COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC JOINT APPLICATION OF KENTUCKY UTILITIES COMPANY AND LOUISVILLE GAS AND ELECTRIC COMPANY FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY AND SITE COMPATIBILITY CERTIFICATES AND APPROVAL OF A DEMAND SIDE MANAGEMENT PLAN AND APPROVAL OF FOSSIL FUEL-FIRED GENERATING UNIT RETIREMENTS	))))))))))	**CASE NO. 2022-00402**

REBUTTAL TESTIMONY OF
LONNIE E. BELLAR
CHIEF OPERATING OFFICER
KENTUCKY UTILITIES COMPANY AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Filed: August 9, 2023

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I. BACKGROUND

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

A. My name is Lonnie E. Bellar. I am the Chief Operating Officer for Kentucky Utilities Company ("KU") and Louisville Gas and Electric Company ("LG&E") (collectively, "Companies") and an employee of LG&E and KU Services Company, which provides services to KU and LG&E. My business address is 220 West Main Street, Louisville, Kentucky 40202.

Q. What are the purposes of your testimony?

A. The purpose of my testimony is to address: (1) my overall reaction to the intervenor testimony; (2) cost estimates and contracting process for the NGCCs; and (3) various arguments made by intervenor witnesses Anna Sommer (Joint Intervenors), Lane Kollen (KIUC), Emily Medine (Kentucky Coal Association), John Wilson (Joint Intervenors), Michael Goggin (Sierra Club), and Andrew Levitt (Sierra Club, Louisville Metro, and LFUCG).

Q. What is your general reaction to the intervenor testimony in its entirety?

A. This is an important case for many of the intervenors as it will determine, at least for the fairly near future, what sources of "fuel" will be used to meet customers' needs for electricity. Several of the intervenors have very clear policies and established positions regarding what type of fuel that should be. The Companies respect those policies and positions and welcome the spirited debate they produce in cases like this one.

For example, the Kentucky Coal Association's position that no coal-fired generation should be retired is in complete accord with its mission to "enhance the ability of the Kentucky coal industry to compete in domestic and world coal markets."[1] The number of mines and the number of suppliers that the Companies rely on to provide coal, as noted in Mr. Sinclair's testimony, has declined and resulted in two suppliers becoming the Companies' dominant suppliers (79 percent in 2022).

Likewise, the Sierra Club's position that coal-fired generation should be retired and the proposed NGCCs should not be built is in complete accord with its mission: "Across America, the Beyond Coal campaign is replacing coal and gas with clean energy. We're mobilizing grassroots activists to advocate for meaningful energy changes in their communities, including retiring coal plants, preventing new fossil fuel plants from being built, and working to stop the expansion of fracked gas."[2]

Finally, the Joint Intervenors are represented by the Earthjustice law firm in this matter whose website states, "Behind nearly every major environmental win, you'll find Earthjustice. Founded in 1971, Earthjustice has saved irreplaceable wildlands, cleaned up the air we breathe, and fueled the rise of 100% clean energy."[3]

The Companies purposely did not oppose the intervention of any intervenor. To the contrary, the Companies have worked diligently to respond to all intervenor data requests and to make all required filings to accommodate and comply with the General Assembly's enactment of Senate Bill 4, which occurred right in the middle of this case. The Companies have done so quickly and as completely as possible so the Companies' proposal could be reviewed, studied, and critiqued. And the intervenors, some with their divergent and mutually exclusive positions and polices, have done so. Some want

[1] https://www.kentuckycoal.com/our-mission/
[2] https://coal.sierraclub.org/campaign
[3] https://earthjustice.org/about

no coal. Some want all coal. Some want no coal, no gas, and all renewables. Such absolute positions, while clear, bring the significant risk of being completely right or wrong in the future.

In the midst of all this, as part of the regulatory compact, the Companies have the responsibility to serve their customers;[4] thus, the only real question before the Commission is whether the Companies' diverse proposed portfolio is the optimal solution to meet customer need based on reliable data. The intervenors with the more ultimate positions propose unrealistic "solutions" that would be more costly to customers and, in many cases, sacrifice reliability. To the contrary, the Companies' proposed portfolio establishes the resource portfolio that will be used to serve its customers well into the next decade which, in turn, provides greater certainty with regard to retail rates over that time period. This certainty is important to all existing customers but also prospective customers supporting continued success in state economic development activities.

Other Company witnesses (Mr. Sinclair and Mr. Wilson) explain in their rebuttal testimony how and why the Companies' data and modeling in this case support approval of the Companies' recommended portfolio along with the proposed demand side management programs. My overall point is that, in contrast to these absolute intervenor positions, the Companies' position reflects a balanced and diversified portfolio of options that lands exactly in the middle of this debate and mitigates the risk of the ultimate intervenor positions. Support for this point also lies in the fact that the KIUC, an entity whose purpose is to advocate for customers' interest (instead of

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[4] Per 807 KAR 5:041, Section 5(1), the Companies are obligated to "make all reasonable efforts to prevent interruptions of service . . ."

exclusively coal or renewable energy interests), favors approval of most of the Companies' proposed portfolio.

II. NGCCS

Q. At pages 11-24 of Joint Intervenor witness Anna Sommer's testimony, she expresses concerns that the Companies' cost estimates for the proposed NGCC's are "at an early stage and likely understated." Do you agree with that general conclusion?

A. No.

Q. Explain your disagreement with Ms. Sommer on this point.

A. The Companies engaged HDR, a well-established engineering firm, for assistance with the design optimization, environmental permitting, and procurement efforts as a way to support Companies' Project Engineering department in a similar fashion as HDR assisted with the Companies' Trimble County 2 Coal Unit and the Cane Rune 7 NGCC. The Companies have considerable experience working with HDR over many years. In preparing cost estimates for the proposed NGCCs, HDR has relied on known, actual, and current costs and its experience in the NGCC market to produce data driven results. Ms. Sommer's concerns do not appear to be based on quantifiable data or based on real-world experience, and, in some cases, are not rooted in reality. For example, one of her concerns is that the Companies' self-build NGCC options were the only thermal plant bids submitted in response to the Companies' Request for Proposals. But that ignores the fact that the Companies cannot invent a market or somehow create bids that were not submitted. The Companies issued a well-considered RFP and considered the submitted responses appropriately. The Companies have no ability to manufacture other responses in a way to create other "data points," to use her term.

