Oxides are a precursor pollutant of ground-level ozone.
[67] LG&E/KU Ex. SAW-1 at 4 of 104 (May 2023 Update) (Provided as Attachment 2 to LG&E/KU Resp. to JI-2 Question No. 60(a)); *see also* Ex. SC-6 (LG&E/KU Resp. to AG 1-1).
[68] Aug. 25, 2023 Hr'g Tr. at 3:33:48 - 3:34:43 (Imber Cross).

ozone-season NOx trading program under the so-called NOx SIP Call,[69] as well as ozone-season and annual NOx and sulfur dioxide emissions trading programs under the *existing and still-effective* Cross-State Air Pollution Rule, which EPA implemented under the Clean Air Act's "good neighbor" provisions to address interstate ozone pollution under the 1997 and 2008 "NAAQS") for ozone and the 1997 and 2006 NAAQS for particulate matter.[70]

Although EPA's earlier efforts to address interstate pollution were also stayed pending judicial review, those regulations were largely upheld and ultimately implemented with minor modifications.[71] The Good Neighbor Rule applies the same four-step analytical framework for identifying contributing states and allocating emission credits that the agency used in those prior rules. And the Supreme Court upheld that approach, reasoning that a nationally uniform analytical and technical framework is necessary to an "efficient and equitable" solution to the problem of interstate pollution.[72]

Second, as Mr. Imber discusses, EPA has demonstrated a commitment to defend the Good Neighbor Plan, including "its commitment to achieving meaningful emission reductions from Kentucky sources of NOx."[73] Indeed, in response to challenges to the Good Neighbor Plan, EPA has taken the position that NOx emissions from Kentucky "are impacting air quality hundreds of miles away," including in nonattainment areas in Michigan, Ohio, New York, New Jersey, and

[69] "Finding of Significant Contribution and Rulemaking for Certain States in the Ozone Transport Assessment Group Region for Purposes of Reducing Regional Transport of Ozone," 63 Fed. Reg. 57356 (Oct. 27, 1998).

[70] *See, e.g.*, "Federal Implementation Plans: Interstate Transport of Fine Particulate Matter and Ozone and Correction of SIP Approvals," 76 Fed. Reg. 48,208 (Aug. 8, 2011); "CSAPR Update for the 2008 Ozone NAAQS," 81 Fed. Reg. 74,504 (Oct. 26, 2016); "Revised CSAPR Update for the 2008 Ozone NAAQS," 86 Fed. Reg. 23,054 (April 30, 2021); *see also* "Rule to Reduce Interstate Transport of Fine Particulate Matter and Ozone (Clean Air Interstate Rule)," 70 Fed. Reg. 25162 (May 12, 2005).

[71] *EPA v. EME Homer City Generation, L.P.*, 572 U.S. 489, 496 (2014) ("*Homer II*").

[72] *EME Homer City Generation, L.P.*, 572 U.S. at 519.

[73] Imber Rebuttal at 5:7-8.

Connecticut.[74] Moreover, "Kentucky's failure to address its role in poor air quality" in those states adversely affects "millions of citizens and imposing unfair regulatory burdens on those downwind."[75] According to EPA, those states must still attain the 2015 ozone NAAQS by August 2024, and they should not "face an attainment deadline with no relief from the significant contribution from upwind sources" in Kentucky.[76] EPA's litigation position "makes it reasonable to believe" EPA would continue to address Kentucky's impacts to downwind ozone problems even if the Good Neighbor Plan is blocked by the courts.[77]

Finally, as Mr. Imber notes,[78] the current judicial challenges are unlikely to result in the wholesale invalidation of the Good Neighbor Plan. Kentucky's primary challenges to EPA's disapproval of the state's implementation plan are: (1) EPA relied on modeling produced after Kentucky issued its SIP and of which Kentucky had no notice; and (2) EPA's reliance upon a "significant contribution" threshold that is different from that used by Kentucky in developing its SIP.[79] But if Kentucky prevails on those points, the likely result is a remand for further notice and comment. Indeed, Kentucky does not actually dispute the validity of EPA's modeling platform showing Kentucky impacts to other states; in fact, Kentucky used an earlier version of the same EPA modeling to develop its state plan. Although Kentucky advocates for a different contribution

[74] *Id.* at 6 (citing Declaration of Rona Birnbaum, EPA Director of the Clean Air Markets Division in the Office of Atmospheric Protection within the Office of Air and Radiation ¶ 10, Commonwealth of Kentucky et al. v. EPA, No. 23-3216 (6th Cir., June 16, 2023) (Doc. 32-3).
[75] Imber Rebuttal at 5 (quoting EPA's Consolidated Response in Opposition to Petitioners' Motions for a Stay Pending Review, Commonwealth of Kentucky et al. v. EPA, Cir. Nos. 23-3216, 23-3225 (Doc. 32-1) (6th Cir., June 23, 2023).
[76] Imber Rebuttal at 6 (citing Declaration of Rona Birnbaum, EPA Director of the Clean Air Markets Division in the Office of Atmospheric Protection within the Office of Air and Radiation ¶ 10, Commonwealth of Kentucky et al. v. EPA, No. 23-3216 (6th Cir., June 16, 2023) (Doc. 32-3).
[77] Imber Rebuttal at 7.
[78] Imber Rebuttal at 7.
[79] *Id.*

threshold, the U.S. Supreme Court previously upheld EPA's use of that very same threshold. Thus, while the ultimate rule may change slightly, the basic framework is likely to be upheld.

B. Regardless of the Good Neighbor Plan, Mill Creek 1 and 2, Ghent 2, and Brown 3 Are Facing Significant Environmental Compliance Costs That Independently Support Retiring Each Unit.

In addition to the Good Neighbor Plan, there are a suite of impending EPA regulations—including revised and existing NAAQS for various pollutants, revisions to Kentucky's Regional Haze regulations, Clean Water Act discharge and cooling water requirements, and greenhouse gas regulation —that will require Mill Creek 1 and 2, Ghent 2, and E.W. Brown to install additional pollution controls or increase costs to continue operating.[80] While there may be some uncertainty over the precise costs of complying with these future regulations, as discussed below, it is *not* reasonable to assume that the Companies can continue operating Mill Creek 1 and 2, Ghent 2, and Brown 3 indefinitely, without incurring *any* additional environmental compliance costs. Just as the Good Neighbor Plan will impose costs on the continued operation of LG&E/KU's coal units, these rules are also expected to have moderate to significant impacts on the costs of operating Mill Creek, Ghent, and Brown, and therefore have the potential to independently "drive" retirement decisions.[81] Further, the costs of complying with some of these regulations were *not* included in LG&E/KU's modeling and including these costs would only increase the benefits to customers of retiring the units as proposed.

Table 1. Summary of Additional Environmental Compliance Risks for Mill Creek 1, Mill Creek 2, Ghent 2, and E.W. Brown 3 ($Millions).

Technology	Rule(s)	Timeline	Mill Creek 1	Mill Creek 2	Ghent 2	E.W. Brown 3

[80] Imber Rebuttal at 14.
[81] *Id.*

Continued $/ton NOx	CSAPR	Ongoing	$4.5	$4.5	$4.5	
Selective Catalytic Reduction (SCR)	-Good Neighbor Plan[82] -Clean Air Act Section 126 -2008 ozone NAAQS -2015 ozone NAAQS -Regional Haze -$PM_{2.5}$ NAAQS	2026, no later than 2028	$110	$110	$126	
Flue Gas Desulfurization (FGD)	-Regional Haze -$PM_{2.5}$ NAAQS				Potential costs to achieve modern SO2 emission rate[83]	
	2020 Clean Water Act: Effluent	2023	$8			

[82] Ex. SAW-1 at 4 of 104; *see also* Corrected LGE Ex. SB4-1 (filed Sept. 8, 2023) (reflecting stay open SCR capital costs for Mill Creek Unit 1, Mill Creek Unit 2, and Ghent Unit 2).
[83] Tr. Aug. 25, 2023, at 5:24-26.

Bottom ash, FGD, leachate elimination	Limitations Guidelines[84]					
	2023 Proposed Limitations[85]	2029	$9.2	$6.5	$1.8	
Cooling water retrofits	Clean Water Act: Section 316b[86]	2026	$25			
Carbon Capture and Sequestration[87]	Clean Air Act: Section 111(d)	2030	$34/ton	$35/ton	$26/ton	$31/ton

1. *Regardless of the Good Neighbor Plan, Mill Creek 1 and 2, Ghent 2, and E.W. Brown 3 Will Incur Increasing Costs to Comply With the Still-Effective Cross-State Air Pollution Rule.*

Even if the Good Neighbor Plan is invalidated or does not ultimately require Mill Creek or Ghent to install and operate SCR, Mill Creek 1 and 2, Ghent 2, and E.W. Brown 3 will continue to incur (likely significant) costs to comply with the still-effective Cross State Air Pollution Rule. As discussed, the Clean Air Act includes a "good neighbor provision" that requires states to prohibit emissions that will contribute significantly to nonattainment or interfere with the maintenance of any of the National Ambient Air Quality Standards.[88] EPA issued the Cross-State Air Pollution Rule

[84] Corrected LGE Ex. SB4-1 (filed Sept. 8, 2023).
[85] *See* Ex. SC-7 at 11, 16 (EPA estimates that the costs to eliminate flue gas desulfurization wastewater at Mill Creek Unit 1 would be approximately $6 million under the 2023 preferred alternative, and $2.5 million at Unit 2); id. at 45(EPA estimates the cost to comply with the proposed discharge limitations for leachate wastewater will be approximately $3.2 million at Unit 1 and $3.9 million at Unit 2); id. at 32 (EPA estimates the cost to eliminate bottom ash wastewater at Ghent Unit 2 will be approximately $1.8 million under the preferred alternative).
[86] Corrected LGE Ex. SB4-1 (filed Sept. 8, 2023).
[87] All costs include the Inflation Reduction Act's 45Q Credit.
[88] 42 U.S.C. § 7410(a)(2)(D).

(also known as "CSAPR"), in part, to address NOx emissions from electric generating units in several states, including Kentucky, that were contributing to downwind states' inability to attain and maintain the 1997 and 2008 ozone NAAQS.[89] Specifically, EPA concluded that Kentucky EGUs contributed to downwind nonattainment in New York, New Jersey, and Maryland.[90] Like the proposed Good Neighbor Plan, CSAPR is an emission trading program, under which EPA establishes emission caps or budgets for each affected electric generating unit, and to exceed that cap, the unit must purchase or trade for additional emission credits. Because air quality in those downwind states continues to be in nonattainment under the 2008 ozone standard, Kentucky EGUs, including Mill Creek 1 and 2, Ghent 2, and E.W. Brown 3 will continue to be subject to CSAPR regardless of the Good Neighbor Plan's fate.[91]

The cost of continuing to comply with the existing CSAPR program could be significant. Indeed, in early 2023, nitrogen oxide emission allowance prices spiked to approximately $50,000 per ton, and then declined to approximately $9,000 per ton during the 2023 ozone season.[92] As explained by LG&E/KU witness Imber, over the last several ozone seasons, Mill Creek 1 and 2 and Ghent 2 have each had to obtain or purchase "easily" 500 NOx emission credits each year, "if not more."[93] Thus, assuming a $9,000 per ton cost, which is consistent with recent NOx allowance prices under the CSAPR program, the continued operation of Mill Creek 1 and 2 and Ghent 2 could *each* require approximately $4.5 million annually. [94] Thus, regardless of the implementation of the Good Neighbor Plan, the operation of Mill Creek 1 and 2 and Ghent 2 is "absolutely" going to

[89] 76 Fed. Reg. 48,208 (Aug. 8, 2011).
[90] Aug. 25, 2023 Hr'g Tr. at 3:31:18-55.
[91] Aug. 25, 2023 Hr'g Tr. at 3:31:55-3:31:08.
[92] Aug. 25, 2023 Hr'g Tr. at 3:35:35-3:36.
[93] Aug. 25, 2023 Hr'g Tr. at 3:38:00-45.
[94] Aug. 25, 2023 Hr'g Tr. at 3:38:49-3:39:20.

continue to be limited by the still-effective CSAPR program,[95] and will expose Kentucky customers to significant costs.

2. *Mill Creek and Ghent Could Be Required to Install SCR Under Section 126 of the Clean Air Act.*

As explained by LG&E/KU witness Imber, even if the Good Neighbor Plan is invalidated or does not ultimately require Mill Creek or Ghent to install and operate SCR, Section 126 of the Clean Air Act likely would.[96] Under Section 126, "[a]ny State … may petition [EPA] for a finding that any major source or group of stationary sources emits or would emit any air pollutant in violation of the" Clean Air Act's prohibition against interstate contribution to nonattainment.[97]

Notably, multiple states, including New York, Connecticut, and Maryland have filed separate Section 126 alleging that sources in Kentucky, including Mill Creek 1 and 2 and Ghent, interfere with attainment of both the 2008 and 2015 ozone NAAQS in each state.[98] In fact, the pending New York petition alleges the Mill Creek and Ghent facilities are among those contributing to ozone nonattainment in New York, and specifically requests that EPA require each of those facilities to install and operate modern pollution controls, like SCR, to reduce NOx emissions contributing to New York's unhealthy air.[99] EPA has a statutory obligation to respond to those petitions. Although the Good Neighbor Plan itself would likely resolve those pending petitions, EPA would likely initiate a formal rulemaking to respond to those petitions should the courts block implementation of the Good Neighbor Plan.

[95] Aug. 25, 2023 Hr'g Tr. at 3:39:20-3:40:05.
[96] Imber Rebuttal at 10-11.
[97] 42 U.S.C. § 7426(b).
[98] *See* Imber at 10 (citing New York and Maryland Petitions Pending Reconsideration), and Petition of the State of New York Pursuant to Section 126 of the Clean Air Act (Posted May 11, 2018), https://www.regulations.gov/document/EPA-HQ-OAR-2018-0170-0004.
[99] Petition of the State of New York Pursuant to Section 126 of the Clean Air Act.

3. *EPA Could Also Require Mill Creek and Ghent 2 to Install SCR Under the Reasonably Available Control Technology Provisions of the Clean Air Act.*

Even if the Good Neighbor Plan did not require Mill Creek or Ghent to install and operate SCR, the Clean Air Act's independent "reasonably available control technology" provisions will likely require the very same controls for Mill Creek 1 and 2, and could require similar pollution control investments at Ghent 2.[100] That is a direct result of failing air quality in the Louisville Metro area.[101]

Under the Clean Air Act, EPA's 2015 issuance of a revised National Ambient Air Quality Standard for ozone triggered a series of related, but independent, obligations designed to ensure that *all* areas of the country come into compliance with the NAAQS as expeditiously as practicable.[102] The good neighbor provision is an example of one such mechanism, and it is designed to protect against pollution that causes air quality problems in *other* states.

But the issuance of the 2015 NAAQS also requires states (or EPA, if the state fails to act) to address air quality problems within the state.[103] As an initial matter, once EPA issues a revised ozone standard, the agency is also required to identify areas of the country that do not meet the NAAQS, known as "nonattainment" areas.[104] For ozone, nonattainment is further divided into five classifications, ranging from marginal nonattainment to extreme nonattainment, based on the severity of the ozone air quality problem in the area.[105] For marginal nonattainment areas, states must generally attain the NAAQS within three years, but such areas "have fewer and/or less

[100] Imber Rebuttal at 10-11; Hr. Video (Aug. 25, 2023) at 4:38:04-4:39:20 (Sierra Club cross-examination of Mr. Imber); *id.* at 4:36:00-4:36:58.
[101] Hr'g Ex. LMG-1.
[102] 42 U.S.C. § 7511; *Ala. Power Co. v. Costle*, 636 F.2d 323, 346 (D.C. Cir. 1979).
[103] *See, e.g.*, 42 U.S.C. § 7502 (setting out requirements for nonattainment areas generally); *id.* § 7511-7513b (specific requirements for ozone nonattainment areas).
[104] 42 U.S.C. § 7407(d)(1)(A).
[105] 42 U.S.C. § 7511.

stringent mandatory air quality planning and control requirements than those in higher classifications."[106] States must require new or modified sources to install the most effective pollution controls available (and comply with the "lowest achievable emission rate" or "LAER" for those controls), but they need not require the state to impose control requirements on existing sources.[107]

If a marginal nonattainment area fails to come into compliance with the NAAQS within three years, however, EPA must reclassify the area as a "moderate" nonattainment area, which results in the imposition of stringent pollution control requirements for both new and existing sources.[108] Specifically, states must still ensure that new or modified sources comply with the "lowest achievable emission rate," but the state must also develop a separate state implementation plan that, among other things, provides for attainment and "the implementation of all reasonably available control measures as expeditiously as practicable (including such reductions in emissions from existing sources in the area as may be obtained through the adoption, at a minimum, of reasonably available control technology)."[109] Reasonably available control technology is a "technology-forcing" standard intended to ensure that existing sources install the "toughest controls considering technological and economic feasibility that can be applied" to ensure attainment as expeditiously as practicable.[110] As with other state implementation planning provisions under the Act, if the state fails to submit a compliant moderate nonattainment plan, EPA must step in and impose a federal plan.[111]

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[106] 83 Fed. Reg. 25776, 25779 (June 4, 2018);; 42 U.S.C. §§ 7511, 7511a.
[107] *See* 42 U.S.C. § 7511(a); 40 C.F.R. § 51.1303(a); *see also* 42 U.S.C. § 7503(a)(2).
[108] 42 U.S.C. § 7511(a) & (b)(2).
[109] 42 U.S.C. § 7502(c)(1).
[110] *Sierra Club v. U.S. EPA*, 972 F.3d 290, 294 (3d. Cir. 2020) (quoting Memorandum from Roger Strelow, Assistant Admin. for Air and Waste Mgmt., U.S. E.P.A., to Regional Admins., Regions I - X, at 2-3 (Dec. 9, 1976), https://www3.epa.gov/ttn/naaqs/aqmguide/collection/cp2/19761209_strelow_ract.pdf (emphasis added).
[111] 42 U.S. C. § 7410(c)(1).

In 2018, EPA designated the geographic area consisting of Bullitt, Jefferson, and Oldham counties in Kentucky and Clark and Floyd counties in Indiana (the "Louisville Metro Area") as being in "marginal" nonattainment under the 2015 ozone NAAQS. The area failed, however, to come into attainment within three years, as required under the Clean Air Act. As a result, EPA designated the area as being in moderate nonattainment.[112] Since then, air quality in the area has further declined, and the area continues to fail to meet the health-based ozone standard.[113] In the meantime, Kentucky has failed to timely develop a state implementation plan to ensure attainment of the NAAQS, and as a result, EPA has authority to implement a plan that could require pollution reductions from Mill Creek and Ghent 2.[114]

EPA's moderate nonattainment designation for the Louisville Metro Area has several important implications for the Companies' CPCN application, and the continued operation of Mill Creek 1 and 2 and Ghent 2. First, because Mill Creek 1 and 2 are located within the Louisville nonattainment area, the state (or EPA, if the state fails) must develop a plan that requires each of those units to install and operate reasonably available control technology no later than 2026.[115] For coal units, SCR is widely considered to be "reasonably available control technology."[116] Thus, "*independent* of any Good Neighbor Plan-related constraints," Mill Creek 1 and 2 will be required to install SCR or reduce operations in the ozone season.[117]

[112] 87 Fed. Reg. 60,897 (Oct. 7, 2022); *see also* Imber Rebuttal at 12; August 25, 2023 Hr'g Tr 4:40:22 - 4:40:40 (Imber cross) (Louisville designated as moderate nonattainment in November 2022).
[113] Hr'g Ex. LMG-1.
[114] August 25, 2023 Hr'g Tr 4:40:48 - 4:41:16 (Imber cross) (The state failed to submit a nonattainment plan by the required January 2023 deadline); August 25, 2023 Hr'g Tr 4:41:58 - 4:42:19 (Imber cross) (if it makes a finding of failure to submit, EPA must impose a nonattainment plan within 2 years).
[115] 42 U.S.C. §§ 7502(c); 7511; 7511a(b); Imber Rebuttal at 15.
[116] August 25, 2023 Hr'g Tr 4:36:00 - 4:36:58 (Imber cross) (noting that the state or EPA must impose RACT on sources in a nonattainment area and that RACT is SCR for NOx).
[117] Imber Rebuttal at 13 (emphasis added).

