COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC 2022 INTEGRATED	**)**	
RESOURCE PLAN OF EAST KENTUCKY	**)**	**CASE NO.**
POWER COOPERATIVE, INC.	**)**	**2022-00098**

RESPONSES TO STAFF'S SECOND INFORMATION REQUEST

TO EAST KENTUCKY POWER COOPERATIVE, INC.

DATED AUGUST 26, 2022

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

2022 INTEGRATED RESOURCE PLAN OF EAST KENTUCKY POWER COOPERATIVE, INC.	))	**CASE NO. 2022-00098**

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 Public Service Commission's Second Request for Information in the above-referenced case dated August 26, 2022, and that the matters and things set forth therein are true and accurate to the best of his knowledge, information and belief, formed after reasonable inquiry.

Scott Drake

Subscribed and sworn before me on this 20th day of September, 2022.

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:

2022 INTEGRATED RESOURCE PLAN OF EAST KENTUCKY POWER COOPERATIVE, INC.	))	**CASE NO. 2022-00098**

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 Public Service Commission's Second Request for Information in the above-referenced case dated August 26, 2022, 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 20th day of September, 2022.

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:

2022 INTEGRATED RESOURCE PLAN OF EAST KENTUCKY POWER COOPERATIVE, INC.	**))**	**CASE NO. 2022-00098**

CERTIFICATE

STATE OF KENTUCKY)
)
COUNTY OF CLARK)

Fernie Williams**,** being duly sworn, states that he has supervised the preparation of the responses of East Kentucky Power Cooperative, Inc. to the Public Service Commission's Second Request for Information in the above-referenced case dated August 26, 2022, 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.

Fernie D. Williams

Subscribed and sworn before me on this 19th day of September, 2022.

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. 2022-00098
SECOND REQUEST FOR INFORMATION RESPONSE

STAFF'S REQUEST DATED AUGUST 26, 2022
REQUEST 1
RESPONSIBLE PARTY: Scott Drake

Request 1. Refer to the 2022 Integrated Resource Plan (IRP), page 20, Table 1-1, and page 44.

Request 1a. Table 1-1 on page 20 of the IRP shows that forecast Demand Side Management (DSM) and Energy Efficiency (EE) programs/initiatives have a greater impact on summer peaks than winter. Given EKPC's current capacity and energy production capability, explain whether EKPC agrees that its DSM and EE programs/initiatives increase the revenue-earning potential of selling energy, capacity and or ancillary services in PJM markets, especially during summer months. If EKPC disagrees, explain why.

Response 1a. East Kentucky Power Cooperative agrees certain programs can be monetized in the markets. Certain program impacts save EKPC costs (payments) to PJM. But because of EKPC's situation, many programs have a neutral or negative impact on costs when attempting to monetize them in PJM. All demand reductions (MWs) participating in a PJM demand reduction program by EKPC or a 3rd party are added to EKPC's load contribution each year. Therefore, for EKPC to benefit from the sale of incremental demand reductions (MWs) stemming from energy efficiency or demand response program participation, the demand reductions (MWs) must participate in a PJM program. Demand reductions (MWs) claimed by a 3rd party in EKPC's zone will result in PJM adding those reductions (MWs) to EKPC's load obligation. That will increase the load obligation payments (costs) for EKPC and its membership.

The interruptible program aligns well with the PJM Capacity Performance Demand Response program parameters. Thus, those resources are monetized in PJM by EKPC. The Direct Load Control ("DLC") program does not align well with the Capacity Performance Demand Response program parameters and is not monetized in that program. However, EKPC, as noted in EKPC's response to Request 45 of the Staff's First Request For Information Dated 06/29/2022, is evaluating offering the DLC resources into the PLM Peak Shaving Adjustment ("PSA") program. In the PSA program, EKPC will not receive a direct payment (monetize) for the resources. PJM will lower EKPC's summer load contributions resulting in a lower load contribution payment to PJM. The energy efficiency programs could be monetized in the PJM Demand Response program if the level of demand reduction from energy efficiency program participation was large enough to justify the measurement and verification compliance costs. At this time, energy efficiency program participation and resulting summer demand reduction simply are not large enough to cost-effectively participate for direct compensation (monetize) in the PJM programs. The resulting demand reduction from energy efficiency program participation still has an impact on the summer load contribution, which, over time, lowers EKPC payment to PJM.

Request 1b. Explain whether EKPC agrees that it has an incentive to maximize cost effective DSM and EE programs/initiatives that have a greater impact on summer peaks, and why. If EKPC disagrees, explain why.

Response 1b. EKPC's goal is to lower costs all year round. PJM is a summer peaking organization. PJM programs that provide direct payment or indirect benefits for DSM programs to EKPC tend to focus monetarily on summer impacts.

Request 1c. To the extent that DSM and EE programs/initiatives increase the revenue earning potential of PJM market participation, explain whether EKPC agrees that the revenue from the sale of incremental energy, capacity or ancillary services resulting from DSM and EE programs/initiatives should be included in the DSM and EE cost effectiveness tests.

