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 JOINT INTERVENORS' 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 Joint Intervenor'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, 2024.

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)

Greg Cecil**,** being duly sworn, states that he has supervised the preparation of the responses of East Kentucky Power Cooperative, Inc. to the Joint Intervenor'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.

Greg Cecil

____

Subscribed and sworn before me on this 2nd day of January, 2024.

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 Joint Intervenor'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.

Scott Drake

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Subscribed and sworn before me on this 2nd day of January, 2024.

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)

Mark Horn**,** being duly sworn, states that he has supervised the preparation of the responses of East Kentucky Power Cooperative, Inc. to the Joint Intervenor'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.

Mark Horn

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Subscribed and sworn before me on this 2nd day of January, 2024.

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 Joint Intervenor'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.

Craig Johnson

____

Subscribed and sworn before me on this 2nd day of January, 2024.

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	**)**	**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	**)**	

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 Joint Intervenor'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 her knowledge, information and belief, formed after reasonable inquiry.

Julia J. Tucker

____

Subscribed and sworn before me on this 2nd day of January, 2024.

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 Joint Intervenor'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.

Thomas J. Stachnik

____

Subscribed and sworn before me on this 2nd day of January, 2024.

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)

Don Mosier**,** being duly sworn, states that he has supervised the preparation of the responses of East Kentucky Power Cooperative, Inc. to the Joint Intervenor'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.

Don Mosier

____

Subscribed and sworn before me on this 2nd day of January, 2024.

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)

Jerry Purvis**,** being duly sworn, states that he has supervised the preparation of the responses of East Kentucky Power Cooperative, Inc. to the Joint Intervenor'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.

Jerry Purvis

____

Subscribed and sworn before me on this 2nd day of January, 2024.

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 Joint Intervenor'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.

Brad Young

____

Subscribed and sworn before me on this 2nd day of January, 2024.

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

JOINT INTERVENORS' REQUEST DATED DECEMBER 20, 2024

REQUEST 1

RESPONSIBLE PARTY: Greg Cecil

Request 1. Provide all EKPC responses to data requests from all parties in this proceeding, including confidential responses. Continue to provide any such documentation, until this docket is closed, on a regular basis.

Response 1. All responses to data requests are publicly available on the website of the Kentucky Public Service Commission and the Joint Intervenors receive these in real-time as they are filed via the Commission's electronic filing system. Confidential documents will be provided to parties in accordance with current non-disclosure agreements as they are tendered to the Commission.

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

JOINT INTERVENORS' REQUEST DATED DECEMBER 20, 2024
REQUEST 2
RESPONSIBLE PARTY: Julia J. Tucker

Request 2. With regards to each modeling run carried out as part of this CPCN, including Attachments and Appendices:

a. Produce all modeling input and output files (in electronic machine readable, unprotected format with original formulas intact) for each run.

b. Produce any workbooks or workpapers, in electronic, machine readable, unprotected format with original formulas intact, used to develop or process inputs to the model.

c. Produce any workbooks or workpapers, in electronic, machine readable, unprotected format with original formulas intact, used to review or process outputs of each model run.

Response 2.

a-c. Refer to EKPC's response to Staff's First Request for Information, Item 19.

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

JOINT INTERVENORS' REQUEST DATED DECEMBER 20, 2024
REQUEST 3
RESPONSIBLE PARTY: Julia J. Tucker and Darrin Adams

Request 3. For each of the Cooper generating units (or for the entire Cooper plant if EKPC does not maintain relevant unit-level data):

a. Produce any profit and loss statement, revenue projection, net present value ("NPV") revenue requirement, or other economic analysis of the unit or plant completed since 2018, including any modeling input and output files, workpapers, or other documents used in carrying out such analysis.

b. Produce the most recent condition assessment for each unit.

c. Produce any analysis or assessment of the impact that retirement of each unit would have on resource adequacy, transmission grid stability, transmission grid support, voltage support, or transmission system reliability.

d. Identify any transmission grid upgrades or changes that would be needed to allow for the retirement of any of the units.

<u>Response 3.</u>

a. Refer to the tab labeled "Source Base Annual – 3MAY24", rows 5585 through 5614 in excel attachment *CONFIDENTIAL-JI1- SUMMARY – 3MAY24.xlsx* for energy revenues, rows 265 through 294 for total operating costs, and rows 869 through 898 for total operating profit (energy revenues minus operating costs), subject to motion for confidential treatment. The EKPC 2022 Integrated Resource Plan included economic information for Cooper Station as well. For JI's convenience, EKPC is providing the aforementioned attachment. See attachment *CONFIDENTIAL – 2022-00098 - Joint Intervenors DR1 Response 30.xlsx*, as tendered under seal in Case No. 2022-00098.

b. Refer to Commission Staff DR1 Responses to Questions 29, 30, 33, 34, 37, 38, 41, 42, 45, and 46.

c. Regarding transmission grid/reliability support, see attachment *JI1-3c-1.xlsx* (N-1 contingency analysis results) and Attachment *JI1-3c-2.xlsx* (N-1-1 contingency analysis results), which contain study results from power-flow analysis conducted in 2022 and 2023 for four different scenarios involving the Cooper units being offline. These files show all results where a simulated transmission contingency in conjunction with the generation outage scenario results in a thermal overload, voltage magnitude, or voltage drop criteria violation in the region. The analysis was conducted on EKPC's power-flow models representing 2030 summer and 2030/31 winter-peak load (50/50 probability) periods.

Additionally, as explained in the response to Request No. 23 below, EKPC performed a post-event analysis to simulate system conditions that occurred during Winter Storm Elliott to assess the potential repercussions if generation had not been available in the area near Cooper Station during the weather event.

d. EKPC expects that the following projects would be needed to improve the reliability of service to customer load in the area with the absence of available generation at Cooper Station:

1. A new Cooper Station 69 kV, 43.37 MVAR capacitor bank
2. A new 345 kV line from Cooper Station to LG&E/KU's Alcalde 345 kV substation (a distance of approximately 5 miles) along with the necessary substation expansion required at both ends to facilitate this new 345 kV connection.

These projects will not provide the same level of reliability for the area as exists with operating generators at Cooper Station – local generation provides a higher degree of reliability for the area than these transmission additions can provide. Therefore, EKPC and/or PJM may identify additional projects that would be needed to maintain adequate reliability if generation is no longer available at Cooper Station. Furthermore, as load continues to grow in the area and/or other generators in the region are retired, additional transmission reinforcements would be needed to help support a minimum level of reliability. While the decision to locate the CCGT facility at Cooper Station is not driven by the transmission-support issues in the area that exist without local generation, this planned generation facility addition will provide the benefit of providing continued support to the transmission system in the area. This will avoid the need to consider major transmission-system modifications in the area to replace a portion of the support that is provided by local generation.

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

JOINT INTERVENORS' REQUEST DATED DECEMBER 20, 2024
REQUEST 4
RESPONSIBLE PARTY: Craig A. Johnson and Julia J. Tucker

Request 4. For each of the Cooper generating units, provide the following projected annual data by unit, or, if EKPC does not maintain unit-level data, by plant, for the years 2025 through 2039:

a. Fixed O&M cost in dollars

b. Non-fuel variable O&M cost in dollars

c. Fuel costs in dollars

d. Capital costs in dollars

e. Heat rate

f. Generation

g. Capacity rating

h. Capacity factor

i. Forced outage rate

j. Planned outage rate

k. Energy revenues in dollars

l. Capacity revenues in dollars

m. Ancillary services revenues in dollars

n. Unforced capacity ("UCAP")

<u>Response 4.</u>

a. Refer to the direct testimony of Brad Young, Attachment BY-1, Appendix T.

b. Refer to excel attachment, *JI1-4b – VOM.xlsx*.

c. Refer to the tab labeled "Source Base Annual – 3MAY24", rows 296 through 433 in excel attachment *CONFIDENTIAL-JI1- SUMMARY – 3MAY24.xlsx*, subject to motion for confidential treatment.

d. Refer to the direct testimony of Brad Young, Attachment BY-1, Appendix R.

e. Refer to the tab labeled "Source Base Annual – 3MAY24", rows 235 through 263 in excel attachment *CONFIDENTIAL-JI1- SUMMARY – 3MAY24.xlsx*, subject to motion for confidential treatment.

f. Refer to the tab labeled "Source Base Annual – 3MAY24", rows 65 through 94 in excel attachment *CONFIDENTIAL-JI1- SUMMARY – 3MAY24.xlsx*, subject to motion for confidential treatment.

g. Refer to the direct testimony of Julia J. Tucker and Attachment JJT-4, for the Winter and ELCC-adjustment summer capacity ratings.

h. Refer to the tab labeled "Source Base Annual – 3MAY24", rows 4966 through 4994 in excel attachment *CONFIDENTIAL-JI1- SUMMARY – 3MAY24.xlsx*, subject to motion for confidential treatment.

i. Cooper 1 – 5.182% for all years

Cooper 2 – 2.361% for all years

j. Planned outages were based on actuals through 2026, see attached excel spreadsheet, *JI1-4j - Planned Outages.xlsx*. For years 2027 through 2029, planned outages were assumed to be two weeks per year for Cooper 1 and three weeks per year for Cooper 2. For years 2029 through 2039, planned outages were assumed to be four weeks per year for Cooper 2 after the proposed co-fire conversion project.

k. Refer to the tab labeled "Source Base Annual – 3MAY24", rows 5585 through 5614 in excel attachment *CONFIDENTIAL-JI1- SUMMARY – 3MAY24.xlsx* for energy revenues, rows 265 through 294 for total operating costs, and rows 869 through 898 for total operating profit (energy revenues minus operating costs), subject to motion for confidential treatment.

l. Refer to the Direct Testimony of Julia J. Tucker for the range of capacity revenues anticipated for each proposed project within this Application

m. Ancillary services were not explicitly modeled. Any ancillary services were included in the forecasted total locational marginal price.

n. UCAP is not used to model either energy or capacity revenues or costs. Forced outage assumptions listed in part i of this response are used to model energy revenues and costs. PJM ELCC ratings are used to determine the capacity value of each resource.

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

JOINT INTERVENORS' REQUEST DATED DECEMBER 20, 2024
REQUEST 5
RESPONSIBLE PARTY: **Craig A. Johnson and Julia J. Tucker**

Request 5. For each of the Cooper generating units, provide the following annual data by unit, or, if EKPC does not maintain unit-level data, by plant, for the years 2019 through 2024:

a. Fixed O&M cost in dollars

b. Non-fuel variable O&M cost in dollars

c. Fuel costs in dollars

d. Capital costs in dollars

e. Heat rate

f. Generation

g. Capacity rating

h. Capacity factor

i. Forced outage rate

j. Planned outage rate

k. Energy revenues in dollars

l. Capacity revenues in dollars

m. Ancillary services revenues in dollars

n. Unforced capacity ("UCAP")

Response 5.

a-j.

						thru Oct
	2019	2020	2021	2022	2023	2024
a. Fixed O&M cost in dollars	$ 28,497,057	$ 28,270,123	$ 26,617,811	$ 28,939,080	$ 30,404,096	$ 24,989,060
b. Non-fuel variable O&M cost in dollars	$ 18,806,446	$ 14,985,777	$ 23,985,465	$ 31,175,891	$ 22,525,872	$ 21,102,507
c. Fuel costs in dollars	$ 7,645,943	$ 3,997,187	$ 16,975,646	$ 29,295,137	$ 32,712,578	$ 23,259,288
d. Capital costs in dollars	$ 799,095	$ 133,073	$ -	$ -	$ 54,591	$ 5,978,414
e. Heat rate						
- Cooper 1	11,692	11,991	8,749	11,147	11,471	11,022
- Cooper 2	11,803	10,957	9,031	10,778	10,424	10,934
f. Generation (Gross)						
- Cooper 1	525,837	51,463	138,094	163,189	78,983	107,147
- Cooper 2	153,963	124,461	402,065	453,499	460,919	288,110
g. Capacity rating (Net kwh)						
- Cooper 1	116,000	116,000	116,000	116,000	116,000	116,000
- Cooper 2	225,000	225,000	225,000	225,000	225,000	225,000
h. Capacity factor						
- Cooper 1	4.19%	4.10%	12.03%	14.40%	6.45%	11.24%
- Cooper 2	6.40%	5.17%	18.08%	20.52%	20.90%	15.08%
i. Forced outage rate						
- Cooper 1	1.42%	2.23%	0.80%	1.68%	3.67%	0.52%
- Cooper 2	0.55%	0.07%	0.47%	0.70%	0.26%	0.22%
j. Planned outage rate						
- Cooper 1	11.03%	7.78%	24.49%	10.94%	19.33%	18.02%
- Cooper 2	5.75%	1.48%	15.35%	37.27%	14.67%	17.19%

k.

