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 A NEW 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

POST-HEARING BRIEF OF JOINT INTERVENORS APPALACHIAN CITIZENS' LAW CENTER, KENTUCKIANS FOR THE COMMONWEALTH, AND MOUNTAIN ASSOCIATION

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Date: May 06, 2025

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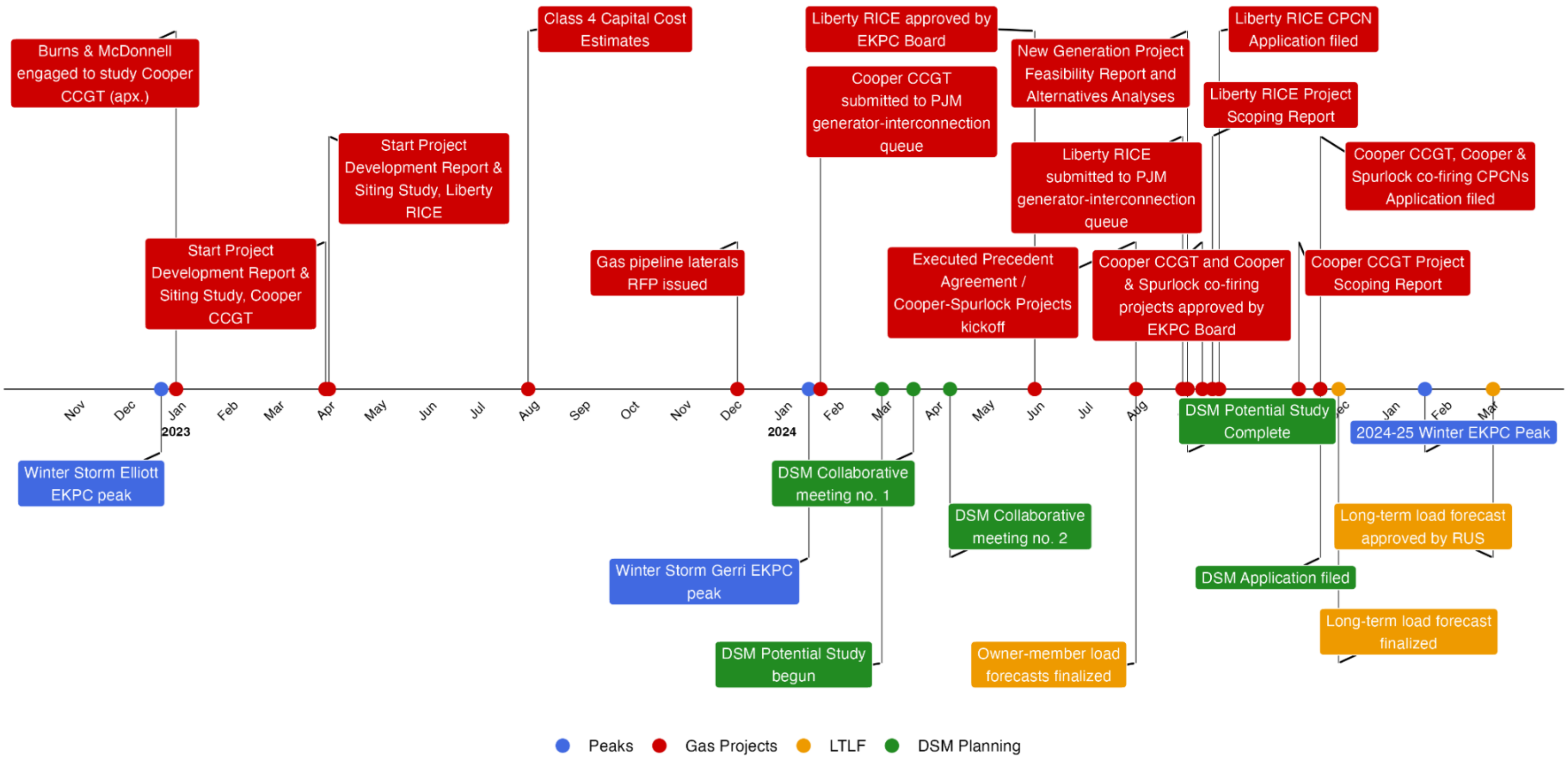
I. Introduction

