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.	: : : : : : :	CASE NO 2022-00402

INITIAL BRIEF OF KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

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Kentucky Industrial Utility Customers, Inc. ("KIUC") submits this Initial Brief in response to the Joint Application of Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU"), (collectively "Companies") for certificates of public convenience and necessity ("CPCN"), approval to retire four coal plants and other relief.

INTRODUCTION AND SUMMARY

This is one of the most important cases that the Kentucky Public Service Commission ("Commission") has been asked to decide in recent memory. And it is being considered at a time of unprecedented contradictory guidance from the state and federal governments.

The Kentucky Legislature has expressed a clear preference for reliable, resilient and dispatchable coal-fired generation through SB 4 (KRS 278.264). However, the federal government: 1) through EPA's proposed Good Neighbor Plan will limit coal generation to only the seven non-ozone months unless selective catalytic reduction ("SCR") for NOX control is installed; 2) is targeting coal and gas generation for premature retirement through a highly questionable best system of emissions reductions ("BSER") of carbon capture and sequestration ("CCS") or hydrogen co-firing in EPA's proposed 111(b) and 111(d) greenhouse gas rules; and 3) through the Inflation Reduction Act dramatically increased the subsidization of weather dependent wind and solar generation, which crowds out dispatchable thermal generation in the competitive wholesale energy and capacity markets. At the same time PJM, MISO, NERC and FERC are all warning of an impending reliability crisis because of the too fast retirement of coal and natural gas plants.[1]

The generation supply portfolio proposed by the Companies reasonably balances these conflicting state and federal directives. The generation supply portfolio proposed by the Companies is realistic, flexible, reliable, and least-cost under a wide range of reasonable assumptions. The portfolio should be approved, with limited exceptions. KIUC's issue by issue recommendations are contained on the following chart.

RESOURCE	ISSUE	RECOMMENDATION
Mill Creek 5 621 Mw Natural Gas Combined Cycle (NGCC)	Should a certificate of public convenience and necessity (CPCN) be approved?	Yes, a CPCN should be approved.
Mill Creek 1 300 Mw Coal Plant And Mill Creek 2 297 Mw Coal Plant	Should both coal units be retired in compliance with SB4?	Yes, Mill Creek 1 should be retired in 2024 and Mill Creek 2 should be retired 2027.
Brown 12 621 Mw NGCC	Should a CPCN be approved?	Yes, a CPCN should be approved.
Brown 3 416 Mw Coal Plant	Should Brown 3 be retired in compliance with SB 4?	Yes, Brown 3 should be retired in 2028.
Ghent 2 495 Mw Coal Plant	Should Ghent 2 be retired in compliance with SB 4?	No, Ghent 2 should not be retired.
Company Owned Solar 120 Mw In Mercer County And 120 Mw In Marion County	Should CPCNs be approved for the two Company owned solar projects?	Yes, CPCNs should be approved.
125 Mw Battery Storage Facility At The Brown Site (BESS).	Should a CPCN be approved?	No, a CPCN should not be approved.
2024-2030 Demand Side Management (DSM)-Energy Efficiency (EE) Plan	Should the DSM-EE plan be approved?	Yes, the DSM-EE plan should be approved.
637 Mw Of Solar Purchase Power Agreements (PPA) From Four Developers	Should the Commission issue a declaratory order that the four solar PPAs do not require Commission approval and that cost recovery should be through the fuel adjustment clause (FAC)?	KIUC originally opposed the solar PPAs as not being in compliance with SB 4. However, based upon the Companies' Rebuttal Testimony we do not oppose the solar PPAs. But cost recovery should not be through the FAC.

[1] Kollen Direct Testimony at 7-9; Sinclair Rebuttal Testimony at 3-4, 29-31.

ARGUMENT

1. A Certificate Of Public Convenience And Necessity Should Be Approved For The 621 Mw Mill Creek 5 Natural Gas Combined Cycle.

