COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:	)	
	)	
Electronic Application of Kentucky Power Company For 1) A Certificate of Public Convenience and Necessity to Construct a Mechanical Draft Cooling Tower at the Mitchell Plant, 2) Approval of Certain Regulatory And Accounting Treatments, and 3) All Other Required Approvals and Relief	)	**Case No. 2026-00001**

DIRECT TESTIMONY OF LUCY METZ

ON BEHALF OF

SIERRA CLUB

May 15, 2026

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1. INTRODUCTION AND PURPOSE OF TESTIMONY

Q Please state your name and occupation.

A My name is Lucy Metz. I am a Senior Associate at Synapse Energy Economics, Inc. ("Synapse"). My business address is 485 Massachusetts Avenue, Suite 3, Cambridge, Massachusetts 02139.

Q Please describe Synapse Energy Economics.

A Synapse is a research and consulting firm specializing in energy and environmental issues, including electric generation, transmission and distribution system reliability, ratemaking and rate design, electric industry restructuring and market power, electricity market prices, stranded costs, efficiency, renewable energy, future of gas utilities planning, environmental quality, and nuclear power.

Synapse's clients include state consumer advocates, public utilities commission staff, attorneys general, environmental organizations, federal government agencies, and utilities.

Q Please summarize your work experience and educational background.

A At Synapse, I conduct analysis and write publications on a variety of topics related to power plant economics and integrated resource planning. I regularly support the development of comments and testimony in litigated dockets across the country, including performing analyses of electric power systems using industry-standard models such as EnCompass and spreadsheet tools. I recently sponsored testimony before the public service commissions of Georgia, Kansas, North Carolina, South Carolina, and Wisconsin.

I hold a Bachelor of Science in Engineering Science from Smith College. A copy of my current resume is attached as Exhibit LM-1.

Q On whose behalf are you testifying in this case?

A I am testifying on behalf of Sierra Club.

Q Have you previously testified before the Kentucky Public Service Commission ("Commission")?

A No, I have not previously testified before this Commission.

Q Have you previously testified in similar certificate of need dockets?

A Yes. I have testified in Certificate of Public Convenience and Necessity ("CPCN") dockets in Georgia, Kansas, North Carolina, and South Carolina.

Q What is the purpose of your testimony in this proceeding?

A In my testimony, I evaluate whether Kentucky Power Company ("Kentucky Power" or "the Company") has demonstrated that constructing a new mechanical draft cooling tower at Mitchell 2 is in the best interest of its ratepayers relative to all other feasible alternatives, including retiring and replacing Mitchell 2.

Q How is your testimony structured?

A In Section 2, I summarize my findings and recommendations for the Commission.

In Section 3, I summarize the Company's request for a CPCN to construct a mechanical draft cooling tower at Mitchell 2.

In Section 4, I assess whether Kentucky Power has presented sufficient evidence to demonstrate that constructing a mechanical draft cooling tower at Mitchell 2 is the lowest-cost option for its ratepayers. I explain my concerns with the Company's economic analysis, and I recommend that the Company complete an updated portfolio analysis prior to the Commission making a decision on this CPCN.

In Section 5, I outline the risks of continuing to rely on Mitchell 2. I also explain the benefits to ratepayers of retiring and replacing the unit, including improved reliability and system performance.

Q What documents do you rely upon for your analysis, findings, and observations?

A My analysis relies primarily upon the workpapers, exhibits, and discovery responses provided by Kentucky Power, as well as publicly available data.

2. FINDINGS AND RECOMMENDATIONS

Q Please summarize your findings.

A My primary findings are:

1. Kentucky Power failed to demonstrate that constructing a new mechanical draft cooling tower at Mitchell 2 is in the best interest of its ratepayers and avoids wasteful duplication.

2. Kentucky Power failed to appropriately compare the full forward-going, avoidable cost of the four resource portfolio options it considered.[1] This cost comparison is necessary for the Commission to make an informed decision about this CPCN.
3. The Company's economic analysis is flawed and fails to provide sufficient information for an apples-to-apples comparison of the revenue requirement of the four options. In summary:
    a. The Company's analysis omits all costs associated with maintaining Mitchell 2 through 2040 other than those specifically associated with the cooling tower.
    b. Kentucky Power uses a depreciation timeline for the draft cooling tower that does not align with Mitchell's retirement date and artificially reduces the net present value of the revenue requirement ("NPVRR") of this option by approximately [redacted]
    c. The Company did not account for the differences in accredited capacity between the scenarios it modeled.
4. Retiring and replacing Mitchell 2 with a cleaner, more efficient, and more flexible resource alternative would deliver performance and reliability benefits to ratepayers. Investing in a replacement resource would also avoid the need to continue investing in an aging coal unit that will likely continue to be expensive to maintain going forward.

[1] For existing resources, avoidable costs (i.e., costs that are not already sunk) include ongoing capital expenditures, environmental compliance costs, fixed and variable operations and maintenance, and fuel costs. For new resources, avoidable costs are equivalent to the all-in cost of the resource.

Q Please summarize your recommendations.

A Based on my findings, I offer the following recommendations:

1. The Commission should deny the Company's request for a CPCN to construct a mechanical draft cooling tower at Mitchell Unit 2.
2. The Commission should find that Kentucky Power has not presented sufficient analysis and evidence in this case to demonstrate that building a mechanical draft cooling tower at Mitchell 2 is the lowest-cost option for its ratepayers.
3. The Commission should instruct Kentucky Power to provide industry-standard capacity expansion and production cost modeling to support its requests to make a major capital investment in existing resources or build new resources in this and all future CPCNs. This is especially important when its integrated resource plan ("IRP") analysis is outdated, as is the case for this docket.
4. The capacity expansion and production cost portfolio analysis should include the following:
    a. All forward-going costs for both existing and new resources. For existing resources, this includes ongoing capital expenditures, environmental compliance costs, fixed operations and maintenance ("FOM"), variable operation and maintenance ("VOM"), and fuel costs. For new resources, this includes all the above cost categories plus initial capital costs.
    b. Sufficient scenario considerations to ensure an economically robust result.

3. SUMMARY OF THE COMPANY'S PROPOSAL

Q What is Kentucky Power requesting in this docket?

A Kentucky Power seeks a CPCN for the Mitchell Cooling Tower Project, which includes constructing a new mechanical draft cooling tower for Unit 2 of the Mitchell Generation Station ("Mitchell Plant") and partially demolishing the existing cooling tower at Mitchell 2.[2] Under its proposal, Kentucky Power would fully demolish the existing cooling tower when the Mitchell Plant retires,[3] currently scheduled for 2040.[4] The Mitchell Cooling Tower Project is necessary because the existing hyperbolic cooling tower has structural damage consisting of "deformations, extensive cracking, and concrete deterioration of the shell," which make it unsafe to continue operating.[5]

The total cost of the proposed project is approximately $191 million.[6] This includes the cost to both construct the new cooling tower and demolish the existing one.[7] Kentucky Power and its ratepayers will pay for half of these costs

[2] *Electronic Application Of Kentucky Power Company For 1) A Certificate of Public Convenience and Necessity to Construct a Mechanical Draft Cooling Tower at the Mitchell Plan 2) Approval of Certain Regulatory and Accounting Treatments, and 3) All Other Required Approvals and Relief*, Case No. 2026-00001, Application at 1 (Feb. 17, 2026) (hereinafter "Application").

[3] *Id.* at 1.

[4] Direct Testimony of Tanner S. Wolffram on Behalf of Kentucky Power Company at 10 (Feb. 17, 2026) (hereinafter "Wolffram Direct").

[5] Direct Testimony of Daniel W. Pizzino on behalf of Kentucky Power Company at 7 (Feb. 17, 2026) (hereinafter "Pizzino Direct").

[6] Application at 8.

[7] Direct Testimony of Shawn P. Malone on behalf of Kentucky Power Company at 6 (Feb. 17, 2026).

($95.5 million), corresponding to its 50-percent ownership share of the unit.[8] Kentucky Power expects that the new mechanical draft cooling tower will go into service in the second quarter of 2028, with the full cooling tower project finished by 2029.[9]

Q Please describe Kentucky Power's resource portfolio.