Q. Do you have confidence in the accuracy and thoroughness of the HDR Study that was used to form the basis of the NGCC cost estimates including the difference between the cost estimates used for what would have been Green River 5 NGCC in 2013 compared to the NGCCs proposed in this case?

A. Yes, the 2022 feasibility study utilized HDR's proven NGCC estimating tools and built upon previously completed studies dating back to 2003. As mentioned above, the Companies have a robust and successful history working with HDR evaluating and implementing generation projects including Trimble County 2, Cane Run 7 combined cycle, EW Brown 10MW Solar Facility, multiple NGCC feasibility studies, as well as evaluating energy storage projects. While HDR utilized similar estimating tools in the studies referenced above, the performance and cost information for the 2022 feasibility study is reflective of today's costs, as indicated in the Companies' response to JI 4.13. In addition, HDR has appreciable and current advanced class NGCC experience as referenced in the Companies' response to JI 4.21. Based on our successful history on Trimble County 2 and Cane Run 7, the referenced studies, the accuracy of the current estimates (JI 1.11 (a)), and HDR's experience with advanced class NGCC projects, the Companies are confident with the accuracy and thoroughness of the current HDR study.

Q. Do you agree that the Companies should select an EPC firm before receiving a CPCN for the NGCCs?

A. No. As explained in the response to JI 1.9, the Companies plan on selecting an EPC firm after regulatory approvals are obtained from the Commission. That selection represents the beginning of a significant investment towards the proposed portfolio, and, therefore, the prudent sequence is to obtain regulatory approval first and then make that selection rather than to expose the Companies and customers to unnecessary financial risk. While prospective EPC firms may enter into a contract with a regulatory out provision, considering the current competitive environment, the Companies will be in a stronger negotiating position to be able to enter into an EPC contract without such a provision.

Q. Do the Companies have a history of engaging EPC firms in the same manner as they are pursuing for the proposed NGCCs in their past significant construction projects?

A. Yes, as stated in the response to JI 1.9, this approach is consistent with the approach the Companies have taken for major generating projects over the last several decades.

Q. Please provide an update on the Companies' RFP process for the planned NGCCs.

A. The due date for the responses to the RFP for the NGCCs was originally scheduled for August 28, 2023. However, in order to facilitate the most complete and comprehensive set of responses possible that due date has been extended to September 11, 2023, based on feedback from potential bidders. After the Companies have had an opportunity to assess and digest the responses, to the extent there are material cost increases compared to the estimates in the record of this case, the Companies will provide and explain those differences in a filing with the Commission.

Q. If the Companies' cost estimates for the NGCCs turn out to be lower than the actual pricing received, how will cost recovery of that difference be treated by the Companies and the Commission?

A. The CPCN process is not a ratemaking process. It is not unusual for cost estimates provided in a CPCN proceeding to differ from the actual costs for a project once it is fully complete and operable. Actual costs could be lower than estimated or actual cost might be higher than estimated. For example, the Companies' execution of the Cane Run 7 NGCC project was completed on time and for less than the budgeted amount. Then, of course, in subsequent rate cases, the Companies only sought recovery of actual costs for Cane Run 7 and the same will be true for the NGCCs proposed in this case. Proposed cost recovery for them will be based on actual costs regardless of whether actuals are lower or higher than estimated costs. Having said that, as explained above, to the extent the RFP responses result in materially higher costs than the Companies' estimates, the Companies will provide and explain those differences in a filing with the Commission.

Q. If the Commission issues the requested CPCNs and approves the requested coal-fired retirements, will the Companies blindly move forward with their plans?

A. No. Consistent with past practice, the Companies will continue to evaluate the appropriateness of the projects for which they receive CPCNs and the appropriateness of each unit to be retired and will act accordingly. If costs increase or circumstances change such that projects or retirements are no longer in the best interest of customers, the Companies will so inform the Commission and take steps necessary to adjust their plans, which could include not building a project or not retiring a unit. I would also add that the Commission's issuance of a CPCN is a separate and independent grant of authority from the Commission's approval to retire generation units under SB4. Thus, the Companies will continue to assess projects approved in a CPCN independently from retirements approved under SB4 to ensure the best decisions are made for customers under each independent grant of authority. I do not expect the Companies' plans to change, but I can ensure the Commission that if circumstances change such that the Companies' plans should change, we will make the necessary adjustments.

Q. Have the Companies considered including a dual fuel option for the proposed NGCCs?

A. Yes, they have considered a dual fuel option that would include on-site fuel oil.

Q. Could a dual fuel option result in a cost for the NGCCs higher than estimated?

A. Yes, it could. As explained in response to KCA 2-51, dual fuel capability for on-site fuel oil was not a component of the estimates for the NGCCs. However, the NGCC estimates include a prudent project contingency amount and that contingency may adequately cover a dual fuel option depending on: (a) a final decision as to the necessity for dual fuel for fuel resiliency mitigation; (b) the quantity of on-site fuel oil and the associated emission control demineralized water required; and (c) other project contingency requirements. The Companies understand that some intervenors and possibly the Commission may be interested in considering some sort of fuel "on-site" for emergency purposes in the event there is a gas supply issue. While no fuel is perfect in that all fuels have execution risk, the Companies are seeking information from responders to the RFP which will facilitate analysis of both: (1) gas compression required to maintain full load capability when gas pipeline conditions deviate from a conservatively expected pressure condition (to include unlikely recurrence of conditions like Winter Storm Elliot); and (2) the cost and operational risks to incrementally install, operate, and maintain the necessary equipment and infrastructure to sustain fuel oil capability within the limits of air permitting and the physical space required for necessary tank storage.