A 621 Mw natural gas combined cycle ("NGCC') at the Mill Creek site ("Mill Creek 5") is part of a realistic, flexible, reliable, and least-cost portfolio that combines coal, gas, solar, hydro and energy efficiency.[2] NGCC technology is highly efficient (low heat rate) and highly reliable (low forced outage rate). The heat rate (conversion efficiency of fossil fuel to electricity) for the Mill Creek 5 NGCC will be approximately 6,200 Btu/Kwh, versus the coal units slated for retirement at over 10,000 Btu/Kwh.[3] The 2018-2022 average forced outage rate for the currently operational Cane Run 7 NGCC was only 1.8% compared to the Brown 3 coal plant forced outage rate over the same period of 6.06%.[4] The ramp rate and load following capability of NGCC generation is superior to coal generation.[5] NGCC generation provides greater resilience by ramping at 80 Mw per minute versus 10 Mw per minute for coal.[6] The Companies have agreed to add dual fuel capabilities (fuel oil) for added reliability.[7] An SCR on the Mill Creek 5 NGCC will control NOx emissions.[8]

A delay in procurement runs the risk that the NGCC unit may not be available from the three companies that manufacture NGCCs, or that the price will go up as more domestic and international buyers move to this technology.[9] A delay in procurement also runs the risk that firm gas transportation may not be available.[10]

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[2] Case No. 2023-00122, Wilson Direct Testimony, Exhibit SB 4-1; Exhibit SAW-1.
[3] Transcript, 8:05:06/11:19:25 (Bellar).
[4] Kollen Direct Testimony Exhibit 4.
[5] Bellar Rebuttal Testimony at 19; Bellar Direct Testimony Case No. 2023-00122 at 16.
[6] Transcript, 7:57:52/11:19:25 (Bellar).
[7] Bellar Rebuttal Testimony at 8.
[8] Transcript, 7:54:24/8:30:45 (Imber).
[9] Bellar Rebuttal Testimony at 22-24.
[10] Schram Direct Testimony at 12; Transcript, 10:01:04/11:19:25 (Bellar).

The risks associated with delay were made clear in the Companies' responses to post-hearing data requests. The competitive bids for constructing the NGCCs were recently received and the cost per Kw is significantly above the assumed price.[11] This increases the present value revenue requirement ("PVRR") of the recommended portfolio but does not affect reliability or resilience.[12] Two conclusions can be reached from this development. The first possible conclusion is that the NGCC CPCNs should be denied, and the Companies should start over. The problem with this conclusion is that the factual assumptions behind any long-term forecast will always be subject to change. Moreover, the Companies have modeled the increased NGCC capital cost and have concluded that even assuming a zero cost for CO_2 their plan remains least-cost.[13] The second possible conclusion is that it is even more important to approve the NGCC CPCNs without delay to lock in delivery and pricing so that the situation does not get worse. The Companies have reached the second conclusion. We agree. Given the world-wide demand for this technology, limited suppliers and stubborn inflation, there is little reason to believe that the market price for NGCCs will go down or that their availability will go up.

NGCC technology performs reasonably well under the EPAs proposed 111(b) and 111(d) Greenhouse Gas Rules. The Mill Creek 5 NGCC will emit 65% less CO_2 per MWh than a coal unit.[14] Under a worst-case scenario, the Companies could comply with 111(b) by electing intermediate load operations and restricting NGCC capacity factors to 50%.[15] Three NGCCs operating at 50% capacity factors would produce the same energy (and the same CO_2) as two NGCCs operating at 75% capacity factors. While building extra generation and not maximizing

[11] Post-Hearing Response to Joint Intervenors No. 4.1.

[12] Id.

[13] Id.

[14] Sinclair Direct Testimony at 23.

[15] Sinclair Rebuttal Testimony at 69.

their energy output would be economically wasteful, it would comply with the proposed greenhouse gas rules.

The requisite air permit for the Mill Creek 5 NGCC is dependent on the retirement of the Mill Creek 1 and Mill Creek 2 coal units. The use of the existing permitted emissions at Mill Creek Units 1 and 2 will allow the NGCC to "*net out*" in the Prevention of Significant Deterioration ("PSD") air permitting process for NOx, SO2 and particulate matter.[16] Therefore, unless the retirements of Mill Creek 1 and Mill Creek 2 are approved, the air permitting process for the Mill Creek 5 NGCC would have to start over.[17]

In their post-hearing data responses, the Companies detailed how a new eighteen-month air permit process would proceed for the Mill Creek 5 NGCC if the Mill Creek 1 and 2 coal units are not retired.[18] A new Title V air permit application under Louisville Metro Air Pollution Control District ("LMAPCD") Regulation 2.04 would need to be filed. This permit would require full non-attainment New Source Review Potential for Significant Deterioration ("NSR-PSD") permitting.[19] Emissions off-setting would be required. But because the Mill Creek area is currently in non-attainment status, it is unlikely that LG&E could find other sources that are able to offset the quantity of emissions necessary to complete the NSR-PSD permit.[20] Therefore, air permitting under this scenario is unlikely to be successful.[21] However, LG&E possibly could offset NOx by installing SCR controls.[22] But even SCR controls would not ensure that an air permit for the NGCC would be approved.