A Kentucky Power's resource portfolio is currently composed mainly of three aging steam turbine units: Mitchell 1, Mitchell 2, and Big Sandy. Mitchell 1 and 2, located in West Virginia, are super-critical coal steam units that were placed in service in 1971.[10] Mitchell 1 has a nameplate capacity of 770 megawatts (MW) and Mitchell 2 has a nameplate capacity of 790 MW. Kentucky Power has a 50-percent ownership share of each unit, and the other 50 percent is owned by Wheeling Power Company, which operates the plant.[11] Big Sandy 1, located in Kentucky, is owned and operated by Kentucky Power. It was originally placed in service in 1963 as a coal-fired unit with a nameplate capacity of 295 MW and was converted to burn natural gas in 2016.[12] The Company also gets about 2 MW of capacity from demand response.[13]

[8] Application at 2, 8.

[9] Wolffram Direct at 6.

[10] Application at 2.

[11] Application at 2.

[12] *Electronic 2022 Integrated Resource Planning Report of Kentucky Power Company*, Case No. 2023-00092, 2022 Integrated Resource Plan at 55 (March 20, 2023) (hereinafter "Kentucky Power 2022 IRP"), available at https://psc.ky.gov/pscecf/2023-00092/sebishop%40aep.com/03202023030104/KPCO_2022_IRP_Volume_A-Public.pdf.

[13] Kentucky Power Response to Sierra Club Data Request No. 1-18, Attachment 1.

Table 1. Kentucky Power generating resources (capacities shown are Kentucky Power share only)

Unit Name	Online Year	Nameplate Capacity (MW)	Winter Accredited Capacity (MW)	Kentucky Power Ownership Share
Mitchell 1	1971	385	281	50%
Mitchell 2	1971	395	305	50%
Big Sandy	1963 (Converted to gas in 2016)	295	232	100%

Sources: Wolffram Direct at 4-5; Kentucky Power response to SC 1-18, Attachment 1; and Kentucky Power 2022 IRP at 55. Winter accredited capacity shown is for planning year 2031.

Q What is the Company's capacity position going forward?

A Figure 1 shows Kentucky Power's projected capacity obligation and its existing resources. Because it is a winter-peaking utility, Kentucky Power expects that PJM's methodology to calculate its capacity obligation will change beginning in planning year 2031/2032.[14] This methodology change will result in Kentucky Power having a capacity need of 296 MW in 2031/2032, declining to 84 MW by 2039/2040.[15] The sudden capacity need starting in 2031/2032 is entirely a result of the methodology change, rather than load growth. Kentucky Power expects that its peak load will gradually decline through 2040; the Company's annual peak load will decrease by 4 percent from 2026 to 2040 while its winter peak will decrease by 15 percent.[16] In the absence of any changes to PJM's methodology,

[14] Wolffram Direct at 7.

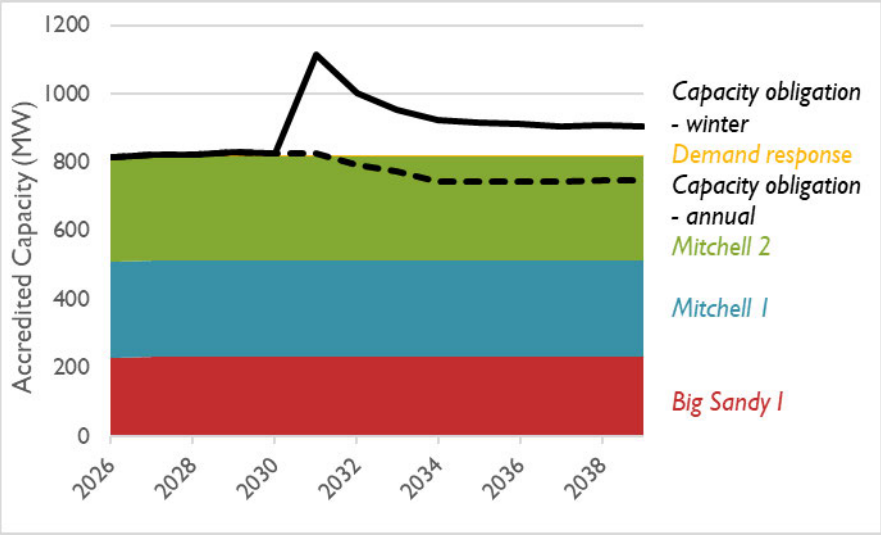
[15] Kentucky Power Response to Sierra Club Data Request No. 1-18, Attachment 1.

[16] *Id.*

the Company's capacity obligation would show a corresponding decline through 2040 (dotted line in Figure 1).[17]

Kentucky Power will therefore need to procure capacity to fill its capacity shortfall starting in planning year 2031/2032. If the Company chooses to retire Mitchell 2, it will need to procure 305 MW of additional replacement capacity.[18]

Figure 1. Kentucky Power capacity position (2026-2040)



Source: Kentucky Power response to SC 1-18, Attachment 1.

Q How have the Company's plans for Mitchell 2 changed over time?

A Until last year, Kentucky Power planned to exit from its ownership share of the Mitchell plant by year-end 2028. In 2021, the Commission denied Kentucky Power's application for expenditures necessary to comply with the 2020 Effluent Limitation Guidelines ("ELG") Rule at the Mitchell Plant, determining that the Company had not met its burden of proof in comparing the ELG investment to

[17] *Id.*

[18] *Id.*

alternatives.[19] As a result, Kentucky Power had to exit from the plant by the end of 2028.

In 2025, Kentucky Power filed a CPCN requesting that the Commission re-consider its earlier decision and allow the Company to continue taking power from the Mitchell Plant beyond the end of 2028, arguing that this was more cost-effective than procuring replacement capacity.[20] While intervenors raised serious concerns about the quality of the Company's alternatives analysis—echoed by the Commission in its order—the Commission approved this request.[21] In addition to concerns with the Company's analysis, the Commission noted that Kentucky Power's delay in seeking to procure replacement capacity for the Mitchell Plant "limited the options that could be considered" in the 2025 CPCN docket.[22] Kentucky Power's delays left the Commission with little choice but to approve the CPCN.

[19] *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, Order at 20–21 (July 15, 2021).

[20] *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, Order at 11 (Dec. 30, 2025).

[21] *Id.* at 32, 37, 58–59, 63.

[22] *Id* at 36. The Commission went on to say that "[I]f Kentucky Power had taken action more quickly after the final Order in Case No. 2021-00004, new build options would have been a possibility even in 2028."

To continue taking power from the Mitchell Plant, Kentucky ratepayers had to pay $138 million in capital costs for the 50-percent share of the 2020 ELG Project ($78 million) and the other non-ELG investments that Wheeling Power had made in the plant between September 2022 and December 31, 2025 ($60 million).[23]

Q Was the Company aware of the structural problems with the Mitchell 2 cooling tower at the time of the 2025 CPCN docket?

A Yes, Kentucky Power was aware of the structural problems with the Mitchell 2 cooling tower at the time of the 2025 CPCN docket, and the Company supplemented its application in October 2025 to inform the Commission that more substantial structural repairs would be necessary than it had initially estimated.[24] Although Kentucky Power recognized that the status of the cooling tower might affect the Commission's decision in the 2025 CPCN docket, the Company did not request approval of the Mitchell Cooling Tower Project at that time.[25] Instead, less than a year later, it filed a separate request in this docket to spend an additional $95.5 million on the cooling tower repair to keep Mitchell 2 operational.

Q What evidence does the Company need to provide to justify its request for a CPCN?

A To justify its request for a CPCN, Kentucky Power must demonstrate (1) a need for the Mitchell Cooling Tower Project, and (2) that the project results in an

[23] *Id* at 9.

[24] *Id* at 10.

[25] *Id* at 10.

absence of wasteful duplication.[26] "Wasteful duplication" can include both "an excess of capacity over need" and "an excess investment in relation to productivity or efficiency."[27] Commission precedent holds that applicants must perform a thorough review of all reasonable alternatives in order to demonstrate an absence of wasteful duplication.[28]

A key issue in this docket is therefore whether Kentucky Power has adequately compared the proposed Mitchell Cooling Tower Project to all reasonable alternatives. To make this comparison, Kentucky Power needs to compare the full forward-going costs of Mitchell 2 to the all-in costs of various alternatives. This analysis is necessary to ensure that the proposed Mitchell Cooling Tower Project avoids wasteful duplication. In the next section of my testimony, I outline my concerns with the Company's analysis, which I find has unquestionably not met this standard.

