COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF EAST	)	
KENTUCKY POWER COOPERATIVE,	)	
INC. FOR 1) CERTIFICATES OF PUBLIC	)	**CASE NO.**
CONVENIENCE AND NECESSITY	)	**2024-00370**
TO CONSTRUCT GENERATION	)	
RESOURCES; 2) FOR A SITE COMPATIBILITY	)	
CERTIFICATE RELATING TO THE SAME;	)	
3) APPROVAL OF DEMAND SIDE MANAGEMENT	)	
TARIFFS; AND 4) OTHER GENERAL RELIEF	)	

RESPONSES TO STAFF'S FIRST INFORMATION REQUEST

TO EAST KENTUCKY POWER COOPERATIVE, INC.

DATED DECEMBER 20, 2024

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF EAST KENTUCKY POWER COOPERATIVE, INC. FOR 1) CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY TO CONSTRUCT GENERATION RESOURCES; 2) FOR A SITE COMPATIBILITY CERTIFICATE RELATING TO THE SAME; 3) APPROVAL OF DEMAND SIDE MANAGEMENT TARIFFS; AND 4) OTHER GENERAL RELIEF	)	**CASE NO. 2024-00370**

CERTIFICATE

STATE OF KENTUCKY)
)
COUNTY OF CLARK)

Darrin Adams, being duly sworn, states that he has supervised the preparation of the responses of East Kentucky Power Cooperative, Inc. to the Commission Staff's First Information Request in the above-referenced case dated December 20, 2024, and that the matters and things set forth therein are true and accurate to the best of his knowledge, information and belief, formed after reasonable inquiry.

Darrin Adams

____

Subscribed and sworn before me on this 2nd day of January, 2025.

Gwyn M. Willoughby
Notary Public

GWYN M. WILLOUGHBY
Notary Public
Commonwealth of Kentucky
Commission Number KYNP38003
My Commission Expires Nov 30, 2025

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF EAST KENTUCKY POWER COOPERATIVE, INC. FOR 1) CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY TO CONSTRUCT GENERATION RESOURCES; 2) FOR A SITE COMPATIBILITY CERTIFICATE RELATING TO THE SAME; 3) APPROVAL OF DEMAND SIDE MANAGEMENT TARIFFS; AND 4) OTHER GENERAL RELIEF	)))))))))	**CASE NO. 2024-00370**

CERTIFICATE

STATE OF KENTUCKY)
)
COUNTY OF CLARK)

Denise Foster Cronin, being duly sworn, states that she has supervised the preparation of the responses of East Kentucky Power Cooperative, Inc. to the Commission Staff's First Request for Information in the above-referenced case dated December 20, 2024, and that the matters and things set forth therein are true and accurate to the best of her knowledge, information and belief, formed after reasonable inquiry.

Denise Foster Cronin

Subscribed and sworn before me on this 2nd day of January 2025.

Gwyn M. Willoughby
Notary Public

GWYN M. WILLOUGHBY
Notary Public
Commonwealth of Kentucky
Commission Number KYNP38003
My Commission Expires Nov 30, 2025

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF EAST KENTUCKY POWER COOPERATIVE, INC. FOR 1) CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY TO CONSTRUCT GENERATION RESOURCES; 2) FOR A SITE COMPATIBILITY CERTIFICATE RELATING TO THE SAME; 3) APPROVAL OF DEMAND SIDE MANAGEMENT TARIFFS; AND 4) OTHER GENERAL RELIEF	)	**CASE NO. 2024-00370**

CERTIFICATE

STATE OF KENTUCKY)
)
COUNTY OF CLARK)

Scott Drake, being duly sworn, states that he has supervised the preparation of the responses of East Kentucky Power Cooperative, Inc. to the Commission Staff's First Request for Information in the above-referenced case dated December 20, 2024, and that the matters and things set forth therein are true and accurate to the best of his knowledge, information and belief, formed after reasonable inquiry.

Scott Drake

Subscribed and sworn before me on this 2nd day of January 2025.

Notary Public

GWYN M. WILLOUGHBY
Notary Public
Commonwealth of Kentucky
Commission Number KYNP38003
My Commission Expires Nov 30, 2025

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF EAST KENTUCKY POWER COOPERATIVE, INC. FOR 1) CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY TO CONSTRUCT GENERATION RESOURCES; 2) FOR A SITE COMPATIBILITY CERTIFICATE RELATING TO THE SAME; 3) APPROVAL OF DEMAND SIDE MANAGEMENT TARIFFS; AND 4) OTHER GENERAL RELIEF	)	**CASE NO. 2024-00370**

CERTIFICATE

STATE OF KENTUCKY)
)
COUNTY OF CLARK)

Mark Horn, being duly sworn, states that he has supervised the preparation of the responses of East Kentucky Power Cooperative, Inc. to the Commission Staff's First Request for Information in the above-referenced case dated December 20, 2024, and that the matters and things set forth therein are true and accurate to the best of his knowledge, information and belief, formed after reasonable inquiry.

Mark Horn

Subscribed and sworn before me on this 2nd day of January 2025.

Gwyn M Willoughby
Notary Public

GWYN M. WILLOUGHBY
Notary Public
Commonwealth of Kentucky
Commission Number KYNP38003
My Commission Expires Nov 30, 2025

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF EAST KENTUCKY POWER COOPERATIVE, INC. FOR 1) CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY TO CONSTRUCT GENERATION RESOURCES; 2) FOR A SITE COMPATIBILITY CERTIFICATE RELATING TO THE SAME; 3) APPROVAL OF DEMAND SIDE MANAGEMENT TARIFFS; AND 4) OTHER GENERAL RELIEF	)	**CASE NO. 2024-00370**

CERTIFICATE

STATE OF KENTUCKY)
)
COUNTY OF CLARK)

Craig Johnson, being duly sworn, states that he has supervised the preparation of the responses of East Kentucky Power Cooperative, Inc. to the Commission Staff's First Request for Information in the above-referenced case dated December 20, 2024, and that the matters and things set forth therein are true and accurate to the best of his knowledge, information and belief, formed after reasonable inquiry.

Craig Johnson

Subscribed and sworn before me on this 2nd day of January 2025.

Gwyn M. Willoughby
Notary Public

GWYN M. WILLOUGHBY
Notary Public
Commonwealth of Kentucky
Commission Number KYNP38003
My Commission Expires Nov 30, 2025

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF EAST KENTUCKY POWER COOPERATIVE, INC. FOR 1) CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY TO CONSTRUCT GENERATION RESOURCES; 2) FOR A SITE COMPATIBILITY CERTIFICATE RELATING TO THE SAME; 3) APPROVAL OF DEMAND SIDE MANAGEMENT TARIFFS; AND 4) OTHER GENERAL RELIEF	)	**CASE NO. 2024-00370**

CERTIFICATE

STATE OF KENTUCKY)
)
COUNTY OF CLARK)

Thomas Stachnik, being duly sworn, states that he has supervised the preparation of the responses of East Kentucky Power Cooperative, Inc. to the Commission Staff's First Request for Information in the above-referenced case dated December 20, 2024, and that the matters and things set forth therein are true and accurate to the best of his knowledge, information and belief, formed after reasonable inquiry.

Tom J. Stachnik

____

Subscribed and sworn before me on this 2nd day of January 2025.

Gwyn M. Willoughby
Notary Public

GWYN M. WILLOUGHBY
Notary Public
Commonwealth of Kentucky
Commission Number KYNP38003
My Commission Expires Nov 30, 2025

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF EAST KENTUCKY POWER COOPERATIVE, INC. FOR 1) CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY TO CONSTRUCT GENERATION RESOURCES; 2) FOR A SITE COMPATIBILITY CERTIFICATE RELATING TO THE SAME; 3) APPROVAL OF DEMAND SIDE MANAGEMENT TARIFFS; AND 4) OTHER GENERAL RELIEF	)	**CASE NO. 2024-00370**

CERTIFICATE

STATE OF KENTUCKY)
)
COUNTY OF CLARK)

Julia J. Tucker, being duly sworn, states that she has supervised the preparation of the responses of East Kentucky Power Cooperative, Inc. to the Commission Staff's First Request for Information in the above-referenced case dated December 20, 2024, and that the matters and things set forth therein are true and accurate to the best of her knowledge, information and belief, formed after reasonable inquiry.

Julia J. Tucker

Subscribed and sworn before me on this 2nd day of January 2025.

Gwyn M. Willoughby
Notary Public

GWYN M. WILLOUGHBY
Notary Public
Commonwealth of Kentucky
Commission Number KYNP38003
My Commission Expires Nov 30, 2025

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF EAST KENTUCKY POWER COOPERATIVE, INC. FOR 1) CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY TO CONSTRUCT GENERATION RESOURCES; 2) FOR A SITE COMPATIBILITY CERTIFICATE RELATING TO THE SAME; 3) APPROVAL OF DEMAND SIDE MANAGEMENT TARIFFS; AND 4) OTHER GENERAL RELIEF	)	**CASE NO. 2024-00370**

CERTIFICATE

STATE OF KENTUCKY)
)
COUNTY OF CLARK)

Brad Young, being duly sworn, states that he has supervised the preparation of the responses of East Kentucky Power Cooperative, Inc. to the Commission Staff's First Request for Information in the above-referenced case dated December 20, 2024, and that the matters and things set forth therein are true and accurate to the best of his knowledge, information and belief, formed after reasonable inquiry.

Brad Young

Subscribed and sworn before me on this 2nd day of January 2025.

Gwyn M. Willoughby
Notary Public

GWYN M. WILLOUGHBY
Notary Public
Commonwealth of Kentucky
Commission Number KYNP38003
My Commission Expires Nov 30, 2025

EAST KENTUCKY POWER COOPERATIVE, INC.
CASE NO. 2024-00370
FIRST REQUEST FOR INFORMATION RESPONSE

STAFF'S REQUEST DATED DECEMBER 20, 2024
REQUEST 1
RESPONSIBLE PARTY: Denise Foster Cronin

Request 1. Explain whether EKPC is aware of any discussion in PJM or any other industry forums indicating plans or changes in plans regarding coal generation units as a result of potential changes to the Environmental Protection Agency (EPA) and associated regulations.

Response 1. No, EKPC is not aware of any discussion in PJM regarding potential EPA regulation changes. While the recent election results will likely delay implementation of some of the regulatory constraints imposed by the current administration, there is no guarantee that a subsequent administration would not impose similar or more-stringent regulation upon EKPC. Federal environmental policy over the past two decades has been inconsistent and often results in wild swings in policies and priorities. For a utility that must make major investments with service lives of multiple decades, the uncertainty arising from the lack of a consistent federal strategy on energy issues makes resource planning unnecessarily complex.

PJM, in fact, due to its concern that its region will not be resource adequate at the end of the decade, filed a proposal with the Federal Energy Regulatory Commission to expedite the interconnection study of 50 projects that score high in measures it has identified as contributing to addressing reliability needs. The 50 projects that best meet the criteria PJM proposed are those that: (1) will provide substantial amounts of Unforced Capacity, (2) have high reliability ratings, (3) are located in areas in which capacity is scarce and (4) can be constructed and achieve commercial operation quickly to meet PJM's near-term resource adequacy needs. Dispatchable generation should receive higher weighting under these criteria than intermittent generation.

It is prudent for EKPC to continue with all the projects it is currently seeking approval for because that will help ensure long-term stability in its energy portfolio by diversifying its fuel sources and reducing its carbon footprint now, instead of being forced to do so at a later time at the risk of even greater costs. Dispatchable generation will always be crucial to providing a reliable and stable electric system. All of the pending CPCN applications, and the New ERA CPCN application to be filed in early 2025, are part of a well-designed, comprehensive resource plan to provide the reasonable, least-cost solution for EKPC's Owner-Members. The Commission should look at the plan in total, because that is how it was assembled.

EAST KENTUCKY POWER COOPERATIVE, INC.
CASE NO. 2024-00370
FIRST REQUEST FOR INFORMATION RESPONSE

STAFF'S REQUEST DATED DECEMBER 20, 2024
REQUEST 2
RESPONSIBLE PARTY: Julia J. Tucker

Request 2. Refer to the Direct Testimony of Don Mosier (Mosier Direct Testimony) page 6, lines 21-23 and page 7, lines 1-4 referencing Winter Storms Elliot and Gerri.

a. Discuss how soon the new dispatchable thermal generation can help EKPC avoid being assessed Performance Assessment Intervals penalties (PAIs) as discussed in FERC dockets EL24-12-000 and EL23-74-000 during Winter Storm Elliot.

b. Describe the financial impacts of these PAIs on EKPC customers. Include in the response how EKPC will expense the penalties and if recovery in rates will be requested.

c. Explain if EKPC is planning to take any actions in the interim to avoid further PAIs.

Response 2.

a. New dispatchable thermal generation does not allow EKPC to directly avoid PAI penalties as those are assessed on a per-resource basis. Adding generation to the PJM system, however, improves the overall supply of capacity available for PJM to dispatch during high-load period such as Winter Storm Elliot which can help reduce capacity shortage scenarios. EKPC has the opportunity to overperform compared to its resources' capacity commitments during PAI events in order to earn bonus payments from PJM. Additional generation resources would widen the pool of available capacity to capture those bonus payments which may help offset any assessed penalties. New dispatchable generation allows EKPC to reliably serve its expected native load and not "lean" on the market during periods of high demand.

b. Penalties associated with PAI events are not directly passed onto the end-use retail member through any recovery mechanism such as the fuel adjustment clause ("FAC") or environmental surcharge ("ESC"). EKPC assumes the risk of penalties associated with PAI events, however, they ultimately effect EKPC's margins. In order to mitigate some of the risk, EKPC opts to purchase insurance products designed to compensate EKPC should a PAI event occur, up to a certain limit.

c. EKPC follows stringent maintenance practices on its units and undergoes seasonal preparedness checks on its generation resources to mitigate potential unplanned outages during peak demand periods. EKPC also maintains prudent fuel inventory to ensure supply is available during peak periods. PJM requires annual winter readiness reporting which includes reporting on EKPC's preparedness checks, fuel supply status for each generator, and cold-weather operations protocols specific to each generator where applicable.

EAST KENTUCKY POWER COOPERATIVE, INC.
CASE NO. 2024-00370
FIRST REQUEST FOR INFORMATION RESPONSE

STAFF'S REQUEST DATED DECEMBER 20, 2024
REQUEST 3
RESPONSIBLE PARTY: Julia J. Tucker and Denise Foster Cronin

Request 3. Refer to the Mosier Direct Testimony page 10, lines 10-20. On December 13, 2024, PJM submitted in Docket No. ER25-712-000 a filing to modify the tariff for its Reliability Resource Initiative (RRI).

a. Explain if EKPC plans to submit to PJM the planned Cooper Station CCGT facility or its planned Liberty RICE units as RRI projects.

b. Explain if EKPC supports PJM's effort at FERC to preserve resource adequacy such as the RRI and other related PJM tariff changes.