Q. Do you agree with Ms. Sommer's concern that the Companies' NGCC self-build plans were the only thermal responsive bids for the generation RFP the Companies issued?

A. No. The facts that the Companies' self-build plans were the only <u>thermal</u> generation alternatives submitted in response to the 2022 RFP is not concerning. In fact, Ms. Sommer admits that this is not "atypical." The Companies own the sites where generation units are planned to be retired. These sites are connected to existing transmission infrastructure, lowering the Companies' cost of land and interconnection for new units compared to potential proposals from other parties. They also provide advantages for permitting the NGCCs.

Q. Ms. Sommer also offers testimony regarding managing solar execution risk (p. 53). What are the Companies' plans to manage that risk?

A. During the evaluation of RFP responses, the Companies assess a solar developer's progress in obtaining local approvals. This progress may include community engagement activities that constitute part of a developer's plan for obtaining such approvals. For executed PPAs, the Companies continue to have ongoing discussions with each developer related to their community engagement and the level of the Companies' involvement that would be helpful in advancing the project. However, Ms. Sommer's suggestion of providing grants or other funding for distributed solar and battery projects would need to be evaluated as part of the total cost of the project and its benefits to all customers. Furthermore, considering the use of distributed solar to "make up any gaps created by the failure of particular projects to reach their commercial online date" ignores the scale differences between utility and distributed solar. Assuming a capacity factor of 16 percent for distributed solar and 25 percent for utility scale solar, it would take over 39,000 distributed solar installations of 4 kW, the most frequently installed size of a distributed solar installation in the Companies' system, to equal the output of a single 100 MW utility scale project.

III. SENATE BILL 4

Q. Ms. Sommer discussed SB4 and suggests that the reliability requirement of SB4 should include consideration of distribution system reliability and its effect of the value of distributed energy resources ("DERs"). How do you respond to that?

A. SB4 does not mention distribution system reliability. Certainly, the Companies have a history of working diligently and investing appropriately in their distribution systems, but that topic is not a part of this proceeding.

Q. On the topic of SB4, are you one of the Companies' witnesses that addressed whether the Companies' proposals to retire some of their coal-fired generation complies with SB4?

A. Yes, and I provided testimony to that effect in Case No. 2023-00122[5] in which the Companies demonstrated that their proposed retirement of coal-fired generation, does, in fact, comply with SB4's requirements.

Q. Do any intervenor witnesses testify as to whether the Companies' proposed coal-fired generation retirements comply with SB4?

A. Yes. Joint Intervenor witness John Wilson provides testimony on this point.

Q. What is Mr. Wilson's opinion?

[5] The Commission consolidated Case No. 2023-00122 into Case No. 2022-00402 by Order of May 16, 2023.

A. Mr. Wilson testifies that the Companies' proposed retirement of seven coal-fired generating units does comply with SB4 and that the "proposed retirements should be approved by the Commission." (p. 4).

Q. Is Mr. Wilson correct that the Commission should approve the retirement of the seven coal-fired generating units?

A. Yes, as explained in more detail in my May 10, 2023 Direct Testimony in Case No. 2023-00021, the Commission should so approve.

Q. Do any other intervenor witnesses discuss SB4 and opine as to the Companies' compliance with it?

A. Yes, KIUC witness Lane Kollen opines that the four proposed PPAs in this matter do not comply with SB4's requirements because: they are not dispatchable; they do not improve system reliability and resiliency; and their pricing relies on federal tax incentives and benefits. KCA witness Emily Medine opines that the Companies' proposals are not compliant with SB4 because they will result in less reliability by not having onsite fuel storage and the Companies' use of net present value revenue requirements instead of a rate impact study runs afoul of the SB4 requirement relating to harming ratepayers.

Q. Do you agree with Mr. Kollen's opinion on PPAs regarding SB4 compliance?

A. I agree with him that the four proposed PPAs are not dispatchable, and, therefore, they are not replacement generating capacity for purposes of SB4. But they were never offered to be SB4 replacement generating capacity and the Companies have not held them out to be as I explained at pp. 10-11 of my May 10, 2023 testimony. Thus, his point on this issue is misplaced. Instead, as the Companies have repeatedly said in this case, the proposed PPAs are an important part of a diversified least-cost portfolio that, taken as a whole, will provide adequate and reliable service with minimal risk while providing a hedge against fuel prices.

Q. Do you agree with Ms. Medine's SB4 opinions?

A. No. As explained above, the Companies are exploring onsite fuel oil and other options to further enhance the reliability of the two proposed NGCC units. As for her argument relating to the Companies' use of net present value revenue requirements instead of a rate impact study to assess cost, SB4 has no such requirement and Mr. Conroy addresses that in his rebuttal testimony. Moreover, the Companies have demonstrated that their proposed portfolio results in improved full-year and summer reliability metrics and essentially equivalent winter reliability metrics.[6] Thus, the Companies have demonstrated that their proposed portfolio will fully satisfy SB4's reliability requirement which has no reference to dual fuel capability for replacement resources.

Q. Mr. Wilson also comments on whether joining an RTO such as PJM would satisfy SB4 even if joining PJM would negate some or all of the Companies' proposed portfolio. What do you understand his opinion to be on that issue?

A. Mr. Wilson's argument seems to be that, because PJM centrally dispatches generating units to meet the RTO's load, having the Companies' load in PJM would mean that they would not have to directly control or point to a particular generation unit to meet the dispatchability requirements of SB4. Furthermore, because PJM attempts to manage its reliability needs via its capacity market, simply being a PJM member would meet the reliability and resilience requirements of SB4. Finally, he believes that simply

[6] Case No. 2023-00122, Direct Testimony of Stuart A. Wilson, Exh. SB4-1 at 14 (May 10, 2023).

being a PJM member will result in lower costs for the Companies' customers, thus meeting the economic requirements of SB4. Essentially, Mr. Wilson argues that any Kentucky utility that is a member of PJM (and likely MISO since his arguments would apply to it) can retire any fossil fuel generator at any time and simply say "We belong to an RTO so we meet the requirements of SB4." While I am not a lawyer, I do not believe that the General Assembly passed SB4 with the idea that any utility could meet all of its requirements by simply relying on someone else (an RTO) to serve customers. Such a blanket approval mechanism for retiring fossil fuel generation units seems nonsensical.

