COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Electronic Application Of Kentucky Power Company For Approval Of (1) A Certificate Of Public Convenience And Necessity To Make The Capital Investments Necessary To Continue Taking Capacity And Energy From The Mitchell Generating Station After December 31, 2028, (2) An Amended Environmental Compliance Plan, (3) Revised Environmental Surcharge Tariff Sheets, And (4) All Other Required Approvals And Relief	)))))))))	Case No. 2025-00175

POST-HEARING BRIEF OF KENTUCKY POWER COMPANY

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I. INTRODUCTION

Kentucky Power Company ("Kentucky Power" or the "Company") filed this application seeking an order from the Public Service Commission of Kentucky (the "Commission") granting: (1) a certificate of public convenience and necessity ("CPCN") authorizing the Company to make the capital investments necessary to continue receiving 50% of the capacity and energy from the Mitchell Generating Station ("Mitchell Plant," "Mitchell," or the "Plant") after December 31, 2028; (2) approval of its 2025 Environmental Compliance Plan ("ECP"); (3) approval of amendments to its Tariff Environmental Surcharge to reflect its 2025 ECP and amended environmental cost recovery surcharge; (4) deferral authority for the approximately $20.1 million share of environmental costs that have been charged to West Virginia customers; and (5) all other required approvals and relief.[1]

The evidence is clear that making the investments necessary for Kentucky Power to continue to receive capacity and energy from the Mitchell Plant is the lowest cost option available to the Company to serve its customers after December 31, 2028, and it is not even close. The Company's proposal, as modified by the settlement agreement dated November 12, 2025 ("Settlement Agreement"), represents the least cost, reasonable alternative for the Company to meet its load requirements in the 2028–2031 time-period and is in the interest of Kentucky Power customers. It also best positions Kentucky Power to have multiple viable and cost-effective options to provide generation service to its customers after 2031. The Commission should approve the Company's application as modified by the Settlement Agreement.

[1] Application at 1.

II. THE COMPANY'S REQUEST

Kentucky Power seeks Commission approval to allow it to make the necessary investment to continue receiving 50% of the energy and capacity of the Mitchell Plant after December 31, 2028. The Company's as-filed proposal requires, and Kentucky Power sought, the following approvals:

- a CPCN to make the investments necessary to continue receiving capacity and energy from the Mitchell Plant after December 31, 2028. This request includes two components:
  - Approval of the investments necessary to reflect a full 50% share of the flue gas desulfurization ("FGD") biological treatment system with ultrafiltration and supporting equipment such as valves, pumps, piping, and tanks at the Mitchell Plant (the "ELG Project," referred to as "Project 23" in the proposed new ECP). This necessary investment includes 50% of the net plant balances for the ELG Project (approximately $57.8 million) estimated as of December 2025 and 50% of the costs West Virginia customers have paid and will pay through the end of December 2025 (approximately $20.1 million) to construct the ELG Project. The necessary investment therefore totals approximately $77.9 million. The Company will also be responsible for 50% of the ongoing operations and maintenance to operate the ELG equipment; and
  - Approval of capital investments estimated to be $60,380,736 through December 2025 necessary to reflect Kentucky Power's 50% share of non-ELG capital projects that were asymmetrically allocated to Wheeling Power Company ("Wheeling Power") because they had useful lives beyond 2028;
- a revised ECP to reflect the addition of Project 23 ("Costs associated with ELG compliance at the Mitchell Plant");
- an increase in the environmental surcharge rate to reflect cost recovery of the revenue requirements associated with Project 23; and
- authority to defer the approximately $20.1 million share of ELG Project costs that have been charged to West Virginia customers and would have been charged to Kentucky Power customers had Kentucky Power been an equal participant in the ELG Project from the beginning so that they can be amortized and collected over a period of 72 months through 2031.[2]

[2] Direct Testimony of Company Witness Tanner S. Wolffram ("Wolffram Direct Testimony") at 6–7.

The estimated cost components and requests, and the filings through which the Company would seek approval to set rates to recover those costs, are summarized below:[3]

Plant Equipment	Estimated Amount	ECP / CPCN Request	Rate Adjustment Request
Mitchell ELG Project	$77,857,684	This Application	This Application
Mitchell non-ELG capital asymmetrically allocated to Wheeling Power since September 2022	$60,380,736	This Application	Company's next base rate case
Total	**$138,238,191**		

In the Company's as-filed case, the expected bill impact on the average residential customer using 1,189 kilowatt-hours ("kWh") per month resulting from the addition of the ELG Project to the Company's ECP and adjusting the environmental surcharge accordingly, was a monthly increase in the customer's total bill of $3.68 (or 2.02%).[4]

On November 12, 2025, following discussions with all of the intervening parties, Kentucky Power entered into the Settlement Agreement with Kentucky Industrial Utility Customers, Inc. ("KIUC").[5] The Attorney General signed the Settlement Agreement as a non-opposing party.[6] The Settlement Agreement accepts the Company's as-filed case with two key modifications. First, the regulatory asset reflecting the approximately $20.1 million representing 50% of the capital costs already paid by West Virginia customers for the ELG Project, including carrying charges at the Company's authorized weighted average cost of capital, would be amortized and recovered

[3] Wolffram Direct Testimony at 7, Figure TSW-1.

[4] Direct Testimony of Company Witness Lerah M. Kahn ("Kahn Direct Testimony") at 9. The monthly bill impacts were calculated based on the average customer bills for the twelve months ended May 2025.

[5] Settlement Testimony of Company Witness Wolffram ("Wolffram Settlement Testimony") at S2; Exhibit TSW-S1 at 1.

[6] Wolffram Settlement Testimony at S2; Exhibit TSW-S1 at 2.

through 2040 and not through 2031 as originally proposed by the Company.[7] Second, the remaining Coal Combustion Residuals ("CCR") Rule project plant balance, estimated to be $15.5 million as of December 31, 2025, will be depreciated through 2040 instead of through 2028 as previously authorized by this Commission in Case No 2021-00004.[8]

The expected bill impact on the average residential customer using 1,189 kWh per month resulting from the Settlement Agreement would decrease from a monthly increase of $3.68 (or 2.02%) in the as-filed case, to $2.33 (or 1.28%) under the terms of the Settlement Agreement.[9]

As demonstrated below, Kentucky Power's proposal represents the lowest-cost reasonable alternative for the Company to meet its customers' needs after 2028 and provides the Company with needed flexibility to address potentially changing environmental requirements after 2031.

III. BACKGROUND

A. Kentucky Power's Resource Portfolio.

Kentucky Power owns and operates the 295 MW, natural gas-fired Big Sandy Plant located near Louisa, Kentucky.[10] Big Sandy Unit 1 was originally placed in service in 1963 and operated as a 278 MW sub-critical coal-fired generating unit through mid-November 2015 when, as approved by the Commission in Case No. 2013-00430, Big Sandy Unit 1 was converted to a natural gas-fired unit.[11] Big Sandy Unit 1 returned to service May 31, 2016.[12]

Kentucky Power also owns an undivided 50% interest in the Mitchell Plant located approximately 12 miles south of Moundsville, West Virginia on the Ohio River.[13] The Plant is

[7] Wolffram Settlement Testimony at S5; Exhibit TSW-S1 at 5.
[8] Wolffram Settlement Testimony at S5; Exhibit TSW-S1 at 5.
[9] Wolffram Settlement Testimony at S6; Exhibit TSW-S2.
[10] Wolffram Direct Testimony at 12.
[11] *Id*.
[12] *Id*.
[13] *Id*.

operated by Wheeling Power pursuant to the Mitchell Plant Operating Agreement and September 1, 2022 Written Consent Action of the Mitchell Operating Committee.[14] The Plant is comprised of two super-critical pulverized coal-fired baseload generating units with Mitchell Unit 1 having a nameplate capacity of 770 MW and Mitchell Unit 2 having a nameplate capacity of 790 MW, for a total nameplate capacity of 1,560 MW.[15] Both units were placed in service in 1971 but have since benefitted from capital investment to ensure continued operation of the plant.[16] Based on the regulatory history further described below, absent the change proposed in this proceeding, Kentucky Power's undivided 50% entitlement to the energy and capacity from the Mitchell Plant will terminate on January 1, 2029.[17]

B. Regulatory History.

On July 15, 2021, the Commission issued an order in Case No. 2021-00004 rejecting the Company's application for a CPCN to install equipment at the Mitchell Plant to comply with both the April 17, 2015 CCR Rule and the November 3, 2015 Steam Electric Effluent Limitation Guidelines ("2020 ELG Rule"). The Commission instead authorized a CPCN only for the equipment necessary to comply with the CCR Rule.[18] The Commission later confirmed that because it had not approved the CPCN for investments necessary to comply with the 2020 ELG Rule, Kentucky Power's interest in the Mitchell Plant must terminate by December 31, 2028.[19]

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[14] *Id.* at 9; Exhibit TSW-1.