Response 3.

a. Yes, provided FERC approves PJM's RRI proposal, EKPC is planning to submit applications for both the Liberty RICE and Cooper CCGT to be considered RRI projects.

b. Yes, EKPC supports PJM's efforts to bring new generation capacity online as soon as possible. It is in EKPC's Owner-Members best interest for PJM to be a robust, reliable system providing economic and dependable generation and transmission resources for the entire PJM membership. Recent surveys / reports indicate that all data implies that PJM, as well as all areas of the continental United States, is facing potential generation shortfalls due to substantial load growth and significant fossil fuel generation retirements. The North American Electric Reliability Corporation ("NERC") published its 2024 Long-Term Reliability Assessment ("LTRA") on December 17, 2024. The 2024 LTRA shows a high risk of capacity and energy shortfalls in the MISO area, and elevated risk of capacity and energy shortfalls in ten other regions including PJM. Refer to attached report in PDF format, *Staff1 - 3b. NERC_Long Term Reliability Assessment_2024pdf*.

EAST KENTUCKY POWER COOPERATIVE, INC.
CASE NO. 2024-00370
FIRST REQUEST FOR INFORMATION RESPONSE

STAFF'S REQUEST DATED DECEMBER 20, 2024
REQUEST 4
RESPONSIBLE PARTY: Don Mosier

Request 4. Refer to the Mosier Direct Testimony page 15, lines 10-22 and page 16, lines 1-2.

a. Explain whether EKPC believes the incoming administration policies could impact the Greenhouse Gas (GHG) Rule that was enacted in April 2024, such as delaying it or reducing its restrictions.

b. Explain whether EKPC intends to go forward with the planned mix of new resources, described as beneficial to EKPC customers, even if GHG standards for carbon intensity are relaxed.

Response 4.

a-b. Yes, EKPC intends to go forward with the planned mix of new resources. The change of administration on January 20, 2025, does not affect this CPCN proposal in any way. EKPC believes that reducing its greenhouse gas emissions long term remains the best strategy to protect its Owner-Members from the current Greenhouse Gas Rule and any future greenhouse gas (GHG) regulations requiring emission reductions. EKPC is committed to reducing its greenhouse gas emissions, as published in its Sustainability Plan, by 35% by 2035.

EAST KENTUCKY POWER COOPERATIVE, INC.
CASE NO. 2024-00370
FIRST REQUEST FOR INFORMATION RESPONSE

STAFF'S REQUEST DATED DECEMBER 20, 2024
REQUEST 5
RESPONSIBLE PARTY: Julia J. Tucker

Request 5. Refer to the Direct Testimony of Julia J. Tucker (Tucker Direct Testimony) page 17, lines 19-22 and Exhibit JJT-4. The Tucker Direct Testimony refers to a short term 350 MW hydro Power Purchase Agreement (PPA) ending in 2025 but containing an option to extend for a longer period of time. Exhibit JJT-4 shows hydro PPA capacity additions of 9 MW in summer 2025 (extending to 2034) and 300 MW in winter 2026 (extending to 2035). In addition, there are seasonal capacity purchases in both summer and winter extending 2025-2030.

a. Explain whether the hydro capacity additions of 9 MW and 300 MW are related to the hydro capacity purchase referenced in the Tucker Direct Testimony. If so, explain how they are related.

b. Explain whether the seasonal capacity purchases over the 2025-2030 forecast period are reliant upon the hydro capacity purchase referenced in the Tucker Direct Testimony.

Response 5.

a. EKPC is currently contracted with Brookfield Hydro Resources ("Brookfield") to purchase energy from the Safe Harbor hydroelectric facility. The current agreement began

December 28, 2023 and ends May 31, 2025. The current agreement extension with Brookfield represents one portion of the 300 MW referenced in the 2026 winter period, which is planned to extend to 2035. The second portion of the 300 MW is a potential purchased power agreement ("PPA") with another hydroelectric dam that would begin July 1, 2025 and extend to 2035, and would include energy, PJM capacity rights, and renewable energy credits as a bundled product. The 9 MW of capacity addition noted in the summer of 2025 is the capacity obligated from this hydro facility into the PJM capacity market. Neither the Brookfield agreement extension nor second hydro PPA have been finalized at this time. The 300 MW shown in Attachment JJT-4 represents the expected peak energy between the two PPAs, however the final quantity could be between 250 MWs and 330 MWs once negotiations are finalized. EKPC plans to bring these long-term PPAs before the Commission early in 2025 for review and approval prior to final commitment.

b. Yes, the seasonal peak energy purchases referenced in the testimony and in Attachment JJT-4 are reliant on the hydro PPAs. Should EKPC not purchase one or both hydro PPAs, it will seek to hedge its native load through other shorter-term PPA arrangements on a seasonal basis for the amount of planned seasonal peak load over its expected available generation. The lower the PPA peak energy quantity, then the higher that native load exposure and expected seasonal purchase. EKPC evaluates both seasonal and weekly hedge opportunities as normal course of business. The hydro PPAs in question provide expected energy at known prices that reduce the quantity of energy needed when assessing those seasonal and weekly hedges.

EAST KENTUCKY POWER COOPERATIVE, INC.
CASE NO. 2024-00370
FIRST REQUEST FOR INFORMATION RESPONSE

STAFF'S REQUEST DATED DECEMBER 20, 2024
REQUEST 6
RESPONSIBLE PARTY: Julia J. Tucker

Request 6. Refer to the Tucker Direct Testimony, page 9, lines 3-8.

a. Explain if EKPC is expecting any data centers or facilities presenting artificial intelligence computing loads to be located within its service territory between now and 2030. If so, and if possible, provide the anticipated load impact(s) as well as the Company names. If so, explain how EKPC has come to expect those new facilities to be located within the territory. If not, please explain why not.

b. Confirm whether the 2024 load forecast includes any projected loads for data centers.

c. If not answered in part a or b above, please summarize any discussions or communications that EKPC has had within any industries, economic development representatives, local officials, or rural cooperative members regarding the location of any data centers or artificial intelligence computing loads to potentially be located within its service territory in the next five years.

Response 6.

a. EKPC has had discussions with potential large data center loads about locating within its owner members' service territory. All parties are under Non-Disclosure Agreement restrictions at this time. No firm plans have been developed or finalized, but discussions are on-going. Initial contact from these parties was initiated through EKPC's Economic Development group. EKPC is in the process of developing a tariff for such loads that will define methods for service and cost recovery methodology. It is EKPC's intention that all costs and risks will be borne by the large load.

b. Confirmed, the 2024 long-term load forecast ("LTLF") discussed in this application does not include any projected loads for data centers.

c. See Response 6a.

EAST KENTUCKY POWER COOPERATIVE, INC.
CASE NO. 2024-00370
FIRST REQUEST FOR INFORMATION RESPONSE

STAFF'S REQUEST DATED DECEMBER 20, 2024
REQUEST 7
RESPONSIBLE PARTY: Julia J. Tucker

Request 7. Refer to the Tucker Direct Testimony, Exhibit JJT-4.

a. Provide a table showing each potential resource's cost and operating characteristics made available to EKPC's resource selection and production cost models. Include in the response all annual and seasonal PPAs.

b. Explain EKPC's modeling assumptions which determined the degree of flexibility the production cost/portfolio selection model was given to decide the timing of unit retirements and additions (including PPAs).

c. Explain EKPC's modeling assumptions for whether there were any costs related to transmission constraints or transmission upgrades.

d. Explain the modeling assumptions for constraints on PPAs inside and outside EKPC's load zone, and whether any costs regarding supplying natural gas to the Cooper Station for the natural gas combined cycle (NGCC) and co-firing Cooper Unit 2 was included in the modeling.

e. If there are any required transmission upgrades connected with the addition of the natural gas combined cycle (NGCC) or any other generation, explain whether the requisite study requests have been submitted to PJM and if so, the projected time table for study completion.

f. Provide a table showing the resource portfolios that were least cost or reasonable least cost from which EKPC selected the resource portfolio identified and represented in Exhibit JJT-4.

Response 7.

a-b. EKPC provided a list of options that it considered in its long-term optimization modeling in the 2022 Integrated Resource Plan. That optimization did not show resources required beyond solar and a combustion turbine generation. Those needs have been addressed in other CPCN cases recently filed at the Commission. Since that optimization run was completed, EKPC has experienced two severe winter storms in December 2022 and January 2024, and updated its load forecast to reflect those experiences.

EKPC has multiple planning objectives which have increased in complexity and risk exposure in recent years. EKPC's first and most critical objective is to serve its Owner-Members in a reliable and economic manner. EKPC's load is winter peaking due to high concentration of electric heat in its service territory. Therefore, EKPC must ensure that it has adequate reliable supply to meet its winter peak load demand. When EKPC first entered PJM, it appeared that PJM had more than adequate winter supply for EKPC to reliably serve its load. However, severe winter storms such as the Polar Vortex in 2014, Winter Storm Elliot in 2022 and Geri in 2024 have proven that PJM is not flush with reliable, dependable winter generation resources. EKPC cannot depend on the market to provide its needed generation for winter storms. Therefore, EKPC must plan on dependable, economic generation that can adequately supply its load.

As a PJM participant, EKPC sells all of its generation into the market and buys all of its load from the market. EKPC must hedge its exposure to market price volatility to ensure economic supply for its Owner-Members. By selling at least as much as it buys from the market, EKPC ensures the cost that is borne by the Owner-Members is capped at the cost of EKPC's generation resources. A second objective is to compare the expected amount of load that EKPC will buy from the market to the expected amount of generation that EKPC will sell into the market. This involves projecting the summer capacity requirement that PJM will assign to EKPC in its Base Residual Auction ("BRA") and comparing that to the net amount of generation that EKPC will sell into the BRA. The net amount of generation is adjusted from nameplate capacity to Effective Load Carrying Capacity ("ELCC"). ELCC values are determined by PJM and past operating performance of individual resources. The BRA prices have varied drastically over the past few years, making it imperative that EKPC ensure that it has more than adequate supply to cover its market price exposure. The ELCC values are used only in the BRA, which only considers summer capacity values at this time. ELCC values do not currently apply to winter operating capacity.

The third objective is to determine what type of generation will best meet the expected needs of the system overall. Recent experience shows that EKPC is buying 30-40% of its energy from the market on an on-going basis. The average price for those purchases is higher than the variable operating cost of the Spurlock coal generation resources and less than the cost to operate a combustion turbine. So, when considering the next resource, it would appear that a generator that could hedge the upper price of these purchases would be prudent. A combined cycle generator fits this profile and was chosen as the preferred resource due to needing additional capacity, needing to secure the BRA position and needing to hedge the upper price that could be incurred on the significant amount of market purchases that EKPC was incurring.

An optimization run was not specifically completed to consider new generation and retirements of existing units. EKPC will not consider retiring existing coal until it becomes mandatory based on costs and operating limitations. The existing units have provided reliable, economic service to the Owner-Members and will continue in operation as long as it is feasible. However, it is apparent that at some point in the foreseeable future Cooper Station will reach the end of its useful life even though that date is not currently projected. It is strategically prudent to ensure that the service provided by that plant be replaced with generation that is as dependable and economic, or even more so, than the existing facility. The only currently demonstrated technology that meets these requirements is a combined cycle plant. New nuclear is not currently financially feasible for a system such as EKPC's. New coal is no longer a viable option based on environmental requirements. Solar or wind require storage options to be comparable to a dispatchable unit, and current battery technologies do not support the financial or operational characteristics to compare favorably to other alternatives. A natural gas generator is the most feasible alternative. Combined cycle is more efficient with a better heat rate as compared to a simple cycle combustion turbine. Given the amount of energy being purchased from the market and the future retirement of a coal generation facility, EKPC's energy needs support a combined cycle generator as opposed to simple cycle. The comparison of specific combined cycle units is discussed in EKPC's response to the Attorney General's First Request for Information Item 10.

In addition to the above demonstration of capacity and energy needs, the new GHG rules place stringent CO2 requirements upon existing coal-fired resources that would force them to close by 2032, co-fire with natural gas through 2039, or install carbon capture and sequestration ("CCS"). Given the combination of increased demand expectations and the GHG rules, EKPC is in need of dispatchable base-load capacity and energy resources that meet these needs. Prematurely retiring the existing coal-fired fleet would leave end-use retail members with the burden of stranded assets in addition to the cost of building replacement capacity. The cost to install CCS at Spurlock alone is estimated to be over $10 billion, and given the geology of the Spurlock site, would require the carbon to be delivered to storage fields outside Kentucky making the project not only financially, but also physically infeasible. The least-cost, quickest, and most reliable solution for EKPC's current coal-fired fleet is to co-fire with natural gas. This allows for 1,560 MW of reliable base-load capacity and energy to be available through 2039.

Even with the co-fire projects, EKPC is still projected to need additional base-load resources to meet its native load and reserve requirement. The natural gas infrastructure needed to support the co-fire projects allows for both the Cooper and Spurlock sites to be well situated for future expansion, such as the Cooper CCGT project. This project provides low-cost dependable energy in an area of the system that needs generation support. EKPC considered other base-load options, such as small modular nuclear reactors ("SMR"), however the technology is still new and untested. The National Renewable Energy Lab ("NREL") annual technology baseline ("ATB") shows that SMR capital costs are anywhere from $6,416/kW to $12,681/kW. That means an SMR of equivalent size (745 MW) to the proposed Cooper CCGT would cost $4.77 billion at a minimum but could exceed $9.44 billion according to NREL. EKPC and its Owner-Members cannot incur the risk associated with being "first to market" with these types of resources. The proposed Cooper CCGT utilizes known and tested technology in using the F-class combustion turbine. Support and parts for these units from both the original equipment manufacturer and aftermarket specialists are widely available. The proposed Cooper CCGT is the most economical solution to provide dispatchable, reliable and competitive energy and capacity to meet the needs of EKPC and its Owner-Members.

c. Neither transmission constraints nor related upgrade costs were explicit in the generation modeling. Transmission congestion costs were included implicitly as a component of forecasted location marginal price ("LMP").

d. Constraints impacting the PPAs were not explicit in the generation modeling. Transmission congestion costs were included implicitly as a component of forecasted LMP. Natural gas prices to supply the Cooper CCGT, representing natural gas commodity plus variable pipeline transportation costs, were included in the cost assumptions within the model. EKPC would only choose to depend on long term PPAs that were supported with physical assets, not financial instruments. Given the locational impacts during severe winter storms, EKPC would far prefer that any PPA be from a physical asset that is located in or very near its service area. This would help lower the risk of requiring rolling blackouts by having generation resources near the load center. EKPC is not currently aware of any long term PPAs that are available from generation located near or within its service area.

e. Please refer to Exhibit 6 (Direct Testimony of Darrin Adams) to the Application, page 10, line 3 through page 11, line 6. As explained there, EKPC has filed an application with PJM for interconnection of the Cooper CCGT facility in order to enter PJM's Cluster Cycle #1, which is expected to commence in the second quarter of 2026 and finish in the fourth quarter of 2027. However, PJM has recently announced its intention to expedite interconnection of a limited number of high-reliability generation resources (termed Reliability Resource Initiative, "RRI") to address concerns about insufficient supply to meet growing electric demand in the short-term. EKPC intends to submit its application for the Cooper CCGT interconnection for selection in this RRI process when the application window opens, which is expected to be in the first quarter of 2025. Projects selected by PJM would be studied as part of the Transition Cycle #2 cluster, which is expected to begin in the second quarter of 2025 and continue through the third quarter of 2026.

f. Refer to Item 7a, above.