Second, as a result of EPA's moderate nonattainment designation, Ghent 2 could also be required to reduce NOx emissions.[118] Although Ghent 2 is not located in the nonattainment area, the Clean Air Act requires that states (or EPA) impose "*all* reasonably available control measures" to ensure Louisville comes into compliance with the NAAQS as expeditiously as practicable.[119] EPA and other states have interpreted that provision to authorize the imposition of reasonable pollution controls at sources that may be located outside the nonattainment area, but which may further attainment.[120] In short, Ghent 2 could likewise be required to reduce emissions to ensure that the Louisville area attains the NAAQS.

Finally, EPA's moderate nonattainment area effectively precludes the construction of any new fossil-fuel generation unit at Mill Creek without requiring Mill Creek 1 and 2 to meet the "lowest achievable emission rate" for new or modified sources. Thus, as Mr. Imber explained, if the Companies install a new gas generator at Mill Creek, as proposed, Mill Creek 1 and 2 cannot continue to operate without both SCR technology and incurring additional costs to "offset" any pollution increase as a result of the addition of the new gas unit.[121]

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[118] August 25, 2033 Hr. Tr. 4:38:04 - 4:39:20 (Imber cross) (agreeing that the state or EPA can impose emissions reductions on sources outside the nonattainment area, and that the state could impose reductions on Ghent if the state found that it was contributing to ozone nonattainment in Louisville).

[119] 42 U.S.C. § 7502(c) (emphasis added).

[120] In Texas for example, the East Texas Combustion Sources Rule, 30 TAC Chapter 117, Subchapter E, Division 4 requires pollution reductions at sources outside the Dallas-Fort Worth nonattainment area to further attainment. Similarly, Georgia Regulation 391-3-1-.03(8)(c)15, imposes a mass-based emission limit on coal fired power plants that are located outside of the Atlanta nonattainment area. And EPA has made clear that "all sources *contributing* to the nonattainment situation are required to implement restrictive available control measures even if it requires significant sacrifice." Memorandum from Roger Strelow, Assistant Administrator for Air and Waste Management, U.S. EPA, to Regional Administrators, Regions I - X (Dec. 9, 1976), at 2 (emphasis added).

[121] August 25, 2023 Hr'g Tr 3:02 - 3:07 (Imber cross) (discussing the permitting of the proposed combined-cycle units, and noting that if a new gas generator is constructed, Mill Creek cannot continue to operate without installing and operating lowest achievable emission rates, which would trigger the installation of SCR).

4. *If the Companies were to Install a New Gas Unit at the Ghent Facility, Ghent 2 Cannot Continue to Operate Without SCR.*

To maintain compliance with the health-based National Ambient Air Quality Standards, the Clean Air Act includes a "prevention of significant deterioration" program to ensure that new or modified sources of pollution do not erode air quality in areas that meet the NAAQS. [122] To that end, even in areas that meet current air quality standards, new or modified sources of pollution must install and operate the "best available control technology" for each criteria pollutant.[123] For NOx pollution, SCR technology is widely accepted as the best available control technology for controlling NOx emissions from coal-burning EGUs like Ghent. Thus, although the Ghent facility is located in an area that currently meets all relevant air quality standards, the Companies could not install a new gas generator at the that facility without either retiring Ghent 2 or installing and operating SCR.

5. *Mill Creek 1 and 2, Ghent 2, and Brown 3 Face Environmental Compliance Risks Under the Clean Air Act's Regional Haze Program.*

Even if EPA were to abandon its Good Neighbor obligation (which it will not do as such obligation was imposed by Congress), the coal units at issue here face significant environmental compliance risk under the Clean Air Act's visibility program, which has the potential to independently drive retirement.[124] Under the Clean Air Act's Regional Haze Rule, by 2021, states were required to develop "comprehensive" state implementation plans that include "enforceable emission limitations" necessary to ensure "reasonable progress" towards eliminating human-caused visibility pollution in national parks, like Kentucky's iconic Mammoth Cave.[125] Each state plan must,

[122] *See* 42 U.S.C.A. Ch. 85, Subch. I, Pt. C, Subpt. I; *Ala. Power Co. v. Costle*, 636 F.2d 323, 362 (D.C. Cir. 1979) (identifying the permitting process as the principal mechanism for maintaining air quality).
[123] 42 U.S.C. § 7475(a)(4).
[124] Imber Rebuttal at 14.
[125] 42 U.S.C. § 7491(b)(2);; 40 C.F.R. § 51.308(f)(2).

among other requirements, (1) reevaluate "best available retrofit technology" (or BART) for electric generating units in existence as of 1977—like Mill Creek 1 and 2, Ghent 2, and E.W. Brown 3[126]—and that do not have modern pollution controls or only moderately effective pollution controls for nitrogen oxide, sulfur dioxide, and particulate matter, which are the primary causes of visibility impairment;[127] and (2) require additional emission reductions as may be necessary to ensure reasonable progress towards the national goal of eliminating pollution in affected national parks.[128] In short, after evaluating several statutory factors, states are required to impose cost-effective pollution controls at large, uncontrolled or under-controlled sources of nitrogen oxides and sulfur dioxide. And like other Clean Air Act programs, if the state fails to issue a lawful Regional Haze plan, EPA must step in and do so.[129]

Applying that regulatory framework, EPA and other states have routinely concluded that pollution controls like SCR technology for nitrogen oxides and flue gas desulfurization for sulfur dioxide pollution are reasonable and cost effective. In fact, EPA's 2005 regulations assumed that coal-fired EGUs could achieve at least an emission limit of no higher than 0.15 lb/MMBtu limit for SO_2 with the installation and operation of flue gas desulfurization.[130] As Mr. Imber acknowledged, however, modern flue gas desulfurization systems are capable of cost-effectively achieving emission rates as low as 0.06 lb/MMBtu SO_2.[131] The rule similarly assumed that tangentially-fired coal units,

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[126] *See* May 10, 2023 Bellar Direct at 7, Ky. PSC Case No. 2023-00122.
[127] 42 U.S.C. § 7479(b)(2)(A), (g)(2) (defining BART-eligible facilities). Although many states addressed BART for older sources in earlier state implementation plans, EPA's 2017 revisions to the Regional Haze Rule make clear that BART was not a once-and-done requirement, and that states "will need" to comprehensively reassess "BART-eligible sources that installed only moderately effective controls (or no controls at all)" for any additional technically-achievable, cost-effective controls. 82 Fed. Reg. 3078, 3,083 (Jan. 10, 2017); *see also id.* at 3,096 ("states must evaluate and reassess all elements required by 40 CFR 51.308(d)").
[128] 42 U.S.C. § 7479(b)(2)(B), (g)(1) (defining reasonable progress); *see also* 40 C.F.R. § 51.308(d), (e).
[129] 42 U.S.C. § 7410(c)(1).
[130] Guidelines for BART Determinations, 40 C.F.R. pt. 51, App'x Y § IV.E.4.
[131] Aug. 25, 2023 Hr'g Tr. at 5:19:44 - 5:19:56 (Imber Cross).

like Mill Creek and Ghent, could achieve an emission limit of at least 0.15 lb/MMBtu limit for NOx with the installation of SCR technology;[132] but as the Good Neighbor Plan makes clear, modern SCRs are capable of cost-effectively reducing NOx emissions to 0.05 lb/MMBTU or lower.[133]

Those emission rates are important because they demonstrate that, independent of the outcome of the Good Neighbor Plan, Mill Creek 1 and 2 and Ghent 2 could be required to significantly decrease NOx emissions to comply with the Regional Haze Rule. Indeed, each of those units currently emit NOx at a rate of approximately 0.3 lb/MMBtu—six times higher than the rate modern SCR controls are capable of cost-effectively achieving. For that reason, LG&E/KU has recognized that Mill Creek will likely need to reduce NOx emissions under the haze program.

Regardless of the Good Neighbor Plan, the Regional Haze Rule could require the installation and operation of SCR technology at Mill Creek 1 and 2, at a cost of $100 million each, and at Ghent 2, at a cost of $126 million. Moreover, unlike the Good Neighbor Plan, which applies to ozone-season NOx emissions, the Regional Haze Rule has no such temporal limitation. That is because power plant emissions typically impact air quality in national parks throughout the year, and in some cases, winter time NOx emissions have a greater impact. Thus, unlike the Good Neighbor Plan, Mill Creek 1 and 2 and Ghent 2 cannot avoid regulation under the Regional Haze Rule simply by voluntarily opting not to operate in the summer.

Moreover, EPA's presumptively-reasonable SO_2 limitations suggest that E.W. Brown 3 could be required to reduce SO_2 emissions to comply with the Regional Haze Rule. Although E.W. Brown has a flue gas desulfurization system, the unit's emission rate is typically twice as much as EPA has deemed presumptively reasonable, and six times the rate that modern flue gas desulfurization systems are capable of achieving. Although the cost to upgrade E.W. Brown's SO2

[132] Guidelines for BART Determinations, 40 C.F.R. pt. 51, App'x Y § IV.E.5.
[133] 88 Fed. Reg. at 36,727 ("The Agency examined the cost for retrofitting a coal unit with new SCR technology, which typically attains controlled NOX rates of 0.05 lb/mmBtu or less.")

pollution controls are uncertain, Mr. Imber conceded that the unit would likely face additional costs if it were required to reduce emissions under the Regional Haze Rule.

Furthermore, Kentucky has yet to develop or propose a regional state implementation plan despite the 2021 deadline. As a result, in August 2022, EPA issued a formal finding that the state failed to submit a plan. That finding triggers a mandatory deadline for EPA to either issue a federal plan or approve a late-submitted state plan by August 2024. To date, Kentucky has still refused to issue a plan. If EPA is required to issue a federal haze plan for Kentucky, it is possible that the agency would require cost-effective and technically-achievable NOx or SO2 reductions from the plants at issue in this case. That risk would be avoided by the retirement of Mill Creek 1 and 2, Ghent 2, and Brown 3.

6. *Mill Creek Could Be Required to Reduce Particulate Matter Pollution Under EPA's Proposed Revisions to the Particulate Matter NAAQS.*

As noted, to protect public health and welfare, the Clean Air Act requires EPA to periodically review and, if appropriate, update National Ambient Air Quality Standards for certain harmful air pollutants.[134] In addition to ozone pollution, EPA must also establish air quality standards for fine particulate matter, which results from the combustion of fossil fuels for electricity generation, among other sources.[135] Exposure to fine particulate matter has been causally linked to asthma, cardiovascular and respiratory illness, adverse nervous system impacts, cancer, and even death.[136] Large segments of the U.S. population, including children and older adults, people with heart or lung conditions, and minority populations, are at risk of adverse health effects associated with exposure to excess particular matter.

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[134] 42 U.S.C. §§ 7408(a), 7409(b)(1).
[135] 88 Fed. Reg. 5558, 5569 (Jan. 27, 2023).
[136] *Id.* at 5560-61.

On January 6, 2023, after its statutorily required review, EPA proposed to strengthen the NAAQS for fine particulate matter, lowering the annual standard from 12.0 micrograms per cubic meter to a range within 9.0 to 10.0 micrograms per cubic meter.[137] Although the proposed standard is not yet final, as part of its proposed rule, EPA indicated that it anticipates that Jefferson County will not meet the revised standard,[138] and would likely be designated as being in nonattainment. Recent Louisville Metro Air Pollution Control District data confirms that assessment.[139]

As explained by LG&E/KU witness Imber, if EPA designates Jefferson County as being in nonattainment (or not meeting the revised particulate matter standard), it would require Kentucky (or, if the state fails to act, EPA) to develop a state implementation plan that includes enforceable emission limitations as necessary to bring the area back into attainment.[140] As noted above, one element of any such state plan is the "implementation of all reasonably available control measures . . . (including such reductions in emissions from existing sources in the area as may be obtained through the adoption, at a minimum, of reasonably available control technology)" and shall provide for attainment of the national primary ambient air quality standards "as expeditiously as practicable."[141] Thus, if Jefferson County is ultimately designated as being in nonattainment, sources within the metro area, including Mill Creek 1 and 2, would be required to install and operate reasonably available control technology for particulate matter, thereby increasing the cost to operate those units.[142]

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137 *Id.* at 5558.

138 U.S. EPA, Fine Particle Concentrations for Counties with Monitors Based on Air Quality Data from 2019 – 2021, at 5 (showing Jefferson County with a PM value of 10.5 which is above the proposed standards), available at https://www.epa.gov/system/files/documents/2023-01/Fine%20Particle%20Concentrations%20for%20Counties%20with%20Monitors.pdf.

139 Ex. LMG-1 at 2.

140 Aug. 25, 2023 Hr'g Tr. at 2:50-2:52 (Imber Cross); see also 42 U.S.C. §§ 7410(a)(2); 7502(c); 7513a.

141 *Id.* § 7502(c)(1).

142 Aug. 25, 2023 Hr'g Tr. at 4:36:00 - 4:37:03 (Imber Cross).

In addition, just as Kentucky is required to reduce its contribution to interstate ozone pollution under the Clean Air Act's Good Neighbor Provision, the state would also be required to implement "adequate provisions ... prohibiting ... any source or other type of emissions activity within the State from emitting any air pollutant in amounts which will ... contribute significantly to nonattainment or interfere with maintenance" of the revised particulate matter NAAQS in any other state.[143] And if EPA determines that Kentucky has not developed a compliant plan, EPA must step in and adopt a federal plan eliminating Kentucky sources' share of any particulate matter pollution that interferes with attainment, or contributes to nonattainment, in any other state.[144] In fact, EPA did just that under the 2006 particulate matter NAAQS, when the agency required Kentucky to participate in the Cross-State Air Pollution Rule pollution trading program for sulfur dioxide, a precursor to fine particulate matter. If EPA finalizes proposed air quality standards for particulate matter, there is a risk that Kentucky sources, including Mill Creek, Ghent, and Brown would have to reduce sulfur dioxide emissions that may contribute to poor air quality in other states. LG&E/KU can mitigate those risks by retiring Mill Creek 1 and 2, Ghent 2, and Brown 3 now.[145]

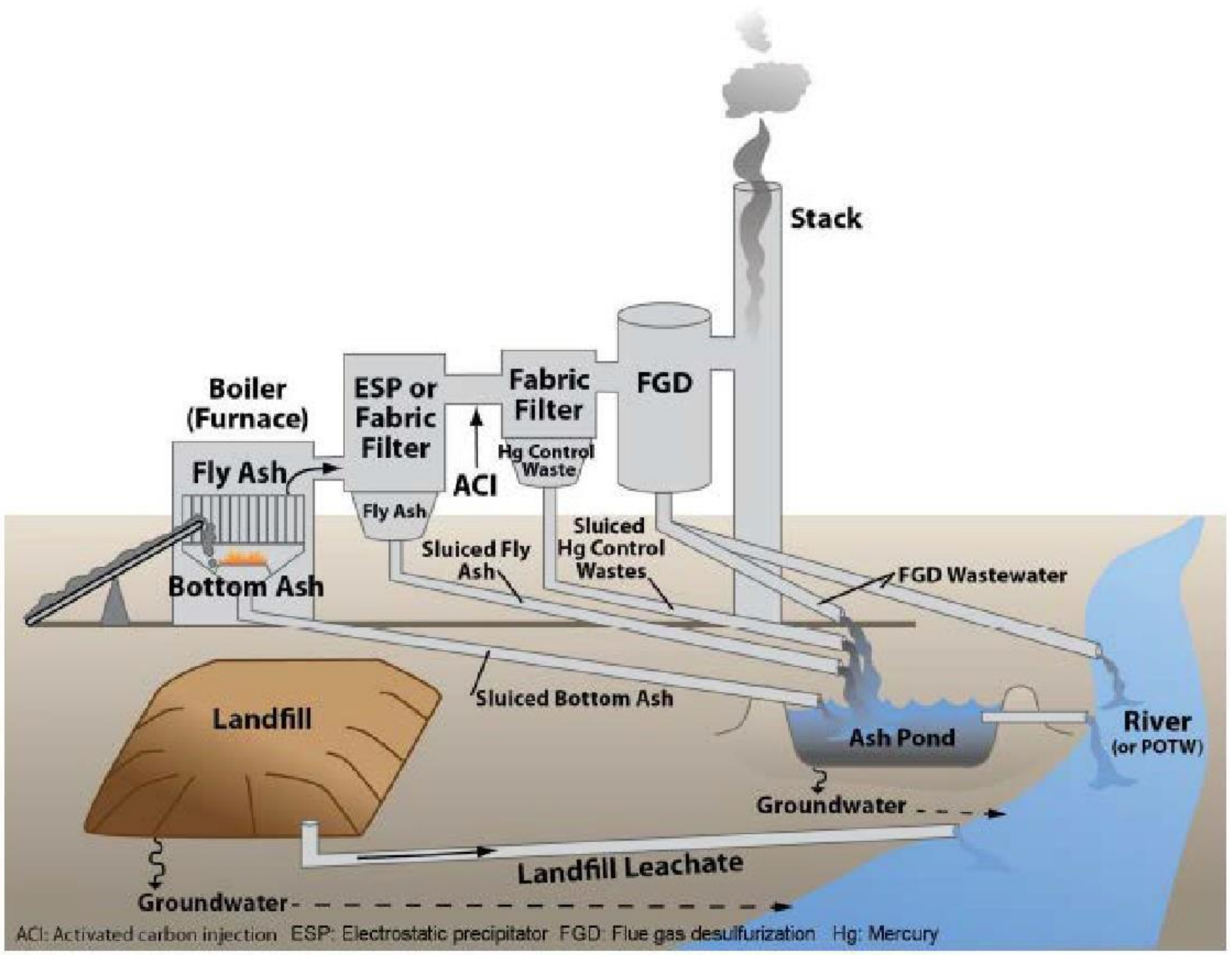
7. *The Clean Water Act's Effluent Limitations Guidelines for Coal-Burning EGUs Could Require Millions in Retrofits***.**

Even if Mill Creek Unit 1 and 2 and Ghent Unit 2 were not facing cost-prohibitive retrofits required to continue operating under the Clean Air Act, the continued operation of each unit could also require significant investments to comply with the Clean Water Act's pollution discharge limitations.[146] Every day, coal-burning EGUs, like Mill Creek 1 and 2, Ghent 2, and Brown 3, discharge millions of gallons of wastewater containing arsenic, lead, mercury, selenium, and other

[143] 42 U.S.C. § 7410(a)(2)(D)(i)(I).
[144] 42 U.S.C. § 7410(c)(1), (k)(1)-(4); *Homer II*, 572 U.S. at 508.
[145] Aug. 25, 2023 Hr'g Tr. at 4:32:02-47 (Imber Cross).
[146] Imber Rebuttal at 14; Aug. 25, 2023 Hr'g Tr. at 5:40:02 - 5:54:49 (Imber Cross).

toxic metals into Kentucky's rivers, lakes, and streams.[147] That pollution is discharged directly from power plant ash-handling and flue gas desulfurization systems, as well as from coal ash impoundments and landfills, as reflected below.