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[16] Bellar Direct Testimony at 8-9.
[17] Transcript, 8:08:40/11:19:25 (Bellar); 11:34:25/11:41:40 (Imber).
[18] Post-Hearing Data Response to KIUC No. 3.
[19] Id.
[20] Id.
[21] Id.
[22] Id.

In sum, delaying a CPCN for the Mill Creek 5 NGCC would have at least three negative consequences. First, it would subject ratepayers to increasing NGCC capital costs. Second, it would compromise the ability to get firm gas transportation. Third, it would increase the risk that an air permit would not be approved.

2. The 300 Mw Mill Creek 1 Coal Plant And 297 Mw Mill Creek 2 Coal Plant Should Be Retied Pursuant To SB 4.

Mill Creek 1 has been scheduled for retirement in 2024 since 2020.[23] To operate beyond 2024, the unit would need process water equipment for Effluent Limitation Guidelines ("ELG") compliance.[24] To operate beyond 2027, Mill Creek 1 would need a cooling tower to comply with Clean Water Act 316(b) regulations.[25] To operate year-round in compliance with the Good Neighbor Plan, it would need to add an SCR prior to the 2027 ozone season.[26] Simply put, Mill Creek 1 will have reached the end of its economic life next year.

Operating Mill Creek 2 year-round would probably require a $110 million SCR for controlling NOX emissions under existing environmental rules even if the Good Neighbor Plan does not go into effect.[27] The Mill Creek region is non-attainment for ozone purposes and the retirement of both coal plants will improve air quality and aid economic development in the greater Louisville region. Mill Creek 2 is the largest source of NOx in the greater Louisville attainment area.[28]

Environmental regulation for the Mill Creek plant is implemented by the LMAPCD.[29] The ozone season for Jefferson County is seven months (April – October). The ozone season is five

[23] Bellar Direct Testimony at 4, Case No. 2023-00122.
[24] Bellar Direct Testimony at 4, Case No. 2023-00122.
[25] Bellar Direct Testimony at 4, Case No. 2023-00122.
[26]Bellar Direct Testimony at 4, Case No. 2023-00122.
[27] Id.; Exhibit SAW-1, page 4.
[28] Imber Rebuttal Testimony at 13.
[29] Imber Rebuttal Testimony at 12.

months under the Good Neighbor Plan (May - September). The Companies entered into an Agreed Order at Mill Creek to not exceed 15 tons of NOx on a daily basis from May through October (6 months) in support of local attainment to the ozone NAAQS. The Agreed Order excludes the month of April. This means that the Companies cannot operate both Mill Creek 1 and 2 during the six-month LMAPCD ozone season.[30] During the six-month LMAPCD ozone season (May - October), only one of the two Mill Creek units can operate. The Companies can operate both units only six months a year, during the five LMAPCD non-ozone months and April.

These operating restrictions significantly reduce the economic, reliability and resilience attributes of Mill Creek 1 and 2 for purposes of newly enacted KRS 278.264. Simply put, power plants with significantly reduced operating capabilities because of environmental restrictions provide less reliability, less resilience and fewer economic benefits to customers. The replacement NGCC will have none of these operating restrictions.

Retiring both Mill Creek 1 and 2 and netting NOX emission reductions is a central assumption in the Mill Creek 5 NGCC air permit.[31] As discussed previously, the use of the existing permitted emissions at Mill Creek Units 1 and 2 will allow the NGCC to "*net out*" in the PSD air permitting process for NOx, SO2 and particulate matter.[32]

If both coal units are not retired, then the air permitting process for the Mill Creek 5 NGCC would have to start over. This process would take at least eighteen months and is unlikely to be successful.[33] In other words, for the Mill Creek 5 NGCC to proceed on schedule, Mill Creek Units 1 and 2 need to be retired. KIUC supports the Mill Creek 5 NGCC and the retirement of Mill Creek Unit 1 in 2024 and Mill Creek Unit 2 in 2027.

[30] See Transcript, 8:06:22/11:19:25 (Bellar).
[31] Imber Rebuttal Testimony at 12-14.
[32] Bellar Direct Testimony at 8-9.
[33] Post-Hear Data Response to KIUC No. 3.