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

[27] *Id*.

[28] *Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for the Construction of Transmission Facilities in Jefferson, Bullitt, Meade, and Hardin Counties, Kentucky*, Case No. 2005-00142, Order at 11 (Sept. 8, 2005).

4. KENTUCKY POWER HAS NOT PRESENTED SUFFICIENT EVIDENCE TO DEMONSTRATE THAT CONSTRUCTING A MECHANICAL DRAFT COOLING TOWER AT MITCHELL 2 IS THE LOWEST-COST OPTION FOR ITS RATEPAYERS

i. The Company's economic analysis is flawed because it omits forward-going costs at Mitchell 2, uses an inconsistent depreciation timeline, and does not consider impacts on Kentucky Power's full resource portfolio

Q What analysis did the Company prepare to support its application in this docket?

A Kentucky Power prepared an economic analysis comparing the 12-year NPVRR of four options for Mitchell 2,[29] as follows:

- Option 1: Expand the paused exterior shell reinforcement for the existing cooling tower
- Option 2: Retire Mitchell 2 and replace it with a gas combined-cycle ("CC") plant
- Option 3: Construct a new mechanical draft cooling tower
- Option 4: Reduce the height of the existing cooling tower, and continue with a reduced scope of exterior shell reinforcement

[29] Direct Testimony of Nicole M. Coon on behalf of Kentucky Power Company at 9 (Feb. 17, 2026) (hereinafter "Coon Direct").

The Company found that the three options that continue operation of Mitchell 2 (Options 1, 3, and 4) had comparable revenue requirements (Table 2).[30] It selected Option 3, because constructing a new mechanical draft cooling tower would avoid the risks associated with continuing to rely on the existing damaged cooling tower.[31]

Table 2. NPVRR results from Kentucky Power economic analysis

Option	Description	NPVRR (million $)
Option 1	Expand exterior shell reinforcement	$142
Option 2	Retire Mitchell 2 and replace with CC unit	$836
Option 3	Construct mechanical draft cooling tower	$147
Option 4	Reduce height of existing tower	$189

Source: Coon Direct Exhibit NMC-1.

Q Did you have any concerns with the Company's economic analysis?

A Yes, I identified several flaws in the Company's economic analysis that bias the results in favor of the options that continue operation of Mitchell 2. First, the Company focuses narrowly on costs associated with the cooling tower, rather than the full avoidable cost of continuing to operate Mitchell 2. As a result, its analysis omits all forward-going costs at Mitchell 2 (except those associated with the cooling tower itself), including ongoing capital expenditures, environmental compliance costs, and FOM costs. In contrast, Kentucky Power included all forward-going costs for the replacement CC unit in Option 2.

Second, the Company's analysis uses a depreciation timeline for the mechanical draft cooling tower that does not align with the planned retirement of Mitchell 2

[30] Wolffram Direct at 10–11.

[31] *Id.*

and is longer than the depreciable life the Company plans to use if the CPCN is approved.[32,33] This further underestimates the revenue requirement of Option 3.

Third, the four options do not include the same amounts of capacity and energy, and it is unclear how these options fit into the lowest-cost pathway for the Company's resource portfolio as a whole.

These omissions and inconsistencies undermine the Company's analysis. Without being able to fairly compare the full forward-looking, avoidable costs of the options that continue operation of Mitchell 2 to the all-in costs of the new generation option, the Company has not demonstrated that Option 3 is in the best interest of its ratepayers and avoids wasteful duplication. I will explain each of these concerns in more detail below.

Q Explain your concerns with the Company's analysis omitting many avoidable forward-looking costs at Mitchell 2.

A I am concerned that the Company fundamentally misunderstands the costs that it should be comparing in its economic analysis. For the Commission to make an informed decision about the Mitchell Cooling Tower Project CPCN, Kentucky Power would need to compare the full forward-going, avoidable costs of the four options. For existing units such as Mitchell 2, avoidable costs include all prospective costs that are not already sunk (ongoing capital expenditures, environmental compliance costs, fixed and variable operations and maintenance, and fuel costs). For new resources such as the CC unit in Option 2, avoidable costs are equivalent to the all-in cost of the resource. Instead of analyzing the full

[32] Kentucky Power Response to KPSC Data Request No. 2-8.

[33] Kentucky Power Response to AG-KIUC Data Request No. 2-2.

avoidable cost of each option in its economic analysis, the Company erroneously focuses on "new" costs, which it appears to define as costs that it was not previously planning to incur.[34]

For the options that continue operation of Mitchell 2 (Options 1, 3, and 4), the Company's analysis narrowly focuses on costs associated with the cooling tower.[35] It includes capital costs for the cooling tower replacement (Option 3) or repair (Options 1 and 4), as well as demolition costs for the existing cooling tower.[36] It also includes lost energy margins associated with derates at Mitchell 2.[37] The analysis omits all other cost categories associated with the continued operation of Mitchell 2 during and after construction of the new cooling tower (such as sustaining capital expenditures and FOM).[38] For the replacement CC unit in Option 2, the Company models both the capital cost of the plant and ongoing operation and maintenance expenses, as well as the energy margins of the plant.[39,40] It also models the cost of obtaining replacement capacity and lost energy margins from June 2027 until May 2031, when the CC unit comes online.[41]

[34] Kentucky Power Response to KPSC Data Request No. 2-7.

[35] *Id.*

[36] Kentucky Power Response to KPSC Data Request No. 1-10, Public Attachments 2, 4, and 5.

[37] Coon Direct at 5–8.

[38] Kentucky Power Response to KPSC Data Request No. 2-7.

[39] Kentucky Power Response to KPSC Data Request No. 1-10, Public Attachment 3.

[40] Kentucky Power Response to Sierra Club Data Request No. 2-5.

[41] Coon Direct at 6.

This narrow framing misrepresents the decision facing the Company. In reality, if the Company pursues Option 3, it will pay 50 percent of the full cost of maintaining Mitchell 2 through 2040, including all the ongoing capital expenditures, environmental compliance costs, and FOM costs (as well as fuel and VOM costs) *in addition to* the capital costs of the mechanical draft cooling tower. If it pursues Option 2, then it will avoid all these future expenditures at Mitchell 2 and will instead pay the full costs of a replacement CC plant. To compare the options accurately, the Company would need to calculate the full forward-going NPVRR of each option.

Q What is the impact of the Company's omission of ongoing capital expenditures from its economic analysis?

A Kentucky Power's omission of ongoing capital expenditures underestimates the revenue requirement of the options that continue operation of Mitchell 2 (Options 1, 3, and 4). All thermal generators require ongoing capital investments to keep equipment operational. This is especially true for coal power plants, which typically have higher fixed costs compared to other types of generating resources as a result of complex mechanical equipment associated with solid fuel handling, ash disposal, and environmental compliance.[42] Based on its size and age, Mitchell 2 likely requires annual capital expenditures of approximately $30 million ($2025).[43] This is an average value, and costs could be higher in years with a major equipment failure or environmental upgrade. Ongoing capital expenditures

[42] Kaplan, S. 2020. "Why Coal Lost—and Can It Recover?" *Power*, available at https://www.powermag.com/why-coal-lost-and-can-it-recover/.

[43] Sargent and Lundy, *Generating Unit Annual Capital and Life Extension Costs Analysis: Final Report on Modeling Aging-Related Capital and O&M Costs* at 58 (Dec. 2018), available at https://www.eia.gov/analysis/studies/powerplants/generationcost/pdf/full_report.pdf.

for coal units also tend to increase as a function of unit age.[44,45] In contrast, a new resource would have much lower near-term ongoing capital costs.

Q Are there known upcoming environmental compliance costs at the Mitchell Plant?

A Yes. In the near term, the Mitchell Plant faces sizeable ELG compliance costs. Costs for compliance with the 2020 ELG Rule are now sunk, since the 2020 ELG Project was completed in 2024, and Kentucky Power does not plan to exit from the plant by year-end 2028.[46] Because of this decision, Kentucky Power faces additional compliance costs under the 2024 ELG Rule by the end of 2034, including the cost to install a zero liquid discharge ("ZLD") system. In the 2025 CPCN docket, the Company estimated that if the Mitchell Plant co-fires with 40 percent gas, capital costs for compliance with the 2024 ELG Rule would be [redacted], including [redacted] to install a ZLD system.[47] The Company has not

[44] *Id.*

[45] As I discuss in Section 5, replacement parts for coal plants are also becoming more expensive and difficult to obtain as U.S. coal generation declines.