Figure 1: Diagram of Typical Coal-Burning EGU Wastewater Discharge System[148]



[147] 80 Fed. Reg. 67,838, 67,839-40 (Nov. 5, 2015) (2015 ELG Rule);; *Southwestern Electric Power Co. v. U.S. Environmental Protection Agency*, 920 F.3d 999, 1009-10 (5th Cir. 2019); *see also* E.W. Brown KPDES Fact Sheet at 6 of 81, Attachment 2 to Response to JI-1 Question No. 1.101(a); Ghent KPDEQ Fact Sheet at 6 of 102, Attachment 2 to Response to JI-1 Question No. 1.101(b-e); Mill Creek KPDES Fact Sheet at 7-8 of 135, Attachment 2 to Response to JI-1 Question No. 1.101(f-h).
[148] Diagram reproduced from *Southwestern Electric Power Co.*, 920 F.3d at 1009.

Under the Clean Water Act, EPA must develop "effluent limitation guidelines" or "ELGs" (*i.e.*, water pollution limits) for large industrial sources of water pollution.[149] These standards must be based on the best-performing technology in the industry that is technically and economically achievable across the industry, and must be updated at least once every five years to reflect improving treatment technology and move towards the Clean Water Act's goal of eliminating water pollution.[150]

When EPA originally regulated steam-electric effluent in the 1970s and 1980s, it adopted discharge limits based on the use of surface impoundments, or "ash ponds," which rely on gravity to remove particulates from wastewater. In recent rulemakings, however, EPA evaluated and developed updated technologies, in addition to impoundments, for different waste streams based on "affordable technologies that are widely available":[151]

• **Chemical precipitation,** which means treating wastewater by introducing chemicals that will react with substances currently dissolved or suspended in the water to produce a solid, non-soluble precipitate

• **Biological treatment**, which means introducing bacteria or other microorganisms to remove pollutants, which then can be filtered out or left to settle out in long-term or short-term wastewater holding tanks or impoundments before the remaining wastewater is discharged.

• **Dry handling or zero discharge**, for fly ash, means "a dry vacuum system that employs a mechanical exhauster to pneumatically convey the fly ash (via a change in air pressure) from hoppers directly to a silo," without getting the ash wet. For

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149 33 U.S.C. § 1311; 40 C.F.R. Part 423 (current ELGs for steam electric generating unit source category).
150 33 U.S.C. § 1311(d).
151 *Southwestern Electric Power Co.*, 920 F.3d at 1009–10; *see generally* 80 Fed. Reg. at 67,840, 67,850-53.

bottom ash, dry handling refers to a "closed-loop" system in which bottom ash is collected in a water quench bath and a drag chain conveyor (mechanical drag system) then pulls the bottom ash out of the water bath on an incline to dewater the bottom ash." *Id.*

• **High recycle ash handling**, for bottom ash, means using a mechanical drag system to separate ash from transport water, but includes a "purge" allowance for the discharge of up to 10% of the volume of the ash handling system.[152]

• **Membrane filtration**, for FGD wastewater, means using thin, semi-permeable filters, film, or osmosis to remove pollutants.

Under the currently effective regulations, the following technologies apply to wastewater streams from coal EGUs, like Mill Creek 1 and 2, Ghent 2, and Brown 3. An EGU may opt to permanently cease burning coal by December 31, 2028, and therefore avoid the costs of retrofitting, as an alternative compliance strategy.

Table 2: Existing ELG Requirements

Wastestream	**Technology**	**Compliance Deadline**
FGD wastewater	Chemical Precipitation + Short-Term Biological Treatment	Permit-by-permit; as soon as possible but no later than December 31, 2025
Fly Ash Transport Water	Dry Handling	Permit-by-permit; as soon as possible but no later than December 31, 2023

[152] 85 Fed. Reg. 64.650, 64,652 (Oct. 13, 2020).

Bottom Ash Transport Water	High-recycle handling system plus purge allowance	Permit-by-permit; as soon as possible but no later than December 31, 2025
Leachate	Continued Ash Impoundment	Permit-by-permit, but fully implemented by 2023

Although LG&E/KU has already obtained approval to retrofit Mill Creek, Ghent, and E.W. Brown to comply with the current regulations, on March 29, 2023, EPA proposed to amend the ELGs in several ways that will directly impact the continued operation of Mill Creek Units 1 and 2, Ghent Unit 2, and E.W. Brown 3 ***First***, EPA proposes to require coal EGUs to comply with a zero-discharge limitation of FGD wastewater commensurate with the installation of membrane filter technology.[153] ***Second***, EPA proposes to eliminate the high-recycle and purge compliance option for bottom ash discharges, and instead would require all coal EGUs to eliminate bottom ash discharges.[154] ***Third***, EPA has proposed to require coal plants that discharge leachate wastewater to install and operate chemical precipitation technology.[155] ***Finally***, EPA's proposed rule would require compliance with the new standards by 2029, but would also allow coal EGUs that are already in compliance with EPA's current regulations (so-called "early adopters") to continue operating without installing new technology, provided they commit to permanently cease burning coal by 2032.[156]

[153] 88 Fed. Reg. 18,824, 18,826, 18,838 (Table VII) (Mar. 29, 2023).
[154] *Id.*
[155] *See also* Ex. SC-7.
[156] 88 Fed. Reg. at 18,826.

As LG&E/KU witness Imber testified,[157] the continued operation of Mill Creek Units 1 and 2, Ghent Unit 2, and E.W. Brown Unit 3 would expose Kentucky ratepayers to additional environmental compliance risk associated with EPA's proposed ELG revisions. Mill Creek, for example, discharges FGD and leachate wastewater, and would therefore incur costs to comply with EPA's new limits for those waste streams. Ghent 2 discharges FGD, bottom ash (as part of a purge allowance under the current rule), and leachate wastewater and would likewise incur costs to comply with the new standard. And E.W. Brown 3 discharges bottom ash (as part of a purge allowance under the current rule) and leachate and would likewise incur costs to come into compliance with the new rule.

In fact, as part of its rulemaking record, EPA estimated the potential, additional compliance costs associated with the proposed rule for certain sources, including Mill Creek and Ghent.[158] EPA does not assert that these cost estimates are comprehensive, but are reflective of anticipated capital costs.

Wastestream	**Mill Creek 1**[159]	**Mill Creek 2**[160]	**Ghent 2**[161]
FGD	$5,871,525	$2,055,376	
Bottom Ash	N/A	N/A	$1,887,619
Leachate	$3,261,151	$3,935,598	

[157] Imber Rebuttal at 14:4-8.
[158] *See generally* Ex. SC-7.
[159] EPA's estimated costs for Regulatory Option 4 assume the continued operation of these units beyond 2032. *See* Ex. SC-7 at 16 and 45 (EPA Memorandum, Generating Unit-Level Costs and Loadings Estimates by Regulatory Option for the 2023 Proposed Rule – DCN SE10381, EPA Docket No. EPA-HQ-OW-2009-0819-9686, *available at* https://www.regulations.gov/document/EPA-HQ-OW-2009-0819-9686.
[160] *Id.*
[161] *Id.* at 32.

Although Mill Creek and Ghent could arguably avoid the costs of installing an SCR under the Good Neighbor Plan by operating those units only in the non-ozone season, the costs to comply with EPA's ELG rules cannot be avoided by partial operation. Moreover, as Mr. Imber testified, any incremental capital cost will only make the Mill Creek and Ghent units more uneconomical to operate relative to other generation.[162] Those costs, like the costs of compliance with the Good Neighbor Plan, the 2015 ozone NAAQS, Clean Air Act Section 126, the Regional Haze Rule, and particulate matter regulation, could be avoided by granting the Companies' application to retire those units.

8. *Retiring Mill Creek Unit 1 Will Avoid a $25 Million Cooling Water Retrofit.*

Even if Mill Creek did not require a $110 million SCR system, and even if the unit did not require significant investments to comply with the Clean Water Act's effluent limitations, it almost certainly cannot continue to operate without the installation of a new, approximately $25 million cooling water intake system.[163] Section 316(b) of the Clean Water Act requires that the "location, design, construction, and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impacts."[164] Cooling water intake systems pose two distinct threats to aquatic life. The first is impingement, which occurs when fish are killed or injured as a result of being pinned against the cooling water intake screens. The second is entrainment, which occurs when aquatic organisms that are small enough to pass through the wire mesh of the cooling water intake screens, are sucked into a facility's cooling water system.[165]

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[162] Hr. Video (Aug. 25, 2023) at 3:00:57 - 3:01:10 (Imber Cross).
[163] Aug. 25, 2023 at 39:27 - 40:11 Hr'g Tr. at (Imber Cross); Corrected LGE Ex. SB4-1 (filed Sept. 8, 2023).
[164] 33 U.S.C. § 1326(b).
[165] 79 Fed. Reg. 48,300, 48,303 (Aug. 15, 2014)

In 2014, EPA finalized rules for cooling water intake structures at coal-burning EGUs.[166] The rule requires that all existing facilities that withdraw more than 2 million gallons of cooling water per day, like Mill Creek, which withdraws 285.7 million gallons a day, to use "best technology available" to avoid fish entrainment and aquatic species impingement.[167] Although the "best" technology available is determined on a site-specific basis, close-cycle cooling system retrofits are assumed to meet the rule's requirements for facilities that withdraw more than 125 million gallons per day.[168] To continue operating Mill Creek Unit 1, the Companies would almost certainly be required to install a $25 million closed-cycle cooling system, making that unit less economical and increasing customer costs even further.[169] Those costs, however, can be completely avoided with the retirement of that unit.

C. EPA's Proposed Carbon Regulations, and the Companies' Subsequent "Stress Test," Confirm that Retiring Mill Creek 1 and 2, Ghent 2, and E.W. Brown 3 Is the Least-Cost, Least-Risk Option.

Retiring Mill Creek 1 and 2, Ghent 2, and Brown 3 will also avoid environmental compliance costs and risks associated with *inevitable* EPA regulations governing greenhouse gas emissions from existing electric generating units. Indeed, the Supreme Court has confirmed that carbon dioxide ("CO_2") is an air pollutant subject to regulation under the Clean Air Act,[170] and EPA has repeatedly concluded that CO_2 emissions "endanger public health or welfare."[171] As a result, EPA has a mandatory duty under the Clean Air Act to regulate carbon dioxide emissions from new and existing

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[166] *Id.* (codified at 40 C.F.R. Pts. 122 and 125).
[167] 79 Fed. Reg. at 48,300; *see also* LG&E/KU Resp. to JI DR1 LGE KU Attach to Q101f-h – Attach 3 at 197-98.
[168] 79 Fed. Reg. at 48,348; *see also* Aug. 25, 2023 at 5:28:37 - 5:30:42 Hr'g Tr. at (Imber Cross).
[169] Corrected LGE Ex. SB4-1 (filed Sept. 8, 2023).
[170] *Massachusetts v. EPA*, 549 U.S. 497, 532 (2007).
[171] *See Coal. for Responsible Regulation, Inc. v. EPA*, 684 F.3d 102, 116-25 (D.C. Cir. 2012) (upholding EPA's 2009 Endangerment Finding, 74 Fed. Reg. 66,496 (Dec. 15, 2009)), *aff'd in relevant part by*, *rev'd in part on other grounds sub nom. Util. Air Regulatory Grp. v. EPA*, 134 S. Ct. 2427 (2014); 80 Fed. Reg. 64,510 (Oct. 23, 2015)

fossil-fuel electric generating units.[172] Moreover, in the Inflation Reduction Act 2022, Congress specifically amended the Clean Air Act to make clear that greenhouse gases are regulated "air pollutants" within the meaning of the Clean Air Act, and appropriated funds to EPA "to ensure that reductions in greenhouse gas emissions [from electricity generation] are achieved through use of the existing authorities of" the Clean Air Act. Pub. L. No. 117–169 (2022), 75 Stat. 1818, § 60107 (codified at 42 U.S.C. 7435(a)(6)); *see also* 75 Stat. 1818, §§ 60101–60108, 60111–60114, 60116, 60201, 60503, 60506.

Although EPA has discretion in establishing the stringency of any CO_2 emission limitations, the agency cannot issue regulations that achieve merely nominal or marginal emission reductions. Instead, performance standards under the Clean Air Act require EPA to cut pollution "as much as practicable" within the confines of the law. *Sierra Club v. Costle*, 657 F.2d 298, 326 (D.C. Cir. 1981).[173] Moreover, under the Clean Air Act, EPA must review and, if appropriate, revise its CO_2 emission standards for new EGUs at least every eight years, 42 U.S.C. § 7411(b)(1)(B); and under section 111(d), EPA must likewise establish emission guidelines covering "any existing source for any air pollutant" when it establishes new source standards, 42 U.S.C. § 7411(d)(1). EPA last promulgated CO2 performance standards for new fossil fuel-fired EGUs on October 23, 2015, 80 Fed. Reg. 64,510 (Oct. 23, 2015), and therefore the agency has a statutory duty to review and update those standards by October 23, 2023. In other words, like EPA's obligation to regulate interstate ozone pollution, the agency's obligation to impose meaningful CO_2 emission limitations at existing power plants like Mill Creek, Ghent, and Brown is *not* going away.

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[172] 42 U.S.C. § 7411(b)(1)(A)-(B) and (d).

[173] In 1977, Congress amended section 111 to require new source standards reflecting "the best technological system of continuous emission reduction" and existing source standards reflecting the "best system of continuous emission reduction." Clean Air Act Amendments of 1977, Pub. L. No. 95-95, § 109(c)(1)(A), 91 Stat. 685, 699-700. In 1990, Congress restored the original "best system of emission reduction" for both new and existing source standards. Clean Air Act Amendments of 1990, Pub. L. No. 101-549, § 403(a), 104 Stat. 2399, 2631.

On May 23, 2023, EPA proposed statutorily required CO_2 emission limits for new and existing EGUs. [174] For existing coal-burning EGUs, like Mill Creek, Ghent, and Brown, EPA's proposed 111(d) regulations establish four subcategories of emission limitations, known as the "best system of emission reduction," depending on the anticipated retirement date of the unit.[175] Under the proposed rule, each subcategory would be required to comply with their respective emission limitation by 2030.[176] As reflected in the table below, if EPA's proposed CO_2 regulations are finalized as proposed, Mill Creek 1 and 2, Ghent 2, and Brown 3 cannot be operated beyond 2032, without incurring significant costs in the form of a 20% capacity factor and lost revenue,[177] significant and cost-prohibitive capital investments to convert those units to burn gas,[178] or potentially hundreds of millions of dollars to retrofit the units to add carbon, capture, and sequestration technology.

Table 3: Summary of EPA's Section 111(d) Rule for GHG Emissions from Existing EGUs[179]

Existing coal-fired EGU subcategory	**Definition**	**Emission Standard (Best System of Emission Reduction)**	**Compliance Deadline**
Long-term	Coal-fired EGUs that do not make a federally-enforceable commitment to	88.4 percent reduction in CO_2 emissions (Carbon, Capture, and Sequestration with 90	2030

[174] 88 Fed. Reg. 33,240, 33,359 (May 23, 2023).
[175] *Id.* at 33,341.
[176] *Id.*
[177] Aug. 25, 2023 at 6:12:40 - 6:13:38 Hr'g Tr. at (Imber Cross).
[178] *See* LG&E/KU Resp. to Staff 5-2 at 9; LG&E/KU Resp. to SC 1-20; LG&E/KU Resp. to JI 1-1.
[179] 88 Fed. Reg. 33,240, 33,359 (May 23, 2023); see also KU/LGE Resp. to Staff 5-2 at 6 of 22.

	permanently cease operations by January 1, 2040.	percent capture efficiency)	
Medium-term	Coal-fired EGUs that make a federally-enforceable commitment to permanently cease operations after December 31, 2031, and before January 1, 2040, and that are not near-term units, as defined below.	16 percent reduction in CO_2 emissions (Natural gas co-firing at 40 percent).	2030
Near-term	Coal-fired EGUs that make a federally-enforceable commitment to permanently cease operations after December 31, 2031, and before January 1, 2035,	No increase in emissions (routine methods of operation)	2030

	and also commit to adopt an annual capacity factor limit of 20 percent of their baseline emissions of the average of the preceding two years.		
Imminent-term	Coal-fired EGUs that make a federally-enforceable commitment to permanently cease operations before January 1, 2032.	No increase in emissions (routine methods of operation)	2030

Although the 2022 Inflation Reduction Act increases the so-called 45Q tax credit for the carbon, capture, and sequestration investments from $50 per metric ton captured to $85 per metric ton,[180] the installation of CCS technology at Mill Creek, Ghent, or E.W. Brown would still be extraordinarily expensive. EPA's cost calculations, published as part of its proposed 111(d) rulemaking, make clear that even with the IRA's enhanced tax credit, the installation of CCS

[180] 26 U.S. Code § 45Q(a);88 Fed. Reg. at 33,348.

technology at Mill Creek 1 or 2, Ghent 2, or E.W. Brown would impose hundreds of millions of dollars in additional costs on ratepayers.[181] Indeed, the capital costs for installation of CCS for each unit would exceed $2,500/kW. Moreover, even accounting for the Inflation Reduction Act's 45Q $85 per ton tax credit, installation and operation of CCS would cost between $26 and $35 per ton removed, which is significantly more than the $0 per ton that LG&E/KU assumed in its modeling. Given that these units each emit millions of tons annually, installing operating CCS would impose a significant cost on customers.