Year	Cooper 1		Cooper 2	
	Energy Revenue ($)	Ancillery Revenue ($)	Energy Revenue ($)	Ancillery Revenue ($)
2019	1,448,621.06	1,059.77	4,124,567.12	3,710.83
2020	1,255,036.06	23,466.82	2,908,080.39	25,860.48
2021	5,440,769.91	5,222.96	15,656,184.88	13,059.04
2022	13,360,326.58	22,145.23	34,088,956.76	27,035.96
2023	2,421,935.58	35,895.66	13,620,781.63	75,196.01
2024	5,966,418.16	45,952.07	13,851,146.70	78,681.19

l. Refer to EKPC's response to Commission Staff's First Request for Information, Item 25, which was filed confidentially pursuant to a motion for confidential treatment.

m.

Year	Cooper 1		Cooper 2	
	Energy Revenue ($)	Ancillery Revenue ($)	Energy Revenue ($)	Ancillery Revenue ($)
2019	1,448,621.06	1,059.77	4,124,567.12	3,710.83
2020	1,255,036.06	23,466.82	2,908,080.39	25,860.48
2021	5,440,769.91	5,222.96	15,656,184.88	13,059.04
2022	13,360,326.58	22,145.23	34,088,956.76	27,035.96
2023	2,421,935.58	35,895.66	13,620,781.63	75,196.01
2024	5,966,418.16	45,952.07	13,851,146.70	78,681.19

n. Refer to EKPC's response to Commission Staff's First Request for Information, Item 25, which was filed confidentially pursuant to a motion for confidential treatment.

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

JOINT INTERVENORS' REQUEST DATED DECEMBER 20, 2024
REQUEST 6
RESPONSIBLE PARTY: Tom Stachnik

Request 6. Has EKPC sought any financing for potential wind, solar, distributed energy, energy storage, or transmission projects from the U.S. Department of Energy's Energy Infrastructure Reinvestment (EIR) program[1]?

a. If so, identify the potential projects for which financing has been sought, and produce any Letter of Interest, application, or other documentation of such proposal.

b. If not, explain why not.

Response 6.

a. EKPC has not sought funding from the EIR program.

b. EKPC concentrated its efforts on applying for funding from the New ERA program under the IRA, for which it is has been selected to receive $679 million in total value of grants and low-interest loans for solar projects, hydro PPA, and certain transmission investments.

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

JOINT INTERVENORS' REQUEST DATED DECEMBER 20, 2024
REQUEST 7
RESPONSIBLE PARTY: Tom Stachnik

Request 7. Has EKPC sought any financing or funding for potential wind, solar, geothermal, or energy efficiency projects from the U.S. Department of Agriculture's Rural Energy for America Program?[2]

a. If so, identify the potential projects for which financing has been sought, and produce any Letter of Interest, application, or other documentation of such proposal.

b. If not, explain why not.

Response 7.

a. EKPC has not recently applied for the REAP Program, though it did receive a REAP grant for Cooperative Solar 1 several years ago.

b. EKPC concentrated its efforts on applying for funding from the New ERA program under the IRA, for which it is has been selected to receive \$679 million in total value of grants and low-interest loans for solar projects, hydro PPA, and certain transmission investments,

EAST KENTUCKY POWER COOPERATIVE, INC.

CASE NO. 2024-00370

FIRST REQUEST FOR INFORMATION RESPONSE

JOINT INTERVENORS' REQUEST DATED DECEMBER 20, 2024

REQUEST 8

RESPONSIBLE PARTY: Julia J. Tucker

<u>Request 8.</u> In selecting the proposed Cooper CCGT project, did EKPC carry out any capacity expansion modeling or production cost modeling?

a. If so:

i. identify what sort of modeling EKPC carried out and what model(s) you used.

ii. produce all modeling input and output files, workpapers, workbooks, and other documents used in such modeling.

iii. detail the results of such modeling.

b. If not, explain why not.

<u>Response 8.</u> a - b. Yes, EKPC used the RTSim production cost modeling software to derive expected variable operating profits and related data for the Cooper CCGT project. EKPC separately estimated capacity revenues for the Cooper CCGT based on a range of recent clearing prices and the PJM-published ELCC rating for CCGT class units, as described in the direct testimony of Julia J. Tucker. Refer to EKPC's response to Staff's First Request for Information, Item 19.

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REQUEST 9
RESPONSIBLE PARTY: Julia J. Tucker

Request 9. Identify each generation resource, demand side resource, and/or market purchase that you evaluated, either individually or in combination, as an alternative to all or some of the proposed Cooper CCGT capacity. For each alternative(s) evaluated,

a. Describe what evaluation you undertook

b. Explain why you rejected the alternative(s)

c. Produce any documentation, workpapers, workbooks, or modeling input and output files regarding such evaluation.

Response 9. a-c See Staff Response 7a.

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REQUEST 10
RESPONSIBLE PARTY: Julia J. Tucker

Request 10. Identify the Net Present Value Revenue Requirement ("NPVRR") for each of the Cooper CCGT, Cooper Co-Fire, and Spurlock Co-Fire Projects. Produce any modeling input and output files, workpapers, workbooks, and other documents used in determining the NPVRR for each project.

Response 10. Traditional planning methodology utilizes comparisons of all available generation technologies, runs them through an optimization analysis and then develops Present Value of Revenue Requirements (PVRR) comparisons of the best alternatives. This methodology is predicated on having ample time to meet the expected need and having multiple alternatives for supply. The defined changes in EKPC's load forecast, based on actual winter peak loads, has expedited the need for new generation. The current environmental requirements eliminate coal from being a viable baseload generation alternative. Nuclear is not at a demonstrated operating and/or price point to be a viable alternative for EKPC. Intermittent generation such as solar or wind can be paired with storage technologies to somewhat emulate a baseload unit. However, market operations during December 2022 showed the vulnerability of storage facilities. The load throughout the region did not dissipate enough to allow the storage facilities to re-charge, thus leaving them useless for much needed generation. Therefore, the only highly demonstrated and proven technology for EKPC to consider for baseload service is a combined cycle gas turbine (CCGT) generator.

The next question would be if the system needed more peaking, intermediate or baseload generation. EKPC modeled a CCGT compared to the market, which would be EKPC's "do nothing" scenario. That comparison demonstrated the value of adding a CCGT to the system and the results have been provided in this case. The qualitative value of adding a CCGT to the system is also a driving force for the decision to construct such a unit. Environmental regulations continue to pressure existing coal units into retirement and new dispatchable plants are not being added at a pace to keep up with retirements. The electric system as a whole is being stretched to its limits and many studies, including the NERC 2024 Long-Term Reliability Assessment ("LTRA") published on December 17, 2024, show major concerns for reliability. Therefore, it is clear on a risk assessed basis, that a CCGT is EKPC's most logical choice for generation to be able to install and operate in a timely fashion. Refer to *Staff3b - NERC_Long Term Reliability Assessment_2024.pdf* attached to EKPC's response to Staff's data requests tendered on January 3rd 2025. Since time is of the essence to move forward with this plan, and there were no truly feasible alternatives for the type of generator needed, EKPC moved forward with a more abbreviated planning analysis than what it would have traditionally completed.

For the economic value as modeled for this application, refer to EKPC's response to Item 3a, above.

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JOINT INTERVENORS' REQUEST DATED DECEMBER 20, 2024
REQUEST 11
RESPONSIBLE PARTY: Tom Stachnik

Request 11. Identify the impact of each of the Cooper CCGT, Cooper Co-Fire, and Spurlock Co-Fire Projects on rates and average monthly bills for residential customers of EKPC's member-owners for each of the years 2025 through 2039.

Response 11. 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 complete proposed portfolio of projects (RICE, Cooper CC, Co-firing and New ERA renewables) which meets generation needs and environmental compliance requirements with modest rate increases, averaging less than 2% per year over the next 20 years.

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JOINT INTERVENORS' REQUEST DATED DECEMBER 20, 2024
REQUEST 12
RESPONSIBLE PARTY: Julia J. Tucker

<u>Request 12.</u> Refer to the Direct Testimony of Don Mosier, p. 5 lines 14-19.

a. Identify EKPC's peak demand during each hour of Winter Storm Gerri.

b. Identify EKPC's peak demand during each hour of Winter Storm Elliott.

c. Identify EKPC's installed peak winter generation capacity in each of the years 2022, 2023, and 2024.

d. Identify the total number of hours in each of the years 2022, 2023, and 2024 during which EKPC's peak demand exceeded its installed peak winter generation capacity.

e. For each of the years 2025 through 2034, identify the total number of hours in which you forecast that EKPC's peak demand will exceed its current installed peak winter generation capacity.

<u>Response 12.</u>

a. Refer to attachment *JI1 – 12.xlsx.*

b. Refer to attachment *JI1 – 12.xlsx.*

c.

- 2022 - 3,427 MW peak winter generation
- 2023 - 3,727 MW peak winter generation
- 2024 - 3,727 MW peak winter generation

d.

- 2022 – 1 hour
- 2023 – 0 hours
- 2024 (through Dec. 22) – 2 hours

e. The long term load forecast assumes normal weather. The number of hours listed below does not consider extreme weather events or planning reserves.

- 2025 – 0 hours
- 2026 – 0 hours
- 2027 – 0 hours
- 2028 – 0 hours
- 2029 – 0 hours
- 2030 – 1 hour
- 2031 – 1 hour
- 2032 – 1 hour
- 2033 – 1 hour
- 2034 – 1 hour

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JOINT INTERVENORS' REQUEST DATED DECEMBER 20, 2024
REQUEST 13
RESPONSIBLE PARTY: Julie Tucker and Brad Young

Request 13. Refer to the Direct Testimony of Don Mosier, p. 7 lines 16-18. With regards to the statement that "EKPC also anticipates seeking a CPCN for additional renewable energy as soon as next year due in part to the investment tax credits and New ERA funds available to cooperatives.

a. Identify by resource type and approximate size in MWs the "additional renewable energy" referred to in the quoted testimony

b. State whether the referenced "additional renewable energy" is reflected in the EKPC Expansion Plan – Q4 2024 set forth in Attachment JJT-4.

i. If so, identify the amount (in MWs) of Winter and Summer capacity from such "additional renewable energy" is reflected therein and in what year such capacity is first reflected.

ii. If not, explain why not.

<u>Response 13.</u>

a. EKPC anticipates seeking CPCNs for additional renewable energy projects in 2025 due in part to the investment tax credits and New ERA funds available to cooperatives. These proposed projects are listed below:

[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
		[redacted]

b. Yes, the additional renewable energy is reflected in the EKPC expansion plan as shown in Attachment JJT-4. EKPC estimates the summer capacity for these additions using PJM's published ELCC class ratings for fixed solar assets. The result can be seen in the summer capacity addition column in Attachment JJT-4. EKPC did not attribute any winter capacity to these resources as solar generation does not coincide with winter peak demand periods.

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JOINT INTERVENORS' REQUEST DATED DECEMBER 20, 2024
REQUEST 14
RESPONSIBLE PARTY: Scott Drake

Request 14. Refer to the Direct Testimony of Don Mosier, p. 13 lines 8-12.

a. Identify and produce the source or basis for the $450,000/MWh cost for utility scale Battery Energy Storage Systems ("BESS") referenced therein.

b. State whether the referenced $450,000/MWh cost figure is inclusive of the Investment Tax Credit ("ITC") for energy storage provided under the federal Inflation Reduction Act.

i. If so, identify what level of ITC is included in that cost figure.

ii. If not, explain why not.

Response 14.

a. EKPC is a member of the National Renewables Cooperative (NRCO) and utilizes NRCO as an independent resource to issue and evaluate EKPC's Request for Proposals (RFP) for utility-scale renewable resources. NRCO performs this function for many cooperatives across the United States and has direct knowledge of the general cost of utility-scale renewables and BESS. Based on proposals evaluated by NRCO for other cooperatives issuing BESS RFPs, the general cost of utility-scale BESS was provided to EKPC. No BESS RFP for EKPC was issued.

b. The general utility-scale BESS cost per MWh provided to EKPC by NRCO did not include ITC from the Inflation Reduction Act.