[46] *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, Application at 6 (June 30, 2025).

[47] Confidential Kentucky Power Supplemental Response to Sierra Club Data Request No. 1-13, "KPCO_R_SC_PHDR_4_ConfidentialAttachment1.xlsx."

provided an estimate of 2024 ELG Rule costs if the plant continues to operate solely on coal, as is currently Kentucky Power's plan.[48]

In addition to installation costs, environmental retrofits result in large operations and maintenance costs, which Kentucky ratepayers will pay each year that the Company maintains an ownership share in the Mitchell Plant. The 2020 ELG compliance equipment for the Mitchell Plant has annual operations and maintenance costs of approximately $1.3 million, of which Kentucky Power pays half ($665,000).[49] Compliance with the 2024 ELG Rule will further increase these costs. In the 2025 CPCN docket, the Company estimated that annual fixed operating costs for the 2024 ELG Rule compliance equipment would be [redacted] if the Mitchell Plant converts to co-fire with 40 percent gas.[50] The

[48] In response to discovery about 2024 ELG costs at Mitchell 2, the Company provided an analysis it completed for the 2025 CPCN docket (see Kentucky Power Supplemental Response to Sierra Club Data Request No. 1-31 and Kentucky Power Response to Sierra Club Data Request No. 2-1). For the 2025 CPCN docket, Kentucky Power calculated environmental compliance costs if the Mitchell Plant co-fired with 40 percent gas and retired by year-end 2034, co-fired with 40 percent gas and retired by year-start 2039, or converted to 100 percent gas. The Company has not provided any more recent analysis of 2024 ELG Rule costs or any analysis of compliance costs if the plant continues to operate on coal.

[49] *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, Direct Testimony of Tanner S. Wolffram at 23 (June 30, 2025), available at https://psc.ky.gov/pscecf/2025-00175/mmcaldwell%40aep.com/06302025034730/03_KPCO_DT_Wolffram.pdf.

[50] Confidential Kentucky Power Supplemental Response to Sierra Club Data Request No. 1-13, "KPCO_R_SC_PHDR_4_ConfidentialAttachment1.xlsx."

Company has not estimated FOM costs if the Mitchell Plant continues to be entirely coal-fired, but costs would likely be equal to or higher than this estimate.

Q Explain your concerns with the Company's assumptions related to depreciation timelines in its economic analysis.

A In its economic analysis, Kentucky Power uses a 25-year depreciation timeline for the mechanical draft cooling tower in Option 3.[51] While this aligns with the theoretical useful life of the cooling tower, the cooling tower will only be in service for 12 years. It is scheduled to come online in 2028, while Mitchell 2 will retire in 2040.[52] Under a 25-year depreciation timeline, the cooling tower would become a stranded asset in 2040 when Mitchell 2 retires.

To avoid creating a stranded asset, the Company plans to use a 12-year depreciation timeline for the draft cooling tower if the CPCN is approved.[53,54] This aligns with standard industry practice of depreciating assets over the time period when they are in use. In its rate impact analysis, the Company accordingly used a 12-year depreciation timeline for the draft cooling tower.[55] It is unclear why the Company chose not to update its economic analysis to match this

[51] Kentucky Power Response to Sierra Club Data Request No. 1-9.

[52] Kentucky Power Response to KPSC Data Request No. 2-8.

[53] *Id.*

[54] Kentucky Power Response to AG-KIUC Data Request No. 2-2.

[55] Kentucky Power Response to Sierra Club Data Request No. 1-9.

assumption. The longer depreciation timeline in the economic analysis artificially reduces the NPVRR of Option 3 by about [redacted].[56]

Q Could the Company extend the retirement of Mitchell 2 to use the cooling tower for a full 25 years?

A Kentucky Power at times suggests that it may delay the retirement of Mitchell 2 to make use of the full 25-year operational life of the cooling tower. For example, witness Wolffram notes that the Mitchell Cooling Tower Project "provides optionality for post-2040 operations" of Mitchell 2.[57] By 2040, Mitchell 2 will be almost 70 years old.[58] As I discuss later in my testimony, it is unrealistic for Kentucky Power to continue operating such an old unit after 2040.

Q Explain your concern with the quantity of energy and capacity provided by each option.

A My last concern is that the four options that the Company analyzed are not equivalent in terms of the amount of capacity and energy they provide. Kentucky Power's share of Mitchell 2 has an estimated 2031 accredited capacity of 324 MW in Option 3,[59] while its share of the CC unit in Option 2 has an accredited capacity of 454 MW (Table 3).[60] Option 2 therefore provides 40 percent more

[56] The Company produced several versions of its cost-of-service workpapers in discovery, to account for various updates and corrections to its initial calculations. This estimate was calculated by adjusting the depreciation timeline in Kentucky Power's Response to KPSC Data Request No. 1-10, Confidential Attachment 4.

[57] Wolffram Direct at 10.

[58] U.S. Energy Information Administration, Form 860, 2024 release.

[59] Kentucky Power Response to Sierra Club Data Request No. 1-10, Public Attachment 1.

[60] Kentucky Power Supplemental Response to Sierra Club Data Request No. 1-15.

accredited capacity than Option 3, which the Company's analysis does not account for. The additional 130 MW of accredited capacity in Option 2 has substantial value and would cover almost half of the Company's projected capacity need in planning year 2031/2032. The Company's analysis includes all the costs of this additional capacity but none of the additional benefits.

Table 3. Comparison of capacity of Mitchell 2 in Option 3 and the replacement CC unit in Option 2

Quantity	Mitchell 2	Gas CC unit	Percent difference
Total nameplate capacity	[redacted]	1,200 MW	[redacted]
Kentucky Power share of nameplate capacity	[redacted]	600 MW	[redacted]
Kentucky Power share of accredited capacity in 2031	324 MW	454 MW	40%

Sources: Kentucky Power Supplemental Response to Sierra Club 1-15 and Kentucky Power Response to Sierra Club 1-10, Confidential Attachment 1. This table shows the accredited capacity of Mitchell 2 as displayed in Kentucky Power's Response to Sierra Club 1-10. This differs slightly from the value of 305 MW in Kentucky Power Response to SC 1-18, Attachment 1 (displayed in Table 1), due to a different calculation methodology. The Company should reconcile these values in future analyses.

Similarly, it is unclear whether the Company's analysis accounts for the different amounts of generation expected from Mitchell 2 compared to a replacement resource such as a gas CC plant. A newer generating resource will have a lower dispatch cost than an aging steam turbine unit such as Mitchell 2, so it will likely be dispatched during more hours and earn a higher energy margin. In contrast, the capacity factor of Mitchell 2 has declined over the past 10 years (see Section 5), indicating the declining economic competitiveness of the unit.

Kentucky Power attempts to quantify the generation of each option using an energy margin metric. However, it is unclear if the Company's energy margin calculation fully accounts for the different characteristics of the four options. To ensure that the NPVRR of the scenarios are comparable, it would be more

transparent for Kentucky Power to model all cost and revenues categories (VOM, fuel costs, energy market revenues) separately.

Q In summary, can the Company's economic analysis be used to compare the NPVRR of the four options?

A No. Based on the shortcomings I described above, Kentucky Power has not appropriately compared the full forward-going, avoidable cost of the four resource portfolios it considered, which would be necessary before the Commission could make an informed decision about this CPCN. The Company has not justified that its proposed Mitchell Cooling Tower Project is the lowest-cost, lowest-risk option for ratepayers and avoids wasteful duplication.

ii. Kentucky Power should complete an updated portfolio analysis, including industry-standard capacity expansion and production cost modeling, prior to the Commission making a decision on this CPCN

Q What kind of analysis do you recommend the Company prepare to support its request in this docket?

A I recommend that Kentucky Power complete an updated analysis consisting of capacity expansion and production cost modeling to compare the portfolio-wide, forward-looking costs of the different options for Mitchell 2. Within this modeling, Kentucky Power should include all avoidable forward-going costs associated with its existing units, including ongoing capital expenditures, environmental compliance costs, FOM costs, VOM costs, and fuel costs. For new resources, it should model all-in resource costs (including initial capital expenditures in addition to the other cost categories listed above).