Response 1c. Revenues from the sale of incremental energy, capacity or ancillary services resulting from DSM and EE programs/initiatives should not be included in the DSM and EE cost effectiveness tests. To do so would double count the benefits from the energy and capacity savings, since the avoided costs associated with these savings are already included in the cost-effectiveness tests.

EAST KENTUCKY POWER COOPERATIVE, INC.
CASE NO. 2022-00098
SECOND REQUEST FOR INFORMATION RESPONSE

STAFF'S REQUEST DATED AUGUST 26, 2022
REQUEST 2
RESPONSIBLE PARTY: Fernie Williams

Request 2. Refer to the IRP, page 65, Table 3-2. Refer also to the IRP, Technical Appendix Volume 1, 2021–2035 Load Forecast, page 4, Table "Coincident Peak Demands and Total Requirements Historical and Projected." Explain the differences between the forecasted summer and winter peak demands in each table, and state which table provides the most accurate forecast and why.

Response 2. The forecast presented in Technical Appendix Volume 1 is the original forecast prepared in 2020. The forecast presented in the IRP, page 65, Table 3-2 has updated actuals for 2020 and 2021 where available. The IRP Table 3-2 also added year 2036 to the forecast presented. After the creation of the forecast in 2020, which is included in the Technical Appendix Volume 1, DSM and Demand Response assumptions were updated. There was also an update to the timing of a large commercial retail member's expansion. These updates were include in the IRP Table 3-2, making the IRP Table 3-2 more up to date and accurate than the 2020 forecast contained in the Technical Appendix Volume 1. Please see Response 4 for additional information by class.

EAST KENTUCKY POWER COOPERATIVE, INC.
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SECOND REQUEST FOR INFORMATION RESPONSE

STAFF'S REQUEST DATED AUGUST 26, 2022
REQUEST 3
RESPONSIBLE PARTY: Fernie Williams

Request 3. Refer to the IRP, page 66, Table 3-3. Refer also to the IRP, Technical Appendix Volume 1, 2021–2035 Load Forecast, page 6, Table "Purchased Power and Total Requirements." Explain the differences in forecast energy and demand response impacts in each table, and state which table provides the most accurate forecast and why.

Response 3. There are no differences in the two tables. The tables start and end in different years, but corresponding years are the same.

EAST KENTUCKY POWER COOPERATIVE, INC.
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STAFF'S REQUEST DATED AUGUST 26, 2022
REQUEST 4
RESPONSIBLE PARTY: Fernie Williams

Request 4. Refer to the IRP, page 67, Table 3-4. Refer also to the IRP, Technical Appendix Volume 1, 2021–2035 Load Forecast, page 5, Table "Energy Sales by Class." Explain the differences in sales forecasts in the corresponding columns of each table, and state which table provides the most accurate forecast and why.

Response 4. **Residential Sales Class** – The difference between the IRP Table 3-4 and the Technical Appendix Volume 1 Load Forecast is that the year 2020 was updated with actual data and the year 2036 was added. Forecasted monthly average use per retail member changed due to new DSM assumption. The IRP Table 3-4 is more accurate as it is more up to date.

Seasonal Sales Class - The difference between the IRP Table 3-4 and the Technical Appendix Volume 1 Load Forecast is that the year 2020 was updated with actual data and the forecast for the year 2036 was added. There was no change to the forecast.

Small Commercial Sales Class - The difference between the IRP Table 3-4 and the Technical Appendix Volume 1 Load Forecast is that the year 2020 was updated with actual data and the forecast for the year 2036 was added. There was no change to the forecast.

Public Buildings Sales Class - The difference between the IRP Table 3-4 and the Technical Appendix Volume 1 Load Forecast is that the year 2020 was updated with actual data and the forecast for year the 2036 was added. There was no change to the forecast.

Large Commercial Sales Class - The difference between the IRP Table 3-4 and the Technical Appendix Volume 1 Load Forecast is that the year 2020 was updated with actual data in IRP Table 3-4 and the forecast for year 2036 was added. The forecast was updated with the most current Demand Response assumptions as well as a timing change for an existing retail member's expansion for 2022. The IRP Table 3-4 is more accurate as it is more up to date.

Public Street and Highway Lighting Sales Class - The difference between the IRP Table 3-4 and the Technical Appendix Volume 1 Load Forecast is that the year 2020 was updated with actual data and the forecast for the year 2036 was added. There was no change to the forecast.

Total Retail Sales - The difference between the IRP Table 3-4 and the Technical Appendix Volume 1 Load Forecast is that the 2020 was updated with actual data and the forecast for the year 2036 was added. Total Retail Sales forecast changed with the update to DSM in residential, and the Demand Response update for Large Commercial, and a change to a large retail member for 2022. The IRP Table 3-4 is more accurate is it is more up to date.

EAST KENTUCKY POWER COOPERATIVE, INC.
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SECOND REQUEST FOR INFORMATION RESPONSE

STAFF'S REQUEST DATED AUGUST 26, 2022
REQUEST 5
RESPONSIBLE PARTY: Fernie Williams

Request 5. Refer to the IRP, page 68, Table 3-4. Refer also to the IRP, Technical Appendix Volume 1, 2021–2035 Load Forecast, page 6, Table "Purchased Power and Total Requirements."