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JOINT INTERVENORS' REQUEST DATED DECEMBER 20, 2024
REQUEST 15
RESPONSIBLE PARTY: Tom Stachnik

Request 15. Refer to the Direct Testimony of Don Mosier, p. 13 lines 12-16.

a. Explain the basis for the claim that "BESS was excluded from the USDA's New ERA program," and identify and produce any documentation supporting that claim.

b. Identify and produce any communications with the USDA or the Rural Utilities Service regarding whether BESS projects could be eligible for New ERA financial support, either as a standalone project or in combination with other eligible clean energy projects.

Response 15.

a. According to the Notice of Funding Opportunity (NOFO) published in the Federal Register on 5/16/2023 (Vol. 88 No. 94) page 31223 C. 1. ii, b. 2, "Energy Storage Systems in support of GHG emission reduction or Renewable Energy Systems" are eligible projects. Standalone BESS or BESS to support fossil generation was not included.

b. The aforementioned NOFO is attached as *JI1 - 15 - NOFO.pdf*.

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REQUEST 16

RESPONSIBLE PARTY: Don Mosier

Request 16. Refer to the Direct Testimony of Don Mosier, p. 15 line 22 to p. 16 line 2. State whether there is a word or words missing from, or other typo in, the statement "But even if the GHG Rule with the new administration . . . ". If so, please correct.

Response 16. The response is missing words and should read as the following: "But even if the GHG Rule *goes away* with the new administration . . ."

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REQUEST 17
RESPONSIBLE PARTY: Don Mosier

Request 17. Refer to the Direct Testimony of Don Mosier, p. 18 lines 4-7. With regards to the sentence "It will also minimize stranded investments, which benefits consumers":

a. Does the "It" refer to the proposed Cooper Combined Cycle Gas Turbine ("CCGT")?

i. If so, explain how the proposed CCGT would minimize stranded investments.

ii. If not, explain what the "It" refers to, and how that would minimize stranded investments.

Response 17.

a i and ii. Yes, "It" refers to the Cooper CCGT. Locating the CCGT at Cooper Station allows for the continued use of an existing facility as well as supporting the co-fire conversion of Cooper 2, which minimizes the stranded investment in that unit.

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JOINT INTERVENORS' REQUEST DATED DECEMBER 20, 2024
REQUEST 18
RESPONSIBLE PARTY: Don Mosier

Request 18. Refer to the Direct Testimony of Don Mosier, p. 19 lines 6-8.

a. State whether EKPC believes that the Cooper Unit 2 gas co-firing project should still proceed "even if the GHG Rule goes away." Explain why or why not.

b. State whether EKPC believes that the Spurlock Units 1-4 gas co-firing project should still proceed "even if the GHG Rule goes away." Explain why or why not.

Response 18.

a. 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 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 GHG emissions, as published in its Sustainability Plan, by 35% by 2035.

b. Yes

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REQUEST 19

RESPONSIBLE PARTY: Julia J. Tucker

Request 19. Refer to the Direct Testimony of Julia Tucker, p. 5 lines 11-19. Produce the EKPC Strategic Plan that is currently in place.

Response 19. Refer to attachment, *CONFIDENTIAL-JI1-19 EKPC-Strategic-Plan-Booklet-04_18_2024.pdf*.

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REQUEST 20

RESPONSIBLE PARTY: Julia J. Tucker

Request 20. Refer to the Direct Testimony of Julia Tucker, p. 9 lines 3-5. Has EKPC created any projection or estimate of the amount of megaload capacity and/or energy demand that may come onto the EKPC system over any of the years 2025 through 2040? If so, produce such projection or estimate. If not, explain why not.

Response 20. See Staff Response 6a.

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JOINT INTERVENORS' REQUEST DATED DECEMBER 20, 2024
REQUEST 21
RESPONSIBLE PARTY: Julia J. Tucker

Request 21. Refer to the Direct Testimony of Julia Tucker, p. 13 lines 8 to p. 15 line 2.

a. Explain how the 7% Capacity Planning Reserve Margin assumed by EKPC differs from PJM's seasonal planning reserve margin.

b. Explain why EKPC does not consider the PJM seasonal planning reserve margin sufficient to account for "unknown risks in weather and generation availability."

c. Explain why EKPC does not consider PJM's ELCC capacity accreditation methodology sufficient to account for "unknown risks in weather and generation availability."

d. Produce any modeling input and output files, workpapers, or other documents used in creating EKPC's 7% Capacity Planning Reserve Margin.

e. Identify how much of the 12% higher than forecasted peak load experienced during Winter Storms Elliott and Gerri has been included in the revised 2024 LTLF.

f. Identify and produce any analysis that EKPC has carried out or reviewed of the impact to its rates of using a 7% Capacity Planning Reserve Margin for each of the winter and summer seasons.

<u>Response 21.</u>

a. Refer to EKPC's response to Staff's First Request for Information, Item 9a and b.

b. EKPC, per Commission orders, cannot plan to exclusively rely on the PJM market for reserves. The long-standing policy of the Commission is that utilities should be able to meet native load based upon "steel in the ground" resources owned and operated by the utility.

c. PJM's ELCC capacity accreditation accounts for risk on PJM's system as a whole, not the risk for EKPC specifically. Sufficient generation may be available in some areas of PJM, while it might not be available within EKPC's system. EKPC must account for the risk of unit outages within EKPC to appropriately hedge its native load.

d. The capacity planning reserve margin ("reserve margin") of seven percent was based on the methodology described in the direct testimony of Julia J. Tucker, page 14 line 4 through page 15 line 4. The analysis compares the normal one-in-two peak load forecast ("normal") from the 2024 LTLF to a one-in-ten extreme weather ("extreme") event occurring for 48 hours every other forecast year. The result of that comparison is a seven percent difference between normal and extreme weather peak loads. Refer to the attached Excel spreadsheet, *JI21d – Extreme Event vs. Forecast.xlsx*.

e. The 2024 LTLF of winter peak demand ranges from 147 MW to 260 MW more than the 2022 LTLF of winter peak demand. The average over the forecast period is 230 MWs – approximately 6.5%.

f. Refer to EKPC's response to Item 11, above.

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JOINT INTERVENORS' REQUEST DATED DECEMBER 20, 2024
REQUEST 22
RESPONSIBLE PARTY: Julia J. Tucker

Request 22. Refer to the Direct Testimony of Julia Tucker, p. 15 lines 7-19. Identify for each of EKPC's generating units how the capacity accreditation changed in MW for the 2025/26 BRA as a result of PJM's shift from EFORd to ELCC as the capacity accreditation methodology.

Response 22. Refer to attached Excel spreadsheet, *JI1-22 – EFORD to ELCC Comparison.xlsx.*

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JOINT INTERVENORS' REQUEST DATED DECEMBER 20, 2024
REQUEST 23
RESPONSIBLE PARTY: Julia J. Tucker

Request 23. Refer to the Direct Testimony of Julia Tucker, p. 26 lines 11-15.

a. Explain in what ways the transmission system in the Cooper area came "perilously close" to not being able to serve load in the region during Winter Storm Elliott.

b. Identify and produce any analysis of how the transmission system in the Cooper area performed during Winter Storm Elliott, and/or why the system came perilously close to not being able to serve load.

c. Identify and produce any analysis of transmission upgrades of expansions that could help ensure reliability and transmission support in the Cooper area during severe weather events like Winter Storm Elliott.

Response 23.

a. Refer to EKPC's response to Staff's first Request for Information, Item 20a.

b. See Attachment *JI1-23b.pdf*, which is a summary report detailing a study that was performed by EKPC Transmission Planning staff in 2023 to simulate the events experienced during Winter Storm Elliott and perform various "what-if" analyses to determine potential repercussions of additional transmission and/or generation outages on the system. Exhibits 3 and 4 provide heat maps – i.e., visual representations of the areas where system voltages were in danger of becoming severely low. Tables 6, 7, 8 and 12 provide details regarding the thermal overloads, low voltage levels, and substation loads that could potentially have been manually shed if generation had not been available at Cooper Station during this weather event.

c. After Winter Storm Elliott and the post-event analysis that EKPC performed, as described in the response above, EKPC's Transmission Planning and Transmission Operations teams discussed potential transmission-system upgrades and additions in the area to reinforce the system in preparation for similar events. The teams agreed on one transmission-system addition that should be implemented as soon as possible, which is installation of a new 43.37 MVAR capacitor bank connected to the Cooper Station 69 kV bus. This project is currently scheduled to be completed by December 2026. This capacitor bank will provide an alternative source of reactive power for the area during periods when one or both Cooper units are unavailable. This addition was identified as an interim solution to bridge the gap until a more robust, longer-term solution (either a transmission or generation solution, or both) to the reliability issues in the area is implemented.

For the longer-term transmission solution, EKPC formed a team of subject-matter experts from various departments (Transmission Planning, Transmission Operations, System Protection, Power Delivery Reliability, Power Delivery Maintenance, etc.) to assess potential transmission alternatives and develop a recommendation for the best transmission alternative to implement in the event that generation is not maintained and/or added at or near Cooper Station. Attachment *JI1-23-c.pdf* provides a summary of the alternatives considered, the relative load-serving benefits and costs, and the recommended solution from the internal EKPC team in the event that generation is no longer located in the area around Cooper Station.

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JOINT INTERVENORS' REQUEST DATED DECEMBER 20, 2024
REQUEST 24
RESPONSIBLE PARTY: Julia J. Tucker

Request 24. Refer to Attachment JJT-5. With regards to the 2029 through 2039 Thermal Unit Net Cost Benefit values for the Cooper CCGT set forth in line 8:

a. Explain how you determined the referenced Net Cost Benefit values, including identification of any modeling program used in determining such values.

b. Produce any modeling input and output files, workpapers, workbooks, or other documents used in determining the referenced Net Cost Benefit values

c. Identify the "expected market price" that you used in determining the referenced Net Cost Benefit values at whatever level of granularity (i.e. hourly, daily, weekly, etc.) was used.

d. With regards to the "cost to run the unit" used in determining the referenced Net Cost Benefit values, identify the costs used for:

i. Natural gas

ii. Variable O&M

iii. Any other cost to run the unit

e. Explain why the annual Net Cost Benefit value for the Cooper CCGT is the same for each of the years 2030 through 2033.

f. Identify the projected annual fixed O&M costs and capital cost of the Cooper CCGT for each of the years 2030 through 2039.

g. Refer to the Direct Testimony of Craig Johnson, p. 6 lines 7-11. State whether the Thermal Unit Net Cost Benefit values for the Cooper CCGT set forth in Attachment JJT-5 assume that the facility will be limited to a maximum 40% capacity factor under the GHG Rule. If not, identify the projected Thermal Unit Net Cost Benefit values if the Cooper CCGT were limited to a maximum 40% capacity factor.

<u>Response 24.</u>

a. Refer to EKPC's response to Staff's First Request for Information, Item 21a.

b. Refer to EKPC's response to Staff's First Request for Information, Item 24.

c. Refer to attached excel spreadsheet, *JI1-24c - NG Coal ADHub.xlsx*.

d.

i. Refer to Item 24c, above.

ii. Refer to Item 4b, above.

iii. Refer to Item 24c, above.

e. The net cost benefit and megawatt hour values for the Cooper CCGT for the years 2030 through 2032 have been updated in the attached Excel spreadsheet, *JI1-24e.xlsx*.

f. Refer to the direct testimony of Brad Young, Attachment BY-1, Appendix T.

g. No, EKPC did not model the Cooper CCGT with a 40 % cap on the capacity factor. An estimate for the net cost benefit and generation in MWh with the 40% cap is provided in the attached excel spreadsheet, *JI1-24g.xlsx*.

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JOINT INTERVENORS' REQUEST DATED DECEMBER 20, 2024
REQUEST 25
RESPONSIBLE PARTY: Julia J. Tucker

Request 25. Refer to Attachment JJT-5. With regards to the 2029 through 2039 Thermal Unit Generation values for the Cooper CCGT set forth in line 20:

a. Explain how you determined the referenced Thermal Unit Generation values, including identification of any modeling program used in determining such values.

b. Produce any modeling input and output files, workpapers, workbooks, or other documents used in determining the referenced Thermal Unit Generation values

c. State whether your analysis used to determine the referenced Thermal Unit Generation values assumed the operation of the Liberty RICE units proposed in Case No. 2024-00310. If not, explain why not.

d. State whether your analysis used to determine the referenced Thermal Unit Generation values assumed that the Cooper Unit 2 gas co-firing and Spurlock Units 1-4 gas co-firing projects would also be operating. If not, explain why not.

e. Explain why the annual Thermal Unit Generation values for the Cooper CCGT is the same for each of the years 2030 through 2033.

f. Refer to the Direct Testimony of Craig Johnson, p. 6 lines 7-11. State whether the Thermal Unit Generation values for the Cooper CCGT set forth in Attachment JJT-5 assume that the facility will be limited to a maximum 40% capacity factor under the GHG Rule. If not, identify the projected Thermal Unit Generation values if the Cooper CCGT were limited to a maximum 40% capacity factor.