As part of its modeling, Kentucky Power should test a scenario that retires and replaces Mitchell 2 in the near term (with no additional investment in the cooling tower) and should allow the model to select the most economic replacement resources for Mitchell 2. It should also model a scenario that includes construction of the new draft cooling tower and allows the model to select any additional capacity needed to close the shortfall beginning in 2031/2032. The Company can then compare the full, portfolio-wide NPVRR of the scenario that retains Mitchell 2—inclusive of the incremental cost to construct a cooling tower with a 12-year depreciation schedule—to the scenario that retires and replaces the unit.

To arrive at meaningful results, Kentucky Power should model a wide range of feasible replacement resources, including battery storage, solar, and gas combustion turbine ("CT") and CC resources. It should also test a wide enough range of scenarios and sensitivities to arrive at a solution that is economically robust.

Q Did the Company complete any capacity expansion modeling to support its request in this docket?

A No, the Company did not complete any capacity expansion modeling to support its application in this docket.[61] The most recent capacity expansion modeling that Kentucky Power conducted was for its 2022 IRP,[62] which is now outdated. At the

[61] Kentucky Power Response to Sierra Club Data Request No. 2-2.

[62] *Id*.

time of the 2022 IRP, the Company was still planning to exit from the Mitchell Plant by year-end 2028.[63]

The Company has conducted more recent production cost modeling in PLEXOS for purposes of calculating energy margins.[64] However, these results do not give information about resource retirement and addition decisions, only about resource dispatch.

Q What are the benefits of performing capacity expansion modeling to support the CPCN application?

A Performing updated capacity expansion and production cost modeling will offer several benefits to Kentucky Power, including the following:

1. It will allow the Company to economically select whether to continue operating Mitchell 2 or retire and replace it, taking into account the costs, outage rates, and energy margins of each unit.
2. It will enable the Company to optimize its decision about Mitchell 2 in the context of other proposed resources in its portfolio, such as the 450 MW CT it plans to add at the Big Sandy site.[65]
3. It will allow the Company to consider a wider range of replacement resources.

[63] Kentucky Power 2022 IRP at 14.

[64] Kentucky Power Response to Sierra Club Data Request No. 2-3.

[65] Kentucky Power Response to Sierra Club Data Request No. 1-18.

Q Why is it important for the Company to optimize its decision about Mitchell 2 in the context of its entire resource portfolio?

A As I discussed above, Kentucky Power projects that its capacity requirement will increase in planning year 2031/2032 as a result of changes in PJM rules, leaving it with a winter shortfall of just under 300 MW.[66] The Company states that it plans to submit an application for a new 450 MW CT at the Big Sandy site,[67] and that it may also secure purchase power agreements and/or short-term bilateral capacity purchases to fill its winter capacity shortfall.[68] If sized correctly, replacement resources for Mitchell 2 could eliminate the need to purchase short-term replacement capacity for the 2031/2032 planning year and/or to build a new CT at the Big Sandy site. I have not seen evidence that the Company included these considerations in its alternatives analysis.

Although the replacement CC unit in Option 2 provides 40 percent more accredited capacity than Kentucky Power's share of Mitchell 2, the Company did not assign any value to this capacity in its analysis—only costs (see Section 4). Robust capacity expansion modeling would allow the Company to accurately account for the portfolio-wide cost of both replacing Mitchell 2's capacity and closing the capacity shortfall that the Company projects starting in planning year 2031/2032.

[66] Wolffram Direct at 7.

[67] Kentucky Power Response to Sierra Club Data Request No. 1-18.

[68] *Id.*

Q Why is it important for the Company to consider a wider range of resource alternatives?

A Capacity expansion modeling would also allow Kentucky Power to consider a wider range of replacement resources for Mitchell 2. It is unclear how the Company selected a CC unit as the replacement resource in Option 2. Kentucky Power should test whether alternate replacement resources, such as renewable energy paired with battery storage or a combustion turbine, could provide the same capacity and energy at lower cost and risk to ratepayers. In its order on Kentucky Power's 2025 CPCN, the Commission wrote that it was concerned with the Company's "failure to conduct resource assessment modeling to identify other potential portfolios before conducting the production cost and financial modeling used to calculate revenue requirements."[69] In this docket, Kentucky Power has again failed to complete rigorous portfolio analysis to identify the costs of alternatives to Mitchell 2. Appropriate, robust capacity expansion modeling would address this shortcoming.

Q Does the fact that the Company is requesting a retrofit of an existing facility rather than construction of a new facility affect the need to perform this type of analysis?

A No. Kentucky Power suggests that because it is requesting approval to perform a capital project at an existing plant, rather than building or retiring generation,

[69] *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, Order at 59 (Dec. 30, 2025).

capacity expansion modeling is unnecessary.[70] This goes against the principles of prudent utility planning. The Company has an obligation to ensure it is serving customers reliably and at the lowest cost. If it would be more cost-effective to retire and replace Mitchell 2 than to make an additional capital expenditure to keep it operating, Kentucky Power should do so. The best way to make this determination is to perform capacity expansion modeling that compares the full forward-going costs of continuing to operate the unit to retiring and replacing it.

Q Are there examples from other jurisdictions of utilities supporting CPCN applications with capacity expansion modeling?

A Yes. There are numerous examples of utilities supporting CPCN applications with capacity expansion modeling. In Kentucky, LG&E/KU supported its recent CPCN for two new CC units, a battery storage project, and a selective catalytic reduction facility at an existing generating station with capacity expansion modeling in PLEXOS.[71] Utilities in other states also follow this practice. In a recent CPCN docket for approval of a new jointly owned CC plant in South Carolina, Santee Cooper and Dominion Energy South Carolina completed capacity expansion modeling in EnCompass and PLEXOS, respectively, to

[70] Kentucky Power Response to Sierra Club Data Request No. 2-2. "[T]he Company is not seeking to build new generation or retire old generation where capacity expansion modeling would be warranted."

[71] *Electronic Application of Kentucky Utilities Company and Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity and Site Compatibility Certificates*, Case No. 2025-00045, Direct testimony of Stuart A. Wilson at 22–26 (Feb. 28, 2025), available at https://psc.ky.gov/pscecf/2025-00045/rick.lovekamp%40lge-ku.com/02282025010202/17-Wilson_Direct_Testimony_2025-00045_REDACTED.pdf.

support their joint application.[72,73] In a similar CPCN docket in North Carolina, Duke Energy Progress supported its application with capacity expansion modeling from its recently completed IRP and Supplemental Planning Analysis.[74] In its recent application for approval of new CC and solar resources, Evergy Kansas Central supported its application with updated capacity expansion modeling, noting that conditions had changed since its prior IRP.[75]

[72] *Joint Application of South Carolina Public Service Authority and Dominion Energy South Carolina, Inc. for a Certificate of Environmental Compatibility and Public Convenience and Necessity for the Construction and Operation of an Advanced Class Combined Cycle Generating Plant and Associated Facilities in Colleton County, South Carolina, Pursuant to S.C. Code Ann. § 58-33-10 et. seq.,* Public Service Commission of South Carolina, Docket No. 2025-323-E, Direct testimony of Franklin Clay Settle at 23 (Dec. 15, 2025), available at https://dms.psc.sc.gov/Attachments/Matter/09520608-ed93-4ded-ac70-b0ff2c60280f.

[73] *Joint Application of South Carolina Public Service Authority and Dominion Energy South Carolina, Inc. for a Certificate of Environmental Compatibility and Public Convenience and Necessity for the Construction and Operation of an Advanced Class Combined Cycle Generating Plant and Associated Facilities in Colleton County, South Carolina, Pursuant to S.C. Code Ann. § 58-33-10 et. seq.,* Public Service Commission of South Carolina, Docket No. 2025-323-E, Direct testimony of James W. Neely, P.E. at 10–11 (Dec. 15, 2025), available at https://dms.psc.sc.gov/Attachments/Matter/80569bbe-7171-4d65-8832-87381df368e8.