In December 2022, Kentucky and much of the rest of the eastern United States was struck by Winter Storm Elliott, a 3-day severe winter weather event that caused demand for energy to spike. Similar winter weather events leading to spikes in energy demand happened with Winter Storm Gerri in January 2024, and Winter Storm Enzo in January 2025. While hourly energy demand reached record or near-record levels during the three storms, there were only a handful of hours during which demand on East Kentucky Power Cooperative, Inc.'s ("EKPC" or "Company") system exceeded its installed capacity. Notably, EKPC made it through all three winter storms without any load shedding thanks to its existing generation and membership in PJM Interconnection ("PJM"). PJM kept the lights on throughout the region, and even exported energy to neighboring regions. Regardless, EKPC viewed Winter Storm Elliott as a "turning point" for the utility, and the "genesis" of its plan for the proposed $1.317 billion Cooper combined cycle gas turbine ("CCGT') at issue in this docket, and the $500 million Liberty reciprocating internal combustion engine ("RICE") gas units proposed in docket 2024-00310.

The events of Winter Storms Elliott, Gerri, and Enzo certainly call for a careful and thorough evaluation of how EKPC can most prudently ensure reliable and affordable service to its Owner-Members and their customers. Unfortunately, the record is clear that such careful and thorough evaluation never occurred. Instead, as demonstrated by the timeline shown in Figure 1, by early 2023, EKPC had already started down the path to a new CCGT and RICE units, even though neither were selected in the Company's 2022 Integrated Resource Plan, and no new resource optimization modeling or load forecast had been carried out. Other, more expeditious resource options, such as pursuing all cost-effective demand response and energy efficiency, were ignored until 2024 and then given short shrift. While EKPC proposed some new solar resources, the Company summarily dismissed pairing them with battery storage, which could provide significant capacity value, despite the availability of federal financial support that numerous other rural electric coops applied for and were approved to receive.

Figure 1 - Timeline[1]



[1] Sources: Young Direct, Attachment BY-4; Horn Direct at 4-5 and Attachment MH-3; Drake Direct at 6, Attachments SD-1, SD-2, SD-3, and SD-7; Tucker Direct, Attachment JJT-2; Case No. 2024-00310, *Electronic Application of East Kentucky Power Cooperative, Inc. For 1) a Certificate of Public Convenience and Necessity to Construct a New Generation Resource; 2) a Site Compatibility Certificate; And 3) Other General Relief*, Application (Sep. 20, 2024) and Response to Joint Intervenors' Post-Hearing Data Request 3, attachment JI_3_-_2020_-_2025_Hourly_Load.xlsx, and Supplemental Response to Request 6, attachment RUS_2024_LTLF_Approval_Letter.pdf (Mar. 31, 2025).

Most of EKPC's evidence boils down to post hoc efforts to rationalize the selection of the Cooper CCGT and Liberty RICE units. EKPC claims the plants would provide economic value based on a single production cost modeling run that assumed construction of the gas plants the Company had already decided to pursue, did not account for capital and other fixed costs, and did not test the projects under a range of forecasted gas and market energy prices. EKPC relies on a new load forecast that is opaque, potentially inflated, and was not finalized until late 2024, after this certificate of public convenience and necessity ("CPCN") application was filed. The Company further boosts its claimed need by assuming a new 7% winter reserve margin, departing from its decade-plus conclusion that a primary benefit of PJM membership was EKPC not having to carry its own winter reserve margin. Finally, EKPC's filings are peppered with references to the Cooper CCGT and Liberty RICE units being a solution to a grid reliability issue in the southern portion of EKPC's service territory, a problem that EKPC has known about but largely ignored since 2007, that could be more quickly addressed through transmission grid upgrades, and for which the Company acknowledges even a generation solution would not necessitate all three of the Cooper CCGT, Liberty RICE units, and the existing Cooper plant.