[15] Wolffram Direct Testimony at 12.

[16] Vaughan Hearing Testimony at 140–41. References to hearing testimony are to the page numbers in hearing transcript filed with the Commission on November 25, 2025.

[17] Wolffram Direct Testimony at 12.

[18] *See* Order, *In The Matter Of: Electronic Application Of Kentucky Power Company For Approval Of A Certificate Of Public Convenience And Necessity For Environmental Project Construction At The Mitchell Generating Station, An Amended Environmental Compliance Plan, And Revised Environmental Surcharge Tariff Sheets*, Case No. 2021-00004 (Ky. P.S.C. July 15, 2021).

[19] *See* Order at 7*, In The Matter Of: Electronic Application Of Kentucky Power Company For Approval Of A Certificate Of Public Convenience And Necessity For Environmental Project Construction At The Mitchell Generating Station, An Amended Environmental Compliance Plan, And Revised Environmental Surcharge Tariff Sheets*, Case No. 2021-00004 (Ky. P.S.C. May 3, 2022); Order at 13, *In The Matter Of: Electronic Application Of Kentucky Power Company*

Based on the Commission's orders, the Company then made the capital investments necessary to comply with the CCR Rule only.[20] The Public Service Commission of West Virginia, however, approved Wheeling Power to also make the investments necessary to comply with the ELG, which were completed on August 5, 2024. Through December 2025, West Virginia customers have been charged approximately $40.2 million for the ELG Project, an amount that would have been split equally with Kentucky Power's customers had Kentucky Power been an equal partner on the ELG Project from the beginning.

IV. LEGAL STANDARDS

A. Certificate of Public Convenience and Necessity.

KRS 278.020(1) requires utilities to obtain a certificate of public convenience and necessity prior to providing utility service to or for the public, or prior to beginning construction of "any plant, equipment, property, or facility for furnishing" service to the public,[21] except where the proposed work constitutes an extension in the ordinary course of business.[22] KRS 278.020(1) provides that a certificate of public convenience and necessity may be granted upon the showing of the need for the proposed action *and* the absence of wasteful duplication.[23] Need may be demonstrated by, *inter alia*, the existence of "a substantial deficiency of service facilities beyond what could be supplied by normal improvements in the ordinary course of business."[24] Wasteful duplication comprises two elements: (a) excess of capacity over need; or (b) excess investment in relation to productivity and efficiency to be gained from the proposed construction.[25] The absence

For Approval Of Affiliate Agreements Related To The Mitchell Generating Station, Case No. 2021-00421 (Ky. P.S.C. May 3, 2022).

[20] Wolffram Direct Testimony at 8.

[21] KRS 278.020(1).

[22] 807 KAR 5:001, Section 15(3).

[23] *Ky. Utils. Co. v. Pub. Serv. Comm'n*, 252 S.W.2d 885, 890 (Ky. 1952).

[24] *Id*.

[25] *Id.*

of wasteful duplication also requires a demonstration that all reasonable alternatives were examined.[26] The fundamental principle of reasonable, least-cost alternative is embedded in such an analysis.[27] Selection of a proposal that ultimately costs more than an alternative does not necessarily result in wasteful duplication.[28] All relevant factors must be balanced.[29]

B. Environmental Compliance Plan.

KRS 278.183 provides that a utility shall be entitled to the current recovery of its costs of complying with the Federal Clean Air Act, as amended, and those federal, state, or local environmental requirements that apply to coal combustion wastes and byproducts from facilities utilized for the production of energy from coal.[30] Pursuant to KRS 278.183(2), a utility seeking to recover its environmental compliance costs through an environmental surcharge must first submit to the Commission a plan that addresses compliance with the applicable environmental requirements. The plan must also include the utility's testimony concerning a reasonable return on compliance-related capital expenditures and a tariff addition containing the terms and conditions of the proposed surcharge applied to individual rate classes. Within six months after submission of an ECP, the Commission must: (1) consider and approve the plan and rate surcharge if the plan and rate surcharge are found reasonable and cost-effective for compliance with the applicable environmental requirements; (2) establish a reasonable return on compliance-related capital expenditures; and (3) approve the application of the surcharge.[31]

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[26] *See* Order at 11, *In the Matter of: Joint Application Of Louisville Gas and Electric Company And Kentucky Utilities Company For A Certificate of Public Convenience and Necessity For The Construction of Transmission Facilities In Jefferson, Bullitt, Meade, and Hardin Counties, Kentucky*, Case No. 2005-00142 (Ky. P.S.C. Sept. 8, 2005).

[27] Order at 13, *In The Matter Of: Electronic Application Of Kentucky Power Company For A Certificate Of Public Convenience And Necessity To Replace And Upgrade Portions Of The Bellefonte Station In Boyd County, Kentucky (Bellefonte Station Upgrade Project)*, Case No. 2024-00343 (Ky. P.S.C. Mar. 7, 2025).

[28] *Id.*

[29] *Id.*

[30] KRS 278.183(1).

[31] KRS 278.183(2).

V. ARGUMENT

A. The Commission Should Grant the Requested CPCN.

1. Kentucky Power's Share of the Capacity and Energy from the Mitchell Plant is Needed After 2028.

There is no doubt that Kentucky Power needs a substantial amount of capacity and energy after 2028, most of which can be provided by the Mitchell Plant. Both the Company's most recent integrated resource plan ("IRP"), Case No. 2023-00092, and testimony in this case provides a detailed description of Kentucky Power's generation needs. The IRP identified a capacity need beginning in 2028 arising from the currently-required termination of the Company's 50% undivided interest in energy and capacity from the Mitchell Plant.[32] The Commission's recent orders also indicate that it now may expect electric utilities to plan to meet their maximum customer demand, which for Kentucky Power as a winter peaking utility, means planning for its winter capacity needs.[33] PJM has also initiated a process to review and potentially add a similar winter capacity requirement beginning in PJM planning years 2029/2030.[34]

Regardless of whether Kentucky Power receives capacity from the Mitchell Plant after 2028, the Company's capacity requirements will increase by 280 MW if PJM implements seasonal capacity requirements.[35] This is demonstrated by the fact that Kentucky Power would require an additional 280 MW of accredited capacity to meet its winter requirements as compared to its summer peak requirements.[36]

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[32] *See* Kentucky Power Company's Integrated Resource Planning Report, Volume A, *In The Matter Of: Electronic 2022 Integrated Resource Planning Report Of Kentucky Power Company*, Case No. 2023-00092 (filed Mar. 20, 2023).

[33] *See* Order, *In The Matter Of: Electronic Investigation Of The Service, Rates and Facilities of Kentucky Power Company*, Case No. 2021-00370 (Ky. P.S.C. June 23, 2023) ("Kentucky law requires retail electric suppliers, such as Kentucky Power, to have sufficient capacity to meet maximum estimate customer demand, including sufficient generation capacity."); *see also* KRS 278.010(14).