A Commission Order approving the retirements of Mill Creek 1 in 2024 and Mill Creek 2 in 2027 pursuant to SB 4 should be contingent on the receipt of a final air permit for the Mill Creek 5 NGCC and the start of commercial operations of the NGCC. If the Mill Creek 5 NGCC cannot be completed because of permitting issues, supply chain issues, natural gas transportation issues, or for any other reason, then the capacity and energy from the two Mill Creek coal units will be needed for native load. Also, if a SB 4 retirement order is not contingent on the receipt of a final NGCC air permit, then an environmental group might happily accept the Commission's retirement order and then challenge the air permit in an effort to get a double "*win*"—the retirement of two coal plants and no new NGCC.

3. A CPCN Should Be Approved For The 621 Mw Brown 12 NGCC.

The 621 Mw Brown NGCC has all of the favorable operational attributes as the Mill Creek 5 NGCC. To summarize:

- NGCC technology is highly efficient (low heat rate) and highly reliable (low forced outage rate).[34]
- The ramp rate and load following capability of NGCC generation is superior to coal generation.[35]
- The Companies have agreed to add dual fuel capabilities (fuel oil) on the NGCC for added reliability.[36]
- An SCR on the NGCC will control NOx emissions.[37]
- Only three companies world-wide manufacture NGCCs and the demand is high so getting in line now has value.[38]
- A delay in the CPCN process runs the risk that firm gas transportation may not be available.[39]
- NGCC technology performs reasonably well under the EPAs proposed 111(b) and 111(d) Greenhouse Gas Rules.[40]

[34] Kollen Direct Testimony, Exhibit 4.

[35] Bellar Rebuttal Testimony at 19; Bellar Direct Testimony Case No. 2023-00122 at 16.

[36] Bellar Rebuttal Testimony at 8.

[37] Transcript, 7:54:24/8:30:45 (Imber).

[38] Bellar Rebuttal Testimony at 22-24; Post-Hearing Data Response to Joint intervenors No. 4.1.

[39] Schram Direct Testimony at 12; Post-Hearing Data Response to Joint Intervenors No. 4.1.

[40] Sinclair Rebuttal Testimony at 69.

- The proposed NGCC will emit 65% less CO_2 per MWh than a coal unit.[41]
- The air permitting issues for the Brown NGCC are also similar to the Mill Creek NGCC.[42] The use of the existing permitted emissions at the Brown 3 coal plant will allow the NGCC to "net out" in the PSD air permitting process for NOx, SO_2 and particulate matter.[43]

The Brown 12 NGCC is an integral part of the Companies' least-cost plan for reliably serving native load for decades into the future. KIUC supports a CPCN for the Brown 5 NGCC.

4. The 416 Mw Brown 3 Coal Plant Should Be Retired Pursuant To SB 4.

Brown 3 is the Companies' least efficient and highest cost coal unit. For 2017-2022, its annual capacity factor averaged only 29%.[44] As a stand-alone unit, there are no economies of scale and its fixed costs are high. Exhibit SAW-1, page 52 shows the "*ongoing stay-open*" costs for Brown 3, Mill Creek 2 and Ghent 2. For the five-year period 2029-2033, the "*ongoing stay-open*" costs for the 416 Mw Brown 3 plant will average $36.6 million per year.[45] This is almost twice the annual "*ongoing stay-open*" costs for the much larger 495 Mw Ghent Unit 2.[46] In sum, Brown 3 is expensive to operate and expensive to maintain.

Importantly, because of rail line limitations, Brown 3 does not use Kentucky coal.[47]

If Brown 3 is not retired in 2028, then the air permit process for the Brown NGCC would have to start over because the air permit assumed the netting of reduced NOX emissions from the retirement of the Brown coal plant.[48] A new air permit process would take approximately eighteen months.[49] This delay would subject consumers to additional price escalations for NGCC

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[41] Sinclair Direct Testimony at 23.

[42] Transcript, 8:08:40/11:19:25 (Bellar); 11:34:25/11:41:40 (Imber).

[43] Bellar Direct Testimony at 8-9; Imber Direct Testimony at

[44] Sinclair Rebuttal Testimony at 67.

[45] Exhibit SAW-1, page 52 of 104.

[46] Id.

[47] Transcript, 8:10:02/11:19:25 (Bellar).

[48] Bellar Direct Testimony at 8-9; Post-Hearing Data Response to KIUC No. 2.