Table 4: Summary of EPA Estimated Cost of Installing Carbon, Capture, and Sequestration[182]

Plant Name	**Unit ID**	**Capacity (MW)**	Capital Costs ($/KW)	Capacity Derated (MW)	CO2 Emissions (Tonnes)	CO2 Emission Rate (Tonne/MWh)	Total Costs ($/MWh)	Total Costs ($/Ton)
Ghent	2	495	2,578	333	173,994	0.15	25	26
E W Brown	3	409	2,963	262	154,126	0.17	31	31
Mill Creek (KY)	1	300	2,572	202	105,392	0.15	32	34

[181] At the hearing in this matter, the Commission took notice of EPA's cost calculations, 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.
[182] *See id.*

Mill Creek (KY)	2	297	2,632	198	105,124	0.15	33	35

Moreover, as explained by Mr. Imber, the costs of installing an operating CCS technology could be much higher than EPA estimates, for several reasons. First, as indicated in the table above, the operation of CCS technology itself uses a significant amount of energy, effectively derating the generation capacity (and thus the value) of any unit.[183] Second, to operate properly, CCS systems are extremely sensitive to the presence of sulfur oxides in the flue gas stream, which may necessitate additional investment in pollution control equipment to make CCS economic.[184] This is particularly true of Ghent 2, which, as discussed, has a relatively high sulfur dioxide emission rate, and may require additional costs to reduce SO2 emissions to a level sufficient for CCS technology to be effective.[185] Third, CCS technology requires significant amounts of additional cooling water, which will increase overall operational costs. Fourth, the installation of CCS may necessitate the acquisition of additional land sufficient to cite such a project. And finally, CCS will require significant transportation or storage costs given that potential CO_2 storage is limited near Ghent, Mill Creek, and E.W. Brown. As a result, transportation and storage sites outside of Kentucky would "likely

[183] Aug. 25, 2023 at 6:57:06 - 6:57:56 Hr'g Tr. at (Imber Cross).
[184] Aug. 25, 2023 at 6:54:22 - 6:56:34 Hr'g Tr. at (Imber Cross). SO_2, which is an ubiquitous combustion byproducts found in coal unit flue gas, reacts with the amine solvent necessary to capture CO_2, the efficiency of the CO_2 capture system and increasing the energy needed to operate a CCS system at a high CO2 removal efficiency. This increase in required energy and decrease in efficiency may, in some circumstances, make an amine system prohibitively expensive to run. *See, e.g.*, 88 Fed. Reg. at 33,413 (proposed 111(d) regulations explaining that "most CCS technologies work much more effectively when the EGU is emitting the lowest levels of SO_2 possible").
[185] Aug. 25, 2023 at 6:55:27 - 6:56:17 Hr'g Tr. at (Imber Cross); 88 Fed. Reg. at 33,349 ("To achieve the necessary limits on SO2 levels in the flue gas for the capture process, steam generating units will need to add an FGD column, if they do not already have one, and may need an additional polishing column.").

need to be identified and the necessary pipelines would need to be sited and built, perhaps for hundreds of miles."[186] None of those site-specific costs or compliance risks are reflected in EPA's cost estimate, and could increase the overall cost significantly.

Despite EPA's potential *underestimate* of CCS costs for Mill Creek, Ghent, and E.W. Brown, the agency's proposed 111(d) rule and the underlying cost analysis provide two important data points confirming that retiring Mill Creek 1 and 2, Ghent 2, and E.W. Brown 3 is the least-cost, least risk option for ratepayers. First, EPA's proposed 111(d) regulation and cost analysis corroborates LG&E/KU's May 2023 analysis demonstrating that retrofitting Ghent 2 or Mill Creek 1 or 2 with SCR technology is *not* the least-cost option for customers.[187] As discussed above, that analysis demonstrated that adding SCR to Ghent 2 was significantly less favorable than retiring the unit in five of six fuel price scenarios, and that "adding SCR is unfavorable even in the fuel price scenario most favorable to coal … unless Ghent 2 can continue to operate until at least 2049—all assuming no CO_2 pricing or other constraint."[188] But EPA's proposed 111(d) rule, if finalized, makes clear that Ghent 2 *cannot* operate until 2049 without installing CCS technology.[189] Moreover, in light of EPA's analysis showing that CCS at Ghent 2 would cost $26 per ton removed (even when accounting for the Inflation Reduction Act's tax credits), it now appears that retrofitting Ghent 2 to add SCR technology would be more expensive than retiring the unit under all scenarios.

Moreover, LG&E/KU's May 2023 analysis demonstrates that installing an SCR on Mill Creek 1 and 2 and operating them through the end of the 2050 analysis period is *never* lower cost than retiring and replacing the units.[190] Thus, even if CCS could be installed at those units at zero

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[186] LG&E/KU Resp. to Staff 5-2 at 7 of 22.
[187] *See* 2022 Resource Assessment at 26 (May 2023 Update to SAW-1), Attachment 2 to Response to JI-2 Question No. 60(a).
[188] *Id.*
[189] LG&E/KU Resp. to Staff 5-2 at 8 of 22.
[190] *Id.* at 9.

dollars per ton (i.e., 45Q tax credits covered 100 percent of the cost), retrofitting the Mill Creek units with SCR would still cost more than retiring and replacing them. Yet, EPA's cost analysis indicates that installing CCS at Mill Creek would cost \$34-35 per ton of CO_2 removed, which would only make the cost of installing SCR and continuing to operate the units more expensive.

Second, EPA's 111(d) cost calculations also corroborates the CO_2 price that LG&E/KU used in its "stress test" evaluating the cost implications of EPA's proposed regulations for new and existing fossil fuel-fired EGUs.[191] Specifically, in response to EPA's proposed CO2 regulations for new and existing sources, LG&E/KU ran a stress test that incorporated certain assumptions for any new gas resources added to the system. For new combined cycle units, LG&E/KU assumed a 50 percent annual capacity factor beginning in 2032, to comply with EPA's proposed regulations for new units.[192] LG&E/KU also included CO2 price assumptions that would evaluated the Ghent and Mill Creek SCR investment decisions and continued Brown 3 investments in the light most favorable to continued operation—namely, the Company include a scenario with a zero dollar per ton CO_2 case, which assumed that the Inflation Reduction Act 45Q tax credits pay for 100 percent of CCS cost.[193] The stress test also included \$15 and \$25 per ton CO_2 costs to evaluate the economics of retrofitting and continuing to operate those units in the event that the Inflation Reduction Act tax credits do not cover the total cost of CCS.

EPA's cost calculations demonstrate that it is *not* reasonable to assume that CCS will impose no additional cost to continue operating Mill Creek, Ghent, or E.W. Brown. Indeed, even with an \$85 per ton tax credit under the Inflation Reduction Act, EPA estimates that installing CCS at Ghent 2 will result in a cost of \$26 per ton of CO_2; at E.W. Brown 3, CCS would cost an additional \$31 per ton; and at Mill Creek, CCS would cost \$34-35 per ton. Those costs roughly align with the

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[191] *Id.* at 7.
[192] *Id.* at 9.
[193] *Id.* at 10.

Company's high-carbon cost assumption of $25 per ton. And with that cost assumption, LG&E/KU's analysis demonstrates that retiring each of those units is lower cost under every scenario than adding SCR and continuing to invest in the operation of those units.[194]

In sum, for a coal-heavy utility, such as LG&E/KU, retiring the coal units as proposed is important to mitigate the risk of future carbon regulation. One way or another, carbon regulations in the power sector will be imposed in coming years. LG&E/KU proposal to retire coal units in this case should be approved for the further reason that doing so is a hedge against future more-stringent carbon regulations.

IV. As LG&E/KU's Data on Winter Storm Elliott Demonstrated and Post-Hearing Data Confirms, Coal-Fired Generation Is Not Fully Reliable. The Commission Should Adopt an ELCC-Type Analysis In Determining Portfolio Reliability.

Both the information provided at the hearing about Winter Storm Elliott and information in post-hearing data requests demonstrates that LG&E/KU's coal units cannot be relied upon to perform at full capacity when needed, including during extreme weather. In other words, Winter Storm Elliott alone shows that the idea that coal is operating at an effective load carrying capacity (ELCC) of 1 and is 100% reliable is inaccurate. The Commission should take these serious reliability failures into account in evaluating the retirement proceedings: coal failed to keep the lights on during Winter Storm Elliott. And data provided by LG&E/KU post-hearing demonstrates that LG&E/KU's coal fleet in fact has significant forced outages, both frequently during winter weather and otherwise.

LG&E/KU's data on this information has concerning discrepancies. Data provided by the Companies post-hearing is seriously inconsistent with the graph provided in Witness Sinclair's rebuttal testimony and discussed extensively at the hearing. For example, some post-hearing data shows that December 23, 2022 was in fact the date with the highest loss of megawatt-hours due to

[194] Id. at 14, Table 2.

forced outages, contrary to the information in the rebuttal testimony.[195] The Companies have not acknowledged or explained the discrepancies between these two sets of information. Moreover, LG&E/KU's own after-action report on Winter Storm Elliott fails to accurately tally the 822+ MW of coal-fired generation unavailable during rolling blackouts, despite all of the relevant information being contained in that report.

For evaluation purposes in this proceeding, the Commission should ideally account for the reliability failures of thermal generation, discounting thermal generation based on the limited information available for reliability purposes in a way commensurate with ELCC. During Elliott, 18% of LG&E/KU's coal-fired generation was unavailable at customers' time of peak need, when LG&E/KU implemented rolling blackouts. The Commission could create a rough proxy for ELCC for all. In any event, LG&E/KU's own data shows that coal-fired generation should not be considered fully reliable but should be evaluated for reliability like all other forms of generation. Its capacity, too, should be discounted as for other sources of generation to determine contribution to reliability. And Brown 3's failure at a time of peak need means that that unit certainly should not be considered a strong contributor to reliability.

It is troubling that LG&E/KU is not accurately monitoring information about winter weather outages in the thermal fleet and correlated outages more broadly. It is especially concerning that LG&E/KU has not recognized problems with correlated outages in the coal and gas fleet due to cold weather, despite ample indication in post-hearing data that such problems in fact exist.[196] It is equally concerning that LG&E/KU does not attempt to account for these problems in its resource

[195] *Compare* Sinclair Reb. Test. at 80:1 *with* LG&E/KU Response to Sierra Club Post-Hearing Data Request Question No. 4.1(c) (attachment).
[196] *E.g.*, LG&E/KU Response to Sierra Club Post-Hearing Data Request No. 4.1(c) (attachment) (listing megawatt-hours of forced outages due to coal and gas failures in winter weather); *see infra.*

planning, instead viewing them—erroneously—as extremely rare and not a subject for planning.[197] Going forward, the Commission should require LG&E/KU to analyze correlated outages and represent them appropriately in modeling, adopting a system similar to ELCC and applying it to thermal as well as other generation, or joining an RTO with such a system.

A. Winter Storm Elliott: Roughly the Same Amount of Coal-Fired Generation as Gas-Fired Generation Unavailable During Rolling Blackouts

As LG&E/KU's own after-action report shows, outages due to reliability issues—both related and unrelated to Winter Storm Elliott—caused the loss of 822 to 836 MW of LG&E/KU's coal-fired generation at the Companies' time of peak need. This is more than twice the generation needed to prevent rolling blackouts during Winter Storm Elliott: LG&E/KU shed 317 MW of load at the time of peak need.[198] If a fraction of this coal-fired generation had been available, LG&E/KU would not have had rolling blackouts. 390 MW were unavailable due to the cold weather—more than the amount needed to stop rolling blackouts. Coal-fired generation is not impervious to cold weather outages, as Winter Storm Elliott demonstrates. Coal-fired generation is, like other forms of generation, plainly subject to correlated outages in cold weather.

LG&E/KU's coal-fired generation failures were therefore one cause of the rolling blackouts during Winter Storm Elliott. They were not the sole cause. An additional 65-150 MW of coal-fired generation from OVEC were also unavailable, for a total of 887-986 MW of missing coal generation as combined between LG&E/KU and OVEC. Further, as LG&E/KU has previously publicly confirmed, 785-943 MW of gas-fired generation were unavailable due to loss of pressure along a gas pipeline. And LG&E/KU was unable to import 400 MW from PJM, as a non-member.[199]

[197] Hr. Video (Aug. 22, 2023) at 9:42:30 (Commission Staff questioning of Mr. Bellar); Hr. Video (Aug. 23, 2023) at 2:52:15 (Commission Chair questioning of Mr. Bellar).
[198] LG&E/KU Response to Att'y Gen. Question No. 1-13(l) (attachment) ("Winter Storm Elliott: Events in the LG&E and KU Balancing Area Authority (BAA), December 23-24, 2022," hereinafter "Winter Storm Elliott Events").
[199] Winter Storm Elliott Events at 1.

However, the amount of LG&E/KU's coal-fired generation that was unavailable at the time of peak need during Winter Storm Elliott due to reliability failures, 822-836 MW, is roughly on par with the amount of gas-fired generation lost due to gas pressure failures, 785-943 MW.[200] Throughout 2022, *more* coal-fired generation than gas-fired generation was offline due to extreme weather: 57% of megawatt-hours that were lost due to cold weather was due to cold weather failures of coal-fired generation, while 43% was due to failures of gas-fired generation.[201] Nevertheless, the Companies have primarily focused on gas, not coal, in assigning blame and discussing remedial measures in this litigation.[202] This is obviously concerning on a going-forward basis as to the Companies' recognition of the reliability failures of coal-fired generation and need for system planning for greater winter weather reliability in the face of those failures.

1. *Coal-Fired Generation Failures During Winter Storm Elliott*

Including the missing megawatts from OVEC, LG&E/KU lost at least 887 MW and possibly up to 986 MW due to the combined failures of its own coal-fired generation (both weather-related and not) and those of OVEC, a coal-fired cooperative. Again, LG&E/KU had rolling blackouts due to a 317-MW shortfall. If at least 317 MW of this coal-fired generation had been available, the Companies would not have had rolling blackouts during Winter Storm Elliott—as multiple witnesses for LG&E/KU confirmed in this proceeding.[203] In addition to the 822-836 MW of coal that

[200] Winter Storm Elliott Events at 2 ("During the time of the load shedding event, derates attributable to the inability of Texas Gas to meet contractual delivery obligations ranged from 785MW to 943 MW."). An additional 138 MW of gas-fired generation at Brown 10 had been offline since December 3 due to a need for turbine seal repairs. Winter Storm Elliott Events at 3.
[201] LG&E/KU Response to Sierra Club Post-Hearing Data Request No. 4.1(c) (attachment).
[202] *E.g.*, Hr. Video (Aug. 22, 2023) at 9:42:30 (Commission Staff questioning of Mr. Bellar); Hr. Video (Aug. 23, 2023) at 2:52:15 (Commission Chair questioning of Mr. Bellar).
[203] Hr. Video (Aug. 22, 2023) at 5:38:50 (Sierra Club cross-examination of Mr. Bellar); Hr. Video (Aug. 24, 2023) at 8:23:30 (Sierra Club cross-examination of Mr. Schram).

Specifically, LG&E/KU experienced the following coal generation failures (including the failure of the coal-fired cooperative OVEC to deliver electricity) during the period in which it had rolling blackouts with up to 317 MW of load shed:

- **Trimble County 1, 370 MW coal-fired unit, offline.**[204] On December 22 at 3:35 PM, Trimble County 1 went offline "due to failure of submerged drag chain conveyor hydraulic gearbox."[205] This was a mechanical failure in the part of the unit that removes bottom ash: as LG&E/KU Witness Bellar explained, "it basically froze up."[206] The mechanical issue was the cause of the unavailability of the unit at the time of peak need during Elliott. LG&E/KU Witness Bellar explained, "We would have had ample generation to serve load had that unit not been forced off."[207]
- **Brown 3, 62-76 MW derate of coal-fired unit.** On December 23 at 7:17 AM, Brown 3 derated by 62 MW due to issues with excess slagging.[208] It derated up to 76 MW during the time of peak need in Winter Storm Elliott. This mechanical failure was unrelated to winter weather.[209] **Note that Brown 3 is one of the units that LG&E/KU seeks to retire in this proceeding: Brown 3's failures during Elliott suggests that it is particularly unreliable.**

[204] Trimble County 1 also supplies power to other utilities; LG&E/KU has 370 MW of generation from the unit. Winter Storm Elliott Events at 3.
[205] Winter Storm Elliott Events at 3; Hr. Video (Aug. 22, 2023) at 5:33:20 (Sierra Club cross-examination of Mr. Bellar).
[206] Hr. Video (Aug. 22, 2023) at 5:34:00. Trimble County 1 has 75 MW that could in theory co-fire with gas. Doing so "would not be routine at all" and "would only be in an extreme emergency to avoid . . . curtailing load or something of that nature," as Witness Bellar explained. Hr. Video (Aug. 22, 2023) at 5:36:45 (Sierra Club cross-examination of Mr. Bellar). Witness Bellar stated that the "proper way to look at it" is that all 370 MW had been forced out due to the mechanical failure. Hr. Video (Aug. 22, 2023) at 5:38:00; *see also id.* at 5:50:30.
[207] Hr. Video (Aug. 22, 2023) at 5:38:50 (Sierra Club cross-examination of Mr. Bellar).
[208] Hr. Video (Aug. 22, 2023) at 5:45:00 (Sierra Club cross-examination of Mr. Bellar).
[209] Hr. Video (Aug. 22, 2023) at 5:44:45 (Mr. Bellar describing the issue as "routine challenges that you can have in operating a unit").

    - The mechanical failure at Brown 3 persisted past the time of peak need. On December 25 at 9:15 PM, all 400 MW of the unit came offline entirely.

- **Trimble County 2, 269 MW derate of coal-fired unit.** On December 23 at 3:48 PM, "a frozen boiler feed pump transmitter . . . caused a unit runback that tripped a coal mill."[210] LG&E/KU Witness Bellar stated that this was "not an uncommon event," although it "was somewhat weather-related."[211]
    - Trimble County 2 had already experienced issues due to cold weather. Earlier that day, at 3:10 PM, Trimble County 2 derated by 37 MW for LG&E/KU[212] because of "low inlet air temperature into the air heater." In essence, the cold air temperature prevented the water coil air heater from reaching the necessary temperature. This derate continued until December 27 at 4:30 PM, even after Trimble County 2 recovered from its larger derate.[213]

- **Mill Creek 4, 121 MW derate of coal-fired unit.** On December 23 at 4:13 PM, Mill Creek 4 "lost a coal feeder" due to cold weather: the "coal tripper froze up."[214] The unit was offline at LG&E/KU's time of peak need and came back online at 6:44 PM.[215]

- **OVEC, 65-150 MW interruption in energy deliveries from coal-fired generation.** LG&E/KU expected OVEC to deliver 156 MW on December 23, but OVEC actually delivered only "91 MW to as little as 6 MW" during LG&E/KU's time of peak need.[216]

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[210] Winter Storm Elliott Events at 5.
[211] Hr. Video (Aug. 22, 2023) at 5:52:08 (Sierra Club cross-examination of Mr. Bellar).
[212] Trimble County 2 also serves other utilities. Winter Storm Elliott Events at 4.
[213] Winter Storm Elliott Events at 5.
[214] *Id.*
[215] *Id.*
[216] *Id.* at 1.

LG&E/KU witnesses reinforced that LG&E/KU itself *does not* anticipate that coal units will perform successfully 100% of the time. As Witness Bellar explained, the Companies "don't expect every unit to operate perfectly."[217] LG&E/KU Witness Schram similarly noted, "Our system on any given day is almost never perfect. . . . . [T]his is pretty complex equipment, it is subject to cold weather stresses, and you do see these types of derates in colder weather."[218]

B. LG&E/KU Data Errors and Discrepancies in Evaluating Forced and Correlated Outages

Troublingly, LG&E/KU has repeatedly provided information with inaccuracies or discrepancies related to forced and correlated outages. LG&E/KU's own after-action report inaccurately tallies Winter Storm Elliott information, and information provided in post-hearing data requests is inconsistent with information provided in rebuttal testimony.