Response 25.

a. Refer to EKPC's response to Staff's First Request for Information, Item 21a.

b. Refer to EKPC's response to Staff's First Request for Information, Item 24.

c. Yes, the modeling included the operation of the Liberty RICE units.

d. Yes, the modeling included the operation of the Cooper 2 and Spurlock 1-4 co-firing projects.

e. Refer to Item 24e, above.

f. Refer to Item 24g, above.

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JOINT INTERVENORS' REQUEST DATED DECEMBER 20, 2024
REQUEST 26
RESPONSIBLE PARTY: Julia J. Tucker

Request 26. Refer to the Direct Testimony of Julia Tucker, p. 26 line 23 through p. 27 line 2.

a. Identify the BRA capacity market clearing prices you assumed in determining that the Cooper CCGT is "anticipated to provide between $5.8 million and $56.4 million in annual capacity market benefits."

b. Identify each specific "recent BRA clearing prices" that are referenced therein.

Response 26.

a and b. EKPC estimated this range using the recently cleared 2024/25 and 2025/26 BRA clearings prices of $28/MW-Day and $270/MW-Day, respectively.

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JOINT INTERVENORS' REQUEST DATED DECEMBER 20, 2024
REQUEST 27
RESPONSIBLE PARTY: Julia J. Tucker

Request 27. Refer to the Direct Testimony of Julia Tucker, p. 29 lines 7-16 and Attachment JJT-5. With regards to the projected "over $117 million in net energy cost benefits over the 10-year period" for the Cooper Co-Fire Project:

a. Explain how you determined the Thermal Unit Net Cost Benefit values for the Cooper 2 Co-Fire 100% NG set forth on line 3 of Attachment JJT-5, including identification of any modeling program used in determining such values.

b. Produce any modeling input and output files, workpapers, workbooks, or other documents used in determining the referenced Net Cost Benefit values.

c. Identify the "expected market price" that you used in determining the Net Cost Benefit values at whatever level of granularity (i.e. hourly, daily, weekly, etc.) was used.

d. With regards to the "cost to run the unit" used in determining the referenced Net Cost Benefit values, identify the costs used for:

i. Natural Gas

ii. Variable O&M

iii. Any other cost to run the unit

e. For each of the years 2030 through 2039, identify in $ per MWh the extent to which you expect the Cooper Co-Fire Project would reduce the variable energy cost of the unit as compared to continuing to operate the Cooper Unit 2 on coal.

f. State whether you compared the projected Thermal Unit Net Cost Benefit value of the Cooper Co-Fire Project to the value of continuing to operate Cooper Unit 2 on coal for the years 2030 through 2039. If so, produce the results of that comparison. If not, explain why not.

g. Identify the projected annual fixed O&M cost and capital cost for Cooper Unit 2 with 100% gas co-firing for each of the years 2030 through 2039.

Response 27.

a. Refer to EKPC's response to Staff's First Request for Information, Item 21a.

b. Refer to EKPC's response to Staff's First Request for Information, Item 24.

c. Refer to Item 24c, above.

d. Refer to Item 24di-iii, above.

e. EKPC did not model the direct comparison between Cooper 2 continuing to operate on 100% coal versus 100% natural gas. However, the model shows that Cooper 2 had an average capacity factor for the 2025-2029 period of 9.6% while operating 100% on coal. After the co-fire project, Cooper 2 had an average capacity factor for the 2029-2039 period of 36.7% while operating 100% on natural gas. This increase indicates the unit is more economic to run on natural gas than on coal.

f. Refer to EKPC's response in Staff First Request for Information, Item 21c.

g. Refer to the direct testimony of Brad Young, Attachment BY-2, Section 7.7.

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JOINT INTERVENORS' REQUEST DATED DECEMBER 20, 2024
REQUEST 28
RESPONSIBLE PARTY: Julia J. Tucker

Request 28. Refer to Attachment JJT-5. With regards to the 2029 through 2039 Thermal Unit Generation values for the Cooper 2 Co-Fire 100% NG set forth in line 15:

a. Explain how you determined the referenced Thermal Unit Generation values, including identification of any modeling program used in determining such values.

b. Produce any modeling input and output files, workpapers, workbooks, or other documents used in determining the referenced Thermal Unit Generation values

c. State whether your analysis used to determine the referenced Thermal Unit Generation values assumed the operation of the Liberty RICE units proposed in Case No. 2024-00310. If not, explain why not.

d. State whether the analysis used to determine the referenced Thermal Unit Generation values assumed that the Cooper CCGT and Spurlock Units 1-4 gas co-firing projects would also be operating. If not, explain why not.

Response 28.

a. Refer to EKPC's response to Staff's First Request for Information, Item 21a.

b. Refer to EKPC's response to Staff's First Request for Information, Item 24.

c. Yes, the modeling included the operation of the Liberty RICE units.

d. Yes, the modeling included the operation of the Cooper CCGT and Spurlock Units 1-4 gas co-firing projects.

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REQUEST 29

RESPONSIBLE PARTY: Julia J. Tucker

Request 29. Refer to Attachment JJT-2, the EKPC 2025-2039 Load Forecast. Produce all supporting modeling input and output files, workbooks, workpapers, and documents, used to develop the 2024 Long Term Load forecast ("LTLF").

Response 29. Please see the response to Commission Staff's First Request for Information in Case No. 2024-00310 (Staff's First Request) Item 1 for supporting workpapers and modeling files related to EKPC's 2024 Long Term Load Forecast. Also see response to Commission Staff's Second Request for Information in Case No. 2024-00310 (Staff's Second Request) Item 7.

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REQUEST 30

RESPONSIBLE PARTY: **Julia J. Tucker**

Request 30. Refer to Attachment JJT-2, the EKPC 2025-2039 Load Forecast, p. 1. Produce the EKPC Load Forecast Work Plan referenced therein.

Response 30. Refer to attachment *JI1–30 2025 – 2039 Load Forecast Work Plan.pdf.*

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REQUEST 31
RESPONSIBLE PARTY: Julia J. Tucker

<u>Request 31.</u> Refer to Attachment JJT-2, the EKPC 2025-2039 Load Forecast, p. 16. With regards to the large commercial sales projections referenced therein:

a. Identify in years the "short term" period in which your projections rely on the input of the owner-members.

b. Produce any written documentation of the input that each of the owner-members provided regarding projected large commercial sales.

c. For each owner-member, identify the projection of each of the following that was input into the large commercial sales projections:

i. Usage for large existing loads;

ii. Number and projected load and energy use of new large commercial customers; and

iii. Number, load, and energy use of existing large commercial customers leaving the system.

d. Explain and produce any documentation of any "additional input" into the large commercial sales projection that was provided by EKPC's Economic Development staff.

<u>Response 31.</u>

a. Projections include input from the owner-members during the short-term period through 2029. Input from the owner-members is based on their negotiations with large commercial consumers.

b. This is confidential information between the owner-member and large commercial consumers. Preliminary forecasts were reviewed and discussed with owner-members and updated large commercial load projections were incorporated into the revised forecast which was approved by the owner-members.

c. Usage for large existing loads was based on historic actuals with adjustments made as needed per feedback from the owner members to capture large commercial consumers leaving the system, decreasing, or expanding load. Projected counts, demand, and energy use for new large commercial consumers is below, shown in aggregate rather than at the owner-member level for confidentiality purposes:

Year	New Consumer Count (Non Cumulative)	Average Load per New Consumer MWh (Non Cumulative)	New Consumer Increased Demand MW (Cumulative)	New Consumer Increased Energy MWh (Cumulative)
2024	11	7,175	13	78,924
2025	7	49,427	72	424,916
2026	2	145,222	126	715,359
2027	3	51,465	156	869,754
2028	5	12,877	166	934,140
2029	4	29,516	182	1,052,205
2030	2	9,198	185	1,070,601
2031	4	9,198	191	1,107,393
2032	5	9,198	199	1,153,383
2033	3	9,198	203	1,180,977
2034	3	9,198	208	1,208,571
2035	4	9,198	214	1,245,363
2036	7	9,198	224	1,309,749
2037	3	9,198	229	1,337,343
2038	5	9,198	236	1,383,333
2039	3	9,198	241	1,410,927

Note that in the above table new consumers are counted in the year they first arrive, even if not at full production or if the consumer starts late in the year. For example, a consumer starting at half production in October 2024 and achieving full production by 2027 is considered a new consumer in 2024.

d. Discussions with the economic development staff included project timelines, load expectations, and potential growth at industrial parks. Input from these discussions was incorporated into the load forecast.

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REQUEST 32

RESPONSIBLE PARTY: Julia J. Tucker

Request 32. Refer to Attachment JJT-2, the EKPC 2025-2039 Load Forecast, p. 17.

a. Produce the EKPC wholesale power cost projection used in the 2024 Load Forecast.

b. Identify for each owner-member the projected distribution adder for the retail rate assumption.

Response 32.

a. Finance provided the annual forecasted change in the wholesale portion of rates (below). The percent change is applied to each owner-member's residential rate.

Year	% Change
2025	[redacted]
2026	
2027	
2028	
2029	
2030	
2031	
2032	
2033	
2034	
2035	
2036	
2037	
2038	

b. Each owner-member provides the distribution adder forecast based on their internal analysis. This is confidential information to the owner-members.

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REQUEST 33
RESPONSIBLE PARTY: Julia J. Tucker

Request 33. Refer to Attachment JJT-2, the EKPC 2025-2039 Load Forecast, p. 26. Identify the amount of energy (in MWh), winter peak (in MW), and summer peak (in MW) savings due to energy efficiency measures installed prior to 2025 assumed to be "embedded" in the load data for 2024.

Response 33. Below are the MWh and MW savings due to energy efficiency measures installed prior to 2025 assumed to be embedded in the load data for 2024:

MWh	Winter MW	Summer MW
166,258	29.0	23.3

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REQUEST 34
RESPONSIBLE PARTY: Julia J. Tucker

Request 34. Refer to Attachment JJT-2, the EKPC 2025-2039 Load Forecast, p. 27. Please state the percentage of residential customers that rely on wood for their primary heating source.

Response 34. Based on EKPC's 2022 Residential Appliance Saturation Survey 5.2% of respondents say they use Wood/Coal for their Main Heating Fuel. Wood and coal are not reported separately.

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JOINT INTERVENORS' REQUEST DATED DECEMBER 20, 2024
REQUEST 35
RESPONSIBLE PARTY: Julia J. Tucker

Request 35. Refer to Attachment JJT-2, the EKPC 2025-2039 Load Forecast, p. 39. With regards to the Large Commercial Class Consumers and Sales:

a. Identify how many Large Commercial Class consumers are in the EKPC system as of the end of 2024.

b. Identify how many of the Large Commercial Class consumers projected to come online in each of 2025, 2026, and 2027 have commenced construction activities.

i. Identify the total projected peak demand and annual energy requirements for the consumers who have commenced construction activities.

c. Identify how many of the Large Commercial Class consumers projected to come online in each of 2025, 2026, and 2027 have entered into any contracts with EKPC or any of its member-owners.

i. Identify the total projected peak demand and annual energy requirements for the Large Commercial Class consumers who have entered into contracts with EKPC or any of its member-owners.

d. Identify the total peak demand for Large Commercial Class consumers in 2023.

e. Identify the projected total peak demand for Large Commercial Class consumers in each of the years 2024 through 2039.

f. Identify and explain each reason why you project that annual average energy use per Large Commercial Class consumer will increase by more than 17% from 2023 to 2026 (from 21,774 MWh to 25,628 MWh).

<u>Response 35.</u>

a. 198. 2024 large commercial consumer counts are based on the average number of consumers through September 2024. Current data for two owner-members is not available and is estimated from the most current available data.

b. EKPC does not track owner-member large commercial consumer construction activities.

c. No contracts have been executed for those years.

d. Peak demand is not captured separately by RUS consumer class.

e. Peak demand is not projected separately by RUS consumer class.

f. New large commercial loads are larger on average than for historical existing consumers. See table in Response 31 c.