[49] Post-Hearing Data Response to KIUC No. 2.

capital costs.[50] A delay also runs the risk that firm gas transportation service might not be available.[51]

As a practical matter, it appears that the Commission has to choose either the inefficient Brown 3 coal plant which does not use Kentucky coal or a state-of-the-art NGCC to replace it. We support replacement.

The retirement of Brown 3 in 2028 pursuant to SB 4 should be contingent on the receipt of a final air permit for the Brown NGCC and the commercial operation of the NGCC. If the Brown NGCC cannot be completed for any reason, then the capacity and energy from the Brown coal plant will be needed. Also, if a SB 4 retirement order is not contingent on the receipt of a final NGCC air permit, then an environmental group might accept the retirement order and then challenge the air permit in an effort to get two "*wins*" – a coal plant retirement and no new NGCC.

5. CPCNs For The Company-Owned Solar Projects In Mercer County (120 Mw) And In Marion County (120 Mw) Should Be Approved.

240 Mw of Company-owned solar is part of a least-cost portfolio and is a relatively small amount of renewable generation for a utility the size of the Companies. The conclusion that Company-owned solar is dispatchable for purposes of SB 4 is not strong. Nevertheless, KIUC supports CPCNs for the 120 Mw Mercer County and 120 Mw Marion County solar facilities.[52]

6. A CPCN For The 125 Mw, Four Hour Battery Storage Facility Should Be Denied.

The Companies' analysis candidly admits that the 125 Mw, four-hour Brown energy storage system ("BESS") is not cost-effective, even after very favorable investment tax credits.[53]

[50] Post-Hearing Data Response to Joint Intervenors No. 4.1.
[51] Id.
[52] Kollen Direct Testimony at 5.
[53] Kollen Direct Testimony at 16-17

The present value cost to consumers from the BESS ranges from a low of $78 million to a high of $130 million.[54] The operational experience that would be gained by the BESS is not worth the significant added cost to consumers.

The all-in energy cost from the BESS is extraordinarily high. In 2026, the all-in cost of the BESS ranges from $3,819/MWh for the low gas forecast to $5,876/MWh for the high gas forecast.[55]

The after-tax cost of the BESS is $113 million.[56] For almost the same amount, a $126 million SCR can be added to the 495 Mw Ghent 2.[57] An SCR on Ghent 2 would certainly be more consistent with the Legislative policy behind SB 4.

7. The Demand Side Management And Energy Efficiency Plan For 2024-2030 Should Be Approved.

The 2024-2030 DSM-EE plan is projected to achieve cumulative peak demand savings of 377 Mw, energy savings of 878 GWh, and 170 thousand Mcf gas savings by 2030 at a cost of $341 million.[58] These programs, especially for low-income residential consumers, are reasonable.[59]

8. The 495 Mw Ghent Unit 2 Coal Plant Should Not Be Retired.

a. The Evidence Supporting The Retirement Of Ghent 2 Does Not Satisfy KRS 278.264. The Retirement Of Ghent 2 Will Harm KU's Ratepayers In Violation Of KRS 278.264 (2) (b) And Will Not Result In Cost Savings To Customers In Violation Of KRS 278.264 (3).

KRS 278.264 has two financial protections for ratepayers that must be satisfied before a retirement can be approved. First, the Commission must find that the retirement will "*not harm the utility's ratepayers by causing the utility to incur any net incremental costs"* that could be

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[54] Kollen Direct Testimony at 16-17.
[55] Kollen Direct Testimony at 17.
[56] Kollen Direct Testimony at 17.
[57] Kollen Direct Testimony at 17.
[58] Bevington Direct Testimony at 12.
[59] Kollen Direct Testimony at 5.

avoided by continuing to operate the unit. KRS 278.264 (2) (b). This is a Hippocratic Oath standard — first do no harm. Second, the utility must provide affirmative evidence that ratepayers will actually benefit from retirement. The utility must provide evidence that "*cost savings will result to customers"* from the retirement. KRS 278.264 (3). Both of these ratepayer financial protections will be violated by the retirement of Ghent 2.

Ghent 2 is a large highly efficient unit.[60] Of the four coal plants sought to be retired (Mill Creek 1, Mill Creek 2, Brown 3 and Ghent 2), Ghent 2 is by far the best unit.