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REQUEST 8
RESPONSIBLE PARTY: Julia J. Tucker

Request 8. Refer to the Tucker Direct Testimony, Exhibit JJT-4. Refer also to the Application, page 13, paragraph 29, which indicates that the proposed NGCC unit will serve as a replacement for Cooper 1 Unit by 2031.

a. Explain the causes for the modeled decrease in existing capacity occurring in 2026 and in 2030.

b. Explain whether the seasonal capacity purchases are modeled as separate bilateral contracts or being purchased through the Base Residual Auction (BRA). Include in the response the purchase prices, how they were derived and whether there are any limits on the amount of capacity purchases that can come from outside EKPC's load zone.

Response 8.

a. The 300 MW decrease in 2026 is due to the expiration of the existing short-term PPA with Safe Harbor Hydro ending on December 31, 2025, sold by Brookfield Hydro Resources ("Brookfield"). This PPA is to be replaced with a long-term PPA on another hydro resource sold by Brookfield, Holtwood, starting January 1, 2026. The 127 MW decrease in 2030 is the combination of three changes that occur between the 2029 and 2030 planning years.

One, the conversion of Spurlock 2 from coal to natural-gas co-fire results in the loss of 2 MW of capacity. Two, the conversion of Cooper 2 from coal to natural-gas co-fire results in the loss of 9 MW of capacity. Three, Cooper 1 is expected to be placed into an “emergency” status, accounting for the loss of 116 MW of capacity. The unit could be available for “emergency” purposes only and thus was not included in the total existing capacity after 2029. These three changes account for the 127 MW of total capacity reduction between 2029 and 2030.

b. Seasonal capacity purchases, while labeled capacity, are actually energy-only purchases that are made to hedge forecasted peak native load. These purchases would not be made in the BRA, but rather on the bi-lateral market with a counterparty delivering energy from an asset-backed resource into the PJM energy market. The quantities listed for seasonal purchases in Attachment JJT-4 are estimates based on forecasted peak load plus reserve margin as compared to expected available generation. No agreements have been entered into at this time to meet any of the seasonal purchases listed in JJT-4. These quantities represent the potential exposure by not owning or contracting for reliable and competitively-priced assets.

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STAFF'S REQUEST DATED DECEMBER 20, 2024
REQUEST 9
RESPONSIBLE PARTY: Julia J. Tucker

<u>Request 9.</u> Refer to the Tucker Direct Testimony page 13, lines 10-14 and page 14, lines 1-22.

a. Explain why the reserve margin is 7 percent.

b. Explain in detail how the 7 percent margin was developed.

c. Explain how PJM's required planning reserve requirement compares to EKPC's 7 percent summer and winter Capacity Planning Reserve Margin and whether the 7 percent is in addition to PJM reserve margin requirements.

d. The current expansion plan does not include the addition of a large load. In the event that a data center that requires hundreds of MWs but will bring very few jobs commits to locate within EKPC service territory, explain how EKPC would accommodate the load and whether the cost to accommodate the data center would be socialized across EKPC's other retail customers.

<u>Response 9.</u>

a and b. EKPC quantified its reserve margin by analyzing the 1 in 10 probability of extreme weather events on the EKPC load forecast by modeling an extreme weather event occurring every two years for a 48-hour period within each of those two-year periods. EKPC's load forecast assumes normal winter peak producing temperature of -2°F. The normal assumption for the hourly load shape on the winter peak day is based on EKPC's typical winter load shape with a morning peak followed by a valley and a late afternoon peak. The extreme event used in this analysis assumes -13°F as the peak producing temperature every two years. Rather than a typical winter peak day hourly shape, the event assumes a 48-hour event with a shape similar to Winter Storm Elliott where load reached peak levels for an extended period of time. This resulted in an increase to the forecasted peak load of 7% over the base forecast, which represents the target for capacity planning.

c. PJM quantifies its reserve margin using the Installed Reserve Margin ("IRM") methodology. According to PJM Manual 20:

> "[IRM] is the installed capacity percent above the forecasted peak load required to satisfy a Loss of Load Expectation (LOLE) of, on average, 1 Day / 10 Years. For a given delivery year, IRM is one of the two primary inputs needed for calculating the Forecast Pool Requirement (FPR)."[1]

PJM issued its 2023 Reserve Requirement Study ("RRS") on December 29, 2023[2], which recommended the following IRM values for 2024 through 2028:

Table I-1: 2023 Reserve Requirement Study Summary Table

RRS Year	Delivery Year Period	Recommended IRM	Average EFORd	Recommended FPR
2023	2024 / 2025	**17.7%**	5.10%	**1.1170**
2023	2025 / 2026	**17.7%**	5.09%	**1.1171**
2023	2026 / 2027	**17.7%**	5.08%	**1.1172**
2023	2027 / 2028	**17.6%**	5.06%	**1.1165**

These values represent an increase of approximately 3% over the recommended IRM from the previous year's 2022 RRS. PJM cited the increase in IRM is due to the increased loss of load expectation ("LOLE") experienced during Winter Storm Elliot ("WSE") and the 2014 Polar Vortex event.

The EKPC planning reserve margin of 7% is not in addition to the PJM planning reserve margin.

d. EKPC would explore all options to reliably serve the load as it has an obligation to do so in accordance with Kentucky law. However, EKPC may initially contract with a reliable generation-backed resource through a Purchased Power Agreement ("PPA") to supply both energy and capacity for the load. A longer-term solution may involve building dedicated assets. Whatever mix of supply is chosen, the risk associated with securing the supply must be borne by the load and not the balance of EKPC's membership. EKPC intends to file a tariff applicable to data centers in 2025 that will encourage economic development while minimizing any negative impacts to existing Owner-Members – all while meeting EKPC's obligation to serve.

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STAFF'S REQUEST DATED DECEMBER 20, 2024
REQUEST 10
RESPONSIBLE PARTY: Julia J. Tucker

Request 10. Refer to the Tucker Direct Testimony, page 15, lines 2-4.

a. Provide the rationale for increasing the reserve margin to three percent.

b. Explain why the original margin was three percent and the reason for the increase to seven percent.

Response 10.

a. The reserve margin used in the 2022 IRP was three percent. It has been increased to seven percent.

b. Refer to Item 9 a and b, above, for explanation of why the seven percent reserve margin was selected.

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REQUEST 11

RESPONSIBLE PARTY: Julia J. Tucker

<u>Request 11.</u> Refer to the Tucker Direct Testimony page 17, lines 15-16, page 19, lines 2-4, page 20, lines 12-16, page 22, lines 12-16, and Exhibit JJT-4.

a. Provide the status of the negotiations regarding the long-term hydro energy only contract and the expected effective date.

b. Explain whether there is any relationship between the long term hydro PPA in 2026 and the 300 MW winter 9 MW summer hydro capacity PPA in Exhibit JJT-4. Include in the response whether the supplier of the hydro energy only PPA is the same forecasted supplier of the hydro capacity shown in Exhibit JJT-4.

c. The 9 MW hydro capacity comes online in 2025 and the 300 MW hydro capacity comes online in 2026. Explain whether this is from the same supplier and if not included in this proceeding, when a CPCN will be filed with the Commission to enter into the contract agreement.

Response 11.

a. EKPC is in the final stages of negotiation and contract review with Brookfield regarding the Holtwood hydro facility. EKPC plans to bring this PPA before the Commission early in 2025 for review and approval prior to final commitment.

b. Yes, the peak energy produced from both hydro PPAs, the Brookfield PPA and the second PPA in the early stages of negotiation, sum to the 300 MW listed for the winter period in JJT-4. The 9 MW of summer capacity is listed only as a financial capacity position and represents the amount of capacity that EKPC expects can be sold into the PJM capacity market from this resource. Refer to response 5a and 5b, above.

c. The existing Brookfield contract on Safe Harbor dam is expected to be extended on a short-term basis from June 1, 2025 through December 31, 2025, with a second short-term agreement beginning January 1, 2026 and extending through December 31, 2027. EKPC intends to bring a long-term PPA with effective dates from January 1, 2028 through May 31, 2035 to the Commission for approval in early 2025. The second PPA, represented by the 9 MW of capacity in the summer period, would be effective July 1, 2025 and extend through May 31, 2034. EKPC would bring this PPA before the Commission for approval in early 2025.

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STAFF'S REQUEST DATED DECEMBER 20, 2024
REQUEST 12
RESPONSIBLE PARTY: Julia J. Tucker

Request 12. Refer to the Tucker Direct Testimony page 18, lines 11-12 and Exhibit JJT-4.

a. Explain why Seasonal Purchases are excluded from the Planning Reserve calculations. Include in the response the extent to which PJM allows EKPC to include seasonal capacity purchases to count toward required planning reserve margins.

b. Explain why only the summer capacity has an effective load carrying capability (ELCC) adjusted.

c. Explain why 6 percent of the long-term load forecast (LTLF) is excluded from the summer peak.

Response 12.

a. The final 2 columns in Attachment JJT-4, Total Capacity vs. Planning Reserves (Excl Seas Pur), is the sum of all existing plus added capacity minus the Capacity Required. Seasonal Purchases are not counted towards either existing or additions to capacity. This is by design as the final two columns are intended to show whether or not EKPC is short or long on expended capacity to meet its peak load energy needs. Where a shortage is anticipated in the short-term, EKPC intends to evaluate seasonal purchases on a timely basis to ensure that the upcoming peak period is hedged appropriately. PJM capacity is only impactful for the summer period. PJM allows for EKPC to either contract for bi-lateral capacity or purchase capacity in the RPM market for the years showing a seasonal summer purchase need (2027, 2028, and 2030). EKPC will evaluate its capacity position leading into each stage of the PJM capacity market and may contract for bi-lateral capacity to reduce exposure to the market.

b. EKPC is both a load serving entity and generation owner within the PJM RPM capacity market ("capacity market"). EKPC must purchase the entirety of its load needs from the capacity. EKPC also offers its generation into the market to offset the expenses incurred by purchasing the load. The capacity market is measured on the summer peak load obligation, meaning EKPC's winter peaks are not factored into the amount of load that must be purchased from the capacity market auction. PJM measures the generator ELCC values throughout the year, including both summer and summer peak period. However, the amount of load that is purchased is based solely on the summer peak load obligation. Therefore, ELCC adjusted generation numbers are only impactful in the context of its financial capacity position, which is based on the summer period only.

c. The 2025/2026 PJM BRA represented the first capacity market clearing using the revised ELCC and load obligation calculations. The difference between EKPC's own summer peak load forecast and the PJM-calculated peak load obligation as cleared in the BRA is approximately six percent. Therefore, EKPC reduced the forecasted summer peaks by six percent to reflect the expected difference between the forecast and future actual load obligation clearings. It is an estimated value and one that can and will change with each capacity market clearing. This is one reason why EKPC intends to carry a seven percent reserve margin on its summer capacity. EKPC, in agreement with past Commission orders, does not intend to lean on the market to shore up its capacity position.

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STAFF'S REQUEST DATED DECEMBER 20, 2024
REQUEST 13
RESPONSIBLE PARTY: Julia J. Tucker

Request 13. Refer to the Tucker Direct Testimony page 19, lines 8-15. Explain how the specific environmental regulations were modeled in the resource selection and production cost / portfolio selection analyses.

Response 13. The two most impactful environmental regulations incorporated into the portfolio selection process were the Good Neighbor Plan and the Greenhouse Gas Rule ("GHG Rule"). The Good Neighbor Federal Implementation Plan ("FIP") impacts only one unit in the EKPC fleet, Cooper 1, as it does not have a Selective Catalytic Reactor ("SCR"). All other units in the EKPC fleet are expected to meet the Good Neighbor Plan FIP as it stands today. The GHG Rule is greatly more impactful to EKPC's existing coal generation fleet than the Good Neighbor Plan. The EPA GHG finalized rule allows operators of existing coal-fired power plants to elect by January 1, 2030, to choose between a "do nothing" option and retire the unit by January 1, 2032. For coal units that prefer to operate longer, they have the option to select "medium-term" that allows existing coal fired operators to elect to "co-fire coal" with 40% natural gas between January

1, 2032, until one day before January 1, 2039. For coal units that need to operate beyond January 1, 2039, they need to select adding carbon capture and sequestration.

For Spurlock EKPC proposed to comply with the GHG Rule by electing to co-fire Spurlock Units 1 through 4 by January 1, 2030. For Cooper Station, EKPC proposes to comply with the GHG rule by electing to co-fire Cooper Unit 2 on January 1, 2030. In addition, EKPC elects to propose in an air permit application to the Kentucky Division of Air Quality and EPA to build and authorize a new CCGT for Cooper Station. The impact of these decisions was included in the production cost model and capacity expansion plan as filed within this application. Under the GHG Rule EKPC would be forced to shut down its existing coal fleet without the proposed natural gas co-fire projects. The financial impact to the total energy position is shown in Attachment JJT-5.

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STAFF'S REQUEST DATED DECEMBER 20, 2024
REQUEST 14
RESPONSIBLE PARTY: Julia J. Tucker

Request 14. Refer to the Tucker Direct Testimony page 19, lines 8-13.

a. Explain how the impacts of environmental regulations were modeled in EnCompass's portfolio production cost modeling phase to arrive at its current expansion plan as shown in Exhibit JJT-4.

b. Explain whether a scenario was run where the current environmental regulations were repealed at a later date due to a changing political climate. If so, explain whether and how that may or may not affect EKCP's expansion plans.

Response 14.

a. EKPC utilized the RTSim production cost simulator, not EnCompass, to produce the production costs to support this Application. Refer to Response 13, above, regarding the environmental regulation impact on generation portfolio selection.

b. There was not a second scenario ran that contemplated the repeal of the existing regulations based upon changing political climate. A "wait and see" strategy to environmental regulations would most definitely result in greater costs to Owner-Members and enhanced compliance risk in the future. Refer to Item 1 and Items 4a and b, above.

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REQUEST 15

RESPONSIBLE PARTY: Julia J. Tucker

Request 15. Refer to the Tucker Direct Testimony page 21, lines 7-10. Explain the ELCC winter and summer rating of the combined cycle gas turbine (CCGT).