IV. PURCHASE POWER AGREEMENTS

Q. Do you agree with Mr. Wilson that the Companies should pursue renewables that allow for downward dispatch or full flexibility instead of "must-take" contracts?

A. No. The Companies have been clear that the penetration level of solar has not yet reached the point that paying for the right to curtail solar PPAs benefits customers. For the solar PPAs, any rights to curtailment come at a cost. These projects are financed by developers with an assumption of revenues from energy production. Furthermore, the IRA's production tax credits provide the owner additional value with each unit of energy produced. The owner will expect to be compensated for curtailed energy, excluding curtailments due to grid conditions, to ensure the project is financeable. The Companies do not understand how customers benefit from paying for such an option until it is needed upon future additions of solar.

Q. Do you agree with Mr. Wilson that, if the Companies are contractually limited from controlling dispatch of renewables, that fact should not affect the Companies' evaluation of their reliability?

A. At the level of the proposed PPAs in this case, the Companies do not expect an inability to dispatch would adversely affect reliability.

Q. Do you agree with Mr. Wilson that the Companies should identify opportunities to "prepare for advanced operational practices," assess reliability accurately, and support "all-source procurement"?

A. Yes, and we already do. The RFP the Companies issued for generation opportunities is an excellent example of this.

Q. Finally with respect to Mr. Wilson, do you agree that the Companies should modify their test for investment in small-frame combustion turbine units to include an expected value for future below-threshold repair costs?

A. I agree that the discussed test may require an incremental step. However, I suspect that the ten-year test recommended by Mr. Wilson may not have a statistically significant data set given the irregular nature of both operation and maintenance on the noted units. The Companies prefer continued use of the expressed methodology as the first level of analysis from which an unfavorable result clearly indicates a decision to retire the unit. If that first level analysis yields an initially favorable result, the Companies may then conduct a second level analysis accounting for operational history and the likelihood of future failure (and further cost) following the potential execution of the repair solution under consideration. Such a second-level analysis has not been required in the Companies' actual experience.

V. GHENT 2

Q. You referred to Mr. Kollen's testimony above regarding the four proposed PPAs. Are you rebutting other portions of his testimony, and, if so, what portions?

A. Yes. I am rebutting the following other opinions Mr. Kollen has offered: (1) the Commission should deny the Companies' request to retire Ghent 2 and authorize a CPCN to add an SCR to Ghent 2 so that it can operate year-round; (2) alternatively, the Commission should direct the Companies to operate Ghent 2 only during the seven-month non-ozone season while evaluating the possibility of adding an SCR to Ghent 2; (3) the Companies should initiate discussion with Kentucky Power Company regarding a possible sale of Ghent 2 or a sale of the excess capacity and energy of Ghent 2 to Kentucky Power; and (4) the Companies' proposed Brown BESS is neither necessary nor economic.

Q. Do you agree with Mr. Kollen that Ghent 2 should not be retired, and, instead, should be fitted with an SCR for continued year-round operation?

A. No. The Companies' analysis on this point is clear. In the Companies' modeling conducted prior to the proposed greenhouse gas standards, fitting Ghent 2 with an SCR was not economic in all but one scenario: long-term high gas prices, with long-term low coal prices, no CO2 costs, and that Ghent 2 will be able to operate until it is 72 years old. Mr. Kollen acknowledges this when he testifies there is a "penalty" for adding an SCR of over $70 million in most scenarios. The Companies' modeling in response to PSC 5-2 continues to show that retrofitting Ghent 2 with an SCR is economical only when assuming the proposed NGCCs are limited to a 50% capacity factor and existing coal and gas units have a net zero cost of compliance with the EPA's proposed greenhouse gas standards. Lastly, the Companies' modeling in response to PSC 6-2 suggests the retirement of Ghent 2 in 2027 or 2028 in all scenarios considered.

Q. Do you agree with Mr. Kollen that, absent an SCR for Ghent 2, the Companies should operate it only during the seven non-ozone months?

A. No. As Mr. Sinclair demonstrates in his rebuttal testimony, operating Ghent 2 in the non-ozone season months through 2034 increases the net present value of revenue requirements in all fuel price scenarios the Companies studied. Just as important, as Mr. Imber testifies in his rebuttal testimony, even if the Companies could comply with the GNP by operating Ghent 2 in just certain months, there may be other EPA requirements that could drive a retirement decision for Ghent 2 based on EPA's semi-annual regulatory agenda.

Q. Do you agree with Mr. Kollen that the Companies should keep Ghent 2 operational and either sell it or sell its excess capacity and energy to Kentucky Power or some other purchaser?

A. No, there is no reason to take on such a risk that could adversely affect customers. As the Companies have demonstrated, keeping Ghent 2 operational and environmentally compliant is not economic and would cost customers unnecessary expense. Mr. Kollen's proposal would be to take on the risk of that additional expense in the hope that the Companies could sell Ghent 2 or its capacity. But that hope is far from a certainty and the Companies see no reason to expose customers to that risk.

VI. BROWN BESS

Q. Do you agree that the Companies' proposal for Brown BESS is neither necessary nor economic, therefore, the Commission should not approve it?

A. No. The Companies believe that the Brown BESS should be approved. As I stated in my December 15, 2022 Direct Testimony, one component of a least reasonable cost portfolio is to have a diversified mix of generation and a small amount of short-term back up stored power. The four-hour 125 MW Brown BESS does just that. While it may not be the most economical source for 125 MW of power, it will allow the Companies to gain valuable experience with managing and using stored power. That experience will help guide the Companies' future decisions regarding utility-scale stored power, which will become critical as more and more renewable resources are added to the Companies' generation portfolio.[7] To the extent that the Commission believes the size of Brown BESS at 125 MW for four hours is too large, the Companies would consider a smaller facility that would still allow for the opportunity to gain operational experience.