[74] *In the Matter of the Joint Application of Duke Energy Progress, LLC and North Carolina Electric Membership Corporation for a Certificate of Public Convenience and Necessity to Construct a 1,360 MW Natural Gas-Fueled Combined Cycle Electric Generating Facility in Person County, North Carolina,* North Carolina Utilities Commission, Docket Nos. E-2, Sub 1349 and EC-67, Sub 57, Direct testimony of Michael Quinto at 10–11 (Feb. 7, 2025), available at https://starw1.ncuc.gov/NCUC/ViewFile.aspx?Id=8542b037-2b41-4d9b-91c9-c25df203be4c.

[75] *In the Matter of the Petition of Evergy Kansas Central, Inc., Evergy Kansas South, Inc., and Evergy Metro, Inc. for Determination of the Ratemaking Principles and Treatment That Will Apply to the Recovery in Rates of the Cost to Be Incurred for*

Examples are not limited to dockets where utilities are requesting approval of new generating resources. Kentucky Power itself completed capacity expansion modeling in PLEXOS as part of its CPCN application for ELG and coal combustion residual (CCR) compliance costs at the Mitchell 2 Plant in 2021.[76] Appalachian Power Company and Wheeling Power Company completed similar capacity expansion analyses to support their CPCN application for ELG and CCR compliance costs at the Amos, Mountaineer, and Mitchell coal plants in West Virginia that same year.[77] As these examples make clear, completing capacity expansion modeling is a basic standard practice in the industry, especially when the utility's most recent IRP is out of date, as is the case for Kentucky Power. As with all analyses, thoughtfully designed inputs and scenario structures are crucial to the effectiveness of such modeling.

Certain Electric Generation Facilities Under K.S.A. 66-117, Kansas State Corporation Commission, Docket No. 25-EKCE-207-PRE, Direct testimony of Cody VandeVelde at 24 (Nov. 6, 2024), available at https://estar.kcc.ks.gov/estar/ViewFile.aspx/S202411061124578067.pdf?Id=9b2d3677-dd53-4b3f-86bd-d57fca5aaf2b.

[76] *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, Direct testimony of Becker at 6 (Feb. 8, 2021), available at https://psc.ky.gov/pscecf/2021-00004/sebishop%40aep.com/02082021020420/KPCO_DT_Becker.pdf.

[77] *Application for the issuance of a Certificate of Public Convenience and Necessity for the internal modifications at coal fired generating plants necessary to comply with federal environmental regulations,* Public Service Commission of West Virginia, Case No. 20-1040-E-CN, Direct testimony of James F. Martin at 9 (Jan. 7, 2021).

5. RETIRING AND REPLACING MITCHELL 2 WITH ALTERNATIVE RESOURCES WOULD OFFER A VARIETY OF BENEFITS IN TERMS OF RISK, RELIABILITY, AND SYSTEM PERFORMANCE

Q Does Kentucky Power's current resource portfolio pose risks for ratepayers?

A Yes. Kentucky Power's resource mix is almost entirely composed of aging steam turbine capacity (Table 4). Mitchell 1 and 2 are currently 55 years old and will be 69 years old by their planned retirement in 2040. Big Sandy is 63 years old and will be 78 by its planned retirement in mid-2041.[78] Data from the U.S. Energy Information Administration suggests that the capacity-weighted average age of U.S. coal plants at retirement is approximately 50 years (Figure 2). All three of Kentucky Power's units have exceeded this age, suggesting that they are likely reaching the end of their useful lives.

Continued reliance on these aging steam units—in particular coal-fired units such as Mitchell 1 and 2—creates risk related to environmental compliance costs, unexpected capital expenditures to maintain plant operations, fuel price escalation, and decreased reliability. Rather than continuing to make capital expenditures at Mitchell 2 to rebuild the cooling tower, it would be in ratepayers' best interest for Kentucky Power to begin transitioning its fleet to more modern generating resources.

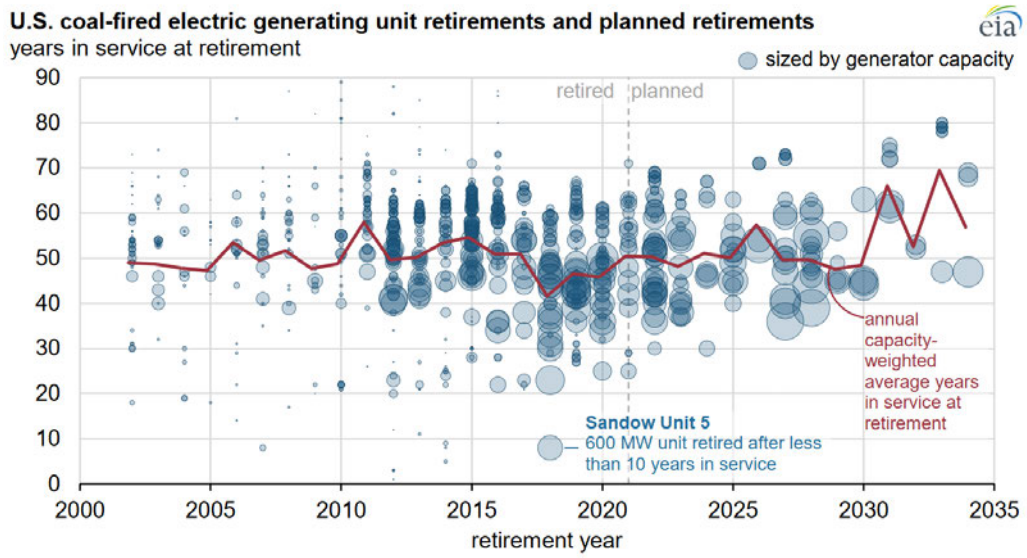
[78] Kentucky Power 2022 IRP at 173.

Table 4. Kentucky Power existing resource ages and planned retirement years

Generator	Current Age	Planned Retirement Year	Age at Planned Retirement
Big Sandy	63	2041	78
Mitchell 1	55	2040	69
Mitchell 2	55	2040	69

Source: Current ages are from U.S. Energy Information Administration, Form 860, 2024 release; planned retirement years from the Direct testimony of Wolffram at 10 and Kentucky Power 2022 IRP at 173.

Figure 2. Capacity-weighted average years in service of U.S. coal-fired units at retirement



Source: U.S. Energy Information Administration. 2021. "Of the operating U.S. coal-fired power plants, 28% plan to retire by 2035." Available at: https://www.eia.gov/todayinenergy/detail.php?id=50658.

Q What are some of the costs and risks of continuing to rely on Mitchell 2 rather than retiring and replacing the unit?

A Environmental regulations could result in higher costs and higher risks for Kentucky Power if it continues to rely on Mitchell 2. While many environmental regulations are being challenged or relaxed at present, coal plants will continue to

face environmental regulation going forward from existing and new programs, including the 2020 and 2024 ELG Rule,[79,80] Mercury and Air Toxics Standards ("MATS"),[81] and the Clean Air Act Section 111 Rule for greenhouse gas emissions.[82] In the near term, the Mitchell Plant likely faces over [redacted] in compliance costs for the 2024 ELG Rule, as I discussed in more detail in Section 4.[83]

In addition to environmental compliance costs, Kentucky Power will need to plan for both routine and unplanned capital expenditures to keep Mitchell 2 and its other units operating as parts break. Replacement parts for coal units become more expensive and difficult to obtain as U.S. coal generation declines. For example, when the boiler feed pump turbine failed at F.B. Culley Unit 3, a coal unit in Indiana, the best option to replace it was to use a part from a retired coal

[79] *Steam Electric Reconsideration Rule*, 85 Fed. Reg. 64,650 (Oct. 13, 2020), available at https://www.govinfo.gov/content/pkg/FR-2020-10-13/pdf/2020-19542.pdf.
[80] *Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category*, 89 Fed. Reg. 40,198 (May 9, 2024), available at https://www.govinfo.gov/content/pkg/FR-2024-05-09/pdf/2024-09185.pdf.
[81] National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired *Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review*, 89 Fed. Reg. 38,508 (May 7, 2024), available at https://www.govinfo.gov/content/pkg/FR-2024-05-07/pdf/2024-09148.pdf.
[82] *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), available at https://www.govinfo.gov/content/pkg/FR-2024-05-09/pdf/2024-09233.pdf.
[83] Confidential Kentucky Power Supplemental Response to Sierra Club Data Request No. 1-13, "KPCO_R_SC_PHDR_4_ConfidentialAttachment1.xlsx."

plant in Montana.[84] The unit was offline from June 2022 to March 2023 while CenterPoint (the owner of the unit) was in the process of obtaining this replacement part.[85,86] Mitchell 2 is also an aging unit, so the availability of replacement parts is a concern for it as well. Outages at Mitchell 2 could result in further large costs for ratepayers if Kentucky Power needs to purchase replacement capacity while Mitchell 2 is offline.