Response 15. The proposed Cooper CCGT has a winter output rating of 745 MW and a summer output rating of 725 MW. The current PJM published class ELCC rating for a Combined Cycle unit is 79%. To estimate the ELCC-adjusted rating of the Cooper CCGT, EKPC multiplied its summer output rating of 725 MW by the class ELCC rating of 79% for a total of 572.75 MW. EKPC rounded this to the nearest whole number, 573 MW, which is shown on Attachment JJT-4 under the ELCC-adjusted summer rating for the Cooper CCGT.

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STAFF'S REQUEST DATED DECEMBER 20, 2024
REQUEST 16
RESPONSIBLE PARTY: Julia J. Tucker

Request 16. Refer to the Tucker Direct Testimony page 23, lines 20-23 and page 24, lines 1-7.

a. Explain how EKPC's development of solar projects overcomes third party solar developer's project completion issues.

b. To the extent that financing is an issue, explain EKPC's advantages over project developers.

c. To the extent that supply chain is an issue, explain EKPC's advantages over project developers.

Response 16.

a. EKPC's development ensures that the entirety of the project lifecycle remains in-house. The major setback from the third-party solar developers was a firm commitment on pricing. EKPC can better control its exposure to prices by controlling the RFP process for material and labor associated with the project. In addition, any issues that may arise in the project are known immediately when EKPC has full control of the project, as opposed to a third-party running the project. This enables EKPC to react more effectively to any challenges in meeting project delivery.

b. The risk to financing is similar whether the project is run by a third party or by EKPC. EKPC is able to leverage financing from the New ERA program, which is not directly available to private developers.

c. EKPC can make the final decision as to when and how any materials needed for the projects are procured. Should an issue arise with a supplier, EKPC will know immediately and can act quickly to remediate the supply concern.

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STAFF'S REQUEST DATED DECEMBER 20, 2024
REQUEST 17
RESPONSIBLE PARTY: Julia J. Tucker

Request 17. Refer to the Tucker Direct Testimony, pages 24-25, lines 21-4.

a. Explain what PJM requires to be a reliability pricing model (RPM) entity.

b. Considering EKPC is currently projected to have a capacity deficit, explain how EKPC is currently meeting its PJM RPM requirements.

Response 17.

a. For a generation resource to participate as market seller in the PJM RPM capacity market it must be either fully integrated or contractually delivered into the PJM RTO. To do this, a resource must hold Capacity Injection Rights ("CIRs") which allows for delivery of the resource capacity into the PJM RTO based on the results of the PJM generation queue study results.

b. EKPC is currently projected to be capacity deficient only in the peak winter season. The PJM RPM capacity market is based solely on the summer peak load obligation as shown in the Direct Testimony of Julia J. Tucker, Figure 3 on page 19, lines 5-6. Refer to Response 12b above for further narrative regarding the PJM capacity market requirements.

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STAFF'S REQUEST DATED DECEMBER 20, 2024
REQUEST 18
RESPONSIBLE PARTY: Julia J. Tucker

Request 18. Refer to the Tucker Direct Testimony page 25, lines 1-12.

a. Explain why and when PJM would call the 2X1 CCGT to run as a single CT only.

b. Explain whether the separate CCGT modes were modeled separately in the EnCompass model.

c. If not addressed in the response to parts a or b above, explain how the EnCompass model treated the separate CCGT modes. Include in the response whether the EnCompass model was allowed to and did dispatch the CCGT modes separately.

Response 18.

a. Given the heat rate of a single simple cycle CT as compared to a 2x1 CCGT it is anticipated that PJM would not call for the single CT often. EKPC offers units on three different offer curves: the cost, price-PLS, and price curves. EKPC would offer the units in such a way on its price curves in such a way that PJM is less likely to clear a single CT over the CCGT configuration. The most likely scenarios that would lead to a single CT being dispatched is if the second CT was on a maintenance or forced outage or there was an emergency system condition that necessitated the dispatch of a single CT over the CCGT.

b. EKPC used the RTSim production cost simulator model for this Application. EKPC modeled only the CCGT configuration within RTSim as the model is driven by economics and there would only be non-economic scenarios which would lead to the single CT being dispatched over the CCGT, as discussed in Response 18a, above.

c. Refer to Response 18 a and b, above.

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STAFF'S REQUEST DATED DECEMBER 20, 2024

REQUEST 19

RESPONSIBLE PARTY: Julia J. Tucker

Request 19. Refer to the Tucker Direct Testimony page 26, lines 16-23, page 27, lines 1-2, and Exhibit JJT-5.

a. Explain the modeling assumptions and supporting calculations in excel spreadsheet format with all cells visible and unprotected. Include in the explanation whether the Exhibit is the product of or derived from the EnCompass model.

b. If not provided in the response to part a above, explain and provide the cost and operating characteristics of each potential resource (including PPAs) made available to the EnCompass model. Include also whether the model was allowed to retire a unit as opposed to cofiring a unit or whether cofiring was assumed to be a base assumption for the model.

Response 19.

a. EKPC utilized the RTSim production cost modeling software to analyze the dispatch of the selected resource mix for the years 2025 through 2039. Refer to attached Excel spreadsheet, *CONFIDENTIAL - INPUTS - 3MAY24.xlsx*, subject to motion for confidential treatment.

b. EKPC did not provide potential resources for the model to choose from, see Item 7a, above.

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STAFF'S REQUEST DATED DECEMBER 20, 2024
REQUEST 20
RESPONSIBLE PARTY: Julia J. Tucker

Request 20. Refer to the Tucker Direct Testimony page 26, line 12.

a. Explain in greater detail what is meant by the phrase "perilously close."

b. Provide whether EKPC had any load shedding programs in effect during this period.

c. Explain if any load shedding programs were considered or implemented after this time.

Response 20.

a. PJM issued two Post Contingency Local Load Relief Warnings ("PCLLRW") in response to system conditions in the Cooper area on December 23, 2022 during Winter Storm Elliott. One PCLLRW was for post-contingent voltage conditions in the area and other was for a post-contingent thermal limit on the EKPC Cooper to KU Elihu 161 kV tie-line. There were no switching or generation solutions to resolve the post-contingent scenario. Without the generation from Cooper supporting both the voltage and local transmission power flow, EKPC would have been required to manually shed load in the area to maintain reliable system conditions.

b. While EKPC maintains a manual load shed and rolling blackout procedure, it did not deploy any load shedding programs during the Winter Storm Elliott event.

c. EKPC has maintained a manual load shed and rolling blackout procedure prior to the Winter Storm Elliott event. The procedures did undergo a review after the event to ensure lessons learned from Winter Storm Elliott were incorporated into the procedure.

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STAFF'S REQUEST DATED DECEMBER 20, 2024

REQUEST 21

RESPONSIBLE PARTY: Julia J. Tucker

Request 21. Refer to the Tucker Direct Testimony page 26, lines 16-23, page 27, lines 1-2, and Exhibit JJT-5.

a. Explain what assumptions or restrictions were placed on the EnCompass model to create the cofiring savings for the CCGT, Cooper Unit 2 and all Spurlock station units. Include in the response whether and how assumptions differed across the analyses. As one example, forecasts of energy prices (PJM LMPs), coal, and natural gas prices the same for all CCGT, Cooper and Spurlock cofiring analyses, but capacity factors and ELCC ratings were different.

b. Within the modeling for Cooper Unit 2, explain whether the model burned 100 percent natural gas post-cofiring or whether the model could and did run the unit with some combination of coal and natural gas or fuel oil.

c. Explain how Cooper Unit 2's worth of over $117 million changes if it is not run at 100 percent natural gas.

Response 21.

a. EKPC utilized the RTSim production cost modeling software for the analysis. The assumptions for natural gas prices were consistent across the Cooper CCGT, Cooper Unit 2 Co-Fire project, and Spurlock Units 1 through 4 co-fire projects as EKPC plans to purchase natural gas from the same pipeline for all of these projects. These projects were allowed to dispatch economically into the PJM energy market using forecasted locational marginal prices ("LMP"). Each of the projects were modeled individually, including separate heat rate, variable O&M, and outage assumptions. Capacity revenues were not modeled in RTSim. However, the capacity revenue estimates for the Cooper CCGT were based on PJM's published ELCC class rating for a CCGT of 79%. Capacity revenue estimates for the Spurlock and Cooper 2 co-fire projects were based on PJM's published ELCC class rating plus each existing unit's ELCC performance adjustment. Spurlock Units 1 and 2 were rated at the PJM published ELCC class rating for coal at 84%, and each received a performance adjustment of 106%. Spurlock Units 3 and 4 were rated at the PJM published ELCC class rating for coal at 84%, and each received a performance adjustment of 107%. Cooper Unit 2 was rated at the PJM published ELCC class rating for coal at 84% and received a performance adjustment of 108%. The range of PJM BRA clearing prices used in the testimony were the 2024/2025 BRA clearing price of $28.92/MW-Day as the low and the 2025/2026 BRA clearings price of $269.92/MW-Day as the high. Capacity factors are different for each unit as they are based on the individual unit's modeled inputs versus the forward LMP. Capacity factors are not a model input, but rather a model output.

b. The model assumed Cooper 2 burn at 100% natural gas with very small amounts of fuel oil used during start-ups. The model did not allow Cooper 2 to burn any coal as it is less economical than operating on 100% natural gas.

c. EKPC did not explicitly model a scenario for Cooper 2 co-fire running on a reduced natural gas consumption. However, in its 2022 IRP, EKPC noted capacity factors for Cooper 2 on 100% coal that are approximately half those of the unit running on 100% natural gas. The total worth of the unit running on 100% coal would then be at least half of the $117 million worth running on 100% natural gas. Under the GHG Rule, EKPC would not be able to run the plant with less than a 40% natural gas, 60% coal split allocation.

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STAFF'S REQUEST DATED DECEMBER 20, 2024
REQUEST 22
RESPONSIBLE PARTY: Brad Young

Request 22. Refer also to the Direct Testimony of Brad Young (Young Direct Testimony), page 16, lines 5-8. Explain whether the model ran the Spurlock units at the full 50 percent natural gas or something less. If less of a percentage, provide the range with which the model ran each Spurlock and Cooper unit with coal and natural gas.

Response 22. Page 16, lines 5-8, are in reference to the manner of construction of the Spurlock gas supply equipment. The question posed refers to a model regarding the 50% gas supply case which is not specific to the manner of construction. Refer to Testimony by Julia Tucker regarding modeling.

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STAFF'S REQUEST DATED DECEMBER 20, 2024
REQUEST 23
RESPONSIBLE PARTY: Julia J. Tucker

Request 23. Refer to the Tucker Direct Testimony page 26, lines 16-23, page 27, lines 1-2, and Exhibit JJT-5 and the Young Direct Testimony, page 18, lines 9-11. It appears based on the testimony submitted, that if the GHG regulations are in effect, then cofiring would be the fastest way to maintain generation capacity because new build units can't be built fast enough for the entire industry to comply. This premise implies that the demand for natural gas would increase natural gas prices (including new gas pipeline construction). Coal prices would also undergo some adjustment.

a. Explain the assumptions used in forecasting coal and natural gas prices.

b. Explain whether the same coal and natural gas forecasts were used in both the With GHG regulations scenarios and the Without the GHG regulations scenarios. If not, explain the differences.

Response 23.

a. The forecasted coal and natural gas pricing were provided by ACES Power Marketing, which is consistent with all EKPC resource planning models. These assumptions do not include any adjustments for increased demand in natural gas as a commodity. While demand for natural gas is expected to increase in general in the United States over the foreseeable future, supply is also expected to increase. The concern is not whether gas as a commodity will be available, but rather how that gas is transported from the supply to the demand. The concern is with natural gas transmission pipeline capacity and the available capacity to reserve space to schedule and deliver natural gas on a firm basis. Refer to the direct testimony of Mark Horn for details regarding the natural gas pipeline extensions for pipeline service to Spurlock and Cooper.

b. There was a single coal and natural gas price forecast used for modeling in this Application.

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STAFF'S REQUEST DATED DECEMBER 20, 2024
REQUEST 24
RESPONSIBLE PARTY: Julia J. Tucker

Request 24. Refer to the Tucker Direct Testimony and Exhibit JJT-5. Provide details and calculations that were utilized to determine the net cost benefits for the years 2029 through 2039.

Response 24. Refer to excel attachment *CONFIDENTIAL - Staff1-24 – 3MAY24.xlsx,* subject to motion for confidential treatment.

EAST KENTUCKY POWER COOPERATIVE, INC.
CASE NO. 2024-00370
FIRST REQUEST FOR INFORMATION RESPONSE

STAFF'S REQUEST DATED DECEMBER 20, 2024
REQUEST 25
RESPONSIBLE PARTY: Julia J. Tucker

Request 25. Refer to the Tucker Direct Testimony page 27, lines 1-2, page 29, lines 15-16, and page 34, lines 1-2. Provide EKPC's capacity market benefits with the Spurlock units and the Cooper units based on BRA clearing prices from the previous 10-years.

Response 25. Refer to attached excel spreadsheet, *CONFIDENTIAL - Staff1-25 - Coal CP Benefits 2016-26.xlsx*, subject to motion for confidential treatment.

EAST KENTUCKY POWER COOPERATIVE, INC.
CASE NO. 2024-00370
FIRST REQUEST FOR INFORMATION RESPONSE

STAFF'S REQUEST DATED DECEMBER 20, 2024
REQUEST 26
RESPONSIBLE PARTY: Brad Young and Mark Horn (Confidential)

Request 26. Refer to the Young Direct Testimony, Attachment BY-1, Appendix R.

a. The estimated cost of the 775 MW Combined Cycle Gas Turbine (CCGT) is $1.317 million, which equates to $1,705 per kw. The March 2023 Energy Information Administration (EIA) Cost and Performance characteristics of New Generating Technologies indicates that the expected cost for constructing this facility in the Kentucky region is $1,124 per kW, which would result in a total cost of $871 million. Provide a detailed rationale for this differential.

b. The cost estimates for the new natural gas pipeline and M&R station are not included in the $1.317 million CCGT estimate. Provide a detailed cost estimate and financially responsible party.

Response 26.

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

EAST KENTUCKY POWER COOPERATIVE, INC.
CASE NO. 2024-00370
FIRST REQUEST FOR INFORMATION RESPONSE

STAFF'S REQUEST DATED DECEMBER 20, 2024
REQUEST 27
RESPONSIBLE PARTY: Tom Stachnik

Request 27. Provide the anticipated impact the Cooper CCGT project will have on residential customer rates from 2029 through 2030.

Response 27. The proposed projects were not modeled individually, but as a package. Many components go into the calculation of overall costs and benefits to members, including capital costs, capacity sales in the PJM market, the value of off-system sales, and the operating cost of the new units versus existing generation. While EKPC does not have a calculation project by project of the cost or benefit to members, our projections indicate that EKPC will be able to implement the proposed portfolio of projects which meets generation needs and environmental compliance with modest rate increased, averaging less than 2% per year over the next 20 years.