As for Mr. Kollen's contention that the cost of an SCR for Ghent 2 is nearly the same as the cost for Brown BESS, he fails to acknowledge that operational experience that Brown BESS will offer or the advantages of having flexible back-up power to complement an expanded reliance on intermittent generation resources. Of course, as I state above, an SCR for Ghent 2 is simply not economic.

VII. GAS FIRED GENERATION

Q. Sierra Club witness Mr. Goggin has provided intervenor testimony. Are you rebutting any portions of his testimony?

A. Yes, in opining that the Companies have overstated the reliability of coal and gas generation, Mr. Goggin opines that fossil fuel generating failures were the primary cause of outage events in Texas during Winter Storm Uri in February 2021 and other major outage events around the country including hot weather events. That opinion, along with his opinion that the Companies cannot take effective steps to prevent the

[7] Mr. Sinclair's Direct Testimony (pp. 24-26) provides more detail regarding the benefits of Brown BESS.

loss of gas supply, mean (according to Mr. Goggin) that the Companies have overstated the reliability of gas-fired generation.

Q. Do you agree that the Companies have overstated the reliability of gas-fired generation? If not, why not?

A. No, I do not. Mr. Goggin has not accurately described the reasons Winter Storm Elliot caused difficulties for the Companies, and, therefore, his premise that the Companies have overstated the reliability of gas-fired generation is flawed. Mr. Goggin attributes "correlated outages" to outages resulting from cold temperatures. The short period of load shed during Winter Storm Elliott relative to the Companies' performance history over an extended number of years serves to validate the random nature of overlapping outages -- not refute it -- as cold temperatures have provided challenges at both gas and coal generating stations for decades. However, our prudent root cause exercise does acknowledge that the sudden onset of extreme cold temperature, and the resulting impact on gas supply, played a common role in some of the events of last December.

Texas Gas' analysis determined that the gas supply issue resulted from a *degradation of gas supply pressure*, not availability of gas. With that more precise causal factor understood, the Companies will focus on the following three improvements: (1) monitoring the mitigation plans developed by Texas Gas to harden their system which mitigates this concern holistically;[8] (2) implement the previously discussed software improvement on the simple cycle combustion turbines at Trimble County, which will mitigate roughly 33% of the capacity reduction and 95% of the load shed noted by Mr. Goggin; and (3) ensure that each of the proposed NGCC installations

[8] Please see attached Rebuttal Exhibit LEB-1 for recent correspondence from Texas Gas on its efforts.

at Mill Creek and Brown includes analysis of gas compression capability incremental to that needed for expected pipeline pressure conditions and total costs and associated risks associated with capability to operate the proposed units on fuel oil for some reasonable number of hours. In short, the unprecedented nature of the roughly four hours of noted concern last December, and the statistical evaluation that follows leads me to disagree with Mr. Goggin's assessment. The combined mitigation efforts of the Companies and Texas Gas lead me to refute it completely.

Q. At pp. 44 of his testimony, Mr. Goggin also opines that batteries are superior to gas-fired generation in providing flexibility and he quotes your Direct Testimony at p. 10 to illustrate his point. Is he misinterpreting your point on this topic?

A. Yes. I provided testimony on this point to explain the benefits of NGCC ramping ability compared to the ramping ability of coal-fired generation. It is undisputed that NGCC ramp rates are faster than coal. So, from the perspective of comparing the portfolio's ramping ability now versus the proposed portfolio (which includes less coal and more gas), ramping ability will be greatly improved which will be of tremendous benefit as the Companies move to more intermittent generation resources. Mr. Goggin does not appear to dispute that. But he also opines that batteries or stored power is even more flexible and has better "ramping ability" than NGCCs. The Companies do not dispute that stored power has benefits, which is precisely why the Companies have proposed Brown BESS. It can be dispatched nearly instantaneously, so it also complements the introduction of more intermittent generation into the Companies' portfolio. However, the lack of need for significant nearly instantaneous dispatchability in the proposed portfolio supports the addition of NGCCs and does not support favoring BESS solely for its dispatch characteristics.

Q. He also states that NGCCs are quite inflexible relative to batteries and that, in fact, the Companies have acknowledged the benefits of batteries. What is your response to that?

A. As indicated in Exhibit SB4-1, battery storage has greater ramping capabilities than NGCCs. The Companies are proposing Brown BESS for that reason and others. However, compared to battery storage, the economics and operating characteristics of NGCCs are far superior for meeting the significant need for energy created by coal unit retirements.

VIII. KENTUCKY COAL ASSOCATION

Q. Kentucky Coal Association witness Emily Medine has provided testimony in this matter. Does she express opinions that you wish to rebut?

A. Yes, and I address her SB4 arguments above. Beyond that, her primary finding is that it is premature for the Commission to approve the proposed NGCCs, solar facilities, and Brown BESS and allow for the retirement of coal-fired generation. Her finding is consistent with the KCA's mission to "enhance the ability of the Kentucky coal industry to compete in domestic and world coal markets," but it is inconsistent with the Commission's and the Companies' regulatory obligation to ensure reliable service in a least cost manner. Having said that, while other of the Companies' witnesses address much of Ms. Medine's testimony, I address her contentions that: (1) the final version of the Good Neighbor Plan ("GNP") in March 2023 differs from the December 2022 proposed version of the GNP such that approval of the proposed NGCCs would be premature; (2) the EPA's May 11, 2023 proposed greenhouse gas ("GHG") rule and their possible effect on the proposed NGCCs mean it is premature to approve the NGCCs; and (3) the Companies' Resource Assessment is biased.

Q. What is your response to Ms. Medine's contention that differences between the proposed GNP and the final GNP make approval of the NGCCs now premature?

A. I disagree with that contention. Mr. Imber addresses the effect of the Sixth Circuit's recent stay of EPA's denial of Kentucky's State Implementation Plan, but as to the effect of the revisions of the December 2022 proposed GNP resulting in the final GNP of March 2023, they have no effect on the need for or timing of the proposed NGCCs. First, of the seven units the Companies propose to retire by 2028, the GNP affects only two: Mill Creek 2 and Ghent 2. The other five proposed retirements, including Mill Creek 1 and Brown 3, have entirely independent and sufficient retirement justifications as Mr. Wilson and I explained in our testimony in Case No. 2023-00122, which has been consolidated into this case.