Q What fuel price risks do coal assets pose to Kentucky Power?

A Coal units pose risk to ratepayers related to fuel price volatility. The coal market has seen dramatic price volatility in some parts of the United States over the past few years.[87] Additionally, as coal plants across the United States retire and the demand for coal decreases, coal companies could consolidate. Concentration of

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[84] *Subdocket for Review of Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South ("CEI South") 2021 Extended Forced Outage at Culley 3 Generating Unit and its Related Impact on Fuel Procurement and Fuel Costs*, Indiana Utility Regulatory Commission, Cause No. 38708 FAC 137, Direct Testimony of Wayne D. Games at 19 (Nov. 16, 2022), available at https://iurc.portal.in.gov/_entity/sharepointdocumentlocation/df488571-5893-ed11-aad1-001dd80726a4/bb9c6bba-fd52-45ad-8e64-a444aef13c39?file=38708%20FAC%20137%20Petitioner%20Exhibit%20No.%201.pdf.

[85] *Id*.

[86] *Subdocket for Review of Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South ("CEI South") 2021 Extended Forced Outage at Culley 3 Generating Unit and its Related Impact on Fuel Procurement and Fuel Costs*, Indiana Utility Regulatory Commission, Cause No. 38708 FAC 137, Order of the Commission at 2 (Jan. 28, 2026), available at https://iurc.portal.in.gov/_entity/sharepointdocumentlocation/4e186869-4939-ef11-8409-001dd80b3563/bb9c6bba-fd52-45ad-8e64-a444aef13c39?file=ord_38708FAC137S1_070324.pdf.

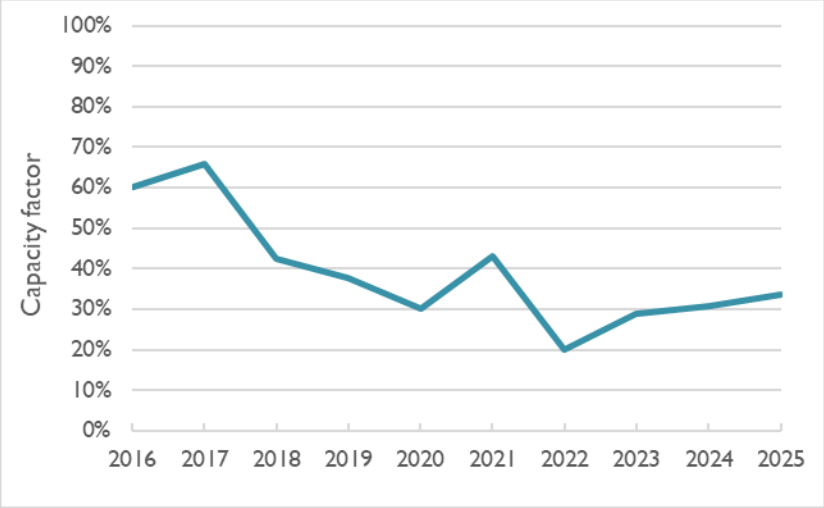
[87] U.S. Energy Information Administration. "Coal Markets." available at https://www.eia.gov/coal/markets/.

the coal supply among fewer companies means less competition, which in turn can lead to higher coal prices.[88]

Q How is the role of coal units such as Mitchell 2 changing as the electric grid shifts towards renewables?

A Rising levels of renewables and other zero-marginal cost and low-operating cost resources are pushing coal units such as Mitchell 2 out of the baseload role for which they were designed and into load-following roles that they are poorly suited to fill. Historical generation data for the unit shows its capacity factor decreasing from 60 percent in 2016 to only 34 percent in 2025 (Figure 3).

Figure 3. Mitchell 2 historical capacity factor



Source: U.S. Energy Information Administration, Form 923 data, 2016–2025 releases.

In addition to signaling the declining economics of coal units, a declining capacity factor can negatively impact unit reliability. A 2024 analysis by the North

[88] Duke Energy. "Coal Retirement Analysis," available at https://www.duke-energy.com/-/media/pdfs/our-company/carolinas-resource-plan/appendix-f-coal-retirement-study.pdf?rev=4c1c4df441a14248b2e23ba0368d9855.

American Electric Reliability Corporation ("NERC") found that coal units' equivalent forced outage rates tend to increase as their capacity factors decrease, especially once the capacity factor drops below 60 percent.[89] This effect is partially driven by increased forced outage hours, but NERC finds that it is also a result of increased time spent in planned and maintenance outages, leading to decreased service hours.[90] Both of these factors (increased forced outage hours and decreased service hours) are likely driven by the same cause: coal units that operate at low capacity factors are acting as load-following resources, which requires more cycling than these units were designed to withstand. Cycling (ramping up and down and startup/shutdown) causes physical damage to coal units through several mechanisms, including thermal fatigue, thermal expansion, corrosion-related issues, fireside corrosion, and rotor bore cracking.[91]

Q How would retiring and replacing Mitchell 2 mitigate the risks outlined above?

A A new generation resource built to replace Mitchell 2 would reduce the risks outlined above. In its existing analysis for this docket, Kentucky Power considered replacing Mitchell 2 with a gas CC unit. This presents one viable

[89] North American Electric Reliability Corporation, *2024 State of Reliability: Technical Assessment of 2023 Bulk Power System Performance* (June 2024), available at https://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/NERC_SOR_2024_Technical_Assessment.pdf.

[90] *Id*.

[91] Hesler, S. 2011. "Mitigating the Effects of Flexible Operation on Coal-Fired Power Plants." *POWER*, available at https://www.powermag.com/mitigating-the-effects-of-flexible-operation-on-coal-fired-power-plants/.

option, but Kentucky Power should also consider the full range of available replacement resources, including solar paired with battery storage or a gas CT.

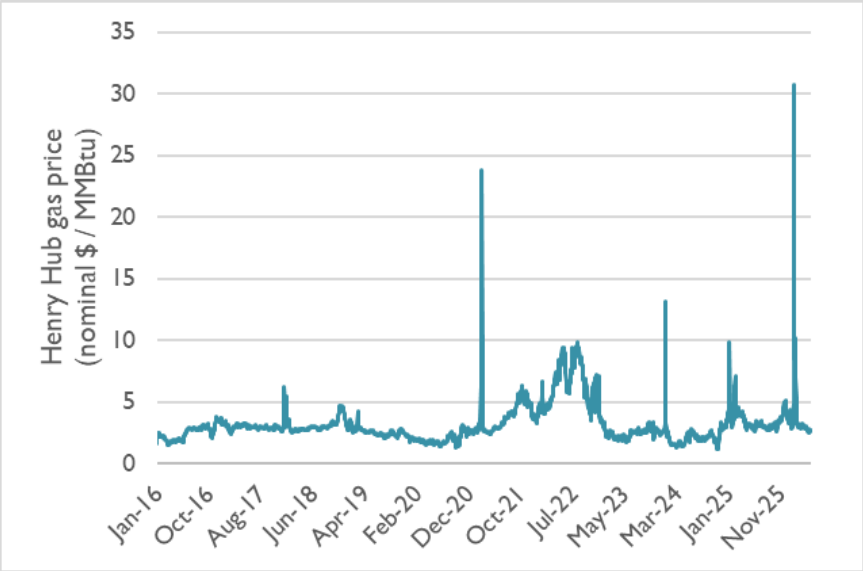
Building battery storage and renewables would lower the risk of future environmental compliance costs compared to continued operation of Mitchell 2. Replacement resources would also be more flexible, making them more compatible with future renewable integration and helping to ensure continued reliability of Kentucky Power's system as the mix of resources on the grid changes.

Gas CC plants come with risks of their own. As with coal plants, a gas CC plant is a capital-intensive asset that will lock in ratepayer funds over the 35-year lifetime of the plant.[92] High demand for gas turbines across the country has meant that new resource prices are currently elevated, and equipment lead-times are long.[93] The Company would also need to secure firm gas supply for a new CC plant, which adds fixed costs over the life of the resource. Finally, CC plants expose ratepayers to gas price volatility (Figure 4).