Request 5a. Explain the differences in distribution and transmission losses, including why they are calculated differently.

Response 5a. Distribution losses are the difference between "Sales to Owner-Members" and the sum of "Total Retail Sales" and "Owner-Member Office Use". Transmission losses are the difference between "Net Total Requirements" and the sum of "Sales to Owner-Members" and "EKPC Facilities Use".

Request 5b. Explain why Purchased Power in Table "Purchased Power and Total Requirements" and Sales to Owner-Member Cooperatives in Table 3-4 are the same in historical years but different in forecasted years, including specifically an explanation of any difference in how the information in the columns is calculated.

<u>Response 5b.</u> The historical losses are the same because there is no revision to historical data. The forecasted years were revised based on the details provided in Staff's First Request for Information Request 13. The calculation of forecasted losses is further explained in the calculation for individual components below.

- The forecast for total retail sales is the sum of all 16 Owner-Member Cooperative ("owner-member") load forecasts.
- The forecast for owner-member office use is the sum of all 16 owner-member projections of office. It is based on recent history and any known changes to office use (i.e. office use reductions or expansions).
- The forecast of average distribution losses is the sum of all 16 owner-member projections of distribution losses. Owner-member projections of distribution loss percentages are based on recent history and expected changes that may affect distribution losses percentages (i.e. improvement programs).
- The forecast for EKPC facility use is based on recent history and any known changes to EKPC facility use.
- The forecast of percent transmission losses is based on recent history and any known changes that may affect transmission loss percentages.

Request 5c. Explain the differences between Net Total Requirements in Table 3- 4 and Table "Purchased Power and Total Requirements," including specifically an explanation of any difference in how the information in the columns is calculated.

Response 5c. The only differences between "Net Total Requirements" in the two tables are the forecasted years. Forecasted years were revised based on the details provided in Staff's First Request for Information Request 13.

EAST KENTUCKY POWER COOPERATIVE, INC.
CASE NO. 2022-00098
SECOND REQUEST FOR INFORMATION RESPONSE

STAFF'S REQUEST DATED AUGUST 26, 2022
REQUEST 6
RESPONSIBLE PARTY: Julia J. Tucker

Request 6. Refer to EKPC's response to Commission Staff's First Request for Information (Staff's First Request), Item 1. Explain negative congestion in the context of the response, how negative congestion was affecting EKPC, and how EKPC's strategy is handling the issue.

Response 6. Congestion costs occur when the dispatch of higher cost units is required to relieve a constraint on the transmission system. The PJM system signals its desire for a unit to increase or decrease its output by providing an appropriate price signal. If the unit needs to increase its output, then the price that PJM will pay for the output will increase. If the unit needs to decrease its output, then the price will be lowered. The difference between the price that is being paid to the generation source and the price being paid by the load is considered congestion cost. It is typical for the load price to be higher than the generation source price, this is called positive congestion. When the load price is lower than the generation source price, this is called negative congestion. This means the load is actually receiving a net benefit from the redispatch of units due to its location on the transmission system.

A Financial Transmission Right ("FTR") allows the holder to exchange its FTR for one MWh of congestion costs, regardless if the cost is positive or negative. FTRs are a hedging mechanism that can be used to help cap the cost of congestion paid by the load. If congestion is positive and costs $2/MWh and the load holds a FTR, it exchanges the FTR and foregoes having to pay the $2/MWh congestion. Depending on what the load paid for the FTR, this can be a positive or negative trade. When congestion is negative, then the market is paying the load for congestion. If congestion is negative in the amount of $2/MWh, then the market will pay the load that amount. If the load holds an FTR, then it will exchange that for the congestion and the market will not pay the load. Again, depending on what the FTR cost to obtain this can be a positive or negative gain.

EKPC initially sought to hedge its congestion exposure by purchasing FTRs. However, actual clearings began to show that EKPC was purchasing FTRs at a price higher than what the actual congestion was costing, and holding FTRs was increasing costs as opposed to capping the expense. By not holding any FTRs, EKPC would have been paid for the negative congestion incurred on the system. This condition has changed over time due to transmission enhancements and power plant retirements. It is not as predictive as it once was. EKPC works with ACES and The Brattle Group each month to model the expected load and transmission conditions for the following three months, with the emphasis on the upcoming month. Based on the model results, EKPC will bid to purchase FTRs at various prices, based on its load expectations, in the FTR auction. Based on the auction clearing price, EKPC may or may not obtain FTRs. This is different than previously when EKPC sought to hedge a certain percentage of its load at the prevailing market price. EKPC now seeks to hedge its load when the price is considered to be favorable. This has allowed EKPC to better match current conditions with expectations as opposed to purchasing far out into the future with more uncertain conditions.