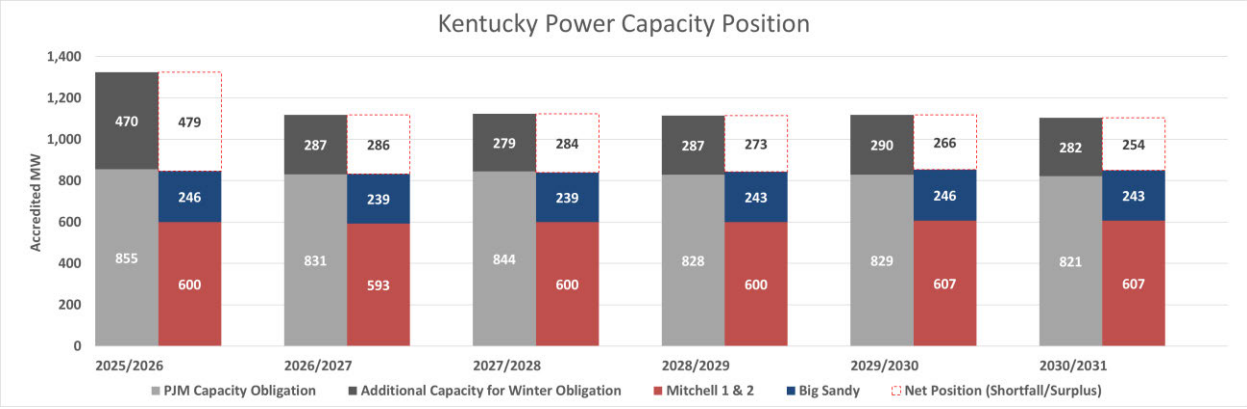
[34] Wolffram Direct Testimony at 13.

[35] *Id*.

[36] *Id.* at 13–15.

The Company would require approximately 580 MW of accredited *summer* capacity beginning in PJM planning year 2028/2029 if it can no longer receive capacity from the Mitchell Plant after December 31, 2028. This is demonstrated by the fact that once the Mitchell Plant capacity is removed from the Company's portfolio in 2028, there would be a 580 MW shortfall from the Company's *summer* capacity requirements.[37] The Company would require roughly 880 MW of accredited *winter* capacity beginning in PJM planning year 2028/2029 if it can no longer receive capacity from the Mitchell Plant after December 31, 2028. This is demonstrated by the fact that once the Mitchell Plant capacity is removed from the Company's portfolio in 2028, there would be an approximate 880 MW shortfall from the Company's *winter* capacity requirements.[38]

Figure TSW-3 in the direct testimony of Company Witness Wolffram, as updated by the table provided in Attachment 1 to the Company's response to KPSC 1-2, reproduced below,[39] demonstrates these concepts, and that the Mitchell Plant capacity and energy is very much needed to meet Kentucky Power's capacity needs after 2028, whether based on its summer or winter peak.

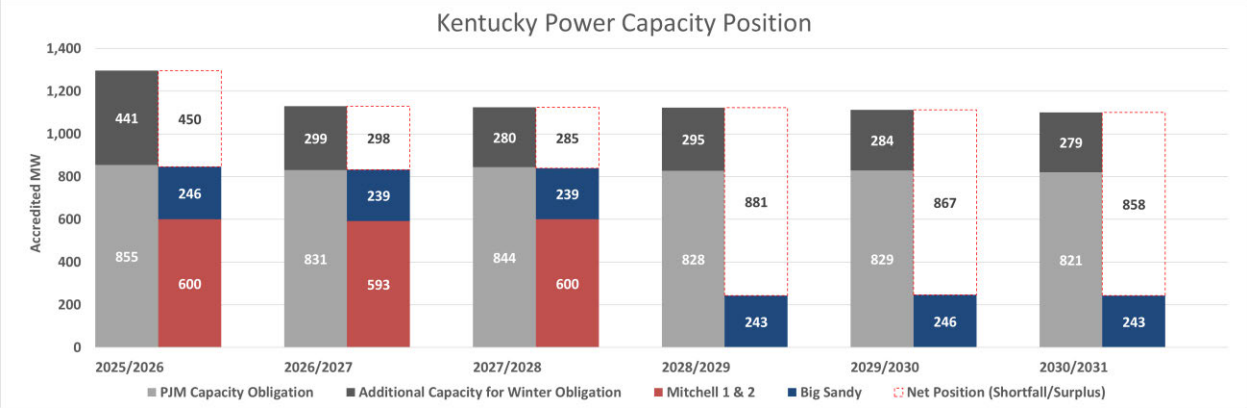


[37] *Id.* at 15.

[38] *Id.*

[39] *Id.*; *see* Company's Response to KPSC 1-2, Attachment 1.

The Company's capacity position if Mitchell's output is no longer available after December 31, 2028 is highlighted in Table TSW-2 from the testimony of Company Witness Wolffram:[40]



The importance of the Mitchell Plant to the Company's capacity position is clear; the capacity therefore is needed.

2. Making the Investments Necessary to Continue Receiving Kentucky Power's Share of the Capacity and Energy from the Mitchell Plant After 2028 will not Result in Wasteful Duplication.

In response to the Commission's order that it must terminate its interest in the Mitchell Plant by December 31, 2028, Kentucky Power began its search for options to replace the capacity and energy from its share of the Mitchell Plant. This search began in the Company's most recent IRP, which evaluated the Company's capacity and energy requirements in light of the required termination of the Company's interest in the Mitchell Plant.[41] Based on the IRP, the Company issued an all-source request for proposals ("RFP") on September 22, 2023, seeking power purchase agreements ("PPA") to address the Company's capacity and energy needs.[42] The Company evaluated both thermal and non-thermal responses to the RFP and selected a renewable energy power agreement ("REPA") for the Bright Mountain Project as an initial step towards addressing

[40] Wolffram Direct Testimony at 14.
[41] *Id.* at 13.
[42] *Id.* at 15.

the Company's capacity and energy needs.[43] The Commission rejected the Company's application for approval of the Bright Mountain REPA in Case No. 2024-00243.[44]

In addition to the review of non-thermal submittals, Kentucky Power reviewed bids for PPAs associated with thermal assets.[45] This review, however, was impacted by changes in the market for thermal resources driven by two events. First, on April 25, 2024, the EPA issued the Greenhouse Gas Emissions Standards for Fossil Fuel-Fired Electric Generating Units ("GHG Rule") and, because that rule would impact the costs associated with thermal generating units, the Company requested that respondents to the RFP refresh their bids.[46] In reviewing the updated pricing, the Company saw a "sharp uptick in cost" from the bidders.[47] Second, capacity prices in PJM increased dramatically during the period when the Company was evaluating bids.[48] Company Witness Vaughan described this change and the impact on pricing at the hearing as follows:

> And so, subsequent to that, you had additional capacity market clears that went from $220 -- you know, about the same time they were bidding last year, in 2024, capacity market had cleared for roughly $220 a megawatt. Since then, we've had a capacity option clear go up to the cap of [$]329, so it would stand to reason that those bids, if refreshed again, would go higher.[49]

Kentucky Power entered into negotiation with one of the bidders to the RFP for the acquisition of an existing generation resource, but those negotiations ultimately were terminated.[50]

[43] *Id.* at 15–16.
[44] *Id.* 16.
[45] *Id.* 16.
[46] Vaughan Hearing Testimony at 151–52.
[47] *Id.* at 152.
[48] *See* Company's Response to KPSC PHDR 15.
[49] Vaughan Hearing Testimony at 152.
[50] Wolffram Hearing Testimony at 67.