Over the last seven years, the average heat rate of Ghent 2 was 10,641 Btu/Kwh.[61] Over the last five years, its forced outage rate was 0.83%, the lowest of all of the Companies' coal-fired units.[62] In 2017-2022, its capacity factor averaged 64%.[63] Over the seven-year period 2016-2022, the average annual net generation from Ghent 2 was 2,713,000 MWh, or about 9% of the Companies' annual retail sales.[64]

The Ghent 2 plant is located on the Ohio River which gives the facility access to low-cost barge-delivered Western Kentucky coal. Ghent 2 is part of the four-unit Ghent complex which creates efficiencies and economies of scale. For example, the fixed O&M costs for continued operation of the 495 Mw Ghent 2 plant from 2023-2028 is projected to average $10.92 million per year. The comparable number for the 416 Mw Brown 3 is $27.15 million per year.[65]

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[60] Kollen Direct Testimony at 10.
[61] Kollen Direct Testimony at 10.
[62] Kollen Direct Testimony at 10.
[63] Sinclair Rebuttal Testimony at 67.
[64] Kollen Direct Testimony Exhibit 3.
[65] Company Response to Sierra Club 1-14.

Ghent 2 currently operates year-round. If the Good Neighbor Plan becomes effective, or if the EPA pursues the same NOX reductions outside of the Good Neighbor Plan, then a $126 million SCR for NOx reduction would be needed for year-round operation.[66]

Keeping Ghent 2 open will not affect the air permitting process for either proposed NGCC. Therefore, Ghent 2 can be complementary to the Companies' proposed portfolio, not contradictory.

Not retiring Ghent 2 provides optionality. As Mr. Kollen testified, even if five-month ozone season NOx control is required, the Companies could operate Ghent 2 during the seven non-ozone months and subsequently add an SCR for year-round operations.[67] Operating only during seven months provides added winter reliability, capacity for load growth and economic development and the opportunity for off-system sales.[68] Operating only during the seven non-ozone months will also reduce the reliance on market energy purchases to serve native load, thus avoiding net incremental purchase power costs that would be recovered from ratepayers through the fuel adjustment clause.

Keeping Ghent 2 open for at least the seven non-ozone months is not costly. Rebuttal Exhibit DSS-2 page 1 of 10 shows the cost of operating Ghent 2 during the seven non-ozone months assuming the rest of the Companies portfolio is approved. Under the six different fuel price scenarios studied by the Companies, for the period 2029-2035, keeping Ghent 2 open seven months would only cost approximately $6.5 million per year.[69] $6.5 million per year is not costly for two utilities that have annual retail electric revenue in excess of $3 billion.

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[66] Imber Rebuttal Testimony at 9-11.
[67] Kollen Direct Testimony at 13
[68] Kollen Direct Testimony at 15.
[69] Sinclair Rebuttal Exhibit DSS-2, page 1.

The Companies' modeling does not include projected profits from off-system sales, but such profits will occur during actual operations and will off-set the $6.5 million added cost. KIUC witness Mr. Kollen testified that profits from off-system sales might completely off-set the $6.5 million added cost. Retiring Ghent 2 would cause KU to miss this off-system sales opportunity. Financially, lost sales revenue is the same as an additional expense. Either way, the net incremental cost to ratepayers will increase.

Forecasted market energy price information was provided in post-hearing discovery. Over the three year period 2025-2027, the Companies estimate that the on-peak energy price in PJM West will average $52.15/MWh.[70] The Companies also estimate that the fuel cost for their coal generation in 2030 will range from $22.07/MWh to $38.30/MWh.[71] Even adding $4/MWh to $6/MWh for variable O&M, this new evidence tends to demonstrate that the cost of keeping Ghent 2 in operation can be completely off-set by profits from off-system sales. Operating at a 65% capacity factor, a $10/MWh margin during the on-peak hours of the seven non-ozone months results in an annual profit from off-system sales of $8.9 million.[72]

Despite increased CO_2 emissions, it is important for the Companies to maximize the value of the coal generation in rate base by selling energy off-system whenever it is economic. This will reduce rates and increase Kentucky coal utilization.

As recognized by PJM, MISO NERC and FERC, this country needs to maintain its thermal generation fleet to ensure reliability.[73] Ghent 2 can be part of that solution as it will improve the reliability and resilience of the transmission grid.

[70] Post-Hearing Data Response to KIUC No. 1.
[71] Post-Hearing Data Response to Staff No. 17.
[72] 34.57 non-ozone weeks x 80 weekly on-peak hours x 495 Mw x 0.65 capacity factor x $10/MWh = $8,898,318.
[73] Kollen Direct Testimony at 7-9; Sinclair Rebuttal Testimony at 3-4, 22, 29-31.