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SECOND REQUEST FOR INFORMATION RESPONSE

STAFF'S REQUEST DATED AUGUST 26, 2022
REQUEST 7
RESPONSIBLE PARTY: Julia J. Tucker

Request 7. Refer to EKPC's response to Staff's First Request, Item 2b. Explain whether EKPC has calculated its avoided cost by the method the Commission laid out in recent net metering cases, such as the Commission's May 14, 2021 Order in Case Number 2020-00174, 2 and if not, provide an estimate of EKPC's avoided costs using that methodology.

Response 7. EKPC has not calculated its avoided cost based on the referenced methodology. Only a distribution utility can offer net metering rates and EKPC is not a distribution utility, it is a wholesale electric generation and transmission utility.

EAST KENTUCKY POWER COOPERATIVE, INC.
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SECOND REQUEST FOR INFORMATION RESPONSE

STAFF'S REQUEST DATED AUGUST 26, 2022
REQUEST 8
RESPONSIBLE PARTY: Fernie Williams

Request 8. Refer to EKPC's response to Staff's First Request, Item 11b. Explain whether EKPC means that everything else being equal, the model provides more accurate demand estimates with the HDD-30 variable in the equation even with the collinearity, and if so, explain how EKPC knows the estimates are more accurate.

Response 8. When preparing the 2020 load forecast, EKPC considered various economic and weather variables for the class forecasts. HDD-30 was evaluated in the regression models, but it was not statistically significant and therefore not included in the final models.

EAST KENTUCKY POWER COOPERATIVE, INC.
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SECOND REQUEST FOR INFORMATION RESPONSE

STAFF'S REQUEST DATED AUGUST 26, 2022
REQUEST 9
RESPONSIBLE PARTY: Fernie Williams

<u>Request 9.</u> Refer to the IRP, page 83 stating that the forecasted seasonal peak demands are calculated by applying load factors to total purchased power. Refer also to EKPC's Response to Staff's First Request, Item 12 stating that the independent forecasts for peaks and energy are used to calculate load factors. Provide a detailed, step by step explanation of how peak demands and load factors are determined, including specifically why the process is not circular in nature.

<u>Response 9.</u> The following steps are performed for each of the 16 owner-members to forecast independent seasonal peaks.

- Calculate heating, cooling, and base load energy from class models and end use appliance peak contributions.
- Calculate monthly heating, cooling, and base load indices by indexing heating, cooling, and base load energy to an index year and month.
- Calculate monthly heating, cooling, and base independent variables by interacting HDD and CDD with monthly indexed heating, cooling, and base load.

- Regression analysis of monthly peak loads using heating, cooling, and base independent variables from above along with binary variables.

Coincidence factors are applied to each owner-member's peak forecast and summed for the EKPC system. DSM and interruptible assumptions are applied to seasonal peaks for the net EKPC seasonal peaks. System load factor is calculated from total requirements and net seasonal peaks.

EAST KENTUCKY POWER COOPERATIVE, INC.
CASE NO. 2022-00098
SECOND REQUEST FOR INFORMATION RESPONSE

STAFF'S REQUEST DATED AUGUST 26, 2022
REQUEST 10
RESPONSIBLE PARTY: Fernie Williams

Request 10. Refer to EKPC's response to Staff's First Request, Item 13. Refer also to the IRP, pages 84-89, Tables 3-13, 3-14, 3-15, 3-16, 3-17, and 3-18. Refer also to the IRP, Technical Appendix Volume 1, 2021–2035 Load Forecast, pages 33-38. Confirm that Tables 3-13, 3-14, 3-15, 3-16, 3-17, and 3-18 on pages 84-89 of the IRP contain the most up-to-date data and forecasts.

Response 10. Yes, the forecasts presented in the Tables listed above of the IRP contain the most up-to-date data and forecasts. Please see responses to Request 2 and 4 to understand the differences.

EAST KENTUCKY POWER COOPERATIVE, INC.
CASE NO. 2022-00098
SECOND REQUEST FOR INFORMATION RESPONSE

STAFF'S REQUEST DATED AUGUST 26, 2022
REQUEST 11
RESPONSIBLE PARTY: Julia J. Tucker

Request 11. Refer to EKPC's response to Staff's First Request, Item 18. For the Spurlock units, explain why the forecast fixed O&M expenses for 2022 and beyond increase three to four times more than the 2021 actual expenses.

Response 11. The projected fixed O&M rates are based on historic averages for the system. The 2021 actual expenses were below that average, however, that one year of lower costs does not change projections for the entire study outlook.

EAST KENTUCKY POWER COOPERATIVE, INC.
CASE NO. 2022-00098
SECOND REQUEST FOR INFORMATION RESPONSE

STAFF'S REQUEST DATED AUGUST 26, 2022
REQUEST 12
RESPONSIBLE PARTY: Fernie Williams

Request 12. Refer to EKPC's response to Staff's First Request, Item 27.

Request 12a. Provide a list of each of the specific EKPC Sustainability Goals that were applied to the top plans selected by the Resource Optimizer to provide the final plan.

Response 12a.