Ms. Medine is correct that the revision may allow some utilities more timing flexibility in achieving NO_x compliance and the Companies have acknowledged that in discovery.[9] But for the Companies, the revisions have no effect. First, as explained in the Resource Assessment,[10] the GNP has no effect on the retirement date of Brown 3, the coal unit with the highest operating costs and which will require a $26 million overhaul in 2027 to operate beyond 2028, as that retirement decision is not related to the GNP.

The final GNP continues to base compliance on implementation of SCR controls on non-SCR units in 2026. Assuming SCR is the compliance strategy, the

[9] See the response to AG 2-4.
[10] See Exhibit SAW-1, Section 1.1.

Companies would have to implement SCR controls in 2026 to provide reliable service while complying with the reduction of allocations in 2026. Assuming no investment in SCR and no NGCCs in 2027 and 2028 as proposed, the Companies' modeling of the GNP depicts a reliance on the allocation market as early as 2026.[11] Under those same operational assumptions, the final GNP depicts a reliance on the allocation market as early as 2027. The result of that is that the timing of the need to transition to lower NO_x emitting sources does not change the analysis in the Companies' Resource Assessment.

Additionally, the Companies have explained in discovery that much of the somewhat more flexible compliance timing requirements were already assumed in the Companies' Resource Assessment[12] which is why the final GNP does not extend the timeline for the NGCCs in this proceeding. Again, the final GNP makes it clear that the Companies will have to rely on the allocation market in 2027 absent installing the NGCCs in 2027 and 2028. Finally, as Mr. Imber testifies in rebuttal, regardless of the GNP, it is likely that the Companies will be required to reduce NOx emissions at the Mill Creek site as soon as practicable and no later than 2026 to address the high likelihood that Jefferson County will be out of compliance with federal ozone standards implemented by Louisville Metro Air Pollution Control District.

Finally, given the market for SCR controls and current supply chain constraints, the Companies would need to start procuring SCR controls now to achieve compliance by 2026. Similar pressures exist in the market for gas-fired generation units. Delaying decisions on NGCC to some unknown future date would at a minimum increase costs

[11] See the response to AG 2-4 for modeling of NO_x emissions at Ghent 2, Mill Creek 2, and Brown 3.
[12] See the response to AG 3-3.

significantly, and perhaps make it impossible to replace the coal-fired units in time to comply with the GNP (or any substitute that would be keyed to the NAAQS compliance date of 2027). Pausing or abandoning the Companies' CPCN proposals now, while it would support KCA's stated core objective by limiting the Companies' compliance option to only continuing to operate coal units, carries an unacceptable degree of risk and would not be prudent. Thus, the time to act is still now.

Q. Please explain her contention regarding the proposed GHG rule.

A. Ms. Medine contends that the Companies' analysis does not reflect the costs associated with carbon capture, co-firing with hydrogen, or reduced utilization capacity, and, therefore, that analysis is flawed. The Companies disagree with that position as Mr. Sinclair explains in his rebuttal testimony.

Q. Ms. Medine states that the Companies' position is that the NGCCs would comply with the proposed GHG Rule by being reduced to intermediate load, but that, according to her employer, Energy Ventures Analysis, Inc., such a reduction would increase the Levelized Cost of Energy by about 25%. Do you agree with this?

A. None of the Companies' analysis in this case utilized the Levelized Cost of Energy. It is a crude metric for casually comparing technologies that is inappropriate in an evaluation and development of generation portfolios that are capable of serving the actual energy needs of customers that vary by hour. Customers do not consume energy on a "levelized" basis. The Companies' analysis performed in response to data request PSC 5-2 properly reflected the economic implications of limiting the proposed Mill Creek Unit 5 and Brown Unit 12 NGCCs to a 50 percent annual capacity factor, and the Companies' response to PSC 6-2 provided additional analysis of the same capacity factor limitation.

Q. Ms. Medine also criticizes the Companies' referral to the EPA's modeling in the proposed GHG rule and claims that reference is misplaced. What is your reaction to that?

A. When she speaks of that modeling, she is referring to the Regulatory Impact Analysis ("RIA") that the EPA provided in the proposed GHG Rule and the July 7, 2023 update to the RIA. She opines that the July 7, 2023 update is inconsistent with the Companies' statement that the NGCCs are likely to meet long-term demand. The Companies disagree with her opinion as Mr. Sinclair explains in his rebuttal testimony.

Q. Ms. Medine argues it is to customers' advantage to delay retiring the units the Companies have proposed to retire in this proceeding. Is she correct?

A. No. Although the Companies do not agree with Ms. Sommer that they have understated the anticipated cost of the Companies' proposed NGCC units, they do agree that there is a general upward trend in NGCC prices. That trend is likely to be exacerbated as more utilities and other generating entities move away from coal-fired units and toward NGCC and SCCT units for reliable around-the-clock energy resources in conjunction with additional renewable resources. There are only three entities that manufacture NGCC units, and they are beginning to become fully committed for the construction timeframe necessary for GNP compliance. Therefore, delay is not to customers' advantage; rather, delay will likely drive up the cost and unnecessarily limit the Companies' options to comply with both the GNP and the proposed GHG Rule.

Q. She also states that, for a fraction of the cost of the proposed portfolio, the Companies could continue to operate the three coal plants they plan to retire rather than replacing them with the new NGCCs. Do you agree?

A. No, of course not. The Companies would not have filed this case if it were that simple. That statement ignores the robust modeling the Companies have performed which supports the fact that the proposed portfolio is the least cost reasonable solution for meeting customer need. As Mr. Wilson explains in his rebuttal, her simplistic analysis for "support" for this contention (Exhibit ESM-4) is misplaced because it makes incorrect assumptions about cost and time periods.