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JOINT INTERVENORS' REQUEST DATED DECEMBER 20, 2024
REQUEST 36
RESPONSIBLE PARTY: Julia J. Tucker

Request 36. Refer to Attachment JJT-3.

a. Confirm that your 2022 Load Forecast projected for 2023 over 2.2 million MWHs more energy sales than your actual 2023 energy sales. If not confirmed, explain why not.

b. Identify and explain any steps you have taken in your 2024 Load Forecast to minimize similar over-projections of future energy sales.

c. Identify in MWHs your actual 2024 energy sales to date.

Response 36.

a. Yes confirmed.

b. 2023 sales were below forecast due to milder than normal winter seasons which explains the large negative variance. The forecast assumes normal weather so actuals will vary from forecast depending on mild or extreme seasons. The large commercial sales were also below forecast. EKPC discussed and updated assumptions for large commercial sales with each of its owner-members.

c. November 2024 year-to-date energy sales to owner-members are 12,517,665 MWh. This is not RUS Form 7 data as typically presented. This is data from EKPC's billing reports and is not weather adjusted.

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REQUEST 37
RESPONSIBLE PARTY: Julia J. Tucker

Request 37. Refer to the Direct Testimony of Craig Johnson, p. 10 lines 1-2.

a. Identify and produce any forecast of natural gas prices for any or all of the years 2025 through 2039 that EKPC relied on for this CPCN application.

b. Identify and produce any forecast of coal prices for any or all of the years 2025 through 2039 that EKPC relied on for this CPCN application.

Response 37.

a and b. Refer to attached excel spreadsheet, *JI1-24c - NG Coal ADHub.xlsx*.

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JOINT INTERVENORS' REQUEST DATED DECEMBER 20, 2024
REQUEST 38
RESPONSIBLE PARTY: Craig A. Johnson

Request 38. Refer to the Direct Testimony of Craig Johnson, p. 10 lines 14-17.

a. Explain how you calculated the $2.5 million annual non-fuel O&M savings referenced therein.

b. Explain how you calculated the estimated 49% reduction in operating variable costs from burning a blend of 50% natural gas.

c. Explain how you calculated the estimated 7% reduction in maintenance costs from burning a blend of 50% natural gas.

d. Identify what level of estimated reductions in operating variable and maintenance costs would result from burning 100% natural gas at Cooper Unit 2 after the Cooper Co-Fire Project.

Response 38.

a. EKPC started with the actual operating and maintenance spend from 2023, then reviewed each line and made adjustments based on anticipated difference from 100% coal to the 50% coal and Natural Gas blend. $2.5Million was the total reduction calculated.

b. EKPC started with the actual operating and maintenance spend from 2023, then reviewed each line and made adjustments based on anticipated difference from 100% coal to the 50% coal and Natural Gas blend. 49% was calculated by using the reduction in Operating variable costs divide by the total 2023 operating variable costs.

c. EKPC started with the actual operating and maintenance spend from 2023, then reviewed each line and made adjustments based on anticipated difference from 100% coal to the 50% coal and Natural Gas blend. 7% was calculated by using the reduction in maintenance costs divide by the total 2023 maintenance costs.

d. EKPC estimates that burning 100% natural gas will reduce operating variable costs by 97.9% and the maintenance costs by 21%. The annual nonfuel O&M savings should be on the order of $5.65 million.

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JOINT INTERVENORS' REQUEST DATED DECEMBER 20, 2024
REQUEST 39
RESPONSIBLE PARTY: Craig A. Johnson

Request 39. Refer to the Direct Testimony of Craig Johnson, p. 13 lines 12-14. With regards to the ongoing Operation and Maintenance costs of the proposed Spurlock Co-Fire Project:

a. Explain in sufficient detail to allow independent verification how you calculated the $13.7 million annual non-fuel O&M savings referenced therein.

b. Explain in sufficient detail to allow independent verification how you calculated the estimated 46% reduction in operating variable costs from burning a blend of 50% natural gas.

c. Explain in sufficient detail to allow independent verification how you calculated the estimated 4% reduction in maintenance costs from burning a blend of 50% natural gas.

d. State whether burning a higher blend of natural gas than 50% would lead to additional reductions in variable operating and maintenance costs. If not, explain why not. If so:

i. Identify for each of the Spurlock units what level of estimated reductions in operating variable and maintenance costs would result from burning 100% natural gas.

ii. Explain why you are not proposing higher than 50% natural gas co-firing at each of the Spurlock units.

<u>Response 39.</u>

a. Reference Excel spreadsheet *JI1-39 - Spurlock Co-fire 50%Blend -O&M change.xlsx*.

b. Reference Excel spreadsheet *JI1-39 - Spurlock Co-fire 50%Blend -O&M change.xlsx*.

c. Reference Excel spreadsheet *JI1-39 - Spurlock Co-fire 50%Blend -O&M change.xlsx*.

d. Theoretically there could be a reduction in O&M nonfuel costs by increasing the Natural gas above 50%, however, the gas provider doesn't have sufficient capacity to allow for a higher blend across all 4 Units at Spurlock. Furthermore Units 3 and Units 4 are Circulating Fluidized Bed boilers which transfer heat via particulate in the flow stream, so increasing Natural Gas to or near 100% would remove most or all particulate in the flow stream. Due to this, EKPC has considerable concern with the reliability and capability of those units with higher Natural Gas content.

i. Reference previous statement, 39d. Gas provider currently does not have the capacity available to support higher than 50% gas at Spurlock for all 4 Units.

ii. Reference previous statement, 39d. Gas provider currently does not have the capacity available to support higher than 50% gas at Spurlock for all 4 Units.

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REQUEST 40
RESPONSIBLE PARTY: Darrin Adams

Request 40. Refer to the Direct Testimony of Darrin Adams, p. 6 line 3 to p. 7 line 2. State whether EKPC analyzed grid-enhancing technologies (GETs) or other alternatives in its power-flow study that could meet the same transmission upgrade requirements at lower cost. If so, explain how GETs and other alternatives were considered. If not, explain why not.

Response 40. Yes, certain grid-enhancing technologies were considered where deemed logical from an engineering standpoint. Use of advanced conductors, in particular Aluminum Conductor Steel Supported ("ACSS"), was considered for identified line rebuild projects, and was recommended for use in the proposed new Cooper-LG&E/KU Alcalde 161 kV line in order to provide an adequate thermal rating for the line without using larger bundles of traditional Aluminum Conductor Steel Reinforced ("ACSR"). EKPC's approach in identifying potential projects to address the numerous thermal overloads identified in the power-flow analysis was to specify the set of mitigation projects that would provide adequate transmission-outlet capability for the added generation, while minimizing overall cost. Therefore, where possible, increases of the maximum operating temperature of the existing conductors in a line were identified. If such conductor temperature increases were not possible, a rebuild of the existing lines in the same right-of-way corridor were identified using either larger ACSR or ACSS conductor-types. In addition to these conductor temperature upgrades and rebuilds of existing lines, EKPC determined that the new Cooper-Alcalde 161 kV line is needed to provide an additional path for the increased power flows created by the Cooper CCGT addition. This plan provides adequate transmission thermal capacity in the area in a manner that minimizes overall cost and the need for greenfield transmission construction.

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REQUEST 41
RESPONSIBLE PARTY: Darrin Adams

Request 41. Refer to the Direct Testimony of Darrin Adams, p. 14 lines 1-20. With regards to the "reliability concerns" that have been a "known problem for several years" referenced therein:

a. State what steps EKPC has taken to address this "known problem" since it was identified in Case No. 2007-00168.

b. State whether EKPC has evaluated upgrades or additions to the transmission system that could address this "known problem" without needing to rely on additional new generation capacity in the area.

i. If so:

1. Explain what evaluations have occurred and their results; and

2. Produce any power flow analysis, report, or other documentation of such evaluation.

ii. If not, explain why not.

c. State whether both existing Cooper units, the proposed Liberty RICE units, and the proposed Cooper CCGT are all necessary to address the "known problem." If so, explain why and provide any analysis supporting that response.

Response 41.

a. First, as approved by the Commission in Case 2007-00168, EKPC completed modifications of its water intake system at Cooper Station to construct barge-mounted pumps in Lake Cumberland for continued reliable intake of cooling water at lower lake levels, as well as construction of a cooling tower for Unit #2. These modifications addressed the immediate concern regarding the ability of the Cooper units to operate due to the emergency draw-down of Lake Cumberland by the U.S. Army Corps of Engineers until necessary repairs of the Wolf Creek Dam could be completed.

Second, beginning in 2015, a simultaneous outage of Cooper Units 1 and 2 (in conjunction with the outage of a single transmission-system element) has been considered to be a single generating unit outage scenario in EKPC's transmission planning process due to the connection of the Cooper Unit 1 emissions system to the scrubber system that had been installed on Cooper Unit 2 in 2012. EKPC believes this to be a prudent decision given the potential for either a planned or unplanned outage of the scrubber to result in both Cooper units not being operational. Therefore, EKPC has taken steps to design the system to withstand a single transmission element outage in the area along with both Cooper Units offline, based on assumed system conditions in available power-flow models. As a result, several projects have been identified and implemented in the area to address violations of EKPC planning criteria identified due to an outage of a transmission element in the area along with a simultaneous outage of one or both Cooper Units. Third, EKPC has decided to install a new 69 kV, 43.37 MVAR capacitor bank at Cooper Station before December 2026 to provide additional reliability and reactive-power margin for the region for high-load periods when one or both Cooper units are not operating.

These actions have helped to maintain reliability, but are not sufficient to cover the wide range of system conditions that are experienced in real-time operations. For instance, during the major ice storm event that occurred in a large portion of Kentucky in February 2021, numerous transmission facilities were out of service in the southern region of Kentucky, making the availability of local generation critical to the continued ability to serve load in the region. As another example, Winter Storm Elliott in December 2022 resulted in an EKPC system demand level never before experienced or contemplated in EKPC's transmission-planning studies. The load level experienced during this event stressed the transmission system to the boundary of its capabilities, with the availability of generation at Cooper being the factor that maintained the system within those capabilities.

b. Yes, EKPC has performed such an evaluation. See the response to Request No. 23, part c., for the requested information regarding this evaluation.

c. Availability of local generation for the southern region of Kentucky provides a high degree of reliability of service for electric demand in the area. Generally, the more generation located in an area, the better the reliability will be. The redundancy provided by multiple generating units, particularly at different locations, is valuable to service reliability. However, for conditions assumed in transmission-planning studies, it is not necessary for all existing generation at Cooper Station plus the planned generation additions at Cooper Station and the Liberty RICE facility to be operating simultaneously to maintain adequate and reliable service for the region.

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REQUEST 42
RESPONSIBLE PARTY: Jerry Purvis

Request 42. Refer to the Direct Testimony of Jerry Purvis, p. 11 line 21 to p. 12 line 2. State whether EKPC has submitted the referenced air permit application to the Kentucky Division of Air Quality. If so, produce that application, including any exhibits or attachments. If not, identify by when EKPC plans to submit the application, and produce it upon submittal.

Response 42. EKPC is preparing the air application to the KY Division for Air Quality. The timeline to submit is in January / February 2025. The application will be available on KDAQ's website.

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JOINT INTERVENORS' REQUEST DATED DECEMBER 20, 2024
REQUEST 43
RESPONSIBLE PARTY: Jerry Purvis

Request 43. Refer to the Direct Testimony of Jerry Purvis, p. 14 line 20 to p. 15 line 3.

a. Explain how EKPC's proposal to co-fire with natural gas Spurlock units 3 and 4 to support compliance with EPA's GHG Rule is consistent with EKPC's comments to EPA on the draft GHG Rule stating that "CFBs cannot co-fire natural gas because they depend upon coal ash contacting the steam generating tubes inside the furnace. Much research would need to be conducted to see if a viable alternative would be possible and economic."[3]

b. Has EKPC now concluded that the Spurlock 3 and 4 CFB units are able to co-fire natural gas?

i. If so, explain what research was carried out to determine that co-firing natural gas at Spurlock 3 and 4 is feasible, and produce any reports, analyses, or other documents supporting such determination.

ii. If not, explain why EKPC is seeking a CPCN for a natural gas co-firing project at Spurlock 3 and 4.

<u>Response 43.</u>

a. EPA assumed in the proposed rule that all coal boilers could co-fire natural gas, making it, in essence, a one-solution-fits-all type of an approach. EKPC's goal through participating in the public rulemaking process was to provide EPA valuable information not known or acknowledged by them for consideration. This quote from the proposed rule was our intent.