With respect to Winter Storm Elliott, LG&E/KU failed to add up the relevant megawatts correctly and accurately recognize the extent of the Companies' coal generation failures in the Companies' own after-action report on Winter Storm Elliott. LG&E/KU's after-action report states, "During the time of the load shedding event, derates attributable to the inability of Texas Gas to meet contractual delivery obligations ranged from 785 MW to 943 MW. Derates unrelated to Texas Gas supply ranged from 45MW to 361MW."[219] But, as confirmed in cross-examination,[220] coal-fired derates due to cold weather totaled 390 MW at the time of load shed: 269 MW lost at Trimble County 2 due to cold weather failures, and 121 MW at Mill Creek 4. An additional 432 MW of coal generation were offline due to mechanical failures: 370 MW at Trimble County 1 and 62 MW at Brown 3. Again, this total is 822 MW of LG&E/KU's own coal-fired generation offline, 390 MW

[217] Hr. Video (Aug. 22, 2023) at 5:52:08 (Sierra Club cross-examination of Mr. Bellar).
[218] Hr. Video (Aug. 24, 2023) at 8:22:15 (Sierra Club cross-examination of Mr. Schram).
[219] Winter Storm Elliott Events at 1.
[220] Hr. Video (Aug. 22, 2023) (Sierra Club cross-examination of Mr. Bellar).

due to cold weather.[221] Both of these figures are evident from the after-action report and were confirmed under cross-examination. Concerningly, both the total 822 MW of failed coal generation and the 390 MW offline specifically due to cold weather are significantly more than the "45MW to 361 MW" that that same after-action report claims were unavailable during the winter storm event.

Also of serious concern, there are significant and serious discrepancies between the data provided in the graph in Witness Sinclair's rebuttal testimony, "Daily MWh Lost – Annual Averages and Cold Weather Event Days" (Sinclair Graph)[222] and data provided by LG&E/KU in response to Sierra Club's post-hearing data requests ("Post-Hearing Data").[223] The Sinclair Graph shows an average daily forced outage range of roughly 7,000-14,000 MWh, with an average that appears to be roughly 10,000. But the Post-Hearing Data shows an average daily forced outage rate of roughly 5,000 MWh across the nine years. Further, there are significant discrepancies between the two sets of data for the specific cold-weather event days:[224]

- **January 3 and January 8, 2014 were the days during the 2014 polar vortex that had the highest level of forced outages. But they were not included in the Sinclair Graph as a cold-weather event day, even though January 6 and 7, with lower levels of forced outages, were.** The 2014 polar vortex data in the Sinclair Graph includes January 6 and 7, 2014, but it does not include January 3 or January 8, 2014. The Post-Hearing Data shows that on January 3, 2014, LG&E/KU had 12,068 MWh of forced outages, and on January 8,

[221] This figure does not include the additional 65 to 150 MW of coal-fired electricity failure from OVEC.
[222] Sinclair Reb. Test. 80:1.
[223] LG&E/KU Response to Sierra Club Post-Hearing Data Request.
[224] All Post-Hearing Data in the bullet points below is found in LG&E/KU Response to Sierra Club Post-Hearing Data Request No. 4.1(a)-(b) (attachment). There also appear to be significant discrepancies *within* the post-hearing data. Summing the unit-specific MWh lost data on December 23, 2022 provided in response to Sierra Club Post-Hearing Data Request No. 4.1(d) (attachment) yields a much lower figure for MWh lost, one that seems to be the same as the figure in the Sinclair Graph.

2014, LG&E/KU had 10,065 MWh of forced outages. This figure is far higher than the forced outages on the two days that were included as "cold weather event days" in the Sinclair Graph (6,030 MW on January 6 and 4,655 MW on January 7).

- **Post-Hearing Data shows far higher levels of forced outages on the February 19 and 20, 2015 cold weather event days than the Sinclair Graph does.** The Post-Hearing Data shows that on February 19, 2015, and February 20, 2015, LG&E/KU had over 11,000 MWh of forced outages each day: 11,529 MWh on February 19, and 11,119 MWh on February 20. The Sinclair Graph reflects only 3,000 MWh of outages for those same days.
- **Post-Hearing Data shows far higher levels of forced outages on December 23, 2022, the date of rolling blackouts during Winter Storm Elliott, than the Sinclair Graph does.** The Post-Hearing Data shows 27,075 MWh of forced outages on December 23, 2022, during Winter Storm Elliott. The Sinclair Graph shows less than 14,000 MWh of forced outages on the same day, including gas pressure issues.
- **Post-Hearing Data shows many dates during and after Winter Storm Elliott with very high forced outages that were not identified as cold weather event days on the Sinclair Graph. Six of the ten highest forced outage days in 2022 occurred from December 24 to December 29, 2022—including outages on December 24 higher than on December 23. LG&E/KU also had high levels of forced outages on December 30 and 31, 2022.** The Post-Hearing Data shows that on December 24, 2023, LG&E/KU had 31,891 MWh of forced outages—higher than the 27,075 MWh on December 23. On December 25, LG&E/KU had 23,990 MWh of forced outages; on December 26, 23,275 MWh; December 27, 22,604 MWh; December 28, 22,170 MWh; and December 29, 22,228 MWh. These are six of the top ten days for forced outages on the LG&E/KU system for 2022. On December 25, 26, and 27, LG&E/KU lost no MWh to maintenance—indicating

that LG&E/KU was again desperate for power. However, none of these dates were identified as cold weather event days on the Sinclair Graph. Further, on December 30, 2022, LG&E/KU lost 14,478 MWh to forced outages, and on December 31, 13,343 MWh. Again, neither of these days are identified as cold weather event days on the Sinclair Graph.

Witness Sinclair's rebuttal testimony carries the caveat that "[o]utages that occurred prior to the onset of cold weather are not included because they obviously were not caused by the cold weather event."[225] But that fact alone does not seem to account for these serious and significant discrepancies. It certainly does not account for the failure to identify dates close in time to the identified cold weather event days with higher levels of outages as also being cold weather event days, like December 24, 2022 or January 3 and January 8, 2014. Moreover, regular high levels of outages prior to the onset of cold weather would be additional cause for concern about the integrity of LG&E/KU's system—further drawing into question the Companies' assertions as to the reliability of their generation fleet. Finally, Witness Sinclair confirmed that the *average line* on the Sinclair Graph *does* include maintenance outages.[226] Because the rebuttal testimony states that the totals for the cold weather event days in the Sinclair Graph do not include maintenance outages or forced outages that "occurred prior to the onset of cold weather," the implicit comparison that the graph is drawing—between annual averages and cold weather event days—is essentially apples to oranges.

LG&E/KU witnesses have repeatedly claimed throughout these proceedings that the Companies do not experience correlated outages on a regular basis during cold weather. For example, according to Witness Sinclair, "The Companies have decades of experience operating their generation fleet during periodic cold weather events, but they have not seen the types of incremental

[225] Sinclair Reb. Test. at 79:18-20.
[226] Hr. Video (Aug. 28, 2023) at

outages described by Ms. Sommer and the Astrape report."[227] Witness Stuart Wilson stated that "these correlated outages are a concern currently in PJM, but the risk of correlated outages remains low for the Companies moving forward."[228] Witness Bellar told Commission staff, "We're not missing anything in our analysis by not evaluating, considering correlated outages. By their very nature and the way we view those or the way I view those, they're very, very rare events."[229] Witness Bellar later stated that the Companies do not need to model correlated outages because they are "extremely low probability."[230]

But the Post-Hearing Data undercuts those claims. It is simply false that "the Companies' generation assets performed *better* during cold weather events than the average annual levels,"[231] taking into account the information in the Post-Hearing Data. The data for December 23-31, 2022, described above, debunk the idea that LG&E/KU's generation is performing better during winter weather. Seven of the ten days with the highest number of forced outages in 2022 fell within that nine-day span. This is not a series of independent coin flips ending up with the extremely bad luck of multiple generators going out at once. As described above, the events of December 23 demonstrate that during Winter Storm Elliott the Companies experienced correlated outages due to winter weather—for both gas *and* coal generation. Further, the comparatively high levels of outages on January 3 and January 8, 2014 indicate that this is a long-standing problem for the Companies. Additionally, the significant and unacknowledged discrepancies between the Post-Hearing Data and the Sinclair Graph severely undermine confidence that LGE&E/KU is accurately evaluating forced-outage data on the LG&E/KU system, including the nature and extent of correlated outages.[232]

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[227] Sinclair Reb. Test. at 79:12-15.
[228] Stuart Wilson Reb. Test. at 22:1-2.
[229] Hr. Video (Aug. 22, 2023) at 9:42:30 (Commission Staff questioning of Mr. Bellar).
[230] Hr. Video (Aug. 23, 2023) at 2:52:15 (Commission Chair questioning of Mr. Bellar).
[231] Sinclair Reb. Test. at 80:11-15.
[232] LG&E/KU has submitted multiple errata filings in these proceedings, including corrections to the rebuttal testimony of Witnesses Imber, Jones, Schram, and Stuart Wilson on September 8.

The Post-Hearing Data also shows that LG&E/KU has concerningly failed to undertake remedial steps commensurate with the scope of the coal-fired generation outages during Winter Storm Elliott. The after-action review recommendations generated following Winter Storm Elliott center on addressing specific issues primarily relating to gas that arose during the storm. Of particular concern, despite the significant multiple cold weather failures, LG&E/KU will only identify up to 20% of critical components that NERC has urged utilities to identify and protect from freezing by October 2023.[233]

C. Need for an ELCC-Type Analysis that Accounts for Coal and Gas Reliability Failures

The Companies' approach to correlated outages is extremely concerning. LG&E/KU Witness Stuart Wilson agreed that knowing how reliable the Companies' resources are and the weaknesses in the system is part of responsible resource planning.[234] But the Companies do not know the nature and extent of correlated outages on the system. LG&E/KU has provided conflicting information about the number of megawatt-hours lost on critical days. LG&E/KU has obscured the extent of coal-fired generation failures during Winter Storm Elliott, both due to winter weather and otherwise—blaming rolling blackouts solely on a contractor's gas pressure issue rather than also taking responsibility for the Companies' own failures, primarily of coal-fired generation. One LG&E/KU witness, when asked what percentage of LG&E/KU's coal-fired generation the witness expected to derate in winter weather, stated that he did not know.[235] This answer was reflective of the response throughout the proceedings: LG&E/KU has not provided a prediction of how much it expects various sources of generation, including coal, to derate in winter weather.

LG&E/KU has not, however, submitted an errata filing regarding the Sinclair Graph—notwithstanding the discrepancies between the Graph and the Post-Hearing Data.

[233] LG&E/KU Response to Commission Post-Hearing Data Request No. 13, Attachment 2 ("After Action Review Recommendations for Generation from Winter Storm Elliott").

[234] Hr. Video (Aug. 23, 2023) at 6:52:15 (3:07 PM).

[235] Hr. Video (Aug. 24, 2023) at 8:22:45 (4:39 PM).

The limited and conflicting data before the Commission does not provide a full picture of the reliability of the Companies' system, especially the risk of coal-fired generation outages—but the reliability contribution of coal-fired generation should certainly be considered less than nameplate or net capacity. It is clear that LG&E/KU's coal-fired generation has had serious reliability failures, including during extreme weather when it is needed most, and that those reliability failures were one cause of the rolling blackouts during Winter Storm Elliott. It is equally clear that the coal-fired units experienced significant correlated outages during Winter Storm Elliott, that LG&E/KU lacks meaningful data on correlated outages and their causes on the days of highest stress on their system, and that LG&E/KU is not planning for the risk of future, similar correlated outages.

Ideally, the Commission should use ELCC rough proxies for evaluating units' reliability contributions. Here, the Commission could do so by discounting thermal units based on their performance during Winter Storm Elliott: for coal-fired units, decreasing capacity contributions by roughly 18%, and for gas-fired units, conservatively by roughly 30%. For solar, the Commission could and should follow the recommendation of Sierra Club Witness Goggin to increase solar winter capacity valuation to 15%;[236] and for battery storage, following Witness Goggin's recommendation to increase capacity valuation to close to 100%.[237] There are two constraints that may make the use of ELCC rough proxies difficult in this matter. First, practically, a decision in this case is required no later than November 6, 2023,[238] and the current modeling does not use these valuations. Second, a long time horizon—such as the twenty-three years used in the Astrape

[236] Goggin Dir. Test. 26:15-17. As Mr. Goggin explains, "Solar resources provide significant output during the winter, including during morning peak demand periods."
[237] Goggin Dir. Test. 25:1-3.
[238] Section 278.264(1) requires that the Commission enter an order in a retirement proceeding "within 180 days of receiving an administratively complete application."

report[239]—is preferable for gaining a probabilistic understanding of correlated outages, to maximize the amount of information going into the probabilistic distribution.

In any event, LG&E/KU in its planning should use a capacity valuation for thermal resources that is on par with solar resources and storage, and that does not erroneously assume that coal-fired or gas-fired generation is fully available at all times. As Winter Storm Elliott demonstrates, they are not. As a condition of approving retirements in this matter, the Commission should direct that LG&E/KU use an ELCC-type planning structure going forward in order to determine and plan for true reliability on the LG&E/KU system, including for thermal generation. Were LG&E/KU to join an RTO that uses such a planning structure, that would plainly satisfy this requirement.

V. Retirement Approval Is Warranted For Brown 3, Ghent 2, Mill Creek 1 and 2, Haefling 1 and 2, and Paddy's Run 12.

Because a range of replacement portfolios satisfy the requirements of K.R.S. §§ 278.262 and 278.264, retirement is warranted. LG&E/KU's replacement portfolio that includes two 621-MW NGCCs, 637 MW of solar PPAs, 240 MW of LG&E/KU-owned solar, DSM/EE, and one 125 MW, 4-hour battery.[240] satisfies the statutory requirements for retirement. So does Joint Intervenor Witness Sommer's alternative portfolio of one 621-MW NGCC at Mill Creek, 637 MW of solar PPAs, 240 MW of LG&E/KU-owned solar, an additional 65 MW of EE, an additional 35 MW of summer DR and 17 MW of winter DR, and one 120 MW, 4-hour battery.[241] This section analyzes how both these portfolios satisfy the statutory requirements for retirement. The following section analyzes how joining PJM under the RTO's current construct also satisfies the statutory requirements for retirement. Adding PJM to either of these portfolios would further strengthen the case for retirement—though both portfolios are over the retirement threshold already.

A. Section 278.264(2)(a)(1): Dispatchability

[239] *See* Stuart Wilson Reb. Test. at 3:17-19.
[240] Exh. SAW-1 at 6 (May 2023 update).
[241] Sommer Dir. Test. at 28:6-29:2.

Sierra Club agrees with LG&E/KU and with Joint Intervenor Witness John Wilson that the Companies' proposed NGCC units and owned solar facilities are dispatchable under § 278.264(2)(a)(1), for the reasons stated by LG&E/KU and Witness John Wilson.[242] Witness John Wilson ably explains the dispatchability of solar power.[243] The Companies' Witness Stuart Wilson reiterated at the hearing that the Companies view solar resources owned by the Companies as dispatchable.[244] Sierra Club further agrees with Joint Intervenor Witness John Wilson that "with negotiated changes to the solar PPA contracts, those resources could also be fully dispatchable" and that any such changes should be factored in to an analysis of replacement generation pursuant to § 278.264(2)(a).[245]

B. Section 278.264(2)(a)(2): Reliability and Resilience

Both LG&E/KU's proposed portfolio and Joint Intervenor Witness Sommer's single NGCC portfolio "maintain or improve the reliability and resilience of the electric transmission grid." § 278.264(2)(a)(3). Both portfolios have an LOLE of less than one, and both are resilient.

1. *Reliability*

Loss of load analysis demonstrates that both LG&E/KU's proposed portfolio and Witness Sommer's single-NGCC alternative maintain or improve reliability. Witness Sommer performed a loss of load analysis on both portfolios using weather-varying solar shapes, rather than the single solar shape based on the existing Brown solar facility that the Companies used.[246] Witness Sommer

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242 Case No. 2023-122, Exh. SB4-1 at 11; John D. Wilson Dir. Test. at 5.
243 John D. Wilson Dir. Test. at 9:4-22 and 10, Figure 1.
244 Hr. Video (Aug. 23, 2023) at 8:02:00 (4:17 PM) (Sierra Club cross-examination of Mr. Stuart Wilson). LG&E/KU Witness Stuart Wilson clarified that he believed LG&E/KU Witness Crockett's testimony regarding the non-dispatchability of intermittent renewable resources to be specifically about the PPAs, and that the Companies "have considered" owned solar "as a dispatchable resource." *Id.*; *compare* Hr. Video (Aug. 22, 2022) at 2:44:15 (11:36 AM) (Commission Chair questioning of Mr. Crockett).
245 John D. Wilson Dir. Test. at 13:18-22.
246 Sommer Dir. Test. at 28, Table 4, & 35:7-10.

determined that the LOLE for the Companies' proposed portfolio is 0.24 and that the LOLE for the single NGCC portfolio is 0.91.[247] Both of these values are below the 3.57 LOLE that the Companies target[248] and, more importantly for this objective standard, below the commonly accepted and lower (more protective of reliability) LOLE metric of one-in-ten.[249]

LOLE is the appropriate reliability metric, rather than reserve margin. As Witness Sommer explains, the Companies' target reserve margin that is based on their preexisting portfolio (rather than their minimum or economic reserve margin) is also not a meaningful reliability metric. That is because target reserve margins "quickly lose their meaning when examining different portfolio compositions."[250] Portfolios with identical reserve margins may deliver wildly different LOLE values, as here.[251] As Witness Sommer explains, "This is the reason that, if possible, we have a preference for directly evaluating portfolio reliability rather than using a proxy value such as a reserve margin target."[252]

Were the Commission to rely on reserve margin instead of or in addition to LOLE in determining reliability, LG&E/KU's current version of the economic or minimum reserve margin is artificially high. LG&E/KU's reserve margin is currently artificially increased by the excessive value of lost load ("VOLL") that the Companies assume. Currently, for reserve capacities less than 3.8% of the hourly load—that is, less than the 243 MW of contingency reserves that the Companies must carry pursuant to the reserve sharing agreement—the Companies place the VOLL at

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[247] Sommer Dir. Test. at 35, Table 8.
[248] Hr. Video (Aug. 24, 2023), at 3:21:15 (Commission Chair questioning of Mr. Stuart Wilson); Case No. 2023-122, Exh. SB4-1 at 13 ("In this analysis, the Companies treat an LOLE of 3.57 as consistent with maintaining adequate reliability because this LOLE is aligned with the Companies' minimum reserve targets, i.e., any portfolio with a lower LOLE than 3.57 provides more than adequate reliability.").
[249] *See* Levitt Dir. Test. at 14:167-168 & n.25.
[250] Sommer Dir. Test. 26:10-11.
[251] Sommer Dir. Test. 26:7-8.
[252] Sommer Dir. Test. 26:12-14.

$21,000/MWh.[253] As Witness Goggin outlines in his testimony, this is far more than the VOLL used by other system operators: MISO has determined that a $3,537/MWh VOLL is appropriate, for example, while ERCOT has used estimates of $2,000/MWh, $5,000/MWh, and $9,000/MWh.[254]

In real-world data, the maximum price for power during Winter Storm Elliott—a time of grave scarcity for the Companies, when contingency reserves were unavailable—was between $3,000 and $4,000 per MWh.[255] If there were any doubt, Winter Storm Elliott demonstrates that at no time will prices equal $21,000/MWh: that number is artificially high, causing the economic reserve margin to be artificially high as well.