The EKPC Sustainability Goals for Energy and the Environment are:

a. Transition to cleaner resources:
    i. 10% energy from new renewables by 2030
    ii. 15% energy from new renewables by 2035
b. Reduction in greenhouse gases:
    i. 35% reduction in total carbon dioxide emissions by 2035
    ii. 70% reduction in total carbon dioxide emissions by 2050

Request 12b. Explain what "top plan" and "top plans," as used in response to Staff's First Request, Item 27(b), refers to.

<u>Response 12b.</u> The "top plan" is the final IRP plan while "top plans" refers to the top plans resulting from the resource planning optimization study, shown on pages 167 and 168 of the IRP.

<u>Request 12c.</u> Explain whether EKPC's Sustainability Goals were applied to each of the ten lowest cost plans selected by the Resource Optimizer. If so, explain how each of the resulting plans compares to the final plan and to each of the lowest cost plans.

<u>Response 12c.</u> The EKPC Sustainability Goals were only applied to the final plan.

<u>Request 12d.</u> Explain in detail the process for applying the Sustainability Goals to the top plan or plans to achieve the final plan e.g. were there meetings where the IRP team discussed and determined how to apply the Sustainability Goals, was a single person responsible for applying to the Sustainability Goals to the top plans, did the sustainability goals have to be met or did they simply inform the determination of the final plan, etc.

<u>Response 12d.</u> Four of the top five plans shown on page 167 of the IRP indicate that the Intermittent Resource (i.e. solar PPA) was an economic alternative chosen by the optimizer. Based on the fact that the optimizer chose the solar PPAs solely on economics, EKPC then took those resources and applied them to match the timing needed to also meet its sustainability goals. Specifically, the percentage amount of renewable energy that was targeted to be supplied throughout the plan. The EKPC executive staff and Board of Directors approved the sustainability goals and they also approved the filing of the Integrated Resource Plan. The specific application of the goals was completed by review of the plan and the targets to be met by the Power Supply staff, including the Senior Vice President and supporting staff. The targets were applied to the plan based on the target years of each goal. These results were reviewed multiple times prior to final approval of the plan. The final plan shows the timing when resources would be expected to be needed to meet EKPC's load obligations, economic criteria and sustainability goals. EKPC will still remain subject to the filing of a CPCN prior to any long term commitments and will have to define the need and economic alternatives prior to entering into any of the proposed solar PPAs.

Request 12e. Explain specifically and in detail how each of the Sustainability Goals was applied to achieve the optimal / final plan, including specifically how application of each of the Sustainability Goals affected the top plan to achieve the final plan.

Response 12e. The new renewable energy was applied to the plan over a time horizon based on possible in service dates derived from consultation with NRCO and their performance of RFPs to solicit potential energy resources. The carbon dioxide reduction was applied to the plan upon review of the emissions and target levels. Where necessary generation was restricted to meet the reduction goal. The top plan, Case 1, shown on page 167 of the IRP was modified to include the amount of solar PPAs that would obtain the renewable energy sustainability target, see Response 12a above. The top plan, Case 1, was also modified on a production cost basis to limit the amount of carbon dioxide to the targets discussed in Response 12b above.

EAST KENTUCKY POWER COOPERATIVE, INC.
CASE NO. 2022-00098
SECOND REQUEST FOR INFORMATION RESPONSE

STAFF'S REQUEST DATED AUGUST 26, 2022
REQUEST 13
RESPONSIBLE PARTY: Fernie Williams

Request 13. Refer to EKPC's response to Staff's First Request, Item 27c.

Request 13a. Explain whether "Best 1" represents a net present value (NPV) revenue gain over expenses, while "Best 10" represents a NPV revenue shortfall over expenses. If not, explain what "System profit" means in this context.

Response 13a. Yes, "Best 1" represents a net present value (NPV) revenue gain over expenses, while "Best 10" represents a NPV revenue shortfall over expenses.

Request 13b. Provide the "System profit" of the optimal/final plan as compared to the ten lowest cost plans.

Response 13b. The data provided in Response 27 c of the Commission's First Request for Information, shows the top ten lowest cost plans. The following is the referenced response. The resulting table below, in dollars, is from the Resource Optimizer for the top ten (10) plans:

Best 1: System profit: $146,459,040.

Best 2: System profit: $115,061,552.

Best 3: System profit: $83,863,144.

Best 4: System profit: $39,368,296.

Best 5: System profit: $7,970,816.

Best 6: System profit: $0.

Best 7: System profit: -$23,227,596.

Best 8: System profit: -$107,090,736.

Best 9: System profit: -$136,847,360.

Best 10: System profit: -$168,245,664.

All plans would be adjusted comparably for the sustainability targets, so the net differences between plans would remain the same as shown previously and the relative rankings would remain consistent.