[92] Kentucky Power Response to Sierra Club Data Request No. 1-14.

[93] GridLab, Energy Futures Group, and Halcyon, *The New Reality of Power Generation: An Analysis of Increasing Gas Turbine Costs in the U.S.* (Sept. 2025), available at https://gridlab.org/gas-turbine-cost-report/.

Figure 4. Historical Henry Hub natural gas price (nominal $ / MMBtu)



Source: U.S. Energy Information Administration. 2026. "Henry Hub Natural Gas Spot Price." Available at: https://www.eia.gov/dnav/ng/hist/rngwhhdD.htm.

While these risks merit serious consideration, continuing to rely on Mitchell 2 poses major cost and reliability risks of its own. In these circumstances, retiring and replacing the unit would likely be beneficial to ratepayers. Completing capacity expansion and production cost modeling, as I recommend above, will help illustrate the tradeoffs of different replacement portfolios for the unit and allow the Commission and the Company itself to make an informed decision.

Q In summary, what are the recommendations in your testimony?

A In my testimony, I find that Kentucky Power has failed to meet industry standards because it did not appropriately compare the proposed Mitchell Cooling Tower Project to alternatives. Therefore, it has not demonstrated that constructing a mechanical draft cooling tower at Mitchell 2 is in the best interest of ratepayers. I recommend that the Commission deny the Company's request for a CPCN at this time and instruct Kentucky Power to provide industry-standard capacity

expansion and production cost modeling to support this and all future requests to build new resources or invest in existing resources. The capacity expansion and production cost portfolio analysis should include all avoidable, forward-going costs for both existing and new resources.

Q Does this conclude your testimony?

A Yes.

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Electronic Application of Kentucky Power Company For 1) A Certificate of Public Convenience and Necessity to Construct a Mechanical Draft Cooling Tower at the Mitchell Plant, 2) Approval of Certain Regulatory And Accounting Treatments, and 3) All Other Required Approvals and Relief	)	**Case No. 2026-00001**

AFFIDAVIT OF LUCY METZ
FOR DIRECT TESTIMONY
ON BEHALF OF SIERRA CLUB

State of Massachusetts)
)

Lucy Metz
Luzy Metz

SUBSCRIBED, ACKNOWLEDGED, AND SWORN to before me by Lucy Metz this 15th day of May, 2026.

Mark A. Orent
Notary Public

Notary ID No.: _____

My Commission expires: 1-6-2028

MARK A. ORENT
Notary Public, Commonwealth of Massachusetts
My Commission Expires January 6, 2028

ESSEX County

Exhibit LM-1

Resume of Lucy Metz

Lucy Metz, Senior Associate

Synapse Energy Economics I 485 Massachusetts Avenue, Suite 3 I Cambridge, MA 02139
lmetz@synapse-energy.com

PROFESSIONAL EXPERIENCE

Synapse Energy Economics Inc., Cambridge, MA. *Senior Associate* Apr. 2025–Present*; Associate* Apr. 2023–Apr. 2025; *Research Associate,* Jul. 2022–Apr. 2023

- Provides expert research, analysis, and deliverables on energy-sector issues, including electric utility resource planning and power plant economics, building decarbonization, industrial sector emissions, and state and local climate policy
- Develops testimony and comments in integrated resource planning dockets, rate cases, certificates of need, and environmental compliance investment dockets across the country
- Conducts analysis using Synapse's Building Decarbonization Calculator (BDC), a stock turnover model that calculates the emissions and energy impacts of heat pump adoption
- Produces data visualization tools in R, including interactive webtool of U.S. industrial emitters
- Assists with power sector dispatch modeling using EnCompass

Laboratory of Dr. Alexander Barron, Department of Environmental Science and Policy, Smith College, Northampton, MA. *Research Assistant*, Jun. 2020–May 2022

- Co-authored paper on carbon neutrality initiatives in higher education
- Designed data visualization and analysis for USREP-ReEDS modeling of Clean Air Act policy
- Calculated CO_2 emissions reductions achievable under Massachusetts climate legislation and drafted white paper with results

Co-Equal, Washington, D.C. *Policy Intern*, Feb. 2021–Mar. 2022

- Performed analysis on a wide range of policy topics requested by members of Congress
- Finalized economic modeling study for public release and presented results

EDUCATION

Smith College, Northampton, MA
Bachelor of Science in Engineering Science, *Magna Cum Laude with Highest Honors*, 2022

SKILLS

Computer: Excel, R, EnCompass, MATLAB, Mathematica, ENERGY STAR Portfolio Manager
Languages: Spanish (proficient)

TESTIMONY

Public Service Commission of South Carolina (Docket No. 2025-323-E): Surrebuttal testimony of Lucy Metz in the matter of the Joint Application of South Carolina Public Service Authority and Dominion Energy South Carolina, Inc. for a Certificate of Environmental Compatibility and Public Convenience and Necessity for the Construction and Operation of an Advanced Class Combined Cycle Generating Plant and Associated Facilities in Colleton County, South Carolina. On behalf of the Sierra Club. Mar. 17, 2026.

Public Service Commission of South Carolina (Docket No. 2025-323-E): Direct testimony of Lucy Metz in the matter of the Joint Application of South Carolina Public Service Authority and Dominion Energy South Carolina, Inc. for a Certificate of Environmental Compatibility and Public Convenience and Necessity for the Construction and Operation of an Advanced Class Combined Cycle Generating Plant and Associated Facilities in Colleton County, South Carolina. On behalf of the Sierra Club. Feb. 17, 2026.

Georgia Public Service Commission (Docket Nos. 56298 and 56310): Direct testimony of Lucy Metz in the matter of Georgia Power Company's Application for Certification of the 2029–2031 All-Source Capacity RFP and Georgia Power Company's Application for the Certification of Supplemental Resources for 2028–2031 Capacity. On behalf of the Sierra Club and the Southern Alliance for Clean Energy (SACE). Nov. 12, 2025.

North Carolina Utilities Commission (Docket Nos. E-2, Sub 1349 and EC-67, Sub 57): Direct testimony of Lucy Metz in the matter of the Joint Application of Duke Energy Progress, LLC, and North Carolina Electric Membership Corporation for a Certificate of Public Convenience and Necessity to Construct a 1,360 MW Natural Gas-Fired Combined Cycle Electric Generating Facility in Person County, North Carolina. On behalf of the Southern Alliance for Clean Energy (SACE). Jun. 9, 2025.

Kansas Corporation Commission (Docket No. 25-EKCE-207-PRE): Settlement testimony of Lucy Metz in Support of Unanimous Partial Settlement on Solar Facility and Testimony in Opposition to Non-Unanimous Partial Settlement on Natural Gas Facilities. On behalf of Citizens' Utility Ratepayer Board (CURB). Apr. 17, 2025.

Kansas Corporation Commission (Docket No. 25-EKCE-207-PRE): Direct testimony of Lucy Metz in the matter of the Petition of Evergy Kansas Central, Inc., Evergy Kansas South, Inc., and Evergy Metro, Inc. for Determination of the Ratemaking Principles and Treatment that Will Apply to the Recovery in Rates of the Costs to Be Incurred for Certain Electric Generation Facilities under K.S.A. 66-1239. On behalf of Citizens' Utility Ratepayer Board (CURB). Mar. 14, 2025.

Public Service Commission of Wisconsin (Docket No. 6690-UR-128): Surrebuttal testimony of Lucy Metz in the matter of the Application of Wisconsin Public Service Corporation for Authority to Adjust Electric and Natural Gas Rates. On behalf of Sierra Club. Sept. 18, 2024.

Public Service Commission of Wisconsin (Docket No. 6690-UR-128): Direct testimony of Lucy Metz in the matter of the Application of Wisconsin Public Service Corporation for Authority to Adjust Electric and Natural Gas Rates. On behalf of Sierra Club. Aug. 19, 2024.

Georgia Public Service Commission (Docket No. 55378): Direct Testimony of Devi Glick and Lucy Metz in re: Georgia Power Company's 2023 Integrated Resource Plan Update. On behalf of Sierra Club. Feb. 15, 2024.

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