In light of the changes in circumstances described above, Kentucky Power then re-evaluated the Mitchell Plant. Company Witness Wolffram described the Company's evaluation process at the hearing:

> We got to a point where those negotiations [for the existing generation resource] were ultimately terminated, and then we had to make evaluations. So we have been very specific in terms of our planning. We have been evaluating replacement options. We went to the market to test it, to see what was out there, and then after we tested the market, we looked back at Mitchell and said, this is still, from our perspective, least cost option. We knew we had a little bit of lead time because our interest in Mitchell continued through 2028. So we were trying to evaluate, and we did evaluate whatever options we had to replace Mitchell, but based on all the analysis we did, Mitchell was the least cost option for our customers. And that's why we -- we brought in the application when we did.[51]

a. ***Kentucky Power's Alternatives Evaluation.***

(i) ***Making the Necessary Investments in the Mitchell Plant is the Least Cost, Reasonable Alternative for Kentucky Power's Customers.***

Kentucky Power evaluated three alternatives for providing capacity and energy to its customers for the years 2029-2031, following the currently required termination of its interest in the capacity and energy from the Mitchell Plant by December 31, 2028:

- Alternative 1: Investment in the Mitchell Plant – This alternative includes the full estimated cost of service for the Company's 50% interest in the Mitchell Plant and includes non-fuel and fuel revenue requirements, with a credit for any estimated energy margins the Plant can produce during its operations. Alternative 1 does not include any capacity revenues as the Mitchell capacity is required to serve the Company's load obligation.[52]

- Alternative 2: PPA – Under Alternative 2, Kentucky Power would address its capacity shortfall by entering into PPAs for thermal resources. The analysis of this alternative utilized the pricing from the Company's 2023 (updated in 2024) All Source RFP ("2023 RFP") as a proxy for what the cost of a PPA would be during the period of 2029-2031.[53] This pricing is conservative because the prices used were from the 2023 RFP process and, in general, prices for capacity resources have

[51] *Id.*

[52] Errata Testimony of Company Witness Alex E. Vaughan ("Vaughan Errata Testimony") at 5.

[53] *Id.* at 6.

continued to increase since that time.[54] Indeed, as Company Witness Vaughan testified, there has been an increase in demand, particularly in PJM, with a simultaneous reduction in supply.[55] The analysis added market capacity purchase costs to the PPA bids in an amount to make the capacity equal to that estimated to be provided by the Company's 50% share of Mitchell so that all three alternatives were evaluated on a comparable basis. In addition to the PPA costs and market purchases themselves, Alternative 2 includes recovery of the annual amount of the remaining Mitchell Plant net book value ("NBV").

- Alternative 3: Market – Under Alternative 3, the Company would address its capacity shortfall by entering into market purchases for the needed capacity and energy. This alternative includes the estimated cost of energy and capacity in the amount that the Mitchell Plant is currently estimated to provide the Company in 2029-2031. The amount and price of energy utilized in Alternative 3 is derived from the Company's latest net energy cost forecast. The amount of capacity required is equal to the amount the Company estimates the Mitchell Plant will provide in 2029-2031. The price of replacement market capacity used is from the Company's latest base fundamental forecast. The capacity price averages roughly $207/MW-day, which is lower than the most recent PJM Reliability Pricing Model base residual auction results. Like Alternative 2, the total cost of this alternative also includes recovery of the annual amounts of the remaining Mitchell Plant NBV.[56]

The Company did not include any new build resources in this analysis because construction of new build resources would not be completed in time to meet the Company's capacity needs that would result from the loss of the Mitchell Plant.[57]

The alternatives analysis performed demonstrated convincingly that Alterative 1, making the investments necessary to continue to receive capacity and energy from the Mitchell Plant after 2028, is the lowest reasonable cost alternative:[58]

[54] Vaughan Hearing Testimony at 151–52.

[55] *Id.* at 186–88.

[56] Vaughan Errata Testimony at 7.

[57] *Id.*

[58] *Id.* at 8, Table AEV-1.

	2029	2030	2031	Total
Alternative 1 - Mitchell				
Mitchell COS	$ 86,378,348	$ 113,272,572	$ 135,755,059	$ 335,405,979
Alternative 2 - PPAs				
Thermal PPAs from RFP	$ 82,746,107	$ 84,763,986	$ 87,792,986	
Remaining NBV Recovery	$ 75,154,986	$ 72,045,688	$ 68,936,390	
Total Cost	$ 157,901,093	$ 156,809,674	$ 156,729,376	$ 471,440,143
Alternative 3 -Market				
Remaining NBV Recovery	$ 75,154,986	$ 72,045,688	$ 68,936,390	
Replacement Market Energy	$ 224,514,595	$ 176,454,655	$ 140,564,210	
Replacement Market Capacity	$ 44,696,074	$ 45,911,294	$ 47,027,351	
Total Cost	$ 344,365,656	$ 294,411,638	$ 256,527,951	$ 895,305,244

Alternative 1 results in a cumulative cost of service during the period from 2029 to 2031 that is approximately $136,000,000 less than the conservatively-priced PPA option, and approximately $560,000,000 less than the market purchase option.

As noted above, the Company's evaluation incorporated a conservative $207/MW-day capacity price. On July 22, 2025, after the Company filed its application in this case, PJM announced the result of the base residual auction for the 2026/2027 planning year. The auction price came in at the FERC-approved cap of $329.17/MW-day.[59] If this updated market price for capacity is utilized instead, the relative economic benefit of the Alternative 1 is even more pronounced:[60]

[59] *See* 20250722-pjm-auction-procures-134311-mw-of-generation-resources-supply-responds-to-price-signal.pdf.

[60] Company's Response to AG-KIUC PHDR 1-1.

	2029	2030	2031	Total
Alternative 1 - Mitchell				
Mitchell COS	$ 86,378,348	$ 113,272,572	$ 135,755,059	$ 335,405,979
Alternative 2 - PPAs				
Thermal PPAs from RFP	$ 91,930,560	$ 93,830,569	$ 91,769,822	
Remaining NBV Recovery	$ 75,154,986	$ 72,045,688	$ 68,936,390	
Total Cost	$ 167,085,546	$ 165,876,257	$ 160,706,212	$ 493,668,015
Alternative 3 -Market				
Remaining NBV Recovery	$ 75,154,986	$ 72,045,688	$ 68,936,390	
Replacement Market Energy	$ 224,514,595	$ 176,454,655	$ 140,564,210	
Replacement Market Capacity	$ 72,411,761	$ 72,912,138	$ 73,269,551	
Total Cost	$ 372,081,342	$ 321,412,482	$ 282,770,151	$ 976,263,975

If the most recent PJM capacity pricing is utilized, Alternative 1 results in a cumulative cost of service that is approximately $160,000,000 less than the conservatively-priced PPA alternative, and approximately $640,000,000 less than the market purchase option. This thorough analysis shows that making the investments necessary to continue to receive capacity and energy from the Mitchell Plant after December 31, 2028, is by far the most cost-effective, reasonable method for Kentucky Power to meet its customers' needs.

(ii) ***The Mitchell Plant Remains the Lowest Cost Alternative Even With Addressing Structural Issues in the Unit 2 Cooling Tower***.