At the exact point in time as referenced above during the proposed rule, EKPC was not aware of CFBs co-firing natural gas with coal to lower CO2 emissions since the technology relied upon coal ash contact with boiler tubing steaming elements to make steam. Furthermore, EKPC's concern was that no one had commercially and successfully completed this design and implementation. The conversion of the Unit 3 and Unit 4 CFB's for co-firing natural gas would rely upon a novel design solutions that was unproven. Additionally, EKPC was highly concerned about preserving unit capacity and fleet capacity since new capacity could not replace existing capacity on terms within the rule to retire by January 1, 2032 or install CCS by January 1, 2030, sooner. So immediately, EKPC hired an engineering consultant to conduct co-firing studies and research on the Spurlock CFB technology. Since then, engineering studies have been conducted on CFB technology to see if it was feasible, doable and practicable. Engineering studies concluded that CFB technology could co-fire up to 50% with natural gas and still provide sufficient steam to the turbine. Pease see Attachment BY-1 to the application.

b. EKPC CFB technology was studied by an engineering consultant that concluded that natural gas could be co-fired in the units with coal and then determined the extent was up to 50% in order to preserve unit rated capacity. Therefore, EKPC is filing a CPCN for the

Commission to consider co-firing Spurlock CFB technology for units 3 and 4 to comply with EPA's final GHG rule for existing units. Pease see Attachment BY-1 to the application.

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JOINT INTERVENORS' REQUEST DATED DECEMBER 20, 2024
REQUEST 44
RESPONSIBLE PARTY: Mark Horn (Confidential)

Request 44. Refer to the Direct Testimony of Mark Horn, p. 4 lines 1-14. With regards to securing a natural gas supply for the Spurlock Co-Fire Project:

a. Identify the estimated capital cost of the natural gas lateral and other infrastructure investments needed to secure such natural gas supply.

i. If the estimated capital cost is anything other than the "estimated investment cost of $400 to $450 million" EKPC cited in its Comments on the Draft 111 GHG Rule,[4] explain why.

b. State whether such capital costs are factored into the Thermal Unit Net Cost Benefit values for the Spurlock Co-Fire Project set forth in Attachment JJT-5.

i. If so, explain how.

ii. If not, explain why not.

Response 44.

a. The estimated capital cost for the interstate pipeline company's pipeline expansion, for what they are calling the Maysville Project, will be approximately [redacted]. This natural gas pipeline expansion project by the interstate pipeline company will secure capacity for the natural gas supply for the proposed Spurlock Co-Fire Project. The interstate pipeline will recoup its capital investment from EKPC over a twenty-year period.

i. Since EKPC submitted Comments on the 111 Draft GHG Rule in August 2023 the estimated investment cost has been revised to reflect more recent costs based on two (2) competitive phases of proposals from the bidders. Since July 2024, EKPC has been working with a Class 4 cost estimate, which is more current, accurate, and lower than the initial estimate from August 2023.

b. These estimated capital costs are not factored into the Thermal Unit Net Cost Benefit values for the Spurlock Co-Fire Project set forth in Attachment JJT-5.

i. Not Applicable.

ii. The estimated capital costs and other infrastructure investments to flow natural gas to a point where Spurlock can have access to the physical natural gas is not an EKPC project. The estimated capital cost for the interstate pipeline company's pipeline expansion is not on EKPC's balance sheet.

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JOINT INTERVENORS' REQUEST DATED DECEMBER 20, 2024
REQUEST 45
RESPONSIBLE PARTY: Mark Horn (Confidential)

Request 45. Refer to the Direct Testimony of Mark Horn, p. 4 lines 1-14. With regards to securing a natural gas supply for the Cooper site:

a. Identify the estimated capital cost of the natural gas lateral and other infrastructure investments needed to secure the referenced natural gas supply.

i. If the estimated capital cost is anything other than the "estimated investment cost of $400 to $450 million" EKPC cited in its Comments on the Draft 111 GHG Rule,[5] explain why.

b. State whether such capital costs are factored into the Thermal Unit Net Cost Benefit values for the Cooper Co-Fire Project and/or Cooper CCGT set forth in Attachment JJT-5.

i. If so, explain how.

ii. If not, explain why not

Response 45.

a. The estimated capital cost for the interstate pipeline company's pipeline expansion, for what they are calling the Pulaski Project, will be approximately [redacted]. This natural gas pipeline expansion project by the interstate pipeline company will secure capacity for the natural gas supply for the Cooper site. The interstate pipeline will recoup its capital investment from EKPC over a twenty-year period.

i. Since EKPC submitted Comments on the 111 Draft GHG Rule in August 2023 the estimated investment cost has been revised to reflect more recent costs based on two (2) competitive phases of proposals from the bidders. Since July 2024, EKPC has been working with a Class 4 cost estimate, which is more current, accurate, and lower than the initial estimate from August 2023.

b. These estimated capital costs are not factored into the Thermal Unit Net Cost Benefit values for the Cooper Co-Fire Project and/or Cooper CCGT set forth in Attachment JJT-5.

i. Not Applicable.

ii. The estimated capital costs and other infrastructure investments to flow natural gas to a point where Cooper can have access to the physical natural gas is not an EKPC project. The estimated capital cost for the interstate pipeline company's pipeline expansion is not on EKPC's balance sheet.

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JOINT INTERVENORS' REQUEST DATED DECEMBER 20, 2024
REQUEST 46
RESPONSIBLE PARTY: Mark Horn

Request 46. Refer to the Direct Testimony of Mark Horn, p. 8 lines 18-21.

a. State whether each of the two Precedent Agreements ("PAs") have been fully executed. If so, when were they fully executed. If not, explain why not and state when you expect the PAs to be fully executed.

b. State whether the pipeline company has requested and received approval from its internal Capital Allocation Committee. If so, when was such approval requested and received. If not, explain why not and state when you expect such approval to be requested and received.

Response 46.

a. The two Precedent Agreements ("PAs") referenced, which consist of a specific PA for Spurlock and a specific PA for Cooper, are in the final negotiation phase and subject to minor clarifications or revisions. It is expected that both PAs will be in their final form and fully executed early in January 2025.

b. The pipeline company has requested and received approval from its internal Capital Allocation Committee. This approval was requested and received on October 15, 2024.

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JOINT INTERVENORS' REQUEST DATED DECEMBER 20, 2024
REQUEST 47
RESPONSIBLE PARTY: Mark Horn

Request 47. Refer to Attachment MH-3. Explain why the referenced document identifies a "Commercial Operation" date of 02/2033 for the Cooper 2x1 CC unit ("CCGT"), rather than the "expectation" stated in the Direct Testimony of Don Mosier, p. 19 lines 3-4, that the proposed CCGT would be "completed and operational" by December 31, 2030.

Response 47. Attachment MH-3 is a timeline with a holistic view of the various Gas Generation Projects shared with all potential bidders early in the RFP process. When the RFP was issued in December 2023 to initiate the bidding process, the Commercial Operation Date ("COD") for the Cooper 2x1 CC unit ("CCGT") was planned to be February 2033. As 2024 progressed and new and more accurate information became available, this schedule was accelerated. The Direct Testimony of Don Mosier stating that the CCGT would be completed and operational by December 31, 2030, is now the current expectation.

EAST KENTUCKY POWER COOPERATIVE, INC.

CASE NO. 2024-00370

FIRST REQUEST FOR INFORMATION RESPONSE

JOINT INTERVENORS' REQUEST DATED DECEMBER 20, 2024

REQUEST 48

RESPONSIBLE PARTY: Scott Drake

Request 48. Refer to the Direct Testimony of Scott Drake, p. 10 lines 13-16. Identify the time period for which EKPC is seeking Commission approval of the proposed DSM-EE programs and changes.

Response 48. Pursuant to the Commission Order dated December 5, 2024, the DSM tariff approval request was suspended by the Commission until June 1, 2025, at the latest. That time is satisfactory to EKPC. The tariffs do not have a sunset provision and will remain in effect until any future changes are approved or required by the Commission.

EAST KENTUCKY POWER COOPERATIVE, INC.

CASE NO. 2024-00370

FIRST REQUEST FOR INFORMATION RESPONSE

JOINT INTERVENORS' REQUEST DATED DECEMBER 20, 2024

REQUEST 49

RESPONSIBLE PARTY: Scott Drake

Request 49. Refer to the Direct Testimony of Scott Drake, p. 18 line 14 to p. 19 line 2. Of the impacts on energy requirements, winter peak, and summer peak set forth therein, identify what portion of such impacts are from new DSM-EE programs being proposed, and what portion is from existing programs for which EKPC is proposing higher incentives.

Response 49. The following tables provide the impacts for new DSM-EE programs and for existing programs for which EKPC is proposing higher incentives:

Load Impacts of New DSM Programs

(negative value= reduction in load)

Year	Impact on Energy Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2025	0	0	0
2026	-5,995	-2	-1
2027	-11,990	-4	-3
2028	-17,985	-7	-4
2029	-23,980	-9	-5
2030	-29,975	-11	-7
2031	-35,970	-13	-8
2032	-41,965	-16	-9
2033	-47,959	-18	-10
2034	-53,954	-20	-12
2035	-59,949	-22	-13
2036	-65,924	-24	-14
2037	-71,877	-26	-15
2038	-77,831	-28	-16
2039	-83,784	-29	-17

Load Impacts of Existing DSM Programs with New Tariffs

(negative value= reduction in load)

Year	Impact on Energy Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2025	-2,939	-1	0
2026	-8,267	-3	-1
2027	-13,594	-5	-2
2028	-18,922	-8	-3
2029	-24,250	-10	-3
2030	-29,577	-12	-4
2031	-34,905	-14	-5
2032	-40,232	-16	-6
2033	-45,560	-19	-6
2034	-50,888	-21	-7
2035	-56,215	-23	-8
2036	-61,543	-25	-9
2037	-66,871	-27	-10
2038	-72,198	-30	-10
2039	-77,526	-32	-11

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

JOINT INTERVENORS' REQUEST DATED DECEMBER 20, 2024
REQUEST 50
RESPONSIBLE PARTY: Scott Drake

Request 50. Refer to the Direct Testimony of Scott Drake, p. 21 lines 16-19.

a. Identify the cost to install Reciprocating Internal Combustion Engines that you used as the new avoided capacity cost value for evaluating DSM-EE programs.

b. Produce the forward cost curve of PJM's BRA mentioned in the referenced text.

Response 50.

a. The installed cost per kW for the Reciprocating Internal Combustion Engine that was used to calculate the new generation capacity avoided cost is $2,200 per kW.

b. The following table provides the forward capacity cost curve of PJM's BRA referenced:

	Forward RTO LDA
PY beginning	Capacity $/MW-day
2024	$28.92
2025	$78.75
2026	$82.00
2027	$82.00
2028	$85.94
2029	$90.06
2030	$94.38
2031	$98.91
2032	$103.66
2033	$108.64
2034	$113.85
2035	$119.32
2036	$125.04
2037	$131.05
2038	$137.34
2039	$143.93
2040	$150.84

EAST KENTUCKY POWER COOPERATIVE, INC.
CASE NO. 2024-00370
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JOINT INTERVENORS' REQUEST DATED DECEMBER 20, 2024
REQUEST 51
RESPONSIBLE PARTY: Scott Drake

Request 51. Refer to the Direct Testimony of Scott Drake, p. 5 lines 13-23.

a. Please provide the avoided cost values for capacity and generation used in the DSM Technical Potential studies for each of the last three IRP filings.

b. To the extent that the values provided in response to subpart a changed from one DSM Technical Potential Study to the next, please explain the basis for each such change and provide supporting calculations, if any.