Kentucky Power Company ("Kentucky Power") will have a significant capacity shortage when its Mitchell generation is no longer available after 2028. Ghent 2 might be part of a least-cost solution for Kentucky Power's ratepayers.[74] In addition, to the extent that the sale of energy and capacity from Ghent 2 to Kentucky Power through a purchase power agreement reduces the remaining net book cost of the unit, then KU's ratepayers will benefit. The retirement of Ghent 2 will eliminate this opportunity, thus potentially increasing the net incremental costs to be recovered from KU's ratepayers. At the time of its proposed retirement in 2028, the remaining net book value of Ghent 2 will be $110.9 million.[75]

Indeed, today (September 22, 2023) Kentucky Power issued three Requests For Proposals to solicit bids for approximately 875 Mw of PJM-accredited summer capacity and approximately 1,300 Mw of PJM-accredited winter capacity through one or more purchase power agreements from the following resources located in the PJM region: solar and wind; coal and gas; and/or standalone storage. All projects must interconnect to the PJM Interconnection or to Kentucky Power's distribution system. Even if a transmission upgrade is needed, this is an opportunity for a possible win-win state-wide solution. Kentucky Power's ratepayers may benefit and KU's ratepayers may benefit.

The Companies provided no evidence regarding how the value of the Ghent 2 asset could be maximized. The Companies simply assumed that if they no longer need Ghent 2, then it has no value. But keeping the unit open could result in benefits for customers by off-system energy sales or a purchase power agreement for the sale of energy and capacity.

74 Kollen Direct Testimony at 15.
75 Companies' Response to KCA No. 3.26.

Through SB 4, the Legislature sent a clear message that the Commission shall presume that Kentucky's coal fleet is a valuable natural resource which should be preserved. Of the units slated for retirement, Ghent 2 is by far the best unit to maintain.[76]

9. KIUC Does Not Oppose The Four Solar PPAs Totaling 637, But Cost Recovery Should Be Through A New Solar PPA Rider Not The Fuel Adjustment Clause.

KIUC originally opposed the four solar PPAs totaling 637 Mw as not being in compliance with SB 4.[77] However, based upon the Companies' Rebuttal Testimony we do not oppose the solar PPAs. Rebuttal Exhibit DSS-2, page 1 shows that under current PPA pricing (which may increase during the contract finalization process), the four solar PPAs will lower costs for consumers over five of six fuel cost scenarios.[78] Also, Mr. Bellar's Rebuttal Testimony clarified that the solar PPAs are a supplement to, not a replacement of, the retiring coal plants.[79]

However, cost recovery of the four solar PPAs should be through a new solar PPA Rider, not the fuel adjustment clause ("FAC").[80] FAC recovery is entirely energy based. There is no demand component to FAC cost recovery. This is appropriate for variable fuel costs. But for solar PPAs, FAC recovery is not consistent with cost-of-service principles. Solar generation has no underlying variable cost component, even though the solar PPAs are priced on a per MWh basis.[81] Whether owned by a developer or by the utility, solar generation is comprised almost entirely of fixed costs.[82] Recovering demand-related fixed costs on an energy basis would improperly burden high load factor customers, like the members of KIUC.

[76] If the Commission approves the retirement of Ghent 2, then the remaining net book cost of the plant should be recovered through KU's retired asset recovery rider, not base rates. This issue was addressed on page 7 of Mr. Kollen's Direct Testimony.

[77] Kollen Direct Testimony at 18-20.

[78] Sinclair Rebuttal Testimony at 11 (In five of six fuel cost scenarios, the PPAs will save customers between $69 million and $734 million PVRR).

[79] Bellar Rebuttal Testimony at 11-12.

[80] Kollen Direct Testimony at 20-22.

[81] Kollen Direct Testimony at 21; Transcript, 9:31:51/10:00:22 (Conroy).

[82] Kollen Direct Testimony at 21; Transcript, 9:34:17/10:00:22 (Conroy).