As discussed in the testimony of Company Witness Snodgrass, the cooling tower for Mitchell Unit 2 was undergoing shell structure updates, including the application of a fiber-reinforced cementitious matrix.[61] In late July 2025, after this application was filed, the AEP Generation Projects team determined that additional repairs would be necessary to address the cooling tower's structural needs and paused the project to determine the best engineering solution and the most economic and efficient path forward to ensure the continued safe and reliable

[61] Direct Testimony of Company Witness Joshua D. Snodgrass ("Snodgrass Direct Testimony") at 8.

operation of the Mitchell Plant for the Company's customers.[62] The Company evaluated four options for the addressing the structural needs of the cooling tower for Mitchell Unit 2:

- Option 1: Expand and extend the exterior shell reinforcement project.
- Option 2: Retire Unit 2 and partially demolish the existing Unit 2 cooling tower.
- Option 3: Construct a new mechanical draft cooling tower and partially demolish the existing Unit 2 cooling tower.
- Option 4: Reduce the height of the existing Unit 2 cooling tower and continue with a reduced scope of exterior shell reinforcement.[63]

Of these options, Options 1 and 2 were considered unlikely to occur based on the cost and risk associated with Option 1[64] and the fact that Option 2 would put the Company in an untenable position of being approximately 400 MW short of capacity beginning at some point in 2027.[65] Accordingly, the Company evaluated the impact of addressing the structural needs of the Unit 2 cooling tower via Options 3 and 4 on the economic analysis included in the application.[66]

This evaluation demonstrated that the cumulative cost of service from 2029 to 2031 for Alternative 1 (making the investments necessary to continue to receive capacity and energy from the Mitchell Plant after December 31, 2028) would increase by approximately $40,000,000 if Option 3 is selected and by approximately $20,000,000 if Option 4 is selected.[67] Even assuming that the option with the higher cost of service is selected (Option 3), Alternative 1 results in a

[62] Supplemental Testimony of Company Witness Alex E. Vaughan ("Vaughan Supplemental Testimony") at 2.

[63] *Id.* at 3.

[64] *Id.* at 6.

[65] *Id.* at 3; Vaughan Hearing Transcript at 119.

[66] Note that the Company is not seeking Commission approval for the Mitchell Unit 2 cooling tower solutions in this proceeding; rather, the various options and analyses were provided for transparency and demonstrative purposes. The Company intends to file an application for CPCN for approval of the selected option for addressing the structural needs of the Mitchell Unit 2 cooling tower in 2026. Vaughan Hearing Testimony at 141.

[67] Vaughan Supplemental Testimony at 9, Table AEV-SD2. Please note that the Company has submitted a Rural Capacity and Energy Affordability Project grant application to the United States Department of Energy for assistance with the cooling tower solution. If this grant is awarded, the price for the cooling tower project will decrease and the benefits as compared to alternatives two and three would increase.

cumulative cost of service from 2029-2031 that remains approximately $95,000,000 less than the as-filed conservatively-priced PPA alternative and approximately $520,000,000 less than the as-filed, market purchase alternative using PJM prices in effect at the time the application was filed.[68] If the most recent PJM capacity pricing is utilized, Alternative 1 with Option 3 for addressing the structural needs of the Unit 2 cooling tower results in a cumulative cost of service for the period of 2029 through 2031 that is approximately $120,000,000 less than the conservatively-priced PPA alternative and approximately $600,000,000 less than the market purchase alternative.[69] The economic benefits of the Company's proposed alternative across all scenario is summarized below:

Alternative	**Cost**	**Increase Over Alternative 1 (assuming Cooling Tower Option 3)**
Alternative 1 (As Filed)	$ 335,405,979	N/A
Alternative 1 (Cooling Tower Option 3)	$ 375,956,757	N/A
Alternative 1 (Cooling Tower Option 4)	$ 356,031,775	N/A
Alternative 2 – PPAs (As-Filed)	$ 471,440,143	$ 95,483,386
Alternative 2 – PPAs (Updated for Most Recent PJM Capacity Pricing)	$ 493,668,015	$ 117,711,258
Alternative 3 – Market (As-Filed)	$ 895,305,244	$ 519,348,487
Alternative 3 – Market (Updated for Most Recent PJM Capacity Pricing)	$ 976,263,975	$ 600,307,218

Even accounting for the requirement to address the structural needs of the Unit 2 cooling tower, making the investments necessary to continue to receive capacity and energy from the

[68] Vaughan Supplemental Testimony at 9, Table AEV-SD2.

[69] Vaughan Supplemental Testimony at 9, Table AEV-SD2; Company's Response to AG-KIUC PHDR 1-1.

Mitchell Plant after December 31, 2028 is by far the most cost-effective, reasonable method for Kentucky Power to meet its customers' needs.

(iii) ***Making the Investment in Mitchell Gives Kentucky Power Flexibility to Address Upcoming Environmental Regulations.***

(a) ***Relevant Environmental Regulations***

There are four environmental regulations relevant to the Mitchell Plant that have been discussed in this case:

- On April 17, 2015, the United States Environmental Protection Agency ("EPA") published the CCR Rule to regulate the disposal and beneficial use of CCR.[70] The Mitchell Plant complied with the CCR Rule by removing existing ash from the ash ponds, over-excavating the ponds to ensure closure by removal, installing a new liner system to accept CCR and Non-CCR wastewater streams, and installing a chemical treatment systems for non-CCR wastewater streams.[71]

- On November 3, 2015, EPA published the 2020 ELG Rule establishing discharge limits on FGD wastewater, transport water used for fly ash and bottom ash handling, and other wastewaters that must be met by December 31, 2028.[72] Compliance with the 2020 ELG Rule required installation of the ELG Project.[73] The ELG Project was completed and fully in service by August 5, 2024.[74]

- On May 9, 2024, EPA published the GHG Rule that set carbon dioxide emission standards for new gas-fired combustion turbines and existing coal, oil, and gas-fired generation units and provided four options for existing coal-fired power plants to continue to operate after 2031 including installation of carbon capture and sequestration technology, co-firing the power plant with natural gas, retirement by

[70] *See* Hazardous and Solid Waste Management System; Disposal of Coal Combustion Residuals From Electric Utilities, 80 Fed. Reg. 21,302 (Apr. 17, 2015) (codified at 40 C.F.R. pts. 257 and 261).

[71] Snodgrass Direct Testimony at 3.

[72] *See* Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, 89 Fed. Reg. 67,838 (Nov. 3, 2015) (codified at 40 C.F.R. pt. 23) (EPA's 2015 Final Rule for the Steam Electric Power Generating category established the first federal limits on toxic metals in wastewater discharges from power plants, including FGD wastewater. On August 31, 2020, the EPA finalized an updated rule revising the regulations for Steam Electric Power Generating category. The 2020 Final Rule updated the requirements for FGD wastewater and bottom ash transport water, and extended timelines for compliance and exempted coal facilities that are closing, repowering, or switching to natural gas by 2028. *See* 85 Fed. Reg. 64,650 (October 13, 2020) (codified at 40 C.F.R. pt. 423).

[73] Snodgrass Direct Testimony at 4.

[74] *Id.*

2032, or convert to 100% natural gas fired.[75] On June 17, 2025, EPA published a proposed rule to repeal the GHG Rule.[76]

- On May 9, 2024, EPA published revised Steam Effluent Limitation Guidelines ("2024 ELG Rule") that require the installation of zero liquid discharge ("ZLD") equipment at the Mitchell Plant for continued operation.[77] On October 2, 2025, EPA issued a proposed rule to extend deadlines for the ELG Rule.[78]

While EPA has taken initial regulatory steps to repeal or revise the GHG Rule and the 2024 ELG Rule, those rules currently remain effective and, unless those rules are changed, the Mitchell Plant cannot continue to operate as a coal plant beyond December 31, 2031, without further investments in environmental upgrades.[79] Importantly, the recent proposed changes apply only to the GHG Rule and the 2024 ELG Rule.[80] EPA has proposed no changes to the CCR Rule or the 2020 ELG Rule, which necessitated the CCR project and ELG Project currently installed and in service at the Mitchell Plant.[81]

(b) ***Evaluation of Post-2031 Environmental Compliance Alternatives for Mitchell***

Kentucky Power evaluated four alternatives for compliance with existing environmental regulations at the Mitchell Plant beyond December 31, 2031:

- Alternative E1 – convert to 40% gas co-fire to comply with the GHG Rule, do not install a ZLD System to comply with the 2024 ELG Rule, and retire by December 31, 2034;

[75] *See* New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule, 89 Fed. Reg. 39,798 (May 9, 2024) (codified at 40 C.F.R. pt. 60).