As Witness Goggin explains, "A higher assumed VOLL increases the estimated cost of outages, and thus the optimal reserve margin."[256] This is true in the SERVM model used by the Companies, with "a large impact . . . particularly at higher values."[257] In Astrape Consulting's analysis conducted for ERCOT, Astrape concluded that an economically optimal reserve margin of 13.25% at a $30,000/MWh VOLL decreased to 11% at $9,000/MWh and 10.25% at $5,000/MWh.[258] Thus, the Companies' increased VOLL is overestimating the economic reserve margin "by several percentage points" and thus capacity needs "by several hundred MW."[259] A 3% overestimate in the reserve margin, commensurate with the change in reserve margin for ERCOT between $5,000/MWh VOLL and $30,000/MWh, equates on the Companies' system to a 190-MW overestimate of capacity need.[260]

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[253] Exh. SAW-1 (May 2023 update) at D-20.
[254] Goggin Dir. Test. at 38:15-39:2.
[255] Hr. Video (Aug. 23, 2023) at 7:37:45 (3:54 PM) (Sierra Club cross-examination of Mr. Stuart Wilson).
[256] Goggin Dir. Test. 39:5-6.
[257] Goggin Dir. Test. 39:6-9.
[258] Goggin Dir. Test. 36:9-11.
[259] Goggin Dir. Test. 39:13-40:2.
[260] Goggin Dir. Test. 39:6-40:2.

The issues with VOLL provide an additional reason to rely on LOLE in determining reliability, based on the information available to the Commission at this time. Going forward, the Commission should direct the Companies and other utilities to use a VOLL in their analysis that equates with market prices and with VOLL used by other system operators in conducting reliability analyses. Here, a VOLL between $3,000/MWh and $4,000/MWh—commensurate with the market prices during Winter Storm Elliott—would have been appropriate.

Measurements of LG&E/KU's system reliability against either standard are, of course, currently based on the full net valuation of thermal resources with no ELCC-type analysis. As stated above, Sierra Club believes an ELCC-type analysis is the best valuation of all resources on the system. However, given the time constraints and the fact that all modeling to date has not been done in an ELCC-type method, analysis based on the currently available information may be necessary.

2. *Resilience*

In evaluating resilience, LG&E/KU recommends that the Commission look to start-up times, ramp rates, and range of dispatchable capacity.[261] Joint Intervenor Witness John Wilson recommends that the Commission also take into account fuel diversity, decentralization, and grid services.[262] Sierra Club agrees with Witness John Wilson that these additional considerations are relevant to resilience. Further, evidence of geographic diversity and/or load diversity—such as via joining a regional transmission organization—would increase resilience as well.[263] As both LG&E/KU and Witness Wilson outline, LG&E/KU's proposed portfolio meets resilience

[261] Case No. 2023-122, Exh. SB4-1 at 15.
[262] John Wilson Dir. Test. at 25:18-21, 26:1-15.
[263] *See* Hr. Video (Aug. 23, 2023) at 7:05:15 (3:20 PM) (Sierra Club cross-examination of Mr. Stuart Wilson) (Mr. Wilson describing the benefits of geographic and load diversity).

requirements.[264] The logic is applicable to a portfolio with one NGCC rather than two: in both instances, the logic hinges on the *nature* of the replacement resources rather than on their quantity.

C. Section 278.264(2)(a)(3): Minimum Reserve Capacity

Both LG&E/KU's proposed portfolio and Witness Sommer's single-NGCC portfolio maintain the minimum reserve capacity for contingency reserves. As LG&E/KU explains:

> Based on the Companies' existing resources, they are assumed to carry 243 MW of spinning reserves to meet their reserve sharing obligation and comply with NERC standards. The reserve margin analysis assumes the Companies would shed firm load in order to maintain their spinning reserve requirements........While the Companies are assumed to carry 243 MW of spinning reserves to meet their reserve sharing obligation, this obligation is not included in the peak demand forecast nor as a reduction in generation resources for the purpose of computing reserve margin.[265]

In other words, LG&E/KU automatically factors in the 243 MW-minimum reserve capacity in its analyses, viewing this requirement as separate and distinct from the reserve margin requirement. Alternatively, if the Commission disagreed with this mode of analysis, the Commission could add 243 MW to the portfolios provided. This 243-MW requirement would be offset, though, by the overestimation caused by the excessive LOLE in LG&E/KU's economic reserve margin—likely roughly 200 MW. *See supra*.

D. Section 278.264(2)(b): No Harm to Utility Ratepayers

LG&E/KU has demonstrated that the PVRR for continuing to operate the existing units is higher than retiring those units and adopting LG&E/KU's preferred portfolio.[266] As Joint Intervenor Witness John Wilson detailed, LG&E/KU specifically evaluated a portfolio that retired Ghent 2 and found that in every sensitivity except for high gas price and low coal-to-gas-price ratio, full retirement of Ghent 2 was warranted.[267] In that single sensitivity, LG&E/KU calculated that

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[264] Case No. 2023-122, Exh. SB4-1 at 15-16; John Wilson at 25:11-26:15.
[265] Exh. SAW-1 (May 2023 Update) at D-19-20. LG&E/KU uses "spinning" and "contingency" reserves synonymously. *See supra*.
[266] Case No. 2023-122, Exh. SB4-1, Table 8.
[267] John Wilson Dir. Test. 31:10-13; Case No. 2023-122, Exh. SB4-1, Table 8.

maintaining Ghent 2 would result in savings for customers.[268] All five other sensitivities found that retirement of Ghent 2 was economic—including for high gas prices and the current coal-to-gas ratio.[269] Because the much greater probability based on available information is that Ghent 2 will be *un*economic, the requirement of § 278.264(2)(b) is met.

Further, Witness Sommer has demonstrated that the PVRR for continuing to operate the units is higher than retiring those units and adopting witness Sommer's one-NGCC portfolio. Witness Sommer's one-NGCC portfolio has a PVRR that is $81,887,968 greater than the Companies' proposed portfolio with the adoption of a capital cost sensitivity.[270] This capital cost sensitivity takes into account the "significant risk that the costs of the combined cycle units will go up and materially so," anticipating that costs will rise by 30%.[271] Witness Sommer extensively details the high probability that NGCC cost estimates will increase substantially.[272] In light of this high likelihood, relying on Witness Sommer's PVRR with the capital cost sensitivity is the most prudent approach. Witness Sommer's PVRR without the capital cost sensitivity is higher, with a roughly $290 million increase over the Companies' proposed portfolio. Even with this higher PVRR, however, retiring all requested units and replacing them with Witness Sommer's portfolio is still more economic than continuing to operate the units.

This conclusion from a range of portfolios demonstrates that retirement meets the no harm to ratepayers requirement. As detailed above in Table 1, Mill Creek 1, Mill Creek 2, Ghent 2, and Brown 3 all face the risk of millions of dollars in additional environmental compliance costs in the near to medium-term. Installation of an SCR is a risk not only under the Good Neighbor Plan but pursuant to Clean Air Act § 126, the 2008 ozone NAAQS, the 2015 ozone NAAQS, PM2.5

[268] John Wilson Dir. Test. 31:10-13; Case No. 2023-122, Exh. SB4-1, Table 8.
[269] Case No. 2023-122, Exh. SB4-1, Table 8.
[270] Sommer Dir. Test. at 32:10-13 (Table 6).
[271] Sommer Dir. Test. at 32:6-7.
[272] *E.g.*, Sommer Dir. Test. at 14:18-16:2, 21:2-24:8.

NAAQS, and the regional haze rule. The regional haze rule would not allow the units to evade SCR operation by operating in non-ozone season. LG&E/KU's updated analysis filed September 8 incorporates stay-open costs for the units pursuant to the ELG Rule and, for Mill Creek 1, the need for a cooling tower in compliance with Clean Water Act § 316b, all of which are million of dollars in additional costs for Mill Creek 1, Mill Creek 2, and Ghent 2.[273] Carbon capture and sequestration under section 111(d) of the Clean Air Act would likewise be severely expensive, as detailed in Table 4 above. Directionally and in their magnitude in the millions of dollars, all of these risks of environmental compliance costs all further reinforce the economic risk to LG&E/KU customers from failing to retire Mill Creek 1, Mill Creek 2, and Ghent 2, in particular. Even without including the likely costs of environmental compliance, the no harm to ratepayers requirement is satisfied; adding in the likely costs to each of these units from this "long litany of EPA regulations facing" them,[274] the fact that retirement is the most prudent course of action is even clearer.

E. Section 278.264(2)(c): Decision to Retire Not the Result of Federal Financial Incentives

There can be no serious question that the decision to retire the seven units, including the four coal units, is not the result of federal financial incentives. LG&E/KU has repeatedly stated that the decision to retire Ghent 2 and Mill Creek 2 is due to compliance with federal environmental requirements—not financial incentive that would change the economics of the coal units.[275]

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[273] Corrected LGE Ex. SB4-1 (filed Sept. 8, 2023).
[274] *See* Hr. Video (Aug. 28, 2023) at 1:12:30 (10:17 AM) (Ky. Coal Ass'n cross-examination of Mr. Sinclair).
[275] Bellar Dir. Test. at 3:6-9 ("[T]he fully implemented Good Neighbor Plan . . . makes it uneconomical to continue operating these units because it is uneconomical to equip the units with selective catalytic reduction ('SCR') controls or operate them only outside of the Ozone Season of May 1 to September 30."); Hr. Video (Aug. 22, 2023) at 7:04:00 (3:55 PM) (Sierra Club cross-examination of Mr. Bellar) ("Since the beginning of this case, the underlying reason for the requested retirements of Ghent Unit 2 and Mill Creek Unit 2 is the fact that environmental compliance makes the units uneconomic, correct?" Yes." "And that remains the underlying reason for the requested retirements, correct?" "Yes.").

LG&E/KU determined in its most recent rate cases, which preceded the enactment of the federal Inflation Reduction Act, "that the then projected remaining economic life for Mill Creek Unit 1 should be updated to 2024" and for E.W. Brown 3 to 2028.[276] Those are the units' retirement dates requested in these proceedings.[277] For Mill Creek 1, as for Ghent 2 and Mill Creek 2, the underlying basis for the request is compliance with federal environmental requirements.[278] For Brown 3, "a significant overhaul" is necessary for continued operation beyond 2028.[279] The but-for causes of unit retirement are federal environmental regulations and long-term maintenance costs for the units, not federal financial incentives.

Further, nothing about the RFP process undermines LG&E/KU's expressed rationales. If anything, the RFP process short-changed LG&E/KU customers by failing to robustly solicit bids based on the passage of the IRA, which occurred after the initial solicitation of RFPs.[280] And it's important to remember that this statutory provision does not ask whether the selected replacement capacity would have been chosen had it not been for federal financial incentives. The question is why the fossil fuel-fired plant is retiring, not whether the choice of specific replacement generation is due to a federal financial incentive. For this reason, Joint Intervenor Witness John Wilson's analysis of the financial impacts of different replacement capacity portfolios[281] is not relevant to the

[276] Bellar Dir. Test. at 2:12-15.
[277] Bellar Dir. Test., Case No. 2023-122, at 3:20-4:1, 6:4-6.
[278] Bellar Dir. Test., Case No. 2023-122, at 4:9-20 (explaining that Mill Creek 1 will become uneconomic by the end of 2024 "due to the cost of additional environmental compliance equipment required for the unit to operate beyond 2024," specifically "process water equipment for Effluent Limitation Guidelines compliance" and the need for "a cooling tower to operate beyond 2027 in compliance with Clean Water Act 316(b) regulations").
[279] Bellar Dir. Test., Case No. 2023-122, at 6:4-6; LG&E/KU Exh. SAW-1 (May 2023 Update) at 4 (Brown 3 "is the Companies' coal unit with the highest operating costs and will require a $26 million overhaul in 2027 to operate safely beyond 2028").
[280] Exh. SAW-1 at 11 (describing LG&E/KU requesting that RFP respondents update their response following the passage of the IRA but not soliciting additional bids).
[281] John Wilson Dir. Test. at 35:16-38:15, 45:12-49:16.

Commission's decision: that the retirement decision is *not* due to federal financial incentives is clear on this record.

Finally, as the Companies note, "federal tax credits" that "inure completely to the benefit of customers . . . must be included in any reasonable PVRR analysis to appropriately reflect the cost of such generation supply alternatives."[282] This issue is not dispositive as to § 278.264(2)(c) here, because as described above there is abundant evidence that the retirement decision is not the "result" of federal financial incentives. Nevertheless, the point is an important one for PVRR analysis in retirement proceedings. As detailed above, Section 278.264(c) should not be interpreted as displacing fundamental principles of utility regulation, including affordable and reasonable rates.

F. Section 278.264(3): All Known Direct or Indirect Costs

As described above, LG&E/KU has demonstrated that its replacement portfolio has a lower cost to customers than continuing to operate the units at issue—including for Ghent 2. Witness Sommer has likewise demonstrated that her one-NGCC and renewables replacement portfolio has a lower cost to customers. This is true even before factoring in the likelihood of significant environmental costs not otherwise accounted for in this proceeding. And it is also true without even taking into account the financial benefits of better health for Kentuckians from retiring the coal-fired units.

VI. A Portfolio of Solar Power, Battery Storage, DSM/EE, and Joining the Regional Transmission Organization PJM Warrants Retirement of All Seven Units At Issue.

Lexington/Louisville and Sierra Club Witness Andrew Levitt found that PJM membership, under current PJM constructs, would yield roughly $125 million to $140 million in resource investment cost savings *annually*, through 883 to 1,511 MW of capacity savings. That savings is equivalent to more than one NGCC, and possibly up to two. Witness Levitt described in detail the reasons for these benefits, including geographic diversity, load diversity, and portfolio diversity.

[282] Case No. 2023-122, Exh. SB4-1, at 21.

Winter Storm Elliott drives home the benefits of RTO membership: LG&E/KU experienced rolling blackouts, while Kentucky utilities in PJM did not; LG&E/KU sought to buy power from PJM during its time of greatest need, but PJM held that power back for its members.

LG&E/KU regularly analyzes the costs and benefits of RTO membership. Witness Levitt found that LG&E/KU's most recent study was severely flawed, including in an error that overestimated the cost of RTO membership on the study's own analysis by $200 million. The study's conclusions are contrary to those of dozens of other studies about the costs and benefits of RTO membership, and in light of its methodological flaws and Witness Levitt's contrary conclusions, those conclusions are suspect. In fact, in addition to the portfolios discussed above, a portfolio that includes all 877 MW of solar power, the 125 MW, 4-hour battery, and the DSM/EE proposed by LG&E/KU—but that joins PJM rather than building two 621-MW NGCCs—also satisfies the statutory requirements for retirement.

A. Under Current Constructs, PJM Membership Would Yield Capacity Savings Equivalent to More than One and Up to Two NGCCs Due to Benefits of RTO Membership.

Lexington/Louisville and Sierra Club Witness Andrew Levitt determined that PJM membership, under current PJM constructs, would yield 883 to 1,511 MW of capacity savings for LG&E/KU.[283] Performing the analysis using LG&E-KU's own RTO study, Witness Levitt determined that PJM membership would yield capacity savings in 2028 of 1,123 MW.[284] That amount is only 119 MW less than the 1,242 MW of capacity for the two NGCCs that LG&E-KU seeks to build in its CPCN. The financial benefits associated with these capacity savings, Witness Levitt calculates, are approximately $125 million to $140 million in resource investment costs *per year*.[285] Further, joining PJM has additional benefits: a hedge in both geography and the sheer

283 Levitt Dir. Test. at 28:377-389.
284 Levitt Dir. Test. at 28:383-385.
285 Levitt Dir. Test. at 30.

number of generators in the system against reliability issues; greater integration of and access to wind and solar;[286] and reasonably anticipable production cost benefits.[287]

The immensely significant capacity savings under PJM's current construct derive from three benefits of joining PJM, as Witness Levitt explains: "demand diversity, reduced reserve margins, and increased solar value."[288] First, regarding demand diversity, Witness Levitt concludes: "Through analysis of hourly load shapes in LG&E-KU and PJM, I find a large demand diversity effect, with a coincidence factor of 95%."[289] Witness Levitt explains that formal resource adequacy pooling via an RTO maximizes benefits to utilities from non-coincident peak demand: "The RTO procures resources to meet the common simultaneous peak demand of all members, which (due to demand diversity) is necessarily lower than the sum of each member's individual peak demand."[290] LG&E/KU particularly stands to benefit from this construct, because of LG&E/KU's "mix of winter-peaking years and summer-peaking years versus PJM's summer peaking system."[291] The Companies agree that taking advantage of demand diversity and resource pooling is beneficial to utilities: indeed, that is a reason that Kentucky Utilities and Louisville Gas and Electric Company now operate together.[292]

Second, joining PJM allows LG&E/KU to benefit from a lower reserve margin—requiring the build-up of less generation to reach the same LOLE. Witness Levitt concludes: "By joining PJM, the target reserve margin needed for LG&E-KU to meet the standard 1-in-10 LOLE reliability target would drop by 16% percentage points, from 31% in winter (the most deficient season

[286] Levitt Dir. Test. at 37.
[287] Levitt Dir. Test. at 34:470-473.
[288] Levitt Dir. Test. at 22:308-309.
[289] Levitt Dir. Test. at 23:322-323.
[290] Levitt Dir. Test. at 10:92-94.
[291] Levitt Dir. Test. at 11:109-110.
[292] Hr. Video (Aug. 28, 2023) at 2:20:45 (Sierra Club cross-examination of Mr. Sinclair); Hr. Video (Aug. 23, 2023) at 7:05:15 (3:20 PM) (Sierra Club cross-examination of Mr. Stuart Wilson) (Mr. Wilson describing the benefits of geographic and load diversity).

following retirements) to 14.7%."[293] Moreover, this is a conservative estimate: LG&E/KU's CPCN plan features a summer reserve margin of 36.4% to 40.7% in summer and 29.4% to 36.0% in winter.[294] At the higher ends of these ranges, the reserve margin savings would correspondingly increase.

This lower reserve margin from joining an RTO is because, as Witness Levitt explains, the reserve margin needed to meet a one-in-ten LOLE reliability standard is much lower for PJM than for LG&E/KU:

> In order to determine the reserve margin . . . both PJM and LG&E-KU perform statistical analyses of load shapes, weather, and forced outage patterns. These analyses show that the LG&E-KU system requires a 23% summer reserve margin and a 31% winter reserve margin to meet the 1-in-10 standard, while the PJM system requires a 14.7% annual installed reserve margin to meet that same reliability metric.[295]

Witness Levitt explains that this is because of the benefits of geographic diversity and (relatedly) load diversity, as well as fuel diversity. Geographically larger systems have "more weather diversity and a greater variety in customer demand patterns," which in turn increases load diversity.[296] Lower reserve margins are therefore necessary to meet the same level of reliability, because peak demand is less concentrated.[297] Further, geographic and fuel diversity provide benefits in increased availability of supply: "a large system with more individual generation resources and a more diverse resource mix can provide the same estimated reliability level with a lower reserve margin because the probability that a large fraction of the fleet will be unavailable is proportionately lower."[298]

Third, LG&E/KU seeks to bring online 1,127 MW nameplate of solar resources. As Witness Levitt explains, LG&E/KU's analysis assigns a capacity value of 866 MW in summer and 0

[293] Levitt Dir. Test. at 18:239-241.
[294] LG&E/KU Joint Application at 10.
[295] Levitt Dir. Test. at 14:173-15:178.
[296] Levitt Dir. Test. at 15:185-186.
[297] *See* Levitt Dir. Test. at 15:185-187.
[298] Levitt Dir. Test. at 15:187-190.