EAST KENTUCKY POWER COOPERATIVE, INC.
CASE NO. 2022-00098
SECOND REQUEST FOR INFORMATION RESPONSE

STAFF'S REQUEST DATED AUGUST 26, 2022
REQUEST 14
RESPONSIBLE PARTY: Julia J. Tucker

Request 14. Refer to EKPC's response to Staff's First Request, Item 29b.

a. Confirm that prior to joining PJM, EKPC had an obligation to have sufficient capacity to serve its system peak demand and planned its system as such.
b. Explain how joining PJM with a summer peaking capacity obligation relieved EKPC from continuing to have sufficient capacity to serve its system peak demand.
c. Using EKPC's logic, explain whether it is fair to say that EKPC could allow its built and owned system capacity to decline over time to the level necessary to satisfy PJM's capacity requirements and could then satisfy any additional energy needs through market purchases.

Response 14a-c. EKPC has always had an obligation to serve its load in a safe, reliable and economic manner. Joining PJM did not change that obligation. The ability to serve that load with different resources changes the economics and the reliability of the system.

Prior to joining PJM, EKPC was a stand-alone balancing authority, and as such, had to balance its load and generation resources on a real time basis. That means EKPC had to ramp generation units up and down and/or secure outside resources to meet its load continually. This continuous matching of load and resources lead to inefficient use of resources at times. Low cost coal units would be held back at some times in anticipation of load increases occurring within the next few hours and the units needed to be held back to follow that load. In order to hold units back, extra generation had to be online and available for service for many low load hours in order to serve the peak load of the day. By joining PJM, the balancing responsibilities were shifted to the larger market with many more resources to follow the load variations. EKPC no longer had to dispatch its specific units to follow the load variations, but could rather operate its units at their most economic levels to provide service to the larger system. EKPC can still provide load following services as requested by the PJM market, but they are provided on an economic basis and not a reliability only basis.

EKPC continually looks to provide its load obligations in the most economic and reliable manner for the long term. If purchases can be made on an economic and reliable basis, then they must be considered. However, EKPC continues to believe one of its core competencies is owning and operating power plants and does not believe that will change any time in the near future. The obligations have not changed.

EAST KENTUCKY POWER COOPERATIVE, INC.
CASE NO. 2022-00098
SECOND REQUEST FOR INFORMATION RESPONSE

STAFF'S REQUEST DATED AUGUST 26, 2022
REQUEST 15
RESPONSIBLE PARTY: Julia J. Tucker

Request 15. Refer to EKPC's response to Staff's First Request, Item 29c. State whether the forecast energy purchase prices used by the Resource Optimizer for IRP planning purposes were renewable prices or fossil-based purchase prices, and explain the response.

Response 15. The forecast energy purchase prices are based on observable actual known energy trading activity in the near term and long-term trend analysis. The blend of the generation expectations from renewable resources and fossil-based resources are blended based on the market's expectation of what will be providing energy to the market.

EAST KENTUCKY POWER COOPERATIVE, INC.
CASE NO. 2022-00098
SECOND REQUEST FOR INFORMATION RESPONSE

STAFF'S REQUEST DATED AUGUST 26, 2022
REQUEST 16
RESPONSIBLE PARTY: Julia J. Tucker

<u>Request 16.</u> Refer to EKPC's response to Staff's First Request, Item 30. Refer also to the IRP, page, 170, Table 8-6, and page 171, Table 8-7.

<u>Request 16a.</u> Provide an update to Table 8-7 showing EKPC's forecast energy requirements, and explain how the energy forecasts correspond to the energy purchases in Table 8-7.

<u>Response 16a,</u> EKPC filed a revised Table 8-10 on May 17, 2022 to the Commission. That table shows the specific expectations of how energy will be served, including lines titled "Solar" and "Firm Purchases – other utilities", which represent how the energy forecast correspond to the energy purchases in Table 8-7.

<u>Request 16b.</u> For Table 8-7, explain whether the Energy Additions and Peaking/Intermediate Capacity Additions are in terms of nameplate capacity or the capacity attributed to the generation resource by PJM.

Response 16b. Nameplate Capacity.

Request 16c. For Table 8-7, explain whether the incremental additions to Total Capacity are in terms of nameplate capacity or the capacity attributed to the generation resource by PJM.

Response 16c. The "Total Capacity" is in terms of capacity attributed to the generation resource by PJM.

Request 16d. "Total Capacity" in Table 8-7 in both summer and winter increase throughout the forecast period, but capacity additions in Table 8-7 are only shown in 2032 (225 MW for winter and 170 MW for summer). Explain why the incremental increases in "Total Capacity" do not have corresponding capacity additions in either the base load or peaking/intermediate columns.

Response 16d. The capacity additions include an assumption of solar potentially being given a capacity credit by PJM. Solar contracts can be negotiated with or without capacity credit. EKPC made the assumption that it would include the solar capacity credit in contract negotiations going forward. Solar energy is intermittent, so it is not represented under Base Load or Peaking / Intermediate Capacity Addition labels.

Request16e. Explain what the incremental additions to Total Capacity in Table 8- 7 are and where they are represented in Table 8-7.

<u>Response 16e.</u> Solar is assumed to get a 60% of nameplate capacity credit in PJM during the summer. EKPC's winter peak occurs during non-daylight hours when the solar generation is not available. Therefore, the new solar resources did not receive any credit for winter capacity. The winter capacity additions are based on winter seasonal peak purchases.