EKPC's application also seeks CPCNs to convert Cooper 2 and all four units at Spurlock to be able to co-fire on natural gas, at an estimated capital cost of $260.8 million, plus nearly $400 million to bring gas supply to the Spurlock site.[2] The primary intent of these gas co-firing projects are to bring Cooper 2 and the Spurlock units into compliance with the U.S. EPA's

[2] The pipeline project to bring gas supply to the Cooper site would also have an estimated capital cost of nearly $400 million, though such pipeline would serve the Cooper CCGT, along with the Cooper 2 gas co-firing project. The combined nearly $800 million capital cost to bring gas to Spurlock and Cooper would be recovered as part of the cost of fuel, rather than as a capital cost on EKPC's books.

Greenhouse Gas emission standards ("GHG Rule"). In 2023, however, EKPC stated in comments to U.S. EPA regarding the then-proposed GHG Rule that circulating fluidized bed ("CFB") units, such as Spurlock 3 and 4, "cannot co-fire natural gas because they depend upon coal ash contacting the steam generating tubes inside the furnace,"[3] and EKPC refuses to produce anything beyond a one-page conclusory summary of an engineering report that purportedly finds that gas co-firing at those units "appears technically feasible."[4] While gas co-firing at Cooper 2 is feasible, the Cooper plant has been losing money for a number of years, raising questions as to whether it is prudent and necessary to invest in the long-term continued operation of Cooper 2, especially if both the Cooper CCGT and Liberty RICE units are approved.

Finally, after years of declining investment in demand-side program potential, EKPC seeks approval of a modest increase in the Company's demand-side management ("DSM") programs. Joint Intervenors support approval of EKPC's DSM proposal, which is clearly cost-effective. Disappointingly, however, EKPC has left vast amounts of cost-effective DSM on the table, proposing only a small percentage of the energy and capacity savings that the Companies' own potential study identified as realistically achievable. In doing so, EKPC is ignoring an

[3] Joint Intervenors' Hearing Ex. 1, East Kentucky Power Cooperative, Inc., *Comments on New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule; Proposed Rule*, Docket ID No. EPA–HQ– OAR–2023–0072-0542, at 29 (posted Aug. 10, 2023).

[4] Responses to Joint Intervenors' Supplemental Information Request to East Kentucky Power Cooperative, . dated January 17, 2025, Case No. 0370, Question 47(c) (Jan. 31, 2025) ("EKPC Resp. to JI 2-47(c)") and Supplemental Responses to Joint Intervenors' Supplemental tion Request to East Kentucky Power Cooperative, Inc. dated January 17, 2025, Question 47(c) (Feb. 11, 2025) ("EKPC Supplemental Resp. 2-47(c)").

opportunity to reduce the cost to customers of its system by hundreds of millions of dollars. The Company is also missing a chance to start reducing now its exposure to costly market energy prices during peak winter conditions, rather than waiting the three to five years it would take for the proposed Cooper CCGT and Liberty RICE units to come online.

II. Demand-Side Management

EKPC's proposed DSM Plan will result in energy and demand savings, with system-wide benefits and direct monthly bill savings for participants. At the same time, the proposed DSM Plan unreasonably pursues a fraction of the identified reasonably achievable potential, despite having a clear roadmap showing the way. That's a problem for at least two reasons.

First, with least-cost service as a goal and claiming no profit motive to do otherwise, it is unreasonable for EKPC to pursue anything less than the reasonably achievable savings potential identified by its third-party experts.

Second, targeted levels of energy and demand savings in the proposed DSM Plan became an input to EKPC's long-term load forecast, which in turn grounds EKPC's claimed need for billion dollar supply-side investments. Pursuing a higher level of savings is more than a matter of budget; it is about the size of the need for relatively expensive supply-side resources.