[76] *See* Repeal of Greenhouse Gas Emissions Standards for Fossil Fuel-Fired Electric Generating Units, 90 Fed. Reg. 25,752 (June 17, 2025) (to be codified at 40 C.F.R. pt. 60).

[77] 89 Fed. Reg. 40,198 (May 9, 2024) (codified at 40 C.F.R. pt. 423).

[78] 90 Fed. Reg. 47,693 (Oct. 2, 2025) (to be codified at 40 C.F.R. pt. 423).

[79] Vaughan Errata Testimony at 8.

[80] Vaughan Hearing Testimony at 121–22.

[81] *Id.*

- Alternative E2 – convert to a 40% gas co-fire to comply with the GHG Rule, install a ZLD System to comply with the 2024 ELG Rule, and retire by January 1, 2039;

- Alternative E3 – convert to 100% gas to comply with the GHG Rule conversion, install a ZLD System to comply with the 2024 ELG Rule, and no retirement deadline (assumed 20-year life); or

- Alternative E4 – construct a new build combined cycle gas plant to replace the Mitchell Plant.[82]

The Company also evaluated a fifth alternative, Alternative E5, where it was assumed the compliance deadlines for the relevant environmental regulations were extended to a point beyond the Mitchell Plant's assumed retirement date of 2040.[83] Alternative E5 is not currently a viable option because it would require a change in federal regulations.[84]

Kentucky Power's analysis was comprised of a cost of service analysis that accounted for recovering the remaining net book value of the Mitchell Plant over the remaining life of the compliance alternative, included the incremental capital investment and operation and maintenance expense levels for each compliance alternative, included other operating expenses such as taxes, applied an estimated unit dispatch analysis based on the operating characteristics of each compliance alternative, and included market purchases for the compliance alternatives with shorter assumed lifespans to ensure an apples to apples comparison.[85] The results of the Company's analysis is shown below:[86]

[82] Vaughan Errata Testimony at 10.
[83] *Id.*
[84] *Id.*
[85] *Id.* at 11–12.
[86] *Id.* at 13, Confidential Table AEV-2.

	Alternative E1	Alternative E2	Alternative E3	Alternative E4	Alternative E5
	40% Co-Fire Only Retire by 12/31/2034	40% Co-Fire, + ELG, Retire by 1/1/2039	100% Gas Conversion,+ ELG, No Set Retirement Date	New Build 1200 MW CC	Delayed Environmental, Retire 12/31/2040
Levelized Cost of Energy ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Present Value Revenue Requirement (Millions of Dollars)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Avg Annual Revenue Requirement (Millions of Dollars)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Average Capacity Factor	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Up-Front Capital Cost (Millions of Dollars)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted][87]

The analysis demonstrates that regardless of which post-2031 environmental compliance alternative is ultimately selected by the Company, making the investment now that would allow Kentucky Power to continue with its undivided 50% interest in capacity and energy from the Mitchell Plant provides the Company and its customers with multiple reasonable cost options to meet its capacity and energy obligations after 2031.[88]

(c) Impact of the Unit 2 Cooling Tower Structural Needs on the Post-2031 Environmental Compliance Alternatives Analysis.

In addition to the evaluation of the cumulative cost of service impacts during the 2029–2031 period associated with the viable options for addressing the structural needs of the Mitchell Unit 2 cooling tower, the Company evaluated the impacts of addressing the Unit 2 cooling tower

[87] For the delayed environmental case, Alternative E5, this figure is the estimated amount of incremental capital needed to continue coal operations at the plant through 2040 rather than the up-front capital cost of the other alternatives.

[88] Vaughan Errata Testimony at 13. Note that the Company is not seeking Commission approval for any post-2031 environmental compliance alternative in this proceeding. If the requested approvals are granted in this case and Kentucky Power is able to continue to take service from the Mitchell Plant after December 31, 2028, the Company will file an application for Commission approval, if required, for its selected environmental compliance alternative.

on the post-2031 environmental compliance alternatives. To evaluate these impacts, the Company conducted a "break-even" analysis to determine the level of capital investment in the Mitchell Plant at which the Mitchell Plant would no longer be the lower-cost option as compared to Alternative E4, to a new build natural gas combined cycle plant.[89] As demonstrated below, the break-even analysis demonstrated that the break-even level of incremental capital investment was significantly higher than any of the current estimated costs for addressing the structural needs of the Mitchell Unit 2 cooling tower:[90]

The evidence is clear that making the investments necessary for Kentucky Power to continue to receive capacity and energy from the Mitchell Plant past December 31, 2028, is the lowest-cost reasonable alternative for the Company to serve its customers. Even considering the capital investment necessary to address the structural needs of the Unit 2 cooling tower, the Mitchell Plant remains the lowest cost alternative. In addition, investing now and maintaining the Company's interest in the Mitchell Plant capacity and energy gives the Company and its customers multiple, viable, cost-effective options for providing service to its customers in compliance with upcoming environmental regulations.

[89] Vaughan Supplemental Testimony at 10.

[90] *Id.* at 10–11; Confidential Table AEV-SD3.

B. The Commission should approve the 2025 Environmental Compliance Plan and the proposed Environmental Surcharge Rate.

The 2025 Environmental Compliance Plan (supported by Company Witness Kahn) adds Project 23 to Kentucky Power's Current Environmental Compliance Plan. Project 23 is described in the 2025 Environmental Compliance Plan as "Costs associated with ELG compliance at the Mitchell Plant."[91] Construction of the ELG Project at the Mitchell Plant was required to comply with federal environmental regulations that "apply to coal combustion wastes and by-products from facilities utilized for production of energy from coal,"[92] in order for the plant to continue to operate after April 11, 2021.[93] Simply put, if Wheeling Power had not undertaken and paid for the work necessary to comply with the ELG Rule, then the Mitchell Plant would have been required to shut down. For these reasons, the ELG Rules' requirements as they apply to the operation of the Mitchell Plant are among the environmental requirements described in KRS 278.183 and are properly recoverable through the environmental surcharge.

The Company proposed to recover $20.1 million, which represents 50% of the ELG Project costs charged to West Virginia customers through December 2025 that would have been charged to Kentucky Power customers had Kentucky Power been an equal partner in the ELG Project from the beginning, through the environmental surcharge over 72 months beginning January 2026 through December 2031 (although the proposed Settlement Agreement would extend this recovery through 2040, as described in Section V.C.).[94] Normally, the Company would request immediate recovery of those amounts.[95] However, this expense allows the Plant to operate as-is through at

[91] Kahn Direct Testimony, Exhibit LMK-1.
[92] KRS 278.183(1).
[93] Wolffram Direct Testimony at 8.
[94] Kahn Direct Testimony at 7.
[95] Wolffram Direct Testimony at 25.

least 2031 and, in an effort to provide rate relief to customers in the near term, the Company proposed to likewise recover the expense through 2031.[96] Kentucky Power proposes to treat the $57.8 million, which represents 50% of the ELG Project-related plant balance estimated as of December 2025, as rate base like all other plant in-service in the environmental surcharge and recover it through 2040.[97] The Company is currently depreciating the Mitchell Plant through 2040.[98] Accordingly, a special depreciation rate that will depreciate the ELG Project through 2040 is appropriate.[99]

The recovery proposals included with the Company's Application produced fair, just, and reasonable rates for the reasons stated above. For the average residential customer using 1,189 kWh per month, the monthly increase in the customer's total bill was expected to be $3.68 (or 2.02%).[100] The proposed Settlement Agreement mitigates the rate impact even further, as discussed in Section V.C.

Kentucky Power's proposals to recover the costs associated with Project 23 through the environmental surcharge are consistent with the statute and are therefore reasonable and should be approved.

C. The Proposed Settlement Agreement is Reasonable and in the Public Interest.

Kentucky Power entered into a Settlement Agreement with KIUC in this case, which brings additional substantial benefits and meaningful rate relief to customers.[101] The Attorney General signed the agreement as a "Non-Opposing Party."[102]

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[96] *Id.*

[97] Kahn Direct Testimony at 7.