<u>Request 16f.</u> Explain how Total Capacity in Table 8-7 exceeds Existing Resources in Table 8-6 for many of the years and seasons, and reconcile these differences. If necessary, provide updates to Tables 8-6 and 8-7.

<u>Response 16f.</u> Total Capacity in Table 8-7 includes capacity credit for the projected additions. Table 8-6 is only the existing resources as of 1/1/2022. As stated on footnote 14 on page 171 of the IRP, 'Only generation added for the purpose of covering summer peak load capacity obligations is considered "capacity" additions. All other intermittent or seasonal purchases are made to hedge the energy price exposure to the EKPC system and not to supply "capacity" to its portfolio or the PJM system.' There is a typo in the Summer 2022 Total Capacity column. It should state 3,132 MW, but all of the numbers in the following years are correct. The winter capacity in Table 8-7 should have reflected a 100 MW purchase that is shown as an energy addition in 2022, so it should have been 3,534 for every year through 2031. An updated Table 8-7 is included below. See attachment, "*PSC Response 16f - IRP Page 171 Revised*".

Table 8-7
EKPC Projected Additions and Reserves
(MW)

Year	Energy Additions	Base Load Capacity Additions		Peaking/ Intermediate Cap. Additions		Total Capacity		Reserves		Reserve Margin	
		Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum
2022	100					3,534	3,132	0	75	7%	25%
2023	110					3,534	3,198	0	77	5%	22%
2024	200					3,534	3,318	0	78	5%	20%
2025						3,534	3,318	0	78	5%	20%
2026	200					3,534	3,438	0	79	4%	19%
2027	200					3,534	3,558	0	79	4%	19%
2028						3,534	3,558	0	80	3%	18%
2029						3,534	3,558	0	80	3%	17%
2030						3,534	3,558	0	80	2%	17%
2031	200					3,534	3,678	0	81	2%	16%
2032[14]	200			225	170	3,759	3,968	0	81	8%	22%
2033						3,759	3,968	0	82	8%	21%
2034						3,759	3,968	0	82	7%	20%
2035						3,759	3,968	0	83	6%	19%
2036						3,759	3,968	0	83	6%	19%

<u>Request 16g.</u> Provide an explanation of and show the calculation of the Total Capacity values in Table 8-7 from the nameplate capacity of the resources used to calculate the Total Capacity values.

<u>Response 16g.</u>

Source	Winter MW	Summer MW
Cooper 1	116	116
Cooper 2	225	225
Spurlock 1	300	300
Spurlock 2	510	510

Gilbert	268	268
Spurlock 4	268	268
Smith 1	142	104
Smith 2	142	104
Smith 3	142	104
Smith 4	93	73
Smith 5	88	73
Smith 6	88	73
Smith 7	88	73
Smith 9	103	75
Smith 10	103	74
Bluegrass 1	189	167
Bluegrass 2	189	167
Bluegrass 3	189	167
SEPA	170	170
Landfill Gas	16.1	16.1
Solar	5.1	5.1
TOTAL	3434.2	3132.2

EAST KENTUCKY POWER COOPERATIVE, INC.

CASE NO. 2022-00098

SECOND REQUEST FOR INFORMATION RESPONSE

STAFF'S REQUEST DATED AUGUST 26, 2022

REQUEST 17

RESPONSIBLE PARTY: Scott Drake

Request 17. Refer to EKPC's response to Staff's First Request, Item 38. Refer also to EKPC's Response to Staff's First Request for Information, Item 29 in Case No. 2019-00096, regarding EKPC's 2019 IRP, in which EKPC stated that "Low-income programs historically have not had TRCs above 1."

Request 17a. Reconcile the discrepancy in the responses regarding low-income programs historically having a TRC above or below 1.0.

Response 17a. In East Kentucky Power Cooperative's Response to Staff's First Request for Information, Item 29 in Case No. 2019–00096, the statement that low-income programs historically have not had TRCs above 1 referred to historical results from utilities generally in the United States. The statement in EKPC's Response to Staff's First Request, Item 38 in this case addresses only the EKPC CARES program.

Request 17b. Explain how EKPC could improve the cost effectiveness of the Residential Energy Audit Program.

Response 17b. The EKPC energy audit program meets a number of end-use members' needs, of which direct energy savings is only one. The program is offered as a retail member service, particularly for addressing high bill complaints. The audit also provides an educational function by giving members more information about their energy use. Additionally, the energy audit program directs retail members to participate in the other DSM programs offered by our owner-members.

The individual measures in the program are all cost-effective. However, by allocating 100% of the fixed software costs to this program, the program overall has a TRC below 1.

The cost-effectiveness of this program would improve if either: (1) the program costs were allocated across all the program uses, or (2) the program benefits were expanded to include the other benefits that retail members receive in addition to direct energy savings.

Increasing the number of participants would also improve the cost-effectiveness of the audit program because the fixed costs would be allocated across more kWh savings.