This section addresses the achievable potential, and the unreasonableness of EKPC's plan to pursue far less savings, with recommendations for the Commission's consideration. For the reasons advanced in Dr. Roumpani's Direct Testimony and those highlighted here, the Commission should direct EKPC to develop a DSM plan that pursues the realistic achievable potential identified in its recent potential study. The Commission should also take that cost-effective demand-side potential and a reasonably timed DSM Plan expansion into consideration when evaluating the claimed needs for additional supply-side resources.[5]

A. DSM-EE Legal Standard

Review of Kentucky Power's DSM Plan is governed by KRS 278.285. Principally, the Commission must determine the reasonableness of a proposed plan, informed by consideration of a non-exhaustive list of eight factors:

> (a) The specific changes in customers' consumption patterns which a utility is attempting to influence;
>
> (b) The cost and benefit analysis and other justification for specific demand-side management programs and measures included in a utility's proposed plan;
>
> (c) A utility's proposal to recover in rates the full costs of demand-side management programs, any net revenues lost due to reduced sales resulting from demand-side management programs, and incentives designed to provide positive financial rewards to a utility to encourage implementation of cost-effective demand-side management programs;
>
> (d) Whether a utility's proposed demand-side management programs are consistent with its most recent long-range integrated resource plan;
>
> (e) Whether the plan results in any unreasonable prejudice or disadvantage to any class of customers;
>
> (f) The extent to which customer representatives and the Office of the Attorney General have been involved in developing the plan, including program design, cost recovery mechanisms, and financial incentives, and if involved, the amount of support for the plan by each participant, provided however, that unanimity among the participants developing the plan shall not be required for the commission to approve the plan;
>
> (g) The extent to which the plan provides programs which are available, affordable, and useful to all customers; and
>
> (h) Next-generation residential utility meters that can provide residents with the amount of current utility usage, its cost, and can be capable of being read by the utility either remotely or from the exterior of the home.

[5] Though not summarized here, JI PH Attachment 1 summarizes the specific DSM-EE program changes proposed by EKPC, reproducing Table 1 of Dr. Roumpani's Direct Testimony.

If after consideration of these statutory factors, along with any other factors deemed informative by the Commission, it determines the plan to be reasonable, the plan should be approved. Apart from those factors, the demand-side management plan statute is not prescriptive with respect to timelines, savings targets, programs, or budget—so long as the plan is reasonable.

The Commission must weigh the reasonableness of a DSM Plan in light of constitutional and statutory obligations to advance the public interest through effective regulation of utility companies' rates and services.[6] These obligations include ensuring rates that are fair, just, and reasonable, and service that is adequate, efficient, and reasonable.[7] As in all instances concerning proposed rate or tariff changes, the regulated utility bears the burden of proof to show that DSM-related rates and tariff changes are just and reasonable.[8]

Commission Orders routinely encourage exploration of all cost-effective demand-side management programs. As noted in the Commission's February 17, 2011, Final Order in Case No. 2010-00222:

> The Commission believes that conservation, energy efficiency and DSM, generally, will become more important and cost-effective as there will likely be more constraints placed upon utilities whose main source of supply is coal-based generation . . . . [T]he Commission believes that it is appropriate to strongly encourage Meade, and all other electric energy providers, to make greater effort to offer cost-effective DSM and other energy efficiency programs.[9]

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[6] KRS 278.030(1); KRS 278.040. *See also* Order*, Application of Duke Energy Kentucky, Inc. to Amend Its Demand Side Management Programs*, Case No. 2019-00277, at 11 (Apr. 27, 2020) (observing statutory obligation to ensure rates are fair, just, and reasonable at the outset of discussion of proposed DSM/EE plan).

[7] KRS 278.030(1), (2).

[8] KRS 278.190(3).

[9] Order, *In the Matter of Application of Meade County Rural Electric Cooperative Corporation to Adjust Electric Rates*, Case No. 2010-00222, at 15–16 (Feb. 17, 2011). *See also* Order, *In the Matter of Consideration of the New Federal Standards of the Energy Independence and Security Act of 2007*, Case No. 2008-00408*,* at 22 (Oct. 6, 2011); Order*, In the Matter of Joint Application of PPL Corporation. E.ON AG., E.ON US Investments Corp., E.ON U.S. LLC.*