[98] Wolffram Direct Testimony at 26.

[99] *Id.*

[100] Kahn Direct Testimony at 9.

[101] Wolffram Settlement Testimony at S2, Exhibit TSW-S1 at 1.

[102] Wolffram Settlement Testimony at S2, Exhibit TSW-S1 at 2.

The Settlement Agreement makes two simple, but meaningful, adjustments to the Company's as-filed Application. First, the Signatory Parties agreed the regulatory asset comprised of the approximately $20.1 million that represents 50% of the capital costs already paid by West Virginia customers for the ELG Project will be amortized and recovered through the environmental surcharge through 2040 and not through 2031 as proposed in the Company's Application.[103] The amount recovered will include carrying charges at the Company's authorized weighted average cost of capital. Second, the Company will, beginning in the first month practicable following an order in this case, recover the remaining CCR project plant balance through 2040 instead of through 2028 as previously authorized by this Commission by its May 3, 2022 Order in Case No 2021-00004.[104] The Company will utilize a separate depreciation rate that will depreciate the remaining CCR plant balance through 2040. Kentucky Power's share of the remaining CCR plant balance is estimated to be $15.5 million as of December 31, 2025.[105]

The Settlement Agreement results in meaningful rate relief for customers in connection with the requests in this case. For the average residential customer using the 1,189 kWh per month, the monthly increase in the customer's total bill will be reduced from $3.68 (or 2.02%) in the as-filed case, to $2.33 (or 1.28%) under the terms of the Settlement Agreement.[106]

KIUC agrees that all other proposals in the Application are reasonable and should be accepted by the Commission.[107] As the Settlement Agreement explicitly recognizes:

> [C]onditions for a utility to obtain energy and capacity have changed significantly since the Company's application to construct the ELG Project was filed in 2021, and that making the investments agreed to herein in order to continue receiving energy and capacity from the Mitchell Plant is the least cost, reasonable alternative

[103] Wolffram Settlement Testimony at S5.
[104] *Id.*
[105] *Id.*
[106] *Id.* at S6.
[107] *Id.,* Exhibit TSW-S1, Section 1.

> to meet the Company's load requirements for at least the 2028-2031 time period. This also enables the Company to have multiple options to continue serving its customers with Mitchell's capacity and energy past 2031 that would otherwise not be available absent granting the CPCN.[108]

The Settlement Agreement reflects a reasonable compromise to ensure that Kentucky Power is able to continue to serve customers with a substantial amount of capacity and energy after December 31, 2028, at a reasonable cost.[109] For these reasons, the Settlement Agreement should be approved in its entirety and without modification.

D. The Fact that the ELG Project Has Already Been Constructed is not a Procedural Barrier to Granting the CPCN in this Instance.

Commission Staff's post-hearing data request 4 suggests that the Commission may be prohibited from granting a CPCN in this instance because the ELG Project has already been constructed and is already in service.[110] Upon review of the case cited by the Commission Staff in that data request, and other cases like it, it is clear that the factual circumstances in that case are distinguishable. There are no such procedural barriers to the Commission granting the requested CPCN here.

In the case cited (Case No. 2020-00290), Bluegrass Water Utility Operating Company, LLC ("Bluegrass Water") made improvements to several sewer and water systems that it either owned and operated or recently purchased.[111] After construction was completed, Bluegrass Water sought a declaratory order from the Commission that a CPCN was not required because the improvements were extensions in the ordinary course of business, or, in the alternative, for approval of a CPCN.[112] The Commission determined that a CPCN was required for certain improvements and ultimately

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[108] *Id.*, Exhibit TSW-S1 at Recital No. 11.

[109] *Id.* at S7.

[110] *See*, KPSC PHDR 4.

[111] Order at 2–3, *In The Matter Of: Electronic Application Of Bluegrass Water Utility Operating Company, LLC For An Adjustment Of Rates And Approval Of Construction*, Case No. 2020-00290 (Ky. P.S.C. Aug. 2, 2021).

[112] *See id.* at 37.

declined to grant Bluegrass Water a CPCN for some of the improvements.[113] The Commission explained that "work on most of the construction items identified was completed," meaning that Bluegrass Water had violated KRS 278.020(1) by "failing to obtain a CPCN before it began construction on those items."[114]

This is factually distinguishable from the CPCN sought by Kentucky Power in this proceeding. Although the ELG Project has already been constructed, the project was constructed exclusively by Wheeling Power and at its exclusive cost. The ELG Project was not constructed in contravention of any Kentucky statute, regulation, or Commission order. In this case, Kentucky Power seeks to continue receiving capacity and energy from the Mitchell Plant to provide service to customers after 2028, and to do that, Kentucky Power must make the capital investments (both in the ELG Project and otherwise) consistent with its ownership share. The Bluegrass Water case stands instead for the proposition that a utility cannot construct facilities and later seek cost recovery for them without the requisite Commission pre-approvals, including a CPCN.

The instant proceeding is instead procedurally similar to the 2013 case where the Commission granted Kentucky Power approval, including a CPCN, to acquire its undivided 50% interest in the Mitchell Plant.[115] The Mitchell Plant was constructed and fully operational prior to the Company's application in that case, and the Company sought a CPCN to make the investments necessary to acquire its undivided 50% interest in the Plant. The Commission's order in that case makes no mention of any procedural issue that would affect the Commission's ability to issue the

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[113] *Id.*

[114] *Id.* at 28.

[115] *See* Order at 43, *In the Matter of: Application Of Kentucky Power Company For (1) A Certificate Of Public Convenience And Necessity Authorizing the Transfer To The Company Of An Undivided Fifty Percent Interest In The Mitchell Generating Station And Associated Assets; (2) Approval Of The Assumption By Kentucky Power Company Of Certain Liabilities In Connection With The Transfer Of The Mitchell Generating Station; (3) Declaratory Rulings; (4) Deferral Of Costs Incurred In Connection With The Company's Efforts To Meet Federal Clean Air Act And Related Requirements; And (5) All Other Required Approvals And Relief*, Case No. 2012-00578 (Ky. P.S.C. Oct. 7, 2013).

CPCN requested because the Mitchell Plant had already been constructed. The Commission therefore can and should grant a CPCN in this case.

E. Sierra Club's Arguments in Opposition to the Application Should be Rejected.

Sierra Club, through its witness Devi Glick, makes multiple arguments assailing the Company's application. These arguments are unsupported by the evidence in this case or by the law. The Commission should disregard Sierra Club's arguments.

1. Sierra Club's Proposal that Kentucky Power to enter into PPA with Wheeling Power Ignores the Reality of Ownership and Affiliate Transaction Laws in Kentucky and West Virginia.

Sierra Club Witness Glick proposed in her testimony that instead of making the investments necessary for Kentucky Power to continue receiving its 50% undivided interest in the Mitchell Plant's capacity and energy past December 31, 2028, Kentucky Power should "explore the option of entering into an agreement with Wheeling Power to buy power from Mitchell for the period 2028–2031."[116] This proposal ignores how a PPA would be priced and the fact that entering into a PPA with Wheeling Power would be functionally the same as the Company's Alternative 1.[117] Importantly, neither Wheeling Power, nor any other utility for that matter, would provide the Company with a PPA for service from the Mitchell Plant for an amount less than its cost of service.[118] Company Witness Vaughan confirmed that this is indeed Wheeling Power's position:

> I'm – I'm telling you in my testimony and today that we discussed this with Wheeling Power, and they indicated that, yes, it would be for cost of service, right? You -- they have to answer to a public service commission as well as Kentucky Power does, so they – there's not going to be a -- a discounted PPA under some sort of scenario here.[119]

[116] Direct Testimony of Sierra Club Witness Devi Glick ("Glick Direct Testimony") at 16.

[117] Rebuttal Testimony of Company Witness Alex E. Vaughan ("Vaughan Rebuttal Testimony") at R9.