MW in winter, while PJM's analysis assigns a 2028 capacity value of roughly 383 MW due to a 34% effective load carrying capability rating.[299] As Witness Levitt explains, this benefit "reflects the greater prominence of summer reliability in the PJM planning environment relative to that in LG&E-KU, itself a function of the particular regional weather, the resulting hourly patterns of demand, as well as resource characteristics."[300]

B. Winter Storm Elliott, In Which LG&E/KU Customers Lost Power But Customers of Kentucky Utilities in PJM Did Not, Demonstrates the Benefits of RTO Membership.

Extreme weather, such as Winter Storm Elliott, concretizes some of the abstract benefits of geographic and fuel diversity, and of RTO membership. First, being part of a larger system—an RTO—means that during extreme weather a utility can take advantage of the fact that not all of the system is likely to be experiencing the extreme weather event at the same time. In other words, stress is spread out differently throughout the grid, and the grid overall is likely less stressed. As Witness Levitt explains:

> In a planning area the size of LG&E-KU, it is less uncommon for the entire area to experience extreme hot or cold weather simultaneously, and so system-wide demand can feature more pronounced extremes. In a larger planning area such as PJM, it is rarer for exceptionally hot or cold weather to affect the entire area at once, and so the extremes of system-wide demand are moderated.[301]

During Winter Storm Elliott, as an example, "all of Kentucky was experiencing extraordinarily low temperature during Winter Storm Elliott, but only a minority of PJM experienced the most extreme exceptional cold during the event," with varying temperatures across the PJM area.[302]

Second, extreme weather events like Winter Storm Elliott demonstrate the benefits of having access to generation from a larger number of units in a larger system. Witness Levitt points out:

> In a smaller system, each generator is proportionately larger compared to the size of the entire portfolio (for example, the three largest generator units in LG&E-KU comprise over

[299] Levitt Dir. Test. at 20:268-271.
[300] Levitt Dir. Test. at 21:278-281.
[301] Levitt Dir. Test. at 16:197-201.
[302] Levitt Dir. Test. at 16:202-205.

> 1,700 MW, compared to a total fleet size of approximately 7,500 MW). Therefore, with just two or three simultaneous unit forced outages, a significant portion of supply can be lost (in this example, 23% of the fleet is lost when the three largest units are unavailable), and replacement power during high-load periods can be more difficult to arrange .... In models that assume random forced outages, events with a larger number of generators facing simultaneous forced outages have a lower estimated probability than those with only a few simultaneous outages.[303]

Finally, being part of an RTO allows a utility to have greater access to the resources across the RTO—that is to say, in times of scarcity an RTO may hold energy back for member utilities. During Winter Storm Elliott, LG&E/KU was "desperate for power" and "looking for all sources of energy to avoid going into a curtailment mode of operation."[304] Beginning at 4:29 PM[305] and continuing throughout the entirety of LG&E/KU's time of rolling blackouts,[306] PJM curtailed 400 MW of imports that LG&E/KU sought. In a situation of load scarcity such as Winter Storm Elliott, PJM curtails imports to utilities that are not members of the RTO in order to hold back that power for its member utilities, which are PJM's priorities.[307] Not only is LG&E/KU more likely than an RTO to experience shortfalls due to its lack of geographic diversity and reliance on a smaller number of generating units, it also is left on its "island"[308] during times of peak need. While other Kentucky utilities are priorities for available power in the RTO to which they belong, LG&E/KU is isolated from broad pools of resources during times of scarcity because of its choice to go it alone, without being part of an RTO. PJM's footprint spans many states; LG&E/KU is part of a reserve

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303 Levitt Dir. Test. at 17:211-18:221.

304 Hr. Video (Aug. 22, 2023) at 6:09:00 (Commission Chair questioning of Mr. Bellar) (Commission Chair: "That's not like an economic, like a power in PJM is $17 a megawatt-hour, we'll take all we can at $17 a megawatt-hour kind of thing. It was you were desperate for power. Is that accurate?" Mr. Bellar: "Correct. We were looking for all sources of energy to avoid going into a curtailment mode of operation, yes.").

305 Winter Storm Elliott Events at 5.

306 Hr. Video (Aug. 22, 2023) at 6:09:15 (3:00 PM) (Sierra Club cross-examination of Mr. Bellar).

307 Hr. Video (Aug. 22, 2023) at 6:11:00 (3:03 PM) (Sierra Club cross-examination of Mr. Bellar).

308 *See* LG&E/KU Response to Joint Intervenors' Post-Hearing Data Request 4.2(e)(i) ("Both portfolios in this modeling exercise—along with all PLEXOS and PROSYM modeling runs for the CPCN—assume no access to the wholesale market (an 'island' mode) to avoid planning for a future based on off-system sales or purchases which might not materialize.").

sharing group only with TVA, which also experienced rolling blackouts during Winter Storm Elliott.[309] **Ultimately, during Winter Storm Elliott, LG&E/KU shed 317 MW of load,[310] while PJM—including its Kentucky member utilities—did not shed load.[311]**

C. LG&E/KU's Most Recent Study of the Cost-Benefit Tradeoff of RTO Membership Contained a Serious Error and Is Flawed.

In November 2022, LG&E/KU filed with the Commission their most recent RTO study, analyzing the costs and benefits of RTO membership for the Companies ("LG&E/KU RTO Study").[312] That study concluded that RTO membership was not in the interest of LG&E/KU customers.[313] This finding is a strong outlier among the "[d]ozens of utility RTO membership studies" that have found benefits from joining RTOs.[314]

As an initial matter, the LG&E/KU RTO Study contained a serious error. The study wrongly concluded that the net present value impact of RTO membership on the Companies would be a cost of $620 million; in May 2022, LG&E-KU revised this number downward to $421 million.[315] This $200 million error was discovered months after the study was filed with the Commission. It was not found by the Companies or their consultant, but by Lexington/Louisville and Sierra Club Witness Levitt in his analysis for this matter.[316] The magnitude of the error, and the fact that it was not discovered by the Companies or their consultant prior to the filing of the study, casts doubt on the quality of the LG&E/KU RTO Study and the robustness of its conclusions more broadly.

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[309] Hr. Video (Aug. 22, 2023) at 6:14:45 (Sierra Club cross-examination of Mr. Bellar).
[310] Winter Storm Elliott Events at 1.
[311] Levitt Dir. Test. at 16:206-207.
[312] Hearing Exh. SC-10 (LG&E/KU, 2022 RTO Membership Analysis).
[313] *Id.* at 4 ("The Companies conclude that seeking RTO membership at this time likely would not benefit customers.").
[314] Levitt Dir. Test. at 38:498-499.
[315] LG&E/KU Response to Sierra Club Question Nos. 2-24(c), 2-26(b).
[316] Levitt Dir. Test. at 39:537-539; Hr. Video (Aug. 28, 2023) at 2:12:15 (11:28 AM) (Sierra Club cross-examination of Mr. Sinclair).

In addition to the specific $200 million error, Witness Levitt identified a series of methodological flaws in the LG&E/KU RTO Study. These flaws include:

- An "inefficient resource mix" in the PJM case in the study: The standalone case appears to have "greater deployment of efficient solar and NGCC units relative to the PJM case," resulting in a lower production cost.[317]
- Fixed retirements: "Retirement of existing generation was a fixed input to the capacity expansion model."[318] In other words, the model could not choose when to add and retire resources in order to reach optimal replacement levels. This is a key flaw in the modeling, because to determine what resource portfolio is least cost, a capacity expansion model must have the ability to optimally add and retire resources.[319]
- Truncated capital cost modeling: The net present value analysis represents only 15 years of annualized capital costs, even though the capital costs of new resource investments span up to 40 years. Witness Levitt concludes, "This skews analysis of the trade-off between production cost savings from NGCC investments and the corresponding capital cost burden."[320]
- Possible mistakes from use of annualization schedules: As Witness Levitt explains, "The NPV approach [used by the LG&E/KU RTO Study] uses a specific set of annualization schedules The highly specific nature of these schedules (which vary by year and by generator type), the need to manually transfer the schedules from LG&E-KU to Guidehouse [the consultant] for consistent use in the capacity expansion model, the fact that an unrelated mistake occurred in transferring data between the Guidehouse stage and the NPV stage, and

[317] Levitt Dir. Test. at 39:543-545.
[318] Levitt Dir. Test. at 40:551-552.
[319] Levitt Dir. Test. at 40:551-557.
[320] Levitt Dir. Test. at 41:562-563.

the lack of an explanation when asked about the schedule used in the capacity expansion model, all suggest these schedules could be discrepant between the NPV analysis and the capacity expansion model."[321]

- Possible failure to harmonize additional methodological assumptions between the NPV analysis and the capacity expansion model, such as discount rate and time horizon.[322]

Witness Levitt explains that either (1) these or other methodological issues with or errors in the study have led to an outlier result in which RTO membership is not beneficial, or (2) there are other, unexplained "more fundamental economic realities that exist in LG&E-KU but do not exist in the dozens of other utilities studied in a pooled energy market."[323] Witness Levitt concludes, reasonably: "Without either, it is not credible to draw the conclusion from the RTO Study that PJM membership entails costs that exceed the production cost benefits and capacity saving benefits."[324]

Witness Levitt is correct. The LG&E/KU RTO Study's outlier conclusion is contrary to Witness Levitt's analysis; contrary to many RTO studies; contrary to virtually all other major utilities' decision to join an RTO, including the choice of many Kentucky utilities to do so; and unexplained by any identified difference between LG&E/KU and other utilities. Occam's Razor indicates that the problem lies with the methodology of the LG&E/KU RTO Study.

D. PJM Is Proactively Managing Reliability Considerations Related to Thermal Retirement That Affect All Utilities, Including LG&E/KU.

In August 2023, a PJM executive appeared before Kentucky legislators to proactively discuss reliability issues, explaining that PJM is "being very vocal about trying to maintain reliability during

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321 Levitt Dir. Test. at 41:564-576.
322 Levitt Dir. Test. at 41:577-580.
323 Levitt Dir. Test. at 42:587-592.
324 Levitt Dir. Test. at 42:592-593.

the early stages of an energy transition."[325] PJM projects possibly 40 gigawatts of thermal retirements by 2030.[326] So far, less than 15 gigawatts of thermal retirements have actually been announced.[327] There are currently 24 gigawatts of gas in the PJM interconnection queue—already, 60% of the capacity that would be necessary to replace the entirety of PJM's projected possible retirements.[328] Additionally, there are 34 gigawatts of battery storage in the PJM queue, which can be dispatched much more quickly than bringing a cold resource online.[329] There are also 150 gigawatts nameplate of solar and 40 gigawatts nameplate of wind.[330] While not every project in the PJM interconnection queue is necessarily going to get built, there is far more nameplate capacity in the PJM queue than PJM's projection of potential retirements.[331]

Last month, PJM's Vice President for State and Member Services Asim Haque testified before the Kentucky General Assembly's Interim Joint Committee on Natural Resources and Energy.[332] PJM is deeply focused on reliability and is now proactively developing a plan to ensure that the RTO maintains high levels of reliability over the long term. As Mr. Haque explained to Kentucky legislators, PJM's "primary focus is the concept of reliability, making sure that electricity is produced and transmitted and that we maintain reliability—very simple, that when consumers flip

[325] Exh. SC-11 (Kentucky Legislature, Interim Joint Committee on Natural Resources and Energy Hearing, Aug. 3, 2023), *available at* https://www.youtube.com/watch?v=Bja3IDPFPMs&ab_channel=KYLRCCommitteeMeetings, at 10:00 (testimony of Mr. Asim Haque).

[326] Exh. DSS-3 at 11; Hr. Video (Aug. 28, 2023) at 2:34:00 (11:50 AM) (Sierra Club cross-examination of Mr. Sinclair).

[327] Exh. DSS-3 at 11; Hr. Video (Aug. 28, 2023) at 2:34:00 (11:50 AM) (Sierra Club cross-examination of Mr. Sinclair).

[328] Exh. DSS-3 at 8; Hr. Video (Aug. 28, 2023) at 2:35:00 (11:51 AM) (Sierra Club cross-examination of Mr. Sinclair).

[329] Exh. DSS-3 at 8; Hr. Video (Aug. 28, 2023) at 2:36:30 (11:52 AM) (Sierra Club cross-examination of Mr. Sinclair).

[330] Exh. DSS-3 at 8; Hr. Video (Aug. 28, 2023) at 2:36:30 (11:52 AM) (Sierra Club cross-examination of Mr. Sinclair).

[331] Exh. DSS-3 at 8.

[332] Exh. SC-11.

the switch, the lights come on........No matter how challenging the circumstances, reliability is our mission."[333] In fact, the purpose of Mr. Haque's visit to the Kentucky legislature was that PJM is "being very vocal about trying to maintain reliability during the early stages of an energy transition."[334]

LG&E/KU Witness Sinclair selectively quoted Mr. Haque in his rebuttal testimony, truncating Mr. Haque's remarks and omitting Mr. Haque's observations that PJM "has time" and is working to resolve its concerns about limited supply-side availability. Crucially, Mr. Haque told legislators:

> With the aggregation of some trends, we are concerned about a supply crunch at the end of this decade. Just for a second, for everyone in this room, because when you hear that there's probably some concern. But just for a second, deep breath. PJM Interconnection actually is very well positioned today........[W]hen the weather gets really hot this summer, two-thirds of the country may have to shut customers off........So first, kind of deep breath, we are not in that highly elevated risk arena. And so we have time. But we don't have a lot of time to waste. And so what we're going to tell you is we've identified some concerns around reliability, and we're going to lead to try to help resolve those concerns.[335]

Mr. Haque described PJM's "reliability initiative," directing legislators to PJM's website where the RTO has described "sixteen critical actions that we plan to take in order to preserve reliability."[336] And specifically, Mr. Haque provided greater detail about PJM's planning and strategy surrounding reliability, explaining that PJM has "reliability safety valves" to ensure that units do not leave the system if needed to preserve reliability and discussing in depth PJM's "reliability must run" process.[337] Mr. Haque also described PJM's concern with "a cost that's affordable for customers,

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[333] *Id.* at 5:50 (testimony of Mr. Haque).
[334] *Id.* at 9:54 (testimony of Mr. Haque).
[335] *Id.* at 13:15 (testimony of Mr. Haque).
[336] *Id.* at 28:15 (testimony of Mr. Haque).
[337] *Id.* at 47:45 (testimony of Mr. Haque) ("In the event that a unit is supposed to leave the system, or in the event that you've said, hey, you coal unit, you can only run for so much time during the year—if we need those units to preserve reliability, we've tried to build in those policies, like we have done in Illinois actually, sort of these reliability safety measures. Currently there is the ability—if we then run what's called a deactivation analysis—if removal of that unit would show that it is going to create reliability challenges, and reliability challenges until we can build transmission effectively to

explaining, "We don't want to create this dynamic where there are units that have hit the end of their useful life as machines and we are effectively trying to keep them around in some level of perpetuity and it's costly to maintain them."[338]

Thus, counter to LG&E/KU Witness Sinclair's picture, Mr. Haque's testimony demonstrates that PJM is proactively focused on affordability and reliability for its members' customers during a time of significant change in the utility landscape throughout the country. Witness Sinclair stated, "The Companies do not believe their customers should be satisfied with a looming 'supply crunch' and no plan to meet it."[339] But Mr. Haque's testimony makes clear that, to the contrary, PJM is actively working to ensure that there is no such actual supply crunch, and that the RTO "maintain[s] reliability" over the long term.

LG&E/KU witnesses repeatedly raised concerns in these proceedings about their perception that PJM has a greater reliability problem than the Companies.[340] But PJM did not experience rolling blackouts during Winter Storm Elliott. PJM has stated concerns about ensuring reliability during an energy transition, but that energy transition is not unique to PJM: as the description above of federal environmental regulation of coal-fired units makes clear, economic and legal hurdles to continued operation of fossil fuel-fired generation is a nationwide phenomenon. Reliability considerations should not prevent LG&E/KU from joining PJM. PJM's proactive measures to ensure reliability, its more fuel-diverse[341] and geographically diverse portfolio than LG&E/KU, and its comparable track record of success during recent extreme weather all show that joining PJM would maintain or improve reliability for LG&E/KU.

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alleviate that reliability challenge, we can ask the unit to stick around to continue to provide power. It's called reliability must-run.").

[338] *Id.* at 45:30 (testimony of Mr. Haque).

[339] Sinclair Reb. Test. at 4:6-7.

[340] *E.g.*, Stuart Wilson Reb. Test. 4:1-2; Hr. Video (Aug. 28, 2023) at 2:36:30 (11:52 AM) (Sierra Club cross-examination of Mr. Sinclair).

[341] Reb. Exh. DSs-3 at 7.

E. A Portfolio of Solar Power, Battery Storage, DSM/EE, and Joining PJM Under Current PJM Constructs Meets the Requirements for Retirement Under § 278.264.

A portfolio that replaces both NGCC units proposed by LG&E/KU meets the statutory requirements for retirement under current PJM constructs. The portfolio would encompass 637 MW of solar PPAs, 240 MW of LG&E/KU-owned solar, DSM/EE, one 125 MW, 4-hour battery, and joining PJM. Such a portfolio would combine replacement physical generation with the benefits like geographic and load diversity to inherently stretch LG&E/KU's existing power supply farther. The fact that this portfolio, in addition to the Companies' proposed portfolio and Witness Sommer's one-NGCC portfolio, satisfies the statutory requirements for retirement additionally supports approval of retirement.

If the Commission were to interpret replacement generating capacity in § 278.264(2)(a) as requiring sufficient capacity and energy for a utility to be fully reliant on the equivalent of its own generation without needing to purchase power from the RTO, this portfolio would not suffice under LG&E/KU's modeling.[342] Were the Commission to adopt that interpretation, the below analysis nevertheless would be applicable to a portfolio with a single NGCC; the solar power, DSM/EE, and battery sought in this case; and the choice to join PJM rather than to build a second NGCC.

Replacement. As discussed above, replacement generating capacity for purposes of § 278.264(2)(a) need not be one-to-one, megawatt-to-megawatt. In accordance with that interpretation, the solar power, battery, and dispatchable DSM/EE would qualify as replacement generating capacity.

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[342] *See* LG&E/KU Reb. Exh. DSS-2 at 9, Table 11. Further, there was discussion at the hearing as to the difference between FRR and BRA membership in PJM. Were LG&E/KU to proceed as FRR members of PJM, LG&E/KU would need to provide sufficient generating capacity to meet the Companies' FRR plan. *See* Hr. Video (Aug. 29, 2023) at 2:46:15 (Commission Chair questioning of Mr. Levitt).

Dispatchability. LG&E/KU's generated power would be dispatchable by PJM, except for behind-the-meter distributed power.[343] Thus, the power generated by this portfolio would be dispatchable in the same way as power generated pursuant to other portfolios.