EAST KENTUCKY POWER COOPERATIVE, INC.
CASE NO. 2024-00370
FIRST REQUEST FOR INFORMATION RESPONSE

STAFF'S REQUEST DATED DECEMBER 20, 2024
REQUEST 28
RESPONSIBLE PARTY: Craig A. Johnson and Jerry Purvis

Request 28. Describe and quantify the impact the Cooper Unit 2 Co-Firing Project will have on the following operating criteria:

a. The unit's net generating capacity.

b. The unit's North American Electric Reliability Corporation (NERC) maximum and minimum dependable capacity for winter.

c. The unit's NERC maximum and minimum dependable capacity for summer.

d. The unit's heat rate for both winter and summer.

e. The ramp rate.

f. The unit's SO2 emissions.

g. The unit's NOx emissions

h. The unit's CO2 emissions.

i. The unit's particulate emissions.

j. The unit's wastewater discharge.

k. Coal Combustion Residuals (CCR).

l. Variable Operating and Maintenance Costs.

Response 28.

a. The Cooper Unit 2 co-fire Project will retain the Unit's current ability to operate at full load (225 MW-net) on 100% coal while also adding the ability to fire on 100% natural gas or co-fire on a bend of coal and natural gas as the fuel source. Based on Owner's Engineer's experience with gas conversion and co-fire projects on similar boilers, it is expected the Unit's net generating capacity will remain unchanged. When firing on 100% natural gas, there is a potential the net MW generation could be slightly lower (approximately 0-5% lower) than the current net capacity.

b. The Unit's NERC maximum and minimum dependable capacity for winter will not be impacted by the addition of gas firing capabilities.

c. The Unit's NERC maximum and minimum dependable capacity for summer will not be impacted by the addition of gas firing capabilities.

d. The Unit's heat rate for both winter and summer will increase slightly (0-2%) and will be directly correlated to the amount of gas firing that is replacing coal.

e. The Unit's ramp rate is expected to be maintained or improved by the addition of gas firing capabilities.

f. Cooper Unit 2 currently utilizes a circulating semi-dry scrubber (CDS) to reduce SO2 post combustion emissions. After the co-fire conversion, the CDS will continue to be utilized to control SO2 emissions while firing required and economic fuel blends. EKPC expects no significant SO2 emission increases as a result of co-firing natural gas in Cooper unit 2 since the

CDS system will remain as an environmental control for SO_2 emissions. Cooper unit 1 will remain unmodified and vent through the CDS and common stack.

g. Cooper Unit 2 currently utilizes a Selective Catalytic Reduction (SCR) system to reduce NOx emissions. The SCR will continue to operate while firing all fuel blends to control NOx emissions. EKPC does not expect an emissions increase as a result of the co-firing project.

h. Co-firing on natural gas is expected to maintain or reduce CO_2 emission rates compared to current, coal fired, levels. The air permit application is currently being prepared for submittal to the Ky Division for Air Quality and EPA for their review and determination.

i. Cooper Unit 2 currently utilizes a pulse jet fabric filter to control PM emissions. The fabric filter will continue to operate while co-firing natural gas and coal to control PM emissions. EKPC expects no emissions increase as a result of the co-firing project on natural gas and coal.

j. EKPC operates under its KPDES water permit KY0003611 issued by the KY Division of Water on October 1, 2023. Should co-firing project water discharges be impacted by the project, EKPC would file a water permit modification. EKPC at this time does not expect changes as a result of this project. EPA final rule for ELG is pending with compliance date required by no later than December 31, 2029. EKPC will file a permit modification to comply with ELG before the expiration date of its existing water permit October 1, 2028 and should anything result from this project would simply request a modification at that time.

k. Co-firing on natural gas will reduce the amount of coal combustion residual (CCR) byproduct produced and managed by this facility.

l. Refer to Direct Testimony of Craig A. Johnson Page 10, Lines 12 through 17.

EAST KENTUCKY POWER COOPERATIVE, INC.
CASE NO. 2024-00370
FIRST REQUEST FOR INFORMATION RESPONSE

STAFF'S REQUEST DATED DECEMBER 20, 2024
REQUEST 29
RESPONSIBLE PARTY: Craig A. Johnson

Request 29. Provide the most recent condition assessment of the Cooper Unit 2 boiler including the following systems:

a. Burners

b. Ignitors

c. Burner Management System

d. Boiler drum

e. Water wall tubes

f. Superheater sections

g. Economizer sections

h. Desuperheater control

i. Auxiliary boiler

Response 29.

a. Reference *Staff1 - 29a. U2 INSPECT BURNERS_YEARL PM_2024.pdf* and *Staff1 – 29a. U2_BURNERS_STORM 2024 COMBUSTION TESTING REPORT.pdf*.

b. Reference *Staff1 – 29b. U2 FLAME RODS&IGNITORS_YEARLY PM_2024.pdf.*

c. Reference *Staff1 – 29c. U2 FLAME_SCANNER_SYSTEM_YEARLY PM_2024.pdf* and *Staff1 - 29c. U2_FPS 2023 Upgrade.pdf.*

d-g. Reference *Staff1 - 29d,e,f,g. U2_BOILER_B&W 2023 INSPECTION REPORT.pdf* and *Staff1 - 29e. U2_BOILER_GECKO ROBOTICS 2021 REPORT.pdf.*

h. Reference *Staff1 - 29h. U2 ATTEMP_BLOCKING_VALVE_INSP_2024.pdf* and *Staff1 - 29h. U2 WATER STEAM SYSTEM_RH_SSH(L,R) CALIBRATION_YEARLY_PM_2024.pdf.*

i. Currently, Cooper does not have an auxiliary boiler.

EAST KENTUCKY POWER COOPERATIVE, INC.
CASE NO. 2024-00370
FIRST REQUEST FOR INFORMATION RESPONSE

STAFF'S REQUEST DATED DECEMBER 20, 2024
REQUEST 30
RESPONSIBLE PARTY: Craig A. Johnson

Request 30. Provide the most recent condition assessment of the Cooper Unit 2 feedwater system including the following systems:

a. Boiler feed pumps

b. Condensate water pumps

c. Low pressure feedwater heaters

d. High pressure feedwater heaters

e. Deaerator

f. Feedwater control system

Response 30.

a. Reference *Staff1 - 30a. U2A_BFP_OVERHAUL_SER#41588.pdf* and *Staff1 - 30a. U2B_BFP_OVERHAUL_SER#41580.pdf* and *Staff1 - 30a. U2C_BFP_OVERHAUL_SER#41647.pdf*.

b. Reference *Staff1 – 30b. U2A_CONDENSATE_PUMP_SER#661NO116.pdf* and *Staff1 – 30b. U2B_CONDENSATE_PUMP_SER#661NO117.pdf.*

c. EKPC continually and periodically monitors feedwater heater performance to determine the need for further inspection. Many of our feedwater heaters are well within industry best practices regarding performance. Given the age of many of these feedwater heaters, EKPC is beginning to perform further inspections. EKPC has provided those reports available.

d. EKPC continually and periodically monitors feedwater heater performance to determine the need for further inspection. Many of EKPC's feedwater heaters are well within industry best practices regarding performance. Given the age of many of these feedwater heaters, EKPC is beginning to perform further inspections. EKPC has provided those reports available.

Reference *Staff1 - 30d. U2 FWH #6 EDDY_CURRENT_REPORT_2019.pdf* and *Staff1 - 30d. U2 FWH #7 EDDY_CURRENT_REPORT_2018.pdf.*

e. Reference *Staff1 - 30e. U2_HIGH PRESSURE PIPING_PRESSURE VESSEL_INSP_2024.pdf.*

f. Reference *Staff1 - 30f. U2 CONDENSATE CYCLE_YEARLY PM_2024.pdf* and *Staff1 - 30f. U2 FWH_LEVL_TRANSMITTERS_YEARLY PM_2024.pdf.*

EAST KENTUCKY POWER COOPERATIVE, INC.

CASE NO. 2024-00370

FIRST REQUEST FOR INFORMATION RESPONSE

STAFF'S REQUEST DATED DECEMBER 20, 2024

REQUEST 31

RESPONSIBLE PARTY: Tom Stachnik

Request 31. Describe the anticipated impact the Cooper Unit 2 co-firing project will have on residential customer rates from 2029 through 2039.

Response 31. The proposed projects were not modeled individually, but as a package. Many components go into the calculation of overall costs and benefits to members, including capital costs, capacity sales in the PJM market, the value of off-system sales, and the operating cost of the new units versus existing generation. While EKPC does not have a calculation project by project of the cost or benefit to members, our projections indicate that EKPC will be able to implement the proposed portfolio of projects which meets generation needs and environmental compliance with modest rate increased, averaging less than 2% per year over the next 20 years.

EAST KENTUCKY POWER COOPERATIVE, INC.
CASE NO. 2024-00370
FIRST REQUEST FOR INFORMATION RESPONSE

STAFF'S REQUEST DATED DECEMBER 20, 2024
REQUEST 32
RESPONSIBLE PARTY: Craig A. Johnson and Jerry Purvis

Request 32. Describe and quantify the impact the Spurlock Unit 1 co-firing project will have on the following operating criteria:

a. The unit's net generating capacity.

b. The unit's NERC maximum and minimum dependable capacity for winter.

c. The unit's NERC maximum and minimum dependable capacity for summer.

d. The unit's heat rate for both winter and summer.

e. The ramp rate.

f. The unit's SO2 emissions.

g. The unit's NOx emissions

h. The unit's CO2 emissions.

i. The unit's particulate emissions.

j. The unit's wastewater discharge.

k. Coal Combustion Residuals (CCR).

l. Variable Operating and Maintenance Costs.

Response 32.

a. The Spurlock Unit 1 co-fire Project will retain the Unit's current ability to operate at full load (300 MW-net) on 100% coal while also adding the ability to co-fire up to 50% natural gas (by heat input). The Unit will have the ability to operate on natural gas only. However, the Unit's net generating capacity is expected to be approximately half of its current full load capacity when operating in this manner.

b. The Unit's NERC maximum and minimum dependable capacity for winter will not be impacted by the addition of gas firing capabilities.

c. The Unit's NERC maximum and minimum dependable capacity for summer will not be impacted by the addition of gas firing capabilities.

d. The Unit's heat rate for both winter and summer will increase slightly (0-1%) and will be directly correlated to the amount of gas firing that is replacing coal.

e. The Unit's ramp rate is expected to be maintained or improved by the addition of gas firing capabilities compared to current, coal fired, levels.

f. Spurlock Unit 1 currently utilizes a wet Flue Gas Desulfurization (FGD) system to reduce SO2. After the co-fire conversion, the FGD will continue to be utilized to control SO2 emissions while firing on all fuel blends. Co-firing on natural gas is expected to maintain or reduce SO2 emission rates compared to current, coal fired, levels' does not expect an SO2 emissions increase as a result of the project.

g. Spurlock Unit 1 currently utilizes a Selective Catalytic Reduction (SCR) system to reduce NOx emissions. The SCR will continue to operate while firing all fuel blends to control

NOx emissions. Co-firing natural gas is expected to maintain or reduce NOx emission rates compared to current, coal fired, levels

h. Co-firing natural gas is expected to maintain or reduce CO2 emission rates compared to current, coal fired, levels. The air permit application is currently being prepared for submission to the State of Kentucky to establish Final Air Permit limits.

i. Spurlock Unit 1 currently utilizes a FGD, cold side Electrostatic Precipitator (ESP), Wet Electrostatic Precip (WESP) and dry sorbent injection (DSI) to control PM emissions. The installed control equipment will continue to operate while firing on all fuel blends to control PM emissions. EKPC does not expect a PM emissions increase as a result of the project.

j. EKPC is operating under its current KPDES water permit No. KY0022250 and expects to renew it for five years from December 28, 2023. EPA requires EKPC to comply with ELG and to modify the permit due to projects. Should co-firing on natural gas change any effluent streams, EKPC will promptly submit a modification. At this time, EKPC does not expect any new wastewater discharges from the existing facility as a result of this project.

k. Co-firing on natural gas will reduce the amount of coal combustion residual (CCR) byproduct produced and managed by the current facility.

l. Refer to Direct Testimony of Craig A. Johnson Page 13, Lines 10 through 14.

EAST KENTUCKY POWER COOPERATIVE, INC.
CASE NO. 2024-00370
FIRST REQUEST FOR INFORMATION RESPONSE

STAFF'S REQUEST DATED DECEMBER 20, 2024
REQUEST 33
RESPONSIBLE PARTY: **Craig A. Johnson**

Request 33. Provide the most recent condition assessment of the Spurlock Unit 1 boiler including the following systems:

a. Burners

b. Ignitors

c. Burner Management System

d. Boiler drum

e. Water wall tubes

f. Superheater sections

g. Economizer sections

h. Desuperheater control

i. Auxiliary boiler

Response 33.

a. Reference *Staff1 – 33 U1 Boiler Inspection 2023.pdf*.

b. Reference *Staff1 – 33 U1 Boiler Inspection 2023.pdf*.

c. Reference *Staff1 - 33c. U1 Flame_Scanners.pdf*.

d. Reference *Staff1 – 33 U1 Boiler Inspection 2023.pdf*.

e. Reference *Staff1 – 33 U1 Boiler Inspection 2023.pdf*.

f. Reference *Staff1 – 33 U1 Boiler Inspection 2023.pdf*.

g. Reference *Staff1 – 33 U1 Boiler Inspection 2023.pdf*.

h. Reference *Staff1 - 33 U1 SSH and RH Attemperator Nozzle Inspection.pdf*.

i. Currently Spurlock does not have an Auxiliary Boiler.

EAST KENTUCKY POWER COOPERATIVE, INC.
CASE NO. 2024-00370
FIRST REQUEST FOR INFORMATION RESPONSE

STAFF'S REQUEST DATED DECEMBER 20, 2024
REQUEST 34
RESPONSIBLE PARTY: Craig A. Johnson

Request 34. Provide the most recent condition assessment of the Spurlock Unit 1 feedwater system including the following systems:

a. Boiler feed pumps

b. Condensate water pumps

c. Low pressure feedwater heaters

d. High pressure feedwater heaters

e. Deaerator

f. Feedwater control system

Response 34.

a. Reference *Staff1 – 34 1A Boiler Feed Pump 2022.pdf* and *Staff1 – 34 Boiler Feed Pump 2023.pdf.*

b. Reference *Staff1 – 34 1A Condensate Pump 2020.pdf* and *Staff1 – 34 1B Condensate Pump 2023.pdf.*

c. EKPC continually and periodically monitors feedwater heater performance to determine the need for further inspection. Many of EKPC's feedwater heaters are well within industry best practices regarding performance. Given the age of many of these feedwater heaters, EKPC is beginning to perform further inspections. Reference *Staff1 - 34 Spurlock LP-5 UNIT 1.pdf* and *Staff1 - 34 U1 #3 FWH Inspection Report.pdf*.

d. EKPC continually and periodically monitors feedwater heater performance to determine the need for further inspection. Many of EKPC's feedwater heaters are well within industry best practices regarding performance. Given the age of many of these feedwater heaters, EKPC is beginning to perform further inspections.

e. Reference *Staff1 – 34 U1 DA 2022 Inspection.pdf*.

f. Feedwater control is based on drum level indication. Spurlock uses multiple "smart" differential pressure transmitters on each of the four units. Maintenance of the drum level control is based on deviation of a transmitter from the group of transmitters on the specific drum.