[118] *Id.*

[119] Vaughan Hearing Testimony at 155; *see also* Company's Response to SC PHDR 2.

The fantasy of Sierra Club's three-year PPA proposal was further exposed during questioning of Sierra Club Witness Glick by the Commission Chair:

> Q. Ms. Glick, you're not suggesting it would be cheaper just to buy from the market?
>
> A. No.
>
> Q. And because they're sister companies, Wheeling and Kentucky Power, that doesn't mean they're obligated to offer each other a kinfolk deal on prices, right?
>
> A. Doesn't mean they're obligated to, but they have -- their parent company ultimately has a financial stake in an arrangement that is mutually beneficial, that makes everybody better off. And they're -- that -- that arrangement could befall somewhere between the cost of service and what they are current in the market, more likely.
>
> Q. But why wouldn't Wheeling just -- if they're going to sell their excess capacity, not just sell it at market price?· You're saying that their parent company should direct them or could direct them to give a better price to Kentucky Power?
>
> A. Because -- I think my position is that the parent company could look at the situation and understand that there's uncertainty from the -- right, from the Commission on whether or not they will be allowed to upgrade, pay for the cooling tower, on whether West Virginia will allow the plant to convert to gas, there are -- there are rules in West Virginia that the Commission's put forward on requiring coal plants to operate at certain capacity factors. So I could see there being just uncertainty on whether there would be intervention and to not allow a coal plant to convert because there's desire to keep the plan operating on coal for policy reasons. So I could see the parent company looking at that context. I -- I don't -- I can't -- I can't speak for them at all, but –
>
> Q. Yeah. And if it were a three-year contract rather than a 12-year contract, you would find that more reasonable?
>
> A. Right. Because then there would be time for the Commission to hear the CPCN for the steam tower conversion to fund the evaluator, look at the analysis on conversion to gas. To have the company do all the analysis, present the options and make a decision on that. And I would have no problem with signing the extension if the plant is converted to gas because the analysis showed that was the least cost option.
>
> Q. And the full cost of service is getting amortized under the settlement through 2040, but you're suggesting that they wouldn't have to do the full cost of service?
>
> A. Right. For the three-year period.

Q. Just do it three years.

A. Right

Q. *Okay. I don't know how realistic any of that is*.

A. *Yes, I don't either*.[120]

Thus, even Sierra Club's own witness could not testify as to whether her recommendation was realistic—it isn't. Sierra Club's proposal represents a fundamental misunderstanding of economics and specifically ignores the fact that the Company would not have access to the energy and capacity from the Plant after 2031.[121] The Company would be forced to acquire costly replacement capacity while, at the same time, continuing to recover its share of the Mitchell Plant's net book value from customers.[122] Moreover, Sierra Club's proposal ignores affiliate transaction statutes in both Kentucky and West Virginia and the prior orders of this Commission and the West Virginia Public Service Commission.[123] The Commission should reject Sierra Club's fantastical proposal and instead rely on the evidence and analysis in this case that proves the Company's proposal is the most reasonable, least-cost option.

2. Conversion to Natural Gas at the Mitchell Plant Would Still Require a Cooling Tower and Some Level of ZLD Expenditures.

Sierra Club also argues that converting the Mitchell Plant to natural gas would alleviate the need to address the structural needs of the Unit 2 cooling tower and to comply with the 2024 ELG Rule through installation of ZLD technology.[124] This simply is factually incorrect. Converting the Mitchell Plant from a coal-fired generation station to a natural gas-fired station would still require a cooling tower, as the gas conversion would, at its essence, simply convert the plant from a coal

[120] Glick Hearing Testimony at 247–50 (emphasis added).

[121] Vaughan Rebuttal Testimony at R9.

[122] *Id.*

[123] *See* Company's Response KPSC 1-23.

[124] Glick Direct Testimony at 4.

fired boiler to a natural gas fired boiler.[125] Alternatives E1, E2, E3, and E5 all require a safe and reliable cooling tower.[126] This was confirmed at the hearing by Company Witness Snodgrass, the Mitchell Plant Manager, in response to a question from Commission Staff:

> Q. Okay. There was a question. If Mitchell -- if the Mitchell plant was converted to 100 percent gas, would it be necessary to complete work on the cooling tower?
>
> A. Yes. Regardless of whether we were gas or coal, the cooling tower would need attention.[127]

Additionally, even if the Mitchell Plant is converted fully to 100% gas operations, it would still need to install ZLD technology to comply with the 2024 ELG Rule for discharges from existing ash ponds.[128] Company Witness Vaughan explained at the hearing in a response to a question from counsel for Sierra Club:

> Q. … On the Effluent Limitation Guidelines for what I'm calling the 2024 ELG Rule, there's been some discussion today about what that requires with regard to coal plants. If Mitchell were to convert 100 percent to gas, would it need to comply with the 2024 ELG Rule's zero liquid discharge requirement?
>
> A. Great question. Nuanced answer for you. So a plant operations would not be compliant with -- with ZLD is my understanding, but you would still have some compliance dollars at a -- a much lower amount for the discharge from the existing impoundments on the Mitchell Plant site. So there – there's – there's ash ponds there that are subject to the ELG rules today. And my understanding from our environmental and engineering teams is there would still be some expense there. And those expenses are included in alternative E3 in the post 2031 analysis. But just to -- to answer your question more directly, the -- the ELG -- 2024 ELG costs are much lower under that option than the options where you continue to burn some level of coal.
>
> Q. Can you tell us -- thank you for that. I appreciate that not every answer can be yes or no. Can you tell us what those costs were that were included in the analysis for E3?

[125] Vaughan Rebuttal Testimony at R6.

[126] *Id.*

[127] Snodgrass Hearing Testimony at 105.

[128] *See* Company's Response to SC PHDR 4.

> A. Off the top of my head, I don't -- I don't remember the exact amount. It's in the work papers that we provided in here. I want to say it was -- I -- I just don't know. I don't want to quote you something wrong. It's – it's –
>
> Q. Fair.
>
> A. -- it's much lower.· It – it's included in -- in the -- the work papers we provide in AG1[-]1. In response to AG1[-]1, there is a detailed work paper for all of these scenarios, including the incremental capital cost and the new operating cost profiles of each compliance option.[129]

As such, a cooling tower is required for all of the post-2031 alternatives that continue to utilize the Mitchell Plant, as well as a reduced level of ZLD investment in the event that the Mitchell Plant is converted to 100% natural gas operations, and the costs associated with those investments have been incorporated into Kentucky Power's analysis. The analysis demonstrates that making the investments necessary for the Company to continue to receive capacity and energy from the Mitchell Plant after December 31, 2028, is the lowest cost, reasonable alternative for the Kentucky Power and its customers.

VI. CONCLUSION

Faced with a December 31, 2028 deadline to address an impending capacity shortfall, Kentucky Power promptly and diligently began the search for a replacement for its 50% undivided interest in the capacity and energy from the Mitchell Plant. This search included an all-source RFP for PPAs and took place during a period when the environmental compliance obligations for coal-fired power plants became far more stringent and capacity prices in PJM skyrocketed to record highs. These factors led Kentucky Power to evaluate whether making the investments necessary to maintain its 50% undivided interest beyond 2028 was in its customers' best interests. The evidence in this case demonstrates that it is.

[129] Vaughan Hearing Testimony at 160–61.

Making the investments necessary for the Company to continue to receive capacity and energy from the Mitchell Plant after December 31, 2028, is by far the lowest-cost, reasonable alternative to provide needed capacity and energy to its customers. Not only is it the best alternative in the period from 2029-2031, but it also provides the Company and its customers with the multiple, viable, and cost-effective alternatives to comply with existing environmental regulations. The Settlement Agreement makes it an even better deal for customers.

The Commission should grant the Company's application, as modified by the Settlement Agreement.

Respectfully submitted,

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