Response 51.

a. The following tables provide the avoided cost values for capacity and generation that were used in the DSM Technical Potential studies for the 2015, 2019, and 2022 IRP filings:

For the 2015 IRP:

	Energy				Generation Capacity	
	Winter On Peak	Winter Off Peak	Summer On Peak	Summer Off Peak	Summer	Winter
	¢ /kWh	¢ /kWh	¢ /kWh	¢ /kWh	$/kW-yr	$/kW-yr
2014					123.00	
2015	5.07	3.73	4.82	2.99	126.50	0.00
2016	5.03	3.93	4.77	3.10	128.00	0.00
2017	5.15	4.04	4.99	3.24	130.50	0.00
2018	5.17	4.14	5.13	3.34	133.50	0.00
2019	5.29	4.21	5.26	3.34	136.75	0.00
2020	5.38	4.31	5.38	3.43	140.00	0.00
2021	5.60	4.43	5.60	3.52	143.25	0.00
2022	5.74	4.56	5.74	3.62	146.75	0.00
2023	5.86	4.66	5.87	3.70	150.25	0.00
2024	5.93	4.72	5.93	3.75	154.00	0.00
2025	6.06	4.82	6.06	3.82	157.75	0.00
2026	6.20	4.92	6.20	3.91	161.50	0.00
2027	6.45	5.08	6.46	4.10	165.25	0.00
2028	6.80	5.25	6.82	4.40	169.25	0.00
2029	7.22	5.47	7.26	4.77	173.25	0.00
2030	7.61	5.68	7.54	5.03	177.50	0.00
2031	7.97	5.91	7.88	5.37	181.76	0.00
2032	8.08	6.02	8.01	5.69	186.12	0.00
2033	8.33	6.30	8.16	5.94	190.59	0.00
2034	8.48	6.46	8.33	6.09	195.16	0.00
2035	8.66	6.63	8.50	6.26	199.85	0.00
2036	8.90	6.81	8.74	6.43	204.64	0.00
2037	9.15	7.00	8.99	6.61	209.56	0.00
2038	9.41	7.20	9.24	6.80	214.58	0.00
2039	9.68	7.40	9.50	6.98	219.73	0.00
2040	9.94	7.60	9.75	7.17	225.01	0.00

For the 2019 IRP:

	Electric Energy Avoided Costs (EE)					Capacity Avoided Costs	
	Winter Peak Energy	**Winter Off-Peak Energy**	**Summer Peak Energy**	**Summer Off-Peak Energy**		**Summer Generation Capacity**	**Winter Generation Capacity**
Year	(¢/kWh)	(¢/kWh)	(¢/kWh)	(¢/kWh)		($/kW-YR)	($/kW-YR)
2018	3.48	2.72	3.47	2.36		29.20	0.00
2019	3.49	2.82	3.34	2.27		27.93	0.00
2020	3.52	2.77	3.28	2.20		42.73	0.00
2021	3.50	2.69	3.28	2.22		44.43	0.00
2022	3.59	2.74	3.43	2.23		47.48	0.00
2023	3.45	2.84	3.38	2.29		55.47	0.00
2024	3.45	2.74	3.48	2.28		58.37	0.00
2025	3.50	2.82	3.46	2.17		73.28	0.00
2026	3.46	2.84	3.40	2.25		83.62	0.00
2027	3.61	2.97	3.36	2.25		100.54	0.00
2028	3.83	3.18	3.58	2.39		106.44	0.00
2029	3.99	3.33	3.79	2.57		114.52	0.00
2030	4.16	3.48	3.98	2.72		122.37	0.00
2031	4.35	3.66	4.19	2.91		126.89	0.00
2032	4.61	3.90	4.45	3.13		134.16	0.00
2033	4.89	4.18	4.74	3.41		132.55	0.00
2034	5.28	4.55	5.10	3.73		144.50	0.00
2035	5.73	4.97	5.52	4.15		140.69	0.00
2036	6.21	5.43	6.00	4.60		145.79	0.00
2037	6.88	6.07	6.60	5.17		147.54	0.00
2038	7.58	6.79	7.28	5.89		148.12	0.00
2039	8.36	7.58	8.07	6.68		151.08	0.00
2040	8.74	7.94	8.84	7.51		154.11	0.00
2041	8.93	8.11	9.03	7.67		157.19	0.00
2042	9.12	8.29	9.23	7.83		160.33	0.00
2043	9.33	8.47	9.43	8.00		163.54	0.00
2044	9.55	8.65	9.65	8.18		166.81	0.00
2045	9.77	8.84	9.87	8.36		170.14	0.00
2046	9.99	9.04	10.10	8.54		173.55	0.00
2047	10.22	9.23	10.33	8.73		177.02	0.00

For 2022 IRP:

Year	Electric Energy Avoided Costs (EE)					Capacity Avoided Costs	
	Winter Peak Energy	Winter Off-Peak Energy	Summer Peak Energy	Summer Off-Peak Energy		Summer Generation Capacity	Winter Generation Capacity
	(¢/kWh)	(¢/kWh)	(¢/kWh)	(¢/kWh)		($/kW-YR)	($/kW-YR)
2021	3.44	2.64	3.24	2.22		9.13	0.00
2022	3.18	2.46	3.10	2.10		36.50	0.00
2023	3.19	2.47	2.99	2.03		55.16	0.00
2024	3.22	2.53	2.97	2.05		60.45	0.00
2025	3.29	2.57	3.03	2.12		67.51	0.00
2026	3.37	2.60	3.08	2.14		74.62	0.00
2027	3.41	2.60	3.12	2.17		77.92	0.00
2028	3.45	2.65	3.15	2.17		80.04	0.00
2029	3.49	2.67	3.19	2.23		78.33	0.00
2030	3.53	2.68	3.23	2.23		79.50	0.00
2031	3.53	2.69	3.27	2.23		85.00	0.00
2032	3.53	2.73	3.25	2.24		87.72	0.00
2033	3.69	2.87	3.26	2.28		90.00	0.00
2034	3.94	3.09	3.55	2.50		92.58	0.00
2035	4.21	3.34	3.89	2.77		95.07	0.00
2036	4.57	3.68	4.28	3.07		99.04	0.00
2037	4.95	4.03	4.74	3.46		104.23	0.00
2038	5.43	4.48	5.24	3.88		108.49	0.00
2039	5.89	4.96	5.87	4.42		112.79	0.00
2040	6.38	5.47	6.47	4.96		119.39	0.00
2041	6.94	6.03	7.07	5.49		125.20	0.00
2042	7.63	6.72	7.88	6.17		130.16	0.00
2043	7.98	7.07	8.78	7.02		132.55	0.00
2044	8.16	7.23	8.98	7.18		134.98	0.00
2045	8.34	7.39	9.18	7.34		137.44	0.00
2046	8.53	7.55	9.38	7.50		140.03	0.00

b. Changes in the avoided energy costs are driven by changes in the forward price market. Changes in the avoided generation capacity stem from changes in the PJM BRA price.

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JOINT INTERVENORS' REQUEST DATED DECEMBER 20, 2024
REQUEST 52
RESPONSIBLE PARTY: Scott Drake

Request 52. Refer to the Direct Testimony of Scott Drake, p. 12 lines 3-7.

a. Please state whether a customer that relies on liquified petroleum gas, bottled gas, propane, wood, coal, fuel oil, or kerosene for their primary heating source would be eligible to receive an incentive for a heat pump through the High Efficiency Heat Pump program.

i. If not, please explain why not for each ineligible primary heating source listed above.

b. Please explain the difference(s) between the "High Efficiency Heat Pump program" and the existing "Heat Pump Retrofit program," including but not limited to differences in customer eligibility requirements, incentive-eligible equipment standards, and incentive amounts available for customers.

Response 52.

a. The High Efficiency Heat Pump program targets end-use members who have decided to install a new heat pump regardless of their current heating system type. The typical end-use member usually installs the Department of Energy's (DOE) minimum standard heat pump. The program incentivizes the end-use member to install a more energy-efficient heat pump like an

ENERGY STAR® rated heat pump instead of the DOE minimum standard heat pump. The program only incentivizes the decision to go from the DOE minimum standard heat pump to the higher energy efficiency heat pumps and does not encourage fuel switching.

b. The target market and the level of efficiency are the main differences in the programs. The target market for the Heat Pump Retrofit Program are end-use members who currently heat their home using electric resistive heat systems and, in Kentucky, those systems are usually an electric furnace or electric baseboard heat systems. Those types of heating systems are extremely energy inefficient. Thus, the goal of this program is providing a $750 incentive to the end-use member for installing the DOE minimum standard heat pump. The end-use member is eligible for a $1,000 incentive when installing the more efficient ENERGY STAR® heat pump. The incentive to mini-split heat pump systems is $500 per indoor head. Again, the goal is to incentivize the end-use member to switch from their existing inefficient electric heat systems to at least the DOE minimum standard heat pumps.

The High Efficiency Heat Pump program only incentives end-use members to install heat pumps with an efficiency rating above DOE minimum standard and assumes the end-use member has already made the decision to install a new heat pump, typically because their existing older heat pump has stopped working. There is no incentive to install the DOE minimum standard heat pump because the assumption is the end-use member is going to install that anyway. The $500 incentive is provided to the end-use member to install a more efficient ENERGY STAR® heat pump or $1,000 incentive for a cold climate air-source heat pump that is even more efficient than ENERGY STAR® rated heat pumps.

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JOINT INTERVENORS' REQUEST DATED DECEMBER 20, 2024
REQUEST 53
RESPONSIBLE PARTY: Scott Drake

Request 53. Refer to the Direct Testimony of Scott Drake, p. 16 lines 3-4, and p. 17 lines 4-6.

a. Please reconcile the statements in the referenced testimony.

b. Please explain the analysis used by EKPC and its owner-member cooperatives to evaluate the impact of a program on rates, given that the RIM cost-effectiveness test "does not provide the magnitude of the change in rates; just the direction of that change."

c. Please explain the range of rate impacts from a DSM program that EKPC or its owner-members would consider to be reasonable. To the extent that EKPC or its owner-members determine the reasonableness of such a rate impact based on a quantitative analysis, please provide workpapers reflecting that analysis.

d. Please explain the range of rate impacts from supply-side generation investments that EKPC or its owner-members would consider to be reasonable. To the extent that EKPC or its owner-members determine the reasonableness of such a rate impact based on a quantitative analysis, please provide workpapers reflecting that analysis.

Response 53.

a. The statement in the Direct Testimony of Scott Drake p.16 lines 3-4 is correct. A RIM greater than 1.0 indicates that rates for non-participants will decrease, while a RIM less than 1.0 indicates that rates for non-participants will decrease. The RIM result does not provide the magnitude of the change, just the direction of that change. The statement on p.17 lines 4-6 refers to using judgment in interpreting the program RIMs. Programs with RIMs above 1.0 will not cause rates for non-participants to rise. If a program has a RIM below 1.0, EKPC uses judgement. Is this a large program or a small program? Are there mitigating factors like how many end-use members will participate over the program's life? Does the program provide a benefit that is not easily quantified? Does the program mitigate risks? Does the program provide savings to a particular class or subclass that would have no access to DSM service without this program? Also, EKPC uses the TRC to determine whether a program or measure should be included in the portfolio of DSM programs. The RIM is a secondary test concerned with equity between participants and non-participants.

b. The impact on rates is best determined at the portfolio level rather than the individual program level. The portfolio RIM is 1.02, indicating a very modest decline in rates. A useful metric is the net RIM costs of the Portfolio divided by the EKPC revenue requirements. Using this metric, the rate impact of this DSM portfolio is - 0.07%.

c. EKPC has not established a range.

d. EKPC has not established a range.

EAST KENTUCKY POWER COOPERATIVE, INC.

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JOINT INTERVENORS' REQUEST DATED DECEMBER 20, 2024

REQUEST 54

RESPONSIBLE PARTY: **Scott Drake**

Request 54. Refer to the Direct Testimony of Scott Drake, p. 20 lines 3-4. State whether there is a word or words missing from, or other typo in, the statement that "DSM-EE programs selected were determined to not be top priority programs by the group."

Response 54. The sentence should have read, "DSM-EE programs selected were determined to be top priority programs by the group."

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JOINT INTERVENORS' REQUEST DATED DECEMBER 20, 2024
REQUEST 55
RESPONSIBLE PARTY: Scott Drake

Request 55. Refer to the Direct Testimony of Scott Drake, p. 20 lines 6-16. Will all EKPC owner-member cooperatives support customer participation in the proposed DSM plan? If not, please explain which programs each EKPC owner-member cooperative will implement.

Response 55. The DSM programs offered by EKPC to its owner-member cooperatives are al a cart. EKPC is unaware of which programs each owner-member will offer to its end-use members.

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JOINT INTERVENORS' REQUEST DATED DECEMBER 20, 2024

REQUEST 56

RESPONSIBLE PARTY: Scott Drake

Request 56. Refer to Attachment SD-7, the 2024 Potential Study, pp. 6-7 Table 2-1. Explain why the 15-Year Sales Forecast shows the same amount of Commercial sector sales in each of the years 2024 through 2038.