EAST KENTUCKY POWER COOPERATIVE, INC.
CASE NO. 2024-00370
FIRST REQUEST FOR INFORMATION RESPONSE

STAFF'S REQUEST DATED DECEMBER 20, 2024
REQUEST 35
RESPONSIBLE PARTY: Tom Stachnik

Request 35. Describe the anticipated impact the Spurlock Unit 1 co-firing project will have on residential customer rates from 2029 through 2039.

Response 35. The proposed projects were not modeled individually, but as a package. Many components go into the calculation of overall costs and benefits to members, including capital costs, capacity sales in the PJM market, the value of off-system sales, and the operating cost of the new units versus existing generation. While EKPC does not have a calculation project by project of the cost or benefit to members, our projections indicate that EKPC will be able to implement the proposed portfolio of projects which meets generation needs and environmental compliance with modest rate increased, averaging less than 2% per year over the next 20 years.

EAST KENTUCKY POWER COOPERATIVE, INC.

CASE NO. 2024-00370

FIRST REQUEST FOR INFORMATION RESPONSE

STAFF'S REQUEST DATED DECEMBER 20, 2024

REQUEST 36

RESPONSIBLE PARTY: Craig A. Johnson and Jerry Purvis

Request 36. Describe and quantify the impact the Spurlock Unit 2 co-firing project will have on the following operating criteria:

a. The unit's net generating capacity.

b. The unit's NERC maximum and minimum dependable capacity for winter.

c. The unit's NERC maximum and minimum dependable capacity for summer.

d. The unit's heat rate for both winter and summer.

e. The ramp rate.

f. The unit's SO2 emissions.

g. The unit's NOx emissions

h. The unit's CO2 emissions.

i. The unit's particulate emissions.

j. The unit's wastewater discharge.

k. Coal Combustion Residuals (CCR).

l. Variable Operating and Maintenance Costs.

<u>Response 36.</u>

a. The Spurlock Unit 2 co-fire Project will retain the Unit's current ability to operate at full load (510 MW-net plus 30 MW equivalent for steam supply to an off-site paper mill) on 100% coal while also adding the ability to co-fire up to 50% natural gas (by heat input). The Unit will have the ability to operate on natural gas only. However, the Unit's net generating capacity is expected to be approximately half of its current full load capacity when operating in this manner.

b. The Unit's NERC maximum and minimum dependable capacity for winter will not be impacted by the addition of gas firing capabilities.

c. The Unit's NERC maximum and minimum dependable capacity for summer will not be impacted by the addition of gas firing capabilities.

d. The Unit's heat rate for both winter and summer will increase slightly (0-1%) and will be directly correlated to the amount of gas firing that is replacing coal.

e. The Unit's ramp rate is expected to be maintained or improved by the addition of gas firing capabilities.

f. Spurlock Unit 2 currently utilizes a wet Flue Gas Desulfurization (FGD) system to reduce SO2 emissions. After the co-fire conversion, the FGD will continue to be utilized to control SO2 emissions while firing on all fuel blends. EKPC does not expect a SO2 emissions increase as a result of the project when co-firing on natural gas.

g. Spurlock Unit 2 currently utilizes a Selective Catalytic Reduction (SCR) system to reduce NOx emissions. The SCR will continue to operate while firing all fuel blends to control

NOx emissions. EKPC does not expect a NOx emissions increase as a result of the project.

h. Co-firing natural gas is expected to maintain or reduce CO2 emission rates compared to current, coal fired, levels. EKPC is preparing the air permit application to submit to the KDAQ and EPA for their determinations.

i. Spurlock Unit 2 currently utilizes a FGD, hot side Electrostatic Precipitator (ESP) and a Wet Electrostatic Precipitator (WESP) and dry sorbent injection to control PM emissions. The control equipment will continue to operate while firing on all fuel blends to control PM emissions. EKPC does not expect a PM emissions increase as a result of the project.

j. EKPC is operating under its current KPDES water permit No. KY0022250 and expects to renew it five years from this date. EPA requires EKPC to comply with ELG and to modify the permit as a result of projects. Should co-firing on natural gas change any effluent streams, EKPC will promptly submit a modification. At this time EKPC does not expect any new wastewater discharges from the existing facility as a result of this project.

k. Co-firing on natural gas will reduce the amount of coal combustion residual (CCR) byproduct produced and managed by the current facility.

l. Refer to Direct Testimony of Craig A. Johnson Page 13, Lines 10 through 14.

EAST KENTUCKY POWER COOPERATIVE, INC.
CASE NO. 2024-00370
FIRST REQUEST FOR INFORMATION RESPONSE

STAFF'S REQUEST DATED DECEMBER 20, 2024
REQUEST 37
RESPONSIBLE PARTY: Craig A. Johnson

Request 37. Provide the most recent condition assessment of the Spurlock Unit 2 boiler including the following systems:

a. Burners

b. Ignitors

c. Burner Management System

d. Boiler drum

e. Water wall tubes

f. Superheater sections

g. Economizer sections

h. Desuperheater control

i. Auxiliary boiler

Response 37.

a. *Reference Staff1 - 37 Spurlock_U2_Spring 2023 Outage_Inspection Final Report.pdf.*

b. *Reference Staff1 - 37 Spurlock_U2_Spring 2023 Outage_Inspection Final Report.pdf.*

c. Reference *Staff1 - 37 U2 Ignitors Weekly PM.pdf.*

d. *Reference Staff1 - 37 Spurlock_U2_Spring 2023 Outage_Inspection Final Report.pdf.*

e. *Reference Staff1 - 37 Spurlock_U2_Spring 2023 Outage_Inspection Final Report.pdf.*

f. *Reference Staff1 - 37 Spurlock_U2_Spring 2023 Outage_Inspection Final Report.pdf.*

g. *Reference Staff1 - 37 Spurlock_U2_Spring 2023 Outage_Inspection Final Report.pdf.*

h. Reference *Staff1 - 37 U2 SSH and RH Attemperator Nozzle Inspection.pdf.*

i. Currently Spurlock does not have an Auxiliary Boiler.

EAST KENTUCKY POWER COOPERATIVE, INC.
CASE NO. 2024-00370
FIRST REQUEST FOR INFORMATION RESPONSE

STAFF'S REQUEST DATED DECEMBER 20, 2024
REQUEST 38
RESPONSIBLE PARTY: Craig A. Johnson

Request 38. Provide the most recent condition assessment of the Spurlock Unit 2 feedwater system including the following systems:

a. Boiler feed pumps

b. Condensate water pumps

c. Low pressure feedwater heaters

d. High pressure feedwater heaters

e. Deaerator

f. Feedwater control system

Response 38.

a. Reference *Staff1 - 38 2A Boiler feed pump 2021.pdf* and *Staff1 - 38 2B boiler feed pump 2023.pdf*.

b. Reference *Staff1 - 38 Condensate water pump 2021.pdf*.

c. EKPC continually and periodically monitors feedwater heater performance to determine the need for further inspection. Many of our feedwater heaters are well within industry best practices regarding performance. Given the age of many of these feedwater heaters, EKPC is beginning to perform further inspections. EKPC has provided those reports available.

Reference *Staff1 - 38 Unit 2 LPFWH 1A and 1B Final Report.pdf*, *Staff1 - 38 Unit 2 LPFWH 2A and 2B Final Report.pdf*, and *Staff1 - 38 Unit 2 LPFWH 3 Final Report.pdf*.

d. EKPC continually and periodically monitors feedwater heater performance to determine the need for further inspection. Many of our feedwater heaters are well within industry best practices regarding performance. Given the age of many of these feedwater heaters, EKPC is beginning to perform further inspections.

e. Reference *Staff1 - 38 U2_Spring 2024 Outage_DA Storage Tank Inspection.pdf*.

f. Feedwater control is based on drum level indication. Spurlock uses multiple "smart" differential pressure transmitters on each of the four units. Maintenance of the drum level control is based on deviation of a transmitter from the group of transmitters on the specific drum.

EAST KENTUCKY POWER COOPERATIVE, INC.
CASE NO. 2024-00370
FIRST REQUEST FOR INFORMATION RESPONSE

STAFF'S REQUEST DATED DECEMBER 20, 2024
REQUEST 39
RESPONSIBLE PARTY: Tom Stachnik

Request 39. Describe the anticipated impact and anticipated timing the Spurlock Unit 2 co-firing project will have on ratepayers from 2030 through 2038. If the impact is not known, explain the process by which EKPC intends to estimate the impact to ratepayers.

Response 39. The proposed projects were not modeled individually, but as a package. Many components go into the calculation of overall costs and benefits to members, including capital costs, capacity sales in the PJM market, the value of off-system sales, and the operating cost of the new units versus existing generation. While EKPC does not have a calculation project by project of the cost or benefit to members, our projections indicate that EKPC will be able to implement the proposed portfolio of projects which meets generation needs and environmental compliance with modest rate increased, averaging less than 2% per year over the next 20 years.

EAST KENTUCKY POWER COOPERATIVE, INC.
CASE NO. 2024-00370
FIRST REQUEST FOR INFORMATION RESPONSE

STAFF'S REQUEST DATED DECEMBER 20, 2024
REQUEST 40
RESPONSIBLE PARTY: Craig A. Johnson

Request 40. Describe and quantify the impact the Spurlock Unit 3 co-firing project will have on the following operating criteria:

a. The unit's net generating capacity.

b. The unit's NERC maximum and minimum dependable capacity for winter.

c. The unit's NERC maximum and minimum dependable capacity for summer.

d. The unit's heat rate for both winter and summer.

e. The ramp rate.

f. The unit's SO2 emissions.

g. The unit's NOx emissions

h. The unit's CO2 emissions.

i. The unit's particulate emissions.

j. The unit's wastewater discharge.

k. Coal Combustion Residuals (CCR).

l. Variable Operating and Maintenance Costs.

<u>Response 40.</u>

a. The Spurlock Unit 3 co-fire Project will retain the Unit's current ability to operate at full load (268 MW-net) on 100% coal while also adding the ability to co-fire up to 50% natural gas (by heat input) at full load.

b. The Unit's NERC maximum and minimum dependable capacity for winter will not be impacted by the addition of gas firing capabilities.

c. The Unit's NERC maximum and minimum dependable capacity for summer will not be impacted by the addition of gas firing capabilities.

d. The Unit's heat rate for both winter and summer will increase slightly (0-1%) and will be directly correlated to the amount of gas firing that is replacing coal.

e. The Unit's ramp rate is expected to be maintained or improved by the addition of gas firing capabilities.

f. Spurlock Unit 3 currently utilizes a Novel Integrated Desulphurization System (NIDS) to reduce SO2. After the co-fire conversion, the NIDS will continue to be utilized to control SO2 emissions while firing on all fuel blends. Co-firing on natural gas is expected to maintain or reduce SO2 emission rates compared to current, coal fired, levels. EKPC does not expect a unit emissions increase as a result of the project.

g. Spurlock Unit 3 currently utilizes a Selective Non-Catalytic Reduction (SNCR) system to reduce NOx emissions. The SNCR will continue to operate while firing all fuel blends to control NOx emissions. Co-firing on natural gas is expected to maintain NOx emission rates compared to current, coal fired, levels. EKPC does not expect a unit emissions increase as a result of the project.

h. Co-firing natural gas is expected to reduce CO2 emission rates compared to current, coal fired, levels. EKPC is preparing an air permit application to submit to the Kentucky Division for Air Quality and EPA for their determination.

i. Spurlock Unit 3 currently utilizes a baghouse to control PM emissions. The baghouse will continue to operate while firing on all fuel blends to control PM emissions. EKPC expects that PM emissions from co-firing natural gas will not result in an emission increase as a result of the project.

j. EKPC is operating under its current KPDES water permit No. KY0022250 and expects to renew it five years from this date. EPA requires EKPC to comply with ELG and to modify the permit as a result of projects. Should co-firing on natural gas change any effluent streams EKPC will promptly submit a modification. At this time EKPC does not expect any new wastewater discharges from the existing facility as a result of this project.

k. Co-firing on natural gas will reduce the amount of coal combustion residual (CCR) byproduct produced and managed from this existing facility.

l. Refer to Direct Testimony of Craig A. Johnson Page 13, Lines 10 through 14.

EAST KENTUCKY POWER COOPERATIVE, INC.
CASE NO. 2024-00370
FIRST REQUEST FOR INFORMATION RESPONSE

STAFF'S REQUEST DATED DECEMBER 20, 2024
REQUEST 41
RESPONSIBLE PARTY: Craig A. Johnson

Request 41. Provide the most recent condition assessment of the Spurlock Unit 3 boiler including the following systems:

a. Burners

b. Ignitors

c. Burner Management System

d. Boiler drum

e. Water wall tubes

f. Superheater sections

g. Economizer sections

h. Desuperheater control

i. Auxiliary boiler

Response 41.

a. Reference *Staff1 – 41 U3 Spring 2024 Boiler Inspection.pdf.*

b. Reference *Staff1 – 41 U3 Spring 2024 Boiler Inspection.pdf.*

c. Unit 3 is a Circulating Fluidized Bed, so it uses ignition temperature to verify combustion. Reference *Staff1 - 41 U3_Boiler_Bed_Thermcouples.pdf*.

d. Reference *Staff1 – 41 U3 Spring 2024 Boiler Inspection.pdf.*

e. Reference *Staff1 – 41 U3 Spring 2024 Boiler Inspection.pdf.*

f. Reference *Staff1 – 41 U3 Spring 2024 Boiler Inspection.pdf.*

g. Reference *Staff1 – 41 U3 Spring 2024 Boiler Inspection.pdf.*

h. Reference *Staff1 – 41 U3 Spring 2024 Boiler Inspection.pdf.*

i. Currently Spurlock does not have an Auxiliary Boiler.