EAST KENTUCKY POWER COOPERATIVE, INC.
CASE NO. 2022-00098
SECOND REQUEST FOR INFORMATION RESPONSE

STAFF'S REQUEST DATED AUGUST 26, 2022
REQUEST 18
RESPONSIBLE PARTY: Julia J. Tucker / Scott Drake

Request 18. Refer to EKPC's response to Staff's First Request, Item 39. Refer also to the IRP, Technical Appendix Volume 2, Demand Side Management Analysis, page DSM17, Table DSM-4.

Request 18a. For Item 39, explain why there is no avoided winter generation capacity costs utilized in the evaluation of DSM programs and provide EKPC's winter avoided capacity costs.

Response 18a. EKPC participates in the PJM capacity market. EKPC's obligation to PJM for capacity is defined by the Reliability Pricing Model (RPM) of PJM. PJM establishes a Variable Resource Requirement against which all supply resources clear. This Variable Resource Requirement incorporates the reserve requirement established for a particular delivery year. The reserve requirement is based on the summer peak load forecast. Only generation added for the purpose of covering summer peak load capacity obligations is considered a capacity addition.

<u>Request 18b.</u> Since EKPC is a winter-peaking utility, explain what the winter peak demand impact is in 2036 for Table DSM-4.

<u>Response 18b</u>. There is no column in Table DSM-4 for the winter peak demand impact. See EKPC's response to data request 18a above which explains why that is. There is a column for the winter peak impact in Table DSM-5. These values give the MW impact of the DSM portfolio coincident with the EKPC winter peak.

EAST KENTUCKY POWER COOPERATIVE, INC.

CASE NO. 2022-00098

SECOND REQUEST FOR INFORMATION RESPONSE

STAFF'S REQUEST DATED AUGUST 26, 2022

REQUEST 19

RESPONSIBLE PARTY: Scott Drake

Request 19. Refer to EKPC's response to Staff's First Request, Item 40b.

Request 19a. Explain the potential incentive or special rate that would be provided to retail members for using this program.

Response 19a. EKPC is considering providing a $0.01/kWh demand response incentive for EV charging at home during off-peak hours of 10PM – 6AM. The participating owner-members will also provide a $0.01/kWh incentive. The total incentive will be $0.02/kWh or about a 20% discount to charge off--peak. EKPC is preparing to file a tariff approval request for a 3-year pilot of this program.

Request 19b. State which EKPC owner-members would benefit most from this program and explain why.

Response 19b. EKPC's owner-members will all benefit by having EV home charging shifted from mostly on-peak to off-peak hours. EKPC's cost will be lowered because the impact of EVs to EKPC's PJM load contribution will be lower; resulting in lower annual load contribution payments to PJM. Lower cost benefits all owner-members over time. The participating owner-members will benefit by having a lower demand charge from EKPC while increasing energy sales from this new load. Since this is new load, the owner-members will benefit equally per participating EV.

Request 19c. State which EKPC owner-members would benefit least from this program and explain why.

Response 19c. The participating owner-members will benefit by having a lower demand charge from EKPC while increasing energy sales from this new load. Since this is new load, the owner-members will benefit equally per participating EV.

EAST KENTUCKY POWER COOPERATIVE, INC.
CASE NO. 2022-00098
SECOND REQUEST FOR INFORMATION RESPONSE

STAFF'S REQUEST DATED AUGUST 26, 2022
REQUEST 20
RESPONSIBLE PARTY: Scott Drake

Request 20. Refer to EKPC's response to Staff's First Request, Item 40c. Refer also to the IRP, Technical Appendix Volume 2, Demand Side Management Analysis, Exhibit DSM-1, 2021 Potential Study, pages 35-36. Explain why there is no plan to incorporate the Critical Peak Pricing with Enabling Tech into EKPC's DSM programs.

Response 20. EKPC and its owner-members are mainly focused on residential DSM programs. To our knowledge, C&I members have not shown interest in a Critical Peak Pricing program, which is an energy rate program. Critical Peak Pricing is somewhat simulated in the economic interruption of the interruptible program. The energy rate (economic interruptions) is the least liked aspect of the interruptible program. Because of these reasons, EKPC has not pursued this program.

EAST KENTUCKY POWER COOPERATIVE, INC.
CASE NO. 2022-00098
SECOND REQUEST FOR INFORMATION RESPONSE

STAFF'S REQUEST DATED AUGUST 26, 2022
REQUEST 21
RESPONSIBLE PARTY: Scott Drake

Request 21. Refer to EKPC's response to Staff's First Request, Item 41b. Given that the IRP is a long-range planning study, explain why the commercial and industrial programs listed in Appendix C of the GDS Associates, Inc. study were not evaluated for the IRP DSM portfolio.

Response 21. EKPC is investing its DSM resources in the residential sector. Please see EKPC's response to Staff's First Request, Item 19. EKPC offers its DLC program to small commercial retail members. The members who participate in the Interruptible program are commercial and industrial retail members. EKPC did evaluate a commercial and industrial program, the small business lighting program, in its HIGH carbon case.