Response 56. The values for Commercial sales in Table 2-1 are incorrect. However, the values for the Residential, Industrial, and Total Sales match the values EKPC provided to GDS. The following table provides the correct Commercial Sales numbers:

	MWH Sales			
	Residential	**Commercial**	Industrial	Total
2024	7,402,322	**2,012,248**	5,701,182	15,115,753
2025	7,428,973	**2,016,275**	5,786,966	15,232,214
2026	7,489,821	**2,023,974**	5,868,476	15,382,271
2027	7,562,150	**2,031,957**	5,883,552	15,477,658
2028	7,667,946	**2,048,924**	5,908,442	15,625,311
2029	7,718,946	**2,056,721**	5,939,702	15,715,369
2030	7,782,382	**2,062,333**	5,970,474	15,815,189
2031	7,846,863	**2,067,869**	5,994,749	15,909,480
2032	7,958,099	**2,082,437**	6,010,626	16,051,163
2033	8,023,613	**2,087,411**	6,034,403	16,145,427
2034	8,123,071	**2,093,470**	6,065,247	16,281,789
2035	8,220,988	**2,102,861**	6,114,680	16,438,529
2036	8,350,740	**2,118,450**	6,167,473	16,636,664
2037	8,431,932	**2,124,070**	6,192,363	16,748,365
2038	8,540,446	**2,136,848**	6,218,017	16,895,311
2039	8,649,913	**2,149,958**	6,241,373	17,041,244
2040	8,785,758	**2,162,215**	6,273,820	17,221,793
2041	8,862,135	**2,168,237**	6,298,290	17,328,662
2042	8,970,157	**2,179,575**	6,314,117	17,463,848

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JOINT INTERVENORS' REQUEST DATED DECEMBER 20, 2024

REQUEST 57

RESPONSIBLE PARTY: Scott Drake

Request 57. For each of the energy efficiency and demand response programs evaluated in Attachment SD-7, the 2024 Potential Study, answer the following requests:

a. Explain in detail how avoided costs were determined for each cost benefit test used (e.g., Total Resource Cost, Utility Cost, Participant Cost, Rate Impact Measure).

b. Provide the values used for each element of the avoided cost categories listed below, identify the source of the values used, and state whether the values are in nominal dollars or in real, inflation-adjusted dollars.

i. Energy cost

ii. Capacity cost

iii. Capacity reserves (if not included in capacity costs)

iv. Natural gas price

v. Environmental externalities, including avoided methane loss from gas transmission, distribution, and storage infrastructure

vi. Line losses, for energy and peak (please specify if the estimate is based on average or marginal line loss rates)

c. State whether any of the following avoided cost categories listed below are included in the avoided cost calculation and if so, please provide the value, source of the value, and state whether the value is in nominal dollars or in real, inflation-adjusted dollars. If any of the avoided cost categories are not included, explain why not.

i. Ancillary services

ii. Transmission and distribution

iii. Non-energy benefits ("NEBs") (please specify which NEBs are included, if any)

iv. Increased reliability

v. Reduced risk (e.g., reduced exposure to future fuel price volatility, future environmental regulation compliance costs, uncertainties of demand forecasts and related capital investments, etc.)

vi. Any other avoided cost values incorporated into cost-effectiveness analysis.

Response 57.

a. For the Total Resource Cost, the Utility Cost, and Rate Impact Measure, the avoided costs of energy, generation capacity, and T&D are included. The values are the same for all three tests. For the Participant Cost, the avoided costs are calculated using the measure savings applied to the median retail rate.

b. The following provides information on the values used for each avoided cost category. Values for each element of the avoided cost categories are in nominal numbers.

i. The avoided energy costs are based on the forward price market. See Table 57-i.

ii. The avoided capacity costs are based on the 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 57-ii.

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

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

v. Environmental externalities are not included in the TRC test.

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

c. Here are the specifics on the distinct categories:

i. Ancillary services: included, $2.50 per MWh

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

iii. Non-energy benefits: tax credits are included as benefits.

iv. Increased reliability. Not included

v. Reduced risk. Not included

vi. Any other avoided cost values incorporated into cost-effectiveness analysis. None.

Table 57-i

Electric Energy Avoided Costs (EE)

Year	**Winter Peak Energy** ($/kWh)	**Winter Off-Peak Energy** ($/kWh)	**Summer Peak Energy** ($/kWh)	**Summer Off-Peak Energy** ($/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

Year	**Summer Generation Capacity** ($/kW-YR)	**Winter Generation Capacity** ($/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

JOINT INTERVENORS' REQUEST DATED DECEMBER 20, 2024
REQUEST 58
RESPONSIBLE PARTY: Scott Drake

Request 58. Refer to Attachment SD-7, the 2024 Potential Study, p. 14. With regards to the incentive levels assumed in estimating Realistic Achievable Potential ("RAP"):

a. Explain why the assumed incentive levels were "closely calibrated to historical levels."

b. State whether you evaluated the impact to RAP of incentive levels that were higher (as a percentage of incremental measure costs) than historical levels. If so, explain the results of such evaluation. If not, explain why not.

Response 58.

a. For the RAP, assumed incentive levels are closely calibrated to historic results. This allows for direct comparisons between technical potential studies over time.

b. EKPC did not evaluate the impact of incentive levels that were higher than historic levels. However, EKPC has two data points: the RAP potential, where incentive levels are closely calibrated to historical results, and the MAP potential, where incentive levels are set at 100% of the measure costs.

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

JOINT INTERVENORS' REQUEST DATED DECEMBER 20, 2024
REQUEST 59
RESPONSIBLE PARTY: Scott Drake

Request 59. Refer to Attachment SD-7, the 2024 Potential Study, pp. 26-27. Please reconcile the statement that: "In the MAP scenario the NPV benefits are more than $640 million over the study timeframe with a TRC ratio of 2.76. In the RAP scenario, the NPV benefits are more than $450 million over the study timeframe with a TRA ratio of 2.61"; with the TRC ratios reported in Table 5-4 of 4.10 and 4.31 for the MAP and RAP scenarios, respectively.

Response 59. The statement from the referenced report includes an error, but the data in Table 5-4 is correct. The statement in the report was intended to read as follows, "In the MAP scenario the net NPV benefits (NPV benefits minus NPV costs) are more than $650 million over the study timeframe with a TRC ratio of 4.10. In the RAP scenario, the net NPV benefits are more than $450 million over the study timeframe with a TRC ratio of 4.35."

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

JOINT INTERVENORS' REQUEST DATED DECEMBER 20, 2024
REQUEST 60
RESPONSIBLE PARTY: Scott Drake

Request 60. Refer to Attachment SD-7, the 2024 Potential Study, p. 39. For each of the Base, Low, and High program scenarios:

a. Explain how the three different spending scenarios referenced therein were determined, including why a higher spending scenario was not included.

b. Identify the annual spending for each of the years 2025 through 2028 needed to achieve the energy and demand savings identified in Table 7-1

c. Identify the Total Resource Cost ("TRC") benefit-cost ratio for each program scenario.

Response 60.

a. The Base spending scenario came from the work of EKPC program managers. They determined the program budgets that would result from estimates of higher incentives and greater participation in current and proposed programs. The High spending level is 200% higher than EKPC's 2023 DSM budget. The Low spending level is 50% higher than the 2023 DSM budget.

b. The annual spending requested is given in Appendix D of the 2024 Potential Study.

c. The Base Case spending closely mirrors the annual spending for the DSM portfolio in this CPCN filing. The TRC for that portfolio is 2.44. The TRCs for the Low and High scenarios have not been calculated.

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

JOINT INTERVENORS' REQUEST DATED DECEMBER 20, 2024
REQUEST 61
RESPONSIBLE PARTY: Scott Drake

Request 61. Refer to Attachment SD-7, the 2024 Potential Study, pp. 20-21 and 25-26. Given the positive TRC ratios and NPV benefits for Residential and Commercial/Industrial DSM-EE found in the 2024 Potential Study, explain in detail why EKPC is not proposing a DSM-EE Program Plan to achieve all, or even most, of the Realistic Achievable Potential for the Residential and Commercial/Industrial sectors.

Response 61. The DSM programs included in this CPCN were identified by EKPC and its owner-member expert staff as the top priority DSM programs for the rural Kentuckians served.

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

JOINT INTERVENORS' REQUEST DATED DECEMBER 20, 2024
REQUEST 62
RESPONSIBLE PARTY: Scott Drake

Request 62. Refer to Attachment SD-7, the 2024 Potential Study, pp. 36-38. Given the positive TRC ratios and NPV benefits for demand response programs found in the 2024 Potential Study, explain in detail why EKPC is not proposing demand response programs to achieve all, or even most, of the demand response Realistic Achievable Potential.

Response 62. The DSM programs, including demand response programs, in this CPCN were identified by EKPC and its owner-member expert staff as the top priority DSM programs for the rural Kentuckians served.

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

JOINT INTERVENORS' REQUEST DATED DECEMBER 20, 2024
REQUEST 63
RESPONSIBLE PARTY: Scott Drake

Request 63. State whether EKPC anticipates seeking Commission approval for any additional DSM-EE or demand response programs in the next three years. If not, explain why not.

Response 63. EKPC performed an extensive review of the cost-effective DSM measures and programs for this CPCN filing. The extensive review is consistent with the extensive review and DSM program changes that EKPC performs every three years as part of EKPC's Integrated Resource Plan (IRP). Because this CPCN filing nearly aligns with EKPC's IRP filing that is due in April, the DSM program review and recommended DSM program changes will be the same for the IRP filing in April. Given that EKPC's normal cadence for DSM program review and changes is every three years and aligns with the IRP filing, EKPC does not anticipate any new DSM-EE programs in the next three years. Although, if unique DSM program opportunities arise during the normal three-year review (ie: Residential EV Off-peak Home Charging Pilot program), EKPC will not hesitate to request Commission approval.

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

JOINT INTERVENORS' REQUEST DATED DECEMBER 20, 2024
REQUEST 64
RESPONSIBLE PARTY: Julia J. Tucker

Request 64. Refer to your response to the Mountain Association and Kentuckians for the Commonwealth data request 1-15(c) in Case No. 2024-00310. Identify what amount of solar generation EKPC would consider enough to "justify energy storage to compliment [sic] that resource."

Response 64. EKPC will continue to evaluate solar and storage options. To date, all of the solar energy that is requested for serving native load is utilized during the generation periods with no extra to charge storage banks.

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

JOINT INTERVENORS' REQUEST DATED DECEMBER 20, 2024
REQUEST 65
RESPONSIBLE PARTY: Julia J. Tucker

Request 65. Refer to your response to the Attorney General's data request 2-1(b) in Case No. 2024-00310.

a. Identify each of the "pending CPCN applications" that are part of the "well-designed, comprehensive resource plan" referenced therein.

b. Identify the total estimated capital cost for the referenced "well-designed comprehensive resource plan."

c. Identify the net present value revenue requirement for the referenced "well-designed comprehensive resource plan".

d. Identify the estimated impact of the referenced "well-designed, comprehensive resource plan" on rates and average monthly bills for residential customers of EKPC's member-owners for each of the years 2025 through 2039.

e. Explain how the Commission should "look at the plan in total" given that EKPC divided the plan over multiple CPCN applications with different schedules and decision deadlines.

f. Identify and produce the modeling input and output files, workbooks, and workpapers, for any capacity expansion or production cost modeling carried out in assembling the referenced "well-designed, comprehensive resource plan."

Response 65.

a. EKPC has filed three CPCNs as part of its resource expansion plan: PSC Case Nos. 2024-00129 (Northern Bobwhite and Bluegrass Plains solar facilities) filed in April 2024 and granted by the Commission in December 2024, 2024-00310 (Liberty RICE) filed in September 2024 and 2024-00370 (Cooper CCGT, Cooper 2 Co-Fire, and Spurlock 1-4 Co-Fire) filed in November 2024. EKPC intends to file a long-term Hydro PPA for Commission approval and a possible four new CPCNs for solar facilities related to the New ERA funding in Q1 2025.

b. Refer to the direct testimony of Brad Young, Attachments BY-1, BY-2, and BY-3, for total capital costs of the pending projects within this Application. Refer to the direct testimony of Brad Young, Attachment BY-1, in PSC Case No. 2024-00310 for the total capital cost of the Liberty RICE project.

c. Refer to EKPC's response to Item 10, above.

d. Refer to EKPC's response to Item 11, above.

e. EKPC has filed only two CPCNs as part of its thermal resource expansion plan. The advanced filing date for the Liberty RICE CPCN was primarily driven by the project's planned commercial operation date.

f. Refer to EKPC's response to Staff's First Request for Information, Item 24.