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STAFF'S REQUEST DATED DECEMBER 20, 2024
REQUEST 42
RESPONSIBLE PARTY: Craig A. Johnson

<u>Request 42.</u> Provide the most recent condition assessment of the Spurlock Unit 3 feedwater system including the following systems:

a. Boiler feed pumps

b. Condensate water pumps

c. Low pressure feedwater heaters

d. High pressure feedwater heaters

e. Deaerator

f. Feedwater control system

<u>Response 42.</u>

a. Reference *Staff1 - 42 U3 3A BFP Volute Replacement 2023.pdf* and *Staff1 – 42 U3 3B BFP Volute Replacement 2024.pdf*.

b. EKPC continually monitors the performance and performs preventative maintenance on these pumps. Given the age of these units a full offsite rebuild has not been needed, so a condition assessment report similar to the other units is unavailable.

c. EKPC continually and periodically monitors feedwater heater performance to determine the need for further inspection. Many of EKPC's feedwater heaters are well within industry best practices regarding performance. Given the age of many of these feedwater heaters, EKPC is beginning to perform further inspections. EKPC has provided those reports available. Reference *Staff1 – 42 U3 Spring Outage 2022 FWH 1, 2, & 3 Eddy Current Testing.pdf*.

d. EKPC continually and periodically monitors feedwater heater performance to determine the need for further inspection. Many of EKPC's feedwater heaters are well within industry best practices regarding performance. Given the age of many of these feedwater heaters, EKPC is beginning to perform further inspections. EKPC has provided those reports available.

e. Reference *Staff1 – 42 U3 Spring 2024 DA Inspection.pdf*.

f. Feedwater control is based on drum level indication. Spurlock uses multiple "smart" differential pressure transmitters on each of the four units. Maintenance of the drum level control is based on deviation of a transmitter from the group of transmitters on the specific drum.

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STAFF'S REQUEST DATED DECEMBER 20, 2024
REQUEST 43
RESPONSIBLE PARTY: Tom Stachnik

Request 43. Describe the anticipated impact the Spurlock Unit 3 co-firing project will have on residential customer rates from 2029 through 2039.

Response 43. The proposed projects were not modeled individually, but as a package. Many components go into the calculation of overall costs and benefits to members, including capital costs, capacity sales in the PJM market, the value of off-system sales, and the operating cost of the new units versus existing generation. While EKPC does not have a calculation project by project of the cost or benefit to members, our projections indicate that EKPC will be able to implement the proposed portfolio of projects which meets generation needs and environmental compliance with modest rate increased, averaging less than 2% per year over the next 20 years.

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STAFF'S REQUEST DATED DECEMBER 20, 2024
REQUEST 44
RESPONSIBLE PARTY: Craig A. Johnson and Jerry Purvis

Request 44. Describe and quantify the impact the Spurlock Unit 4 co-firing project will have on the following operating criteria:

a. The unit's net generating capacity.

b. The unit's NERC maximum and minimum dependable capacity for winter.

c. The unit's NERC maximum and minimum dependable capacity for summer.

d. The unit's heat rate for both winter and summer.

e. The ramp rate.

f. The unit's SO2 emissions.

g. The unit's NOx emissions

h. The unit's CO2 emissions.

i. The unit's particulate emissions.

j. The unit's wastewater discharge.

k. Coal Combustion Residuals (CCR).

l. Variable Operating and Maintenance Costs.

<u>Response 44.</u>

a. The Spurlock Unit 4 co-fire Project will retain the Unit's current ability to operate at full load (268 MW-net) on 100% coal while also adding the ability to co-fire up to 50% natural gas (by heat input) at full load.

b. The Unit's NERC maximum and minimum dependable capacity for winter will not be impacted by the addition of gas firing capabilities.

c. The Unit's NERC maximum and minimum dependable capacity for summer will not be impacted by the addition of gas firing capabilities.

d. The Unit's heat rate for both winter and summer will increase slightly (0-1%) and will be directly correlated to the amount of gas firing that is replacing coal.

e. The Unit's ramp rate is expected to be maintained or improved by the addition of gas firing capabilities.

f. Spurlock Unit 4 currently utilizes a Novel Integrated Desulphurization System (NIDS) to reduce SO2. After the co-fire conversion, the NIDS will continue to be utilized to control SO2 emissions while firing on all fuel blends. Co-firing on natural gas is expected to maintain or reduce SO2 emission rates compared to current, coal fired, levels. EKPC does not expect an emissions increase as a result of the project.

g. Spurlock Unit 4 currently utilizes a Selective Non-Catalytic Reduction (SNCR) system to reduce NOx emissions. The SNCR will continue to operate while firing all fuel blends to control NOx emissions. Co-firing on natural gas is expected to maintain NOx emission rates compared to current, coal fired, levels. EKPC does not expect a NOx emission increase as a result of the project.

h. Co-firing natural gas is expected to maintain or reduce CO2 emission rates compared to current, coal fired, levels. The air permit application is currently being prepared for submittal to the Kentucky Division for Air Quality and EPA to review and make determinations for emissions limitations.

i. Spurlock Unit 4 currently utilizes a baghouse to control PM emissions. The baghouse will continue to operate while firing on all fuel blends to control PM emissions. Co-firing on natural gas is expected to maintain or reduce PM emission rates compared to current, coal fired, levels. EKPC does not expect PM emissions to increase as a result of the project.

j. EKPC is operating under its current KPDES water permit No. KY0022250 and expects to renew it five years from this date. EPA requires EKPC to comply with ELG and to modify the permit as a result of projects. Should co-firing on natural gas change any effluent streams EKPC will promptly submit a modification. At this time EKPC does not expect any new wastewater discharges from the existing facility as a result of this project.

k. Co-firing on natural gas will reduce the amount of coal combustion residual (CCR) byproduct produced from the current facility.

l. Refer to Direct Testimony of Craig A. Johnson Page 13, Lines 10 through 14.

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STAFF'S REQUEST DATED DECEMBER 20, 2024
REQUEST 45
RESPONSIBLE PARTY: Craig A. Johnson

Request 45. Provide the most recent condition assessment of the Spurlock Unit 4 boiler including the following systems:

a. Burners
b. Ignitors
c. Burner Management System
d. Boiler drum
e. Water wall tubes
f. Superheater sections
g. Economizer sections
h. Desuperheater control
i. Auxiliary boiler

Response 45.

a. Reference *Staff1 – 45 U4 Fall 2024 Boiler Inspection.pdf*.

b. Reference *Staff1 – 45 U4 Fall 2024 Boiler Inspection.pdf*.

c. Unit 4 is a Circulating Fluidized Bed, so it uses ignition temperature to verify combustion. Reference *Staff1 – 45 U4_Boiler_Bed_Thermcouples.pdf*.

d. Reference *Staff1 – 45 U4 Fall 2024 Boiler Inspection.pdf*.

e. Reference *Staff1 – 45 U4 Fall 2024 Boiler Inspection.pdf*.

f. Reference *Staff1 – 45 U4 Fall 2024 Boiler Inspection.pdf*.

g. Reference *Staff1 – 45 U4 Fall 2024 Boiler Inspection.pdf*.

h. Reference *Staff1 – 45 U4 Fall 2024 Boiler Inspection.pdf*.

i. Currently Spurlock does not have an Auxiliary Boiler.

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STAFF'S REQUEST DATED DECEMBER 20, 2024
REQUEST 46
RESPONSIBLE PARTY: Craig A. Johnson

Request 46. Provide the most recent condition assessment of the Spurlock Unit 4 feedwater system including the following systems:

a. Boiler feed pumps

b. Condensate water pumps

c. Low pressure feedwater heaters

d. High pressure feedwater heaters

e. Deaerator

f. Feedwater control system

Response 46.

a. Reference *Staff1 - 46 U4 4A BFP Volute Replacement 2018.pdf* and *Staff1 - 46 U4 4B BFP Volute Replacement 2019.pdf*.

b. EKPC continually monitors the performance and performs preventative maintenance on these pumps. Given the age of these units a full offsite rebuild has not been needed, so a condition assessment report similar to the other units is unavailable.

c. EKPC continually and periodically monitors feedwater heater performance to determine the need for further inspection. Many of EKPC's feedwater heaters are well within industry best practices regarding performance. Given the age of many of these feedwater heaters, EKPC is beginning to perform further inspections. EKPC has provided those reports available. Reference *Staff1 - 46 U4 Fall Outage 2022 FWH 1, 2, & 3 Eddy Current Testing.pdf*.

d. EKPC continually and periodically monitors feedwater heater performance to determine the need for further inspection. Many of EKPC's feedwater heaters are well within industry best practices regarding performance. Given the age of many of these feedwater heaters, EKPC is beginning to perform further inspections. EKPC has provided those reports available.

e. Reference *Staff1 - 46 U4 Fall 2024 DA Inspection.pdf.*

f. Feedwater control is based on drum level indication. Spurlock uses multiple "smart" differential pressure transmitters on each of the four units. Maintenance of the drum level control is based on deviation of a transmitter from the group of transmitters on the specific drum.

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STAFF'S REQUEST DATED DECEMBER 20, 2024
REQUEST 47
RESPONSIBLE PARTY: Tom Stachnik

Request 47. Describe the anticipated impact the Spurlock Unit 4 co-firing project will have on residential customer rates from 2029 through 2039.

Response 47. The proposed projects were not modeled individually, but as a package. Many components go into the calculation of overall costs and benefits to members, including capital costs, capacity sales in the PJM market, the value of off-system sales, and the operating cost of the new units versus existing generation. While EKPC does not have a calculation project by project of the cost or benefit to members, our projections indicate that EKPC will be able to implement the proposed portfolio of projects which meets generation needs and environmental compliance with modest rate increased, averaging less than 2% per year over the next 20 years.

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STAFF'S REQUEST DATED DECEMBER 20, 2024
REQUEST 48
RESPONSIBLE PARTY: Craig A. Johnson

Request 48. Refer to the Direct Testimony of Craig Johnson (Johnson Direct Testimony), page 4, lines 18-23. Explain whether the water from the cooling tower will be cycled back for reuse by the CCGT steam turbine.

Response 48. Cooling water from the cooling tower (known as circulating water) will be cycled back through the steam condenser for reuse by the CCGT. A relatively small portion of circulating water will be extracted from the cooling water cycle as blowdown to control the scaling of the tower and to remain thermally efficient. The water drawn from Lake Cumberland will makeup to the cooling water cycle for the water that is blown down.

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STAFF'S REQUEST DATED DECEMBER 20, 2024
REQUEST 49
RESPONSIBLE PARTY: Craig A. Johnson

Request 49. Refer to the Johnson Direct Testimony, page 9, 7-11 and page 10, lines 1-2. If the CCGT capacity factor is limited to 40 percent under the GHG regulation, explain the anticipated capacity factor if the GHG regulation is struck down or sent back to the EPA for revision.

Response 49. The modeling performed predicts that the CCGT will operate at a 52% capacity factor on average. If and when GHG rule is vacated, re-written, repealed or replaced, EKPC will submit an air permit modification to EPA and KDAQ for a revision to comply with new EPA rule. Without knowing the substance of any new requirements, it is not possible to anticipate a different capacity factor.

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STAFF'S REQUEST DATED DECEMBER 20, 2024
REQUEST 50
RESPONSIBLE PARTY: Craig A. Johnson

Request 50. Refer to the Johnson Direct Testimony, page 9, lines 18-19 and page 10, lines 12-15.

a. Explain whether the statement means that Cooper Unit 2 will burn natural gas as the primary fuel and coal will be added to the fuel mix only when gas supply is constrained, or coal is relatively more economic.

b. Explain whether the same is true for the Spurlock units in that under normal market conditions, EKPC anticipates operating the Spurlock units with 50/50 coal/natural gas fuel blend.

Response 50.

a. EKPC anticipates that natural gas will be the primary fuel burned in Cooper Unit 2 and coal will be used during times when there is volatility in the natural gas market or natural gas supply is constrained.

b. The forward price curve for coal is less than the forward price curve for natural gas at Spurlock Station. The minimum amount of natural gas EKPC can co-fire the units with is 40% and remain in compliance with the GHG rules. EKPC is designing the units to utilize up to 50%

co-firing of natural gas. This allows compliance with the GHG rules and still allows the cheaper fuel of coal to be utilized. This will also allow for natural gas to be burned during times of minimum low load conditions with no co-firing of coal. The minimum sustainable load for our boilers is approximately 50% of the unit rating. This minimum load can be achieved by burning only natural gas. This requires firing the boilers at an equivalent 50% heat input which could be from natural gas only. Natural gas utilization during minimum load conditions will allow for many auxiliaries to be powered off while the back-end temperatures out of the furnace are maintained high enough to keep the units within their permitted air emission limits. The design of a 40% natural gas co-fire would not give the required heat input to achieve this desired low load operating condition on natural gas only. Units 3 and 4 utilize a different type of combustion than Units 1 and 2. Units 3 and 4 may always need to have a certain amount of coal blended in with the natural gas to achieve low load conditions.

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STAFF'S REQUEST DATED DECEMBER 20, 2024
REQUEST 51
RESPONSIBLE PARTY: Craig A. Johnson

Request 51. Refer to the Johnson Direct Testimony, page 10, lines 20-21 and page 12, lines 12-15. The statement on page 10 indicates that Spurlock units will be cofired up to 50 percent natural gas. The statement on page 12 indicates a minimum of 50 percent natural gas co-firing. Reconcile the two statements for each Spurlock unit.

Response 51. The use of the term "minimum" was not a good description of why EKPC chose 50% co-fire as the design point. Firing Unit 1 or Unit 2 boilers with natural gas only with no coal co-firing satisfies the minimum 50% heat input required to keep the unit online while still meeting air permit emission limits. As stated in response 50b, this will give EKPC the most operational flexibility. Designing for 40% natural gas as required by the GHG rule would not give that same operational flexibility.

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STAFF'S REQUEST DATED DECEMBER 20, 2024

REQUEST 52

RESPONSIBLE PARTY: Craig A. Johnson

Request 52. Refer to the Johnson Direct Testimony, page 9, lines 22-23.

a. Explain whether the predicted percent degradation in heat rate for Cooper Unit 2 means that the cost of energy bid into the PJM energy market will be slightly higher or that the unit may be called upon to run less.

b. Explain whether the Spurlock units will experience a similar degradation in heat rate and energy market competitiveness.

Response 52.

a. Even with a slight performance degradation of less than 3% in net heat rate while burning natural gas, the variable dispatch cost of Cooper Unit 2 will be lower while burning 100% natural gas than the variable dispatch cost while burning coal. This is because of lower fuel cost, SO2 scrubber cost and lower CCR waste disposal cost in the total variable O&M cost while burning natural gas. Cooper Unit 2, as stated in the application and testimony, should have lower maintenance costs while burning natural gas as the primary fuel. Also as stated, the forward price of natural gas is lower than the forward price of coal. EKPC expects Cooper Unit 2 to have a higher capacity factor in the PJM market in the future as compared to today.

b. The models used to predict performance show a slight degradation of less than 1.5% in net heat rate for each unit. Modeling shows that the small amount of performance degradation while co-firing 50% natural gas with 50% coal is not enough to affect the energy market competitiveness.