Q. Ms. Medine also states that the Companies fail to acknowledge the construction risk of the "overly ambitious construction plan" given high inflation, supply chain and labor shortages, and transmission interconnection challenges. Do you agree?

A. No, as I explained in my December 15, 2022 Direct Testimony,[13] the Companies have a long and good history of taking on multiple complex projects simultaneously and completing them on time and as planned. As I testified above, moving forward expeditiously is critical to ensuring successful execution of the proposed portfolio. The Companies do acknowledge that executing all of the proposed projects and retirements will be challenging. But we are also very comfortable in the timeline we have prepared and in our ability to meet that timeline and ensure environmental compliance in a least cost manner.

Q. You state above that Ms. Medine opines that the Companies' Resource Assessment is inappropriately biased. Please describe her opinion on that point.

[13] See pages 24-25 of my Direct Testimony.

A. At page 28 of her testimony, she states that the Resource Assessment is biased towards closing three coal-fired units and replacing them with NGCCs. Mr. Crockett addresses her claim of bias in his rebuttal testimony. She also argues that if this alleged bias had not been in place, the Companies would have done the following as part of their analysis:

- Considered the "devastating impact" of the proposed investments on customers;
- Considered the impact of the proposed investments on local and state economies;
- Taken steps to "fine tune" their cost estimates for the NGCCs and alternatives including costs for firm transportation of natural gas;
- Acknowledged that replacement of coal with natural gas absent carbon capture will not achieve net-zero emission objectives; and
- Acknowledged that to achieve net-zero emissions from gas by 2040 or 2050, the NGCCs would have to be retrofit with carbon capture or converted to green hydrogen.

Q. Do you agree with her concerns about the Companies not considering these items?

A. Not at all. Through the robust and comprehensive analysis and modeling the Companies have performed as reflected in Exhibit SAW-1 and Exhibit SB4-1, the Companies have identified the least cost reasonable portfolio for meeting customer need. Various portfolios and sensitivity analyses were performed, both before and after Senate Bill 4 was passed, to identify the recommended portfolio. Although some of the intervenor testimony suggests alternate portfolios, none of them are a least cost reasonable portfolio required for a CPCN. As to her specific points about the cost of the proposed portfolio to customers and its effect on local and state economies, identifying the least cost reasonable solution is exactly what the Companies needed to do to minimize cost to customers and burden on local or state economies. Indeed, as the Companies' analysis shows, her "all coal" solution is the one that would harm customers by burdening them with unnecessary costs. As for "fine tuning" the cost estimates for the NGCCs, I have explained above the Companies' confidence in those estimates.

Finally, as to her points on net-zero emissions, Ms. Medine seems to be referring to but does not understand PPL's position on net-zero emissions. PPL has said, "We view our path to net-zero emission as a continuum, with a primary focus on eliminating our gross emissions, leveraging technology to remove emissions where they cannot be eliminated due to cost or reliability constraints, and finally, considering carbon offsets for any remaining emissions as the least-preferred option."[14] While that path is a continuum, there was no reason to factor PPL's stated corporate goal into the Companies' modeling. The retirements and replacements the Companies have proposed are based on economics, compliance with increasingly stricter environmental requirements, and reliability,[15] which are precisely the factors that should be considered for CPCN purposes.

IX. RTO

Q. Do you have a final comment concerning Mr. Levitt's recommendation?

A. Yes. Mr. Sinclair discusses in detail in his rebuttal testimony the reasons why Mr. Levitt's analysis that PJM membership would result in net benefits is incomplete and fails to address material uncertainties. My broader comment is that RTO membership will not allow Mill Creek Unit 1 and 2, Brown Unit 3, or Ghent Unit 2 to avoid the environmental compliance challenges discussed throughout our analysis. These units in an RTO membership scenario will need to comply with EPA's regulations. Finally,

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[14] See the response to KCA 2-13.
[15] See the response to JI 1-149.

RTO membership will not increase the economic life of these units or change their lack of cost effectiveness under the analysis presented in this case.

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

The undersigned, **Lonnie E. Bellar**, being duly sworn, deposes and says that he is Chief Operating Officer for Louisville Gas and Electric Company and Kentucky Utilities Company and an employee of LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of his information, knowledge, and belief.

Lonnie Bellar

Lonnie E. Bellar

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 7th day of August, 2023.

Caroline J. Davison

Notary Public

Notary Public ID No. KYNP63286

My Commission Expires:

January 22, 2027

CAROLINE J. DAVISON
COMM EXPIRES 01/22/2027
NOTARY
PUBLIC
ID # KYNP63286
STATE AT LARGE, KENTUCKY

July 31, 2023

Mr. Chuck Schram
Director, Power Supply
LG&E and Kentucky Utilities
220 West Main Street
Louisville, KY 40202

Dear Chuck,

In an effort to keep KU informed on progress toward our continued efforts to further prepare for winter storm events, the attached document includes updates on infrastructure work at critical locations on the north end of the Texas Gas system and the assessment of our Asset Reliability Program

As always, we appreciate our partnership with LG&E and KU and look forward to providing dependable service for years to come.

Best Regards,

Charles Backstrom
VP Marketing and Business Development

Inclement Weather Assessment

Boardwalk evaluated potential site-specific vulnerabilities, including but not limited to horsepower reliability, redundant horsepower, air systems, fuel systems, and ancillary equipment. Projects listed in "2023 Boardwalk Targeted Reliability Projects" were identified to continue to advance our winter readiness and reliability.