A new PPA Rider can be designed consistent with cost-of-service principles. The PPA Rider recommended by Mr. Kollen is modeled after the Group 1/Group 2 approach in the Companies' environmental surcharges and retired asset recovery riders.[83] This approach first allocates to the residential class (Group 1) their share of the total revenue requirement and then recovers those costs as a percent charge on each residential customer's total bill. The residual amount is then recovered from the non-residential customers (Group 2) as a percent charge on the non-fuel portion of their bills. This process results in cost recovery from both groups based on energy and demand.[84]

Also, a new PPA Rider can result in a better regulatory review process. It would give the Commission the opportunity to review and pre-approve the solar PPAs, whereas FAC recovery subjects the Companies to after-the-fact disallowances on six-month and two-year intervals. Over twenty years the four solar PPAs could cost over $1 billion.[85] Commission pre-approval for a commitment of this size is appropriate, especially since the Companies earn no profit on solar PPAs. Finally, rider recovery would allow for the immediate flow-through to customers of revenues received from the sale of renewable energy certificates ("RECs") associated with the solar PPAs.[86]

The Companies have expressed a willingness and potential preference to recover solar PPA costs through a new rider. "*However, given the significant increase in the solar resources proposed in this proceeding, the use of a separate rider may have merit as an alternative means of cost recovery. Such a rider could provide a forum for updates on the status and cost*

[83] Kollen Direct Testimony at 21-22.
[84] Kollen Direct Testimony at 21.
[85] Transcript, 9:28:52/10:00:22 (Conroy).
[86] Transcript, 9:27:35/10:00:22 (Conroy).

of such resources prior to contractual commitments, providing a final prudency check before cost recovery is approved.”[87]

Both Virginia and West Virginia have recently recognized that solar PPAs should not be recovered on an energy (FAC) basis, and that cost-of-service principles should apply.

In a June 13, 2023 Order[88], the Virginia State Corporation Commission determined that the same cost-of-service principles that apply to traditional dispatchable generation and Company-owner solar should also be applied to solar PPAs.

> *“We find that the Cost of Service Classification methodology should be approved for use to allocate costs and benefits of VCEA Resources recovered through Rider CE, Rider PPA, and Rider OSW. In making this determination we note:*
>
> *the Cost of Service Classification methodology is generally consistent with how the Company has historically allocated costs and benefits;*
>
> ***
>
> *the Cost of Service Classification methodology follows cost causation principles, wherein the classification of costs and benefits as demand-related or energy-related results in those costs and benefits being allocated on a demand-related (Factor 1) or energy-related (Factor 3), respectively;*
>
> *it is reasonable and appropriate to allocate costs and benefits of intermittent generation using the same cost allocation methodology as traditional dispatchable units;*
>
> ***
>
> *it is reasonable and appropriate to use the same allocation methodology to allocate Company-owned resources and PPAs.”*[89]

In a January 17, 2023 Order, the West Virginia Public Service Commission approved Appalachian Power’s and Wheeling Power’s request to allocate solar PPA costs among retail rate classes 50% on energy and 50% on demand. “*Specifically, the Companies propose …a class allocation based on a 50/50 split of annual energy and demand, with the demand allocation based on the twelve coincident peak (12 CP) allocation factor. Similarly, the Companies have*

[87] Conroy Rebuttal Testimony at 3.

[88] Ex Parte: Establishing a proceeding concerning the allocation of RPS-related costs and the determination of certain proxy values for Virginia Electric Power Company, Case No. 2021-00156, June 13, 2023 Order.

[89] Id. at 6-7.

supported the 50/50 split of the PSA and PPA costs. The Commission will allow the allocation of the costs and benefits from the PSA and PPA properties as proposed by the Companies."[90]

In sum, recovery of solar PPA costs through a new rider modeled on the environmental surcharge and retired asset recovery rider would: appropriately reflect cost-of-service, allow for a Commission prudence review before the PPAs are finalized, allow for the immediate flow-through to customers of revenue from the sale of RECs, and would be consistent with recent rulings in Virginia and West Virginia.

CONCLUSION

LG&E and KU have a long track record of providing high-quality service at reasonable rates. No one knows the operation of their system better than the Companies. Therefore, KIUC recommends that the Companies' Application be approved with only three changes: 1) Ghent 2 should not be retired; 2) a CPCN for the BESS should be denied; and 3) solar PPA costs should not be recovered in the FAC. These recommendations are complementary to the Companies' plan, not contradictory.

Respectfully submitted,

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[90] Appalachian Power Company and Wheeling Power Company; Petition for Commission Approval of Cost Recovery for Three Purchase and Sale Agreements and Three Purchased Power Agreements for Renewable Energy, Case No. 22-0044-E-PC, January 17, 2023 Order at 5.