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STAFF'S REQUEST DATED DECEMBER 20, 2024
REQUEST 53
RESPONSIBLE PARTY: Darrin Adams

<u>Request 53.</u> Refer to the Direct Testimony of Darrin Adams, (Adams Direct Testimony), pages 7-9. Absent the construction of the CCGT at Cooper station, explain whether any of the transmission projects identified that EKPC would be responsible for completing are in EKPC's five-year construction workplan currently. Include in the response when each project is scheduled to begin, to be completed and identify the project.

<u>Response 53.</u> Absent the construction of the CCGT at Cooper Station, none of the transmission projects identified in the referenced testimony are currently needed, and therefore would not be included in EKPC's five-year construction work plan if not for the planned Cooper CCGT.

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STAFF'S REQUEST DATED DECEMBER 20, 2024
REQUEST 54
RESPONSIBLE PARTY: Darrin Adams

Request 54. Refer to the Direct Testimony of Darrin Adams, (Adams Direct Testimony), Attachment DA-1, Table 4.1 pages 10-11 and Table 4.2, page 12. To the extent that Louisville Gas & Electric (LG&E) and Kentucky Utilities Company (KU) (jointly, LG&E/KU) are required to complete the transmission projects associated with its transmission system, explain whether EKPC will be responsible for paying the cost of the upgrades on LG&E/KU systems.

Response 54. Since the LG&E/KU upgrades listed in the referenced testimony have been identified as needed due to the addition of the Cooper CCGT, the expectation is that EKPC will be responsible for the costs of those upgrades, which is consistent with cost allocation parameters utilized for affected-system upgrades identified for other projects in the PJM generator-interconnection queue.

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STAFF'S REQUEST DATED DECEMBER 20, 2024
REQUEST 55
RESPONSIBLE PARTY: Jerry Purvis

Request 55. Refer to the Direct Testimony of Jerry B. Purvis (Purvis Direct Testimony), page 10, lines 21-23.

a. Explain if EKPC's choice to co-fire Cooper Unit 2 and Spurlock Units 1-4 with 40 percent natural gas means that EKPC anticipates the Spurlock Units 1-4 and Cooper Unit 2 will burn no more than 40 percent natural gas (and 60 percent coal) or does EKPC anticipate burning up to 100 percent natural gas.

b. If EKPC's choice to co-fire Spurlock Units 1-4 and Cooper Unit 2 means neither of these items in response a., explain.

c. Explain if EKPC believes that the response in a. is there will be no impact to the PJM unit capacity rating under either scenario. If EKPC believes there would be an impact to the PJM unit capacity rating, explain the impact and why.

d. If there is an affect on the PJM capacity rating, explain what environmental measures would have to be undertaken to maintain the load factor over 40 percent.

Response 55.

a. EPA's GHG final rule for existing units on April 24, 2024, set minimum standards to achieve carbon dioxide emission reductions over a defined timeline. One option available under the final rule was to co-fire fossil units at 40% to achieve CO2 reductions to comply. Cooper unit 2 is being designed to be capable of burning the minimum of 40% and to over comply combusting up to 100% natural gas. Spurlock 1-4 are being designed to combust up to 50% to achieve the minimum rule standards in an effort to comply and to over comply by the EPA GHG final rule emission standards. If EKPC elects to burn more natural gas and the technology installed respectively can do so, and it is economic, and the Ky Division for Air Quality (KDAQ) and EPA permits us to do so, EKPC will co-fire natural gas up to the units' respective design in order to be economic, and reliable. EKPC as a prudent non-profit utility extracts value from assets on behalf of the owner member rural cooperatives.

b. EKPC plans to comply by meeting the minimum standards of the final rule to comply and if when conditions exists and it is economic, and technologically feasible and in the final air permit available, will combust more natural gas to achieve lowest delivered costs to our owner members up to the constraints in the respective unit specific design.

c. EKPC is modifying existing units under the CAA title V/ PSD which means this is a significant revision. The request is to achieve the capacity design ratings the units possess for our company and owner members as bid into PJM.

d. EKPC cannot speculate what load factors an unforeseen PJM market in 2025 and beyond provide. What EKPC can do is submit permit applications to KDAQ and EPA to achieve the units at rated capacity to burn natural gas and coal as prescribed by the EPA final rule. KDAQ and EPA will review the applications, ask questions, receive responses, and make a determination for each title V / PSD application for Cooper and Spurlock Stations.

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STAFF'S REQUEST DATED DECEMBER 20, 2024

REQUEST 56

RESPONSIBLE PARTY: Mark Horn

Request 56. Refer to the Direct Testimony of Mark Horn (Horn Direct Testimony), page 7, lines 1-8. Provide a description of how the Risk Factor and Weighting were assigned for each of the parameters listed.

Response 56. The Risk Factors and Weighting of each of those parameters were determined prior to receiving any of the proposals from the potential bidders. The qualitative bid analysis for Phase 1 proposals was designed to evaluate the drivers for key potential risks. Given that the natural gas pipeline expansions are critical path for the proposed new generation projects, these Risk Factors were considered based on their potential to add cost or time to the proposed projects and ultimately their impact the overall success of the required natural gas expansion projects.

Where applicable, the Risk Factor for each parameter was assessed based on the information provided with each party's proposal for each individual project. The Weighting for each Risk Factor was developed based on the combined experience and judgement of the project team that had history with other similar projects. The project team included members from EKPC, Burns & McDonnell, and ACES that provided input based on the understood industry standards for natural gas pipeline expansion projects.

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STAFF'S REQUEST DATED DECEMBER 20, 2024
REQUEST 57
RESPONSIBLE PARTY: Scott Drake

__Request 57.__ Provide the current status of the existing energy efficiency programs, including the following:

a. Button-Up Weatherization Program (residential)

b. CARES Low-Income Weatherization (residential)

c. Heat Pump Retrofit Program (residential)

d. Touchstone Energy Program (residential)

e. Direct Load Control of Air Conditioners and Water Heaters: Switches and Bring Your Own Thermostat (BYOT) (residential)

f. EV Off-Peak Charging Program (residential)

__Response 57.__

a. The Button-up Weatherization program is an ongoing DSM program. EKPC's Owner-Members have completed 30 Button-up enrollments year-to-date (YTD) as of December 23, 2024. The air-sealing improvements and in some cases attic insulation improvements, have saved 151 MWh YTD in 2024. Winter demand has decreased by 0.12 MW and summer demand by 0.65 MW YTD. EKPC has spent $27,358 YTD on the Button-Up Program.

b. The CARES Low-Income Weatherization program is an ongoing DSM program. EKPC's Owner-Members have completed 109 CARES Low-Income weatherization enrollments YTD. Weatherization and HVAC improvements completed have saved 515.69 MWh YTD. Winter demand has decreased by 0.157 MW and summer demand by 0.079 MW YTD. EKPC has spent $274,253 YTD on the CARES Low-Income Weatherization program.

c. The Heat Pump Retrofit program is an ongoing DSM program. EKPC's Owner-Members have completed 340 Heat Pump Retrofit enrollments YTD. The heat pump retrofits completed on those homes have saved 2,409.921 MWh YTD. Summer demand has been reduced by 0.11 MW. EKPC has spent $556,440 YTD on the Heat Pump Retrofit program.

d. The Touchstone Energy® Home program is an ongoing DSM program. EKPC's Owner-Members have completed 601 Touchstone Energy® Homes YTD. The Touchstone Energy® Home program has saved 1,906.37 MWh. Winter demand has decreased by 1.57 MW and summer demand by 0.43 MW. EKPC has spent $871,450 YTD on the Touchstone Energy Home program.

e. The Direct Load Control of Air Conditioners and Water Heaters Switches and Bring Your Own Thermostat (BYOT) (residential) programs are ongoing DSM programs. EKPC has 16,594 air conditioner switch participants and 13,322 water heater participants total as of December 23, 2024. EKPC has 6,500 BYOT participants as of December 23, 2024.

f. The EV Off-peak Home Charging pilot program is an ongoing DSM program. EKPC has 177 participants in the EV Off-Peak Charging pilot program with 194 electric vehicles YTD. EKPC has paid $535.57 in off-peak incentives. Energy and demand reductions from this pilot are being evaluated as part of this pilot program and will not be available until the end of this pilot program.

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STAFF'S REQUEST DATED DECEMBER 20, 2024

REQUEST 58

RESPONSIBLE PARTY: Scott Drake

Request 58. Refer to the Direct Testimony of Scott Drake (Drake Direct Testimony), page 13, lines 8-17. Provide the avoided costs used to determine the cost-effectiveness of the demand-side management (DSM) programs along with cost justification for the avoided costs.

Response 58. Below are the avoided costs used to determine the cost-effectiveness of the DSM programs, along with cost justification for the avoided costs. The values of the avoided costs are in nominal numbers.

a. The avoided energy costs are based on the PJM LMP forward price market. See Table 58-i.

b. The avoided capacity costs are based on EKPC's cost of installing Reciprocating Internal Combustion Engines (RICE). The annual avoided capacity cost rate is calculated using a carrying charge rate (10.8%). These values are next allocated to winter and summer. The summer values come from the BRA auction. The winter values are calculated as the difference between the total avoided cost (RICE) and the summer avoided cost (BRA). See Table 58-ii.

c. A 3 percent adder to avoided capacity cost for reserves was used for screening DSM measures.

d. The avoided cost for natural gas was $3.94 per Mcf.

e. Line losses of 6% were used for both energy and peak in the cost-effectiveness analyses. They are based on average line loss rates.

f. Ancillary services: $2.50 per MWh

g. Transmission and Distribution: $39.58 /kW-year in 2024.

Table 58-i

Year	**Electric Energy Avoided Costs (EE)**			
	Winter Peak Energy	**Winter Off-Peak Energy**	**Summer Peak Energy**	**Summer Off-Peak Energy**
	($/kWh)	($/kWh)	($/kWh)	($/kWh)
2024	$0.0482	$0.0422	$0.0494	$0.0345
2025	$0.0527	$0.0460	$0.0538	$0.0376
2026	$0.0547	$0.0486	$0.0567	$0.0385
2027	$0.0562	$0.0485	$0.0562	$0.0372
2028	$0.0561	$0.0490	$0.0549	$0.0367
2029	$0.0568	$0.0499	$0.0551	$0.0377
2030	$0.0587	$0.0503	$0.0558	$0.0384
2031	$0.0596	$0.0504	$0.0579	$0.0385
2032	$0.0599	$0.0505	$0.0583	$0.0385
2033	$0.0604	$0.0507	$0.0586	$0.0386
2034	$0.0614	$0.0515	$0.0592	$0.0387
2035	$0.0631	$0.0531	$0.0604	$0.0396
2036	$0.0643	$0.0545	$0.0623	$0.0410
2037	$0.0650	$0.0558	$0.0629	$0.0426
2038	$0.0656	$0.0571	$0.0636	$0.0442
2039	$0.0660	$0.0584	$0.0639	$0.0459
2040	$0.0663	$0.0594	$0.0640	$0.0479
2041	$0.0664	$0.0611	$0.0641	$0.0496
2042	$0.0665	$0.0626	$0.0642	$0.0517
2043	$0.0657	$0.0636	$0.0637	$0.0539
2044	$0.0645	$0.0650	$0.0628	$0.0562
2045	$0.0635	$0.0662	$0.0608	$0.0583
2046	$0.0643	$0.0679	$0.0596	$0.0609
2047	$0.0658	$0.0695	$0.0609	$0.0623
2048	$0.0673	$0.0711	$0.0623	$0.0638

Table 57-ii

Capacity Avoided Costs		
	Summer Generation Capacity	**Winter Generation Capacity**
Year	($/kW-YR)	($/kW-YR)
2024	$10.56	$164.04
2025	$28.74	$145.85
2026	$29.93	$144.67
2027	$29.93	$144.67
2028	$31.37	$143.23
2029	$32.87	$141.72
2030	$34.45	$140.15
2031	$36.10	$138.49
2032	$37.84	$136.76
2033	$39.65	$134.94
2034	$41.56	$133.04
2035	$43.55	$131.04
2036	$45.64	$128.96
2037	$47.83	$126.76
2038	$50.13	$124.47
2039	$52.53	$122.06
2040	$55.06	$119.54
2041	$57.70	$116.90
2042	$60.47	$114.13
2043	$63.37	$111.22
2044	$66.42	$108.18
2045	$69.60	$104.99
2046	$72.95	$101.65
2047	$76.45	$98.15
2048	$80.12	$94.48

EAST KENTUCKY POWER COOPERATIVE, INC.
CASE NO. 2024-00370
FIRST REQUEST FOR INFORMATION RESPONSE

STAFF'S REQUEST DATED DECEMBER 20, 2024
REQUEST 59
RESPONSIBLE PARTY: Scott Drake

Request 59. Refer to Drake Direct Testimony, page 17. Explain how EKPC's low-income program has a cost-effectiveness score of 3.46 when low-income programs tend to be not cost effective.

Response 59. Typically, low-income DSM-EE programs have an extremely high implementation cost. EKPC and its Owner-Member cooperatives designed the CARES low-income program with a low implementation cost. The CARES program simply provides incentives directly to the local Community Action Agencies (CAA) or qualifying Affordable Housing Organizations (AHO) to supplement grants and donations those organizations obtain from other resources to improve the housing stock of a qualifying Kentucky family. EKPC's cost of implementation is virtually zero. During times that EKPC has a low avoided cost of capacity, the CARES program still has a TRC around 1.0 or sometimes slightly lower. Due to EKPC's avoided cost of capacity changing to the RICE generation cost, which is higher than the avoided cost of capacity in the last few IRP filings, the result is a much higher TRC this time.

EAST KENTUCKY POWER COOPERATIVE, INC.
CASE NO. 2024-00370
FIRST REQUEST FOR INFORMATION RESPONSE

STAFF'S REQUEST DATED DECEMBER 20, 2024
REQUEST 60
RESPONSIBLE PARTY: Scott Drake

Request 60. Refer to Drake Direct Testimony, Attachment SD-8.

a. Provide a total DSM revenue requirement for all current and proposed programs. Include in the response a total DSM revenue requirement broken out by residential and non-residential.

b. Provide the current DSM rates that each cooperative charge on a per kWh basis. Include in the response the new proposed DSM rates along with a dollar per kWh difference between the current and proposed rates.

c. Explain how EKPC currently recovers its DSM related program costs, shared savings, and/or potential lost revenues.

Response 60.

a. Refer to the Direct Testimony of Scott Drake (Drake Direct Testimony), page 21, line 3-8, of the forecasted $7.8M cost, $3.01M is attributed to non-residential DSM program costs.

b. Neither EKPC nor any of its Owner-Member cooperatives charge a per kwh rate because none of these utilities utilizes the DSM rider.

c. EKPC recovers the DSM expenditures through the normal rate provisions and will request rate recovery for the Commission approved DSM program expenses during the test year of the next EKPC rate case.