2023 Boardwalk Targeted Reliability Projects

Station	**Project**	**Class**	**Planned Completion Date**
Slaughters	Building heat for T2	Cold Weather	10/30/2023
Slaughters	T2 fuel run weather shelter	Cold Weather	9/1/2023
Slaughters	T3 fuel run weather shelter	Cold Weather	9/1/2023
Slaughters	T2 loading valve insulated weather box	Cold Weather	Complete
Slaughters	T2 vent valve weather box	Cold Weather	Complete
Slaughters	T3 anti surge valve insulated weather box	Cold Weather	Complete
Slaughters	T3 hot bypass valve insulated weather box	Cold Weather	Complete
Slaughters	T3 loading valve insulated weather box	Cold Weather	Complete
Slaughters	T3 vent valve weather box	Cold Weather	Complete
Slaughters	3rd Party reliability assessment	Reliability	Complete
Company Wide	Reliability culture 3rd party assessment	Reliability	8/15/2023
Hardinsburg	T3 fuel run weather shelter	Cold Weather	9/1/2023
Hardinsburg	T5 fuel run weather shelter	Cold Weather	9/1/2023
Hardinsburg	T6 fuel run weather shelter	Cold Weather	9/1/2023
Hardinsburg	Air dryer replacement	Cold Weather	11/1/2023
Hardinsburg	T5 Solar automation upgrade and modernization	Reliability	11/15/2023
Hardinsburg	Metal particle detectors	Reliability	Complete
Hardinsburg	T3 valve limit switch upgrades	Reliability	10/1/2023
Hardinsburg	T3 battery replacement	Reliability	9/1/2023
Hardinsburg	Station Emergency Shutdown battery replacement	Reliability	9/1/2023
Hardinsburg	3rd Party reliability assessment	Reliability	Complete
Hardinsburg	T3 anti surge valve insulated weather box	Cold Weather	8/17/2023
Hardinsburg	T3 loading valve insulated weather box	Cold Weather	8/17/2023
Hardinsburg	T3 vent valve weather box	Cold Weather	8/17/2023
Hardinsburg	T5 anti surge valve insulated weather box	Cold Weather	8/17/2023
Hardinsburg	T5 hot bypass valve insulated weather box	Cold Weather	8/17/2023
Hardinsburg	T5 loading valve insulated weather box	Cold Weather	8/17/2023
Hardinsburg	T5 blow down valve weather box	Cold Weather	8/17/2023
Hardinsburg	T6 anti surge valve insulated weather box	Cold Weather	8/17/2023
Hardinsburg	T6 hot bypass valve insulated weather box	Cold Weather	8/17/2023
Hardinsburg	T6 loading valve insulated weather box	Cold Weather	8/17/2023

Hardinsburg	T6 vent weather box	Cold Weather	8/17/2023
Calvert City	T2 anti surge valve insulated weather box	Cold Weather	9/14/2023
Calvert City	T2 loading valve insulated weather box	Cold Weather	9/14/2023
Calvert City	T2 vent valve weather box	Cold Weather	9/14/2023
Calvert City	T3 anti surge valve insulated weather box	Cold Weather	9/14/2023
Calvert City	T3 vent valve weather box	Cold Weather	9/14/2023
Calvert City	T3 loading valve insulated weather box	Cold Weather	9/14/2023
Calvert City	T4 anti surge valve insulated weather box	Cold Weather	9/14/2023
Calvert City	T4 hot bypass valve insulated weather box	Cold Weather	9/14/2023
Calvert City	T4 loading valve insulated weather box	Cold Weather	9/14/2023
Calvert City	T4 blow down valve weather box	Cold Weather	9/14/2023
Midland 3	T1 fuel run weather shelter	Cold Weather	10/1/2023
Midland 3	T2 fuel run weather shelter	Cold Weather	10/2/2023
Midland 3	T3 fuel run weather shelter	Cold Weather	10/1/2023
Midland 3	Air dryer replacement	Cold Weather	10/25/2023
Midland 3	Building heat upgrade	Cold Weather	10/1/2023
Midland 3	T1 anti surge valve insulated weather box	Cold Weather	8/17/2023
Midland 3	T1 hot bypass valve insulated weather box	Cold Weather	8/17/2023
Midland 3	T1 loading valve insulated weather box	Cold Weather	8/17/2023
Midland 3	T1 vent weather box	Cold Weather	8/17/2023
Midland 3	T2 anti surge valve insulated weather box	Cold Weather	8/17/2023
Midland 3	T2 hot bypass valve insulated weather box	Cold Weather	8/17/2023
Midland 3	T2 loading valve insulated weather box	Cold Weather	8/17/2023
Midland 3	T2 vent valve weather box	Cold Weather	8/17/2023
Midland 3	T3 anti surge valve insulated weather box	Cold Weather	8/17/2023
Midland 3	T3 hot bypass valve insulated weather box	Cold Weather	8/17/2023
Midland 3	T3 loading valve insulated weather box	Cold Weather	8/17/2023
Midland 3	T3 vent valve weather box	Cold Weather	8/17/2023

Boardwalk has reviewed the Slaughters and Hardinsburg site-specific checklists for inclement weather and revised based on lessons learned from this event.

Boardwalk will continue to identify and procure critical spare parts that will improve reliable operations.

Boardwalk has utilized a third-party reliability consultant to conduct an assessment of critical infrastructure, horsepower, auxiliary equipment, critical spare parts, operating procedures for the Slaughters and Hardinsburg Compressor Stations, with the goal of enhancing reliability during extreme conditions.

Boardwalk has utilized a third-party reliability consultant to conduct a comprehensive Enterprise Asset Management (EAM) Assessment of our Asset Reliability Program.

Pre-Inclement Weather Measures

- Boardwalk will continue to emphasize the following action steps:
    - Holding meetings between Asset Reliability, Regional Vice Presidents (RVPs) and Area Managers to discuss concerns and/or areas of focus.
    - Reviewing site-specific checklists to ensure proactive measures are in place. Boardwalk will utilize Operation Management System (OMS) to trigger a work order to perform and document this task.
    - Verifying valve insulated boxes installed on critical boxes are fully intact, sealed, and box heaters, as needed, are lit and operational.
    - Verifying fuel gas weather shelters are fully intact and tarps are installed as needed.
    - Validating horsepower readiness prior to inclement weather by working with Gas Control to start and run critical horsepower.
    - Where appropriate operating compressor stations on backup generator power at those close coupled to powerplants or other critical facilities.
    - Coordinating with Gas Control to put horsepower online prior to an inclement weather event when physically and hydraulically feasible.