Reliability. As discussed above, PJM remains a reliable option in the midst of a national energy transition. Further, were LG&E/KU to join PJM, PJM's reliability LOLE standard of one day in ten years is equal to LG&E/KU's most protective reliability standard and is more reliable than the 3.57 LOLE that LG&E/KU regularly cites as its target.[344] Reliability as measured by LOLE would be met or enhanced by joining PJM. Additionally, PJM's move toward seasonal capacity accreditation and its efforts to account for correlated outages would further enhance reliability.[345]

LG&E/KU, in evaluating a portfolio that did not include the two NGCCs, raised concerns about roughly 1,700 gigawatt-hours of energy that would need to be procured from outside LG&E/KU were neither NGCC built.[346] Notably, though, LG&E/KU Witness Sinclair explained, "I'm not saying that load wouldn't be served at all" and noted that if the Companies were in PJM, they would be purchasing power from the pooled resources of the RTO, "so, yeah, I'm not saying we wouldn't get served."[347]

Resilience. In evaluating resilience, LG&E/KU recommends that the Commission look to start-up times, ramp rates, and range of dispatchable capacity.[348] Because LG&E/KU would be bidding into and buying generation from a much more fuel-diverse market, these qualities would be enhanced.[349]

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[343] *See* John Wilson Dir. Test. 40:14-24.
[344] Levitt Dir. Test. 14:170-172; Case No. 2023-122, Exh. SB4-1 at 13; Stuart Wilson Reb. Test. at 22:13-14
[345] *See* Goggin Dir. Test. 30:16-20.
[346] LG&E/KU Reb. Exh. DSS-2 at 9 & Table 11.
[347] Hr. Video (Aug. 28, 2023) at 2:56:45 (1:05 PM) (Sierra Club cross-examination of Mr. Sinclair).
[348] Case No. 2023-122, Exh. SB4-1 at 15.
[349] *Compare id.* (explaining that NGCC units have faster start-up times and ramp rates than retiring units and describing the broader range of dispatchable capacity for the collective proposed NGCC

Minimum Reserve Capacity. PJM would be the reliability coordinator responsible for establishing minimum reserve capacity requirements were LG&E/KU to join the RTO: that is one of the functions of RTOs, as discussed above.

No Harm to Utility Ratepayers. While Witness Levitt did not calculate a full PVRR analysis, the financial benefits of avoided capacity under current PJM constructs are substantial: $125 million - $140 million per year in cost savings due to reduced capacity needs.[350] Further, the potential for production cost benefits under current PJM constructs is up to $70 million per year.[351] The LG&E/KU RTO Study tallied costs and benefits of PJM membership other than production cost or resource investment, such as PJM administrative fees and transmission cost allocation, and determined that those other costs and benefits equal a net cost of roughly $20 million - $45 million per year.[352] Witness Levitt concludes that "PJM membership is expected to yield a significant overall net benefit."[353]

Witness Levitt's testimony does not, however, conduct a full RTO benefits assessment for the overarching purpose of evaluating whether the Companies should join PJM: instead, it evaluates the avoided capacity savings of joining PJM in an alternative portfolio that removes one or both NGCCs.[354] If the Commission finds that the information available from the LG&E/KU RTO Study—flawed for the reasons outlined above—and Witness Levitt's testimony is insufficient to determine whether this requirement is satisfied, that is not a reason to deny retirement of the seven

units, owned solar, and battery) *with* LG&E/KU Reb. Exh. DSS-3 at 7 (showing PJM's existing installed capacity mix, which is more diverse than LG&E/KU's).

[350] Levitt Dir. Test. Table 1.

[351] Levitt Dir. Test. Table 1.

[352] Levitt Dir. Test. 42:594-596.

[353] Levitt Dir. Test. 42: 597-599; *see also* Hr. Video (Aug. 29, 2023) at 2:19:00 (LG&E/KU cross-examination of Mr. Levitt).

[354] Hr. Video (Aug. 29, 2023) at 2:13:30 (10:36 AM) (Commission Chair questioning of Mr. Levitt).

units: both LG&E/KU's portfolio and Witness Sommer's one-NGCC portfolio satisfy the requirements of § 278.264.

Decision Not Result of Federal Financial Incentives. As described above, LG&E/KU's retirement decision is not the result of federal financial incentives. For the four coal-fired units, LG&E/KU's decision is the result of burdens in the future: environmental regulations or significant, expensive maintenance. For the three gas peaker units, LG&E/KU's decision is the result of the economics of maintenance.

All Known Direct or Indirect Costs. Again, Witness Levitt concludes based on the $125 million - $140 million in anticipated cost savings due to reduced capacity needs and up to $70 million in production cost benefits that PJM membership will, overall, significantly benefit LG&E/KU.

VII. CPCN Approval of the Solar Power and Battery Is Warranted; Approval is Not Warranted for the Two NGCCs.

LG&E/KU has met the CPCN standard for approval of the solar power and the battery. The Companies have not met the CPCN standard for approval of the two NGCCs, because they have failed to demonstrate an absence of wasteful duplication—particularly as to *two* NGCCs, which is an extreme overbuild. Sierra Club requests that the Commission grant the CPCNs as to the solar power and the battery storage, issue a declaratory order as to the solar PPAs, and approve the DSM/EE plan with the modifications proposed by the Joint Intervenors.

As to the NGCCs, the Commission should deny at least one CPCN outright. As detailed below, LG&E/KU's own analysis of the energy shortfall in a portfolio with no NGCCs demonstrates that two NGCCs is a severe overbuild: building to *five times* the Companies' level of energy needs. This is the definition of wasteful duplication. Witness Sommer's alternative portfolio including only one NGCC satisfies the requirements of § 278.264, maintaining reliability and providing sufficient generation for LG&E/KU customers. Further, a portfolio in which instead of building the NGCCs, LG&E/KU joins PJM may also satisfy the requirements of § 278.264; a portfolio that joins PJM instead of building one of the NGCCs certainly does.

For the second NGCC, LG&E/KU has not met its burden under § 278.020 to demonstrate that it has thoroughly explored all reasonable alternatives. That is because LG&E/KU has not thoroughly explored the alternative of joining an RTO, despite stating in initial direct testimony in this case that it had. The flawed LG&E/KU RTO Study does not suffice, due to the methodological issues and error identified in these proceedings. Witness Levitt's testimony, by contrast, indicates that joining the RTO PJM under its current capacity construct "is expected to yield a significant overall net benefit."[355] As Witness Levitt outlines, this conclusion is in line with dozens of studies that find net benefits to utilities of joining RTOs, and there is no reasoned explanation for the LG&E/KU RTO Study's departure from this conclusion. In light of the significant shortcomings of the LG&E/KU RTO Study, the Commission should at minimum defer a decision as to approval for one NGCC for failure to meet the Companies' burden of showing absence of wasteful duplication.

If the Commission does not deny the NGCC outright—given that the proposal for one NGCC does meet the requirements of § 278.264 but does not meet the requirements for a CPCN under § 278.020, due to the failure to fully evaluate reasoned alternatives—at minimum the Commission should defer the decision as to a CPCN pending an investigation into whether LG&E/KU should join an RTO. Such an investigation is necessary for independent reasons, as detailed below. It will also allow a determination, at least as a preliminary matter, whether RTO membership is a viable alternative to constructing any NGCC prior to placing steel in the ground. The Commission should defer the decision as to a CPCN while the investigation proceeds but approve the retirements, knowing that at least one alternative portfolio that meets the requirements

[355] Levitt Dir. Test. at 42:598-599.

of § 278.264 is an available option. This deferral is practical in light of the proposed timeline for NGCC construction.

A. LG&E/KU Has Met the CPCN Requirements for the Solar Power and Battery Storage the Companies Seek. Maximal Approval of DSM/EE is Also Warranted.

LG&E/KU has met the requirements for a CPCN for the owned solar capacity that the Companies seek, and demonstrated that a declaratory order is warranted for the solar PPAs. Solar capacity, in particular, will benefit the Companies' customers through portfolio diversity. As Witness Goggin explains, "Geographically diverse renewables, as well as a more diverse portfolio of solar and wind resources, provide more dependable capacity because their output profiles are weakly or negatively correlated."[356] For similar reasons, to the extent the solar PPAs would need Commission approval on the merits, approval is warranted.

LG&E/KU has also met the CPCN requirements for the Brown battery. LG&E/KU Witness Bellar explained that the Companies will need stored power to optimize the grid and that the battery is a first step in this direction.[357] The Companies previously built an initial solar facility and have leveraged that experience to build more, and "expect the same for Brown BESS as it pertains to stored power."[358] As stored power becomes more important to a transitioning grid, the Companies have demonstrated a need for this initial step in battery storage. This is particularly true because of batteries' flexibility. Witness Goggin explains that "batteries offer nearly instantaneous response with no minimum output level"; that they can "absorb power during periods of low demand or high supply, including renewable output that would have been curtailed"; and that they "offer twice the ramp range that conventional generators offer, as they can ramp between fully charging and fully discharging."[359]

[356] Goggin Dir. Test. 22:6-8.
[357] Bellar Dir. Test. 22:9-13.
[358] Bellar Dir. Test. 22:14-18.
[359] Goggin Dir. Test. 45:10-15.

In fact, the Companies are underestimating the benefits of both solar power and battery storage by almost 200 MW. As Witness Goggin explains, LG&E/KU undervalues the capacity of solar by assigning it a 0 MW value in winter.[360] Further, Witness Goggin explains that the battery is more reasonably estimated to have "nearly 100% capacity value," rather than the 82% capacity value estimated by the Companies—particularly based on the levels of solar penetration that the Companies plan on having.[361]

Finally, Sierra Club agrees with the Joint Intervenors' proposals for maximizing DSM/EE.

B. LG&E/KU Has Not Demonstrated Need and an Absence of Wasteful Duplication Warranting CPCNs for the Two NGCCs At This Time.

LG&E/KU has not met the CPCN requirements for the two NGCCs, however. First, *two* NGCCs is an enormously significant overbuild. This is shown by LG&E/KU's own modeling. The Companies modeled a portfolio that included all aspects of its proposed portfolio except the two NGCCs.[362] In other words, the portfolio not only did not build the NGCCs but also retired *all* the coal units that the Companies have requested. [363] This portfolio also limited the SCCTs to 10% operation, a conservative estimate.[364] LG&E/KU's own analysis concluded that for a mid-gas price, mid coal-to-gas-price-ratio scenario, the portfolio retiring all the coal units and building no gas units does not serve 1,733 GWh in 2028.[365] The two NGCCs that the Companies have proposed would generate a combined 8,567 GWh of energy in 2028 under the same mid-gas price, mid coal-to-gas-price-ratio scenario.[366] One NGCC would produce roughly 4,250 GWh.[367] This amount of energy

[360] Goggin Dir. Test. 23:13-14, 26:7-17.
[361] Goggin Dir. Test. 25:1-2.
[362] Reb. Exh. DSS-2 at 8-9
[363] Hr. Video (Aug. 28, 2023) at 3:01:00 (1:09 PM) (Sierra Club cross-examination of Mr. Sinclair).
[364] *Id.* at 8. By contrast, LG&E/KU relaxed SCCT operating limits from 25% to "within air permit limits" in analyzing a portfolio it ascribed to the Kentucky Coal Association. *Id.* at 3.
[365] Reb. Exh. DSS-2 at 9, Table 11.
[366] Reb. Exh. DSS-2 at 6, Table 8; *see also* Hr. Video (Aug. 28, 2023) at 3:00:00 (1:08 PM) (Sierra Club cross-examination of Mr. Sinclair).
[367] Hr. Video (Aug. 28, 2023) at 3:00:00 (1:08 PM) (Sierra Club cross-examination of Mr. Sinclair).

produced by just *one* NGCC is roughly *two and a half times* the energy shortfall that results from retiring all the coal units and replacing them solely with the solar power, DSM, and battery storage from LG&E/KU's proposed portfolio.

In other words, two NGCCS would create roughly *five times* the amount of energy needed for the Companies. The 4,250 GWh resulting from one NGCC, alone, would more than cover the projected 1,733 GWh needed from retiring all the coal units at issue.[368] That 1,733 GWh need not even come from one NGCC, of course. But it certainly need not come from *two* NGCCs, quintuple the amount of energy needed. A utility cannot receive approval for a CPCN where the utility seeks to build "an excess of capacity over need" or "an unnecessary multiplicity of physical properties."[369] Building a portfolio with two NGCCs where only the energy equivalent of 40% of one NGCC is needed is wasteful duplication.

Second, as to building *any* NGCC LG&E/KU has not adequately shown that "a thorough review of all reasonable alternatives has been performed."[370] Specifically, LG&E/KU has not adequately demonstrated that it fully considered RTO membership as an alternative to construction of the NGCCs. LG&E/KU plainly sees RTO membership as a potential alternative: Witness Bellar's direct testimony stated, in response to the question "Did the Companies consider RTO membership in their analysis?," "Yes."[371] Witness Bellar went on to state that the Companies "recently filed an updated RTO membership analysis" that "shows that RTO membership is not advantageous to the Companies' customers at this time."[372] That membership analysis, Witness Bellar confirmed, was the LG&E/KU RTO Study filed with the Commission in November 2022.[373] As described above,

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[368] Hr. Video (Aug. 28, 2023) at 3:01:00 (1:09 PM) (Sierra Club cross-examination of Mr. Sinclair).
[369] *In re Elec. Application of Ky. Power for a CPCN*, Case No. 2022-00118 (Ky. P.S.C. 2022) at 16 (quoting *Ky. Utils. Co. v. Pub. Serv. Comm'n*, 252 S.W. 2d at 890).
[370] *Id.*
[371] Bellar Dir. Test. 26:4-5.
[372] Bellar Dir. Test. 26:5-7.
[373] Hr. Video (Aug. 22, 2023) at 7:08:00 (Sierra Club cross-examination of Mr. Bellar).

Lexington/Louisville and Sierra Club Witness Levitt determined that analysis was deeply flawed methodologically and contained a grave error.

Thus, LG&E/KU in no way conducted "a thorough review" of the "reasonable alternative" of joining an RTO for capacity savings.[374] The Companies also plainly thought of the "supply-side resources" relevant to the RTO consideration as the NGCCs, specifically, having emphasized in these proceedings that the LG&E/KU RTO Study would have built two NGCCs.[375] Because the Companies failed to adequately consider the reasonable alternative of avoiding capacity expenditures on one or both proposed NGCCs by, instead, joining an RTO, they have not met the CPCN standard for an absence of wasteful duplication for the NGCCs, and the CPCN should be denied.

The Commission might, however, view this as an odd outcome since that the proposal for one NGCC does meet the requirements of § 278.264 but does not meet the requirements for § 278..020 given the unanswered questions about RTO membership. As discussed below, for independent reasons the Commission should open an investigation into whether LG&E/KU should join an RTO in order to benefit customers. But the Commission should also at minimum defer a decision on whether to approve one NGCC until LG&E/KU at least preliminarily evaluates whether RTO membership is in fact a reasonable alternative. LG&E/KU's timelines for construction place the two NGCCs on track to build one NGCC by 2027 and the other by 2028.[376] This timeline provides the opportunity for a more robust evaluation of an alternative of RTO membership.

VIII. The Commission Should Open an Investigation Into LG&E/KU's Current Lack of RTO Membership and Whether Joining an RTO Is Warranted.

[374] *See In re Elec. Application of Ky. Power Co. for a CPCN*, Case No. 2022-00118 (Ky. P.S.C. 2022) at 16 (quoting *Ky. Utils. Co. v. Pub. Serv. Comm'n*, 252 S.W. 2d at 890).
[375] *See* Bellar Dir. Test. 26:7-14 (describing the LG&E/KU RTO Study's analysis of the supply-side resources).
[376] Joint Application at 3.

LG&E/KU has not sought to join an RTO in this proceeding. However, LG&E/KU witnesses have repeatedly stated that the Companies remain open to joining an RTO.[377] Witness Levitt's analysis, and his discovery of a major error in the LG&E/KU RTO Study, cast doubt on the quality of LG&E/KU's past analysis of the costs and benefits of RTO membership, and indicate that RTO membership is likely to be significantly beneficial to LG&E/KU customers from a financial perspective. This proceeding has also raised significant questions about the reliability of LG&E/KU's generation fleet, including its coal fleet; the quality of LG&E/KU's monitoring of that reliability, particularly LG&E/KU's assessment of correlated outages; and the transparency and accuracy with which LG&E/KU publicly discusses its challenges and failures.

In light of these significant developments, the Commission should open an investigation into LG&E/KU's current status of non-membership in an RTO, and whether LG&E/KU should join an RTO. The Commission could open this investigation as a condition of approval of the coal-fired unit retirements. *See* K.R.S. § 278.264(1) ("The commission shall enter an order approving, *approving with conditions*, or denying the application ...." (emphasis added)). Or it could open the investigation on its own motion, as the Commission opened in its investigation into LG&E/KU's then-membership in MISO in 2003.[378] *See* § 278.250 ("Whenever it is necessary in the performance of its duties, the commission may investigate and examine the condition of any utility subject to its jurisdiction.").

Further, the Commission should open the investigation immediately. PJM is currently developing a proposal to move to a seasonal capacity market and seasonal capacity accreditation, in large part to ensure reliability and to avoid problems like the correlated outages that plagued

[377] *E.g.*, Sinclair Reb. Test. 4:14-16.
[378] *In re Investigation Into the Membership of Louisville Gas & Elec. Co. & Ky. Utils. Co. In the Midwest Indep. Transmission System Operator, Inc.*, No. 2003-00266 (Ky. PSC May 31, 2006).

LG&E/KU during Winter Storm Elliott.[379] Opening a docket to investigate whether LG&E/KU customers would be better served by joining an RTO does not mean that the Companies, immediately, will have to make a decision as to whether to join PJM or another RTO. The investigation into the Companies' MISO membership, for example, spanned years—though an investigation need not be that lengthy.[380] The Commission can set a schedule for the docket that allows time to ensure changes in PJM become clear before the Commission issues a final order in the proceeding. But now, on a timeline to be able to rapidly take advantage of RTO membership once the landscape becomes clear, is the time for investigation, so that LG&E/KU can be poised to act. As an initial matter, the Commission should direct that the Companies conduct a new RTO study subject to input from the Commission and stakeholders. Initial steps should include resolving guiding principles for the assessment, scope and high-level method of the assessment, whether to assess membership in one or both neighboring RTOs, selection of a consultant to perform quantitative evaluation modeling, and initial configuration by the consultant of modeling based on LG&E/KU's system. After PJM finalizes the proposed changes to its capacity market and accreditation, the evaluation could then proceed quickly.

The serious flaws in LG&E/KU's RTO Study, and the benefits of resource pooling revealed by Winter Storm Elliott, demonstrate that filing an annual report on the costs and benefits of remaining outside an RTO is no longer adequately protective of LG&E/KU customers. The serious issues that have emerged in this proceeding show that an independent investigative inquiry by the Commission, into whether LG&E/KU's continued decision to remain on an energy "island" truly benefits LG&E/KU's customers, is necessary.

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[379] *See* Levitt Dir. Test. II.E; Stuart Wilson Reb. Test. at 3:6-4:22.
[380] *See In re Investigation*, No. 2003-00266 (Ky. PSC May 31, 2006).

CONCLUSION

For the retirement proceeding, the Commission should approve the seven unit retirements requested. For the CPCN proceedings, the Commission should approve the 240 MW of LG&E/KU-owned solar and the battery. The Commission should deny the CPCNs for the two NGCCs, particularly because two NGCCs is a substantial overbuild of energy. The Commission should approve the declaratory orders for the solar PPAs and approve the DSM/EE program as recommended by the Joint Intervenors. Finally, the Commission should open an investigation into LG&E/KU's current lack of membership in an RTO.

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Respectfully submitted,

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CERTIFICATE OF SERVICE

This is to certify that the foregoing copy of Sierra Club's post-hearing brief in this action is being electronically transmitted to the Commission on September 22, 2023, and that there are currently no parties that the Commission has excused from participation by electronic means in this proceeding.

/s/ Joe F. Childers
JOE F. CHILDERS