Where a utility has the benefit of a territory-specific demand-side potential study, the Commission has encouraged aggressive pursuit of all reasonable cost-effective DSM programs.[10] It has further stated that "[c]onsideration and discussion of DSM and EE programs are necessary factors to provide to prove the absence of wasteful duplication and prove that all reasonable alternatives were explored before concluding that proposed new generation is the least cost most reasonable option."[11]

B. The DSM plan will increase cost-effective savings, particularly with reasonable and factually-supported improvements.

EKPC's proposed DSM Plan will contribute cost-effective energy and demand savings with real benefits to all members, but the proposal also falls short of being reasonably available,

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Louisville Gas and Electric Company and Kentucky Utilities Company for Approval of an Acquisition of Ownership and Control of Utilities, Case No. 2010-00204, at 14 (Sept. 30, 2010) ("DSM, energy efficiency, and conservation are important now and will become more important and cost-effective in the future as more constraints are likely to be placed on utilities that rely significantly on coal-fired generation.").

[10] Order, *In the Matter of Electronic Application of Kentucky Power Company For: (1) Approval of Continuation of Its Targeted Energy Efficiency Program; (2) Authority to Recover Costs and Net Lost Revenues, and to Receive Incentives Associated with the Implementation of Its Demand Side Management Programs; (3) Acceptance of Its Annual DSM Status Report; and (4) All Other Required Approvals and Relief*, Case No. 2023-00362, at 7 (Dec. 15, 2023); Order, *In the Matter of Electronic Application of Kentucky Power Company for: (1) Approval of Continuation of Its Targeted Energy Efficiency Program (2) Authority to Recover Costs and Net Lost Revenues, and to Receive Incentives Associated with the Implementation of Its Demand-Side Management Programs; (3) Acceptance of Its Annual DSM Status Report; (4) Authorization to Conduct a Market Potential Study; and (5) All Other Required Approvals and Relief*, Case No. 2022-00392, at 7 (Jan. 6, 2023) ("The [Market Potential Study] will assist Kentucky Power in identifying DSM and energy efficiency programs for h residential and commercial–industrial customers that are cost-effective and avoid more expensive supply-side resources. The Commission encourages Kentucky Power to aggressively pursue all reasonable cost-effective DSM programs given the high-avoided capacity costs that will occur now that the Rock has expired.").

[11] Order, *Investigation of Amendments to the Public Utility Regulatory Policies Act of 1978 and Demand Response Practices*, Case No. 2022-00370, at 3-4 (Nov. 15, 2023).

affordable, and useful by unreasonably missing out on cost-effective potential. As intended, the 2024 Potential Study estimates territory-specific savings potential,[12] and as part of assuring reasonable least-cost service, the Commission should require EKPC to pursue at least the estimated achievable potential.

1. The DSM Plan will provide benefits to all customers.

Undisputed evidence from EKPC and Joint Intervenors shows, that sustaining and expanding DSM-EE programs will provide benefits to all customers. Benefits begin with the fact that the proposed DSM-EE program investments are the most cost-effective resource available.[13] This is true historically: the cost of energy and demand savings achieved through the 2021-2023 DSM plan years is well below EKPC's avoided costs for energy, generation, transmission, and distribution.[14] And there is every reason to think that these system-wide cost benefits will continue as the DSM Plan expands: the Total Resource Cost test ("TRC") scores[15] for the

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[12] As observed and explained in Dr. Roumpani's direct testimony, the 2024 Potential Study relies on a number of conservatisms that cause the study to underestimate cost-effective, achievable savings. Roumpani Direct, Section VII at 45-59. These conservatisms include insufficient evaluation of the impact of a broader range of incentives, industry best practices for overcoming barriers to participation unique to the region, behind the meter potential, altered program designs, and emerging technologies. *Id.* In urging Dr. Roumpani's recommendation that EKPC be required to propose a plan capable of delivering the identified realistic achievable potential, neither Dr. Roumpani nor Joint Intervenors maintain that the 2024 Potential Study certainly understates the actual potential.

[13] *E.g.*, EKPC Resp. to JI 1-57(c) (reflecting avoided energy costs of $0.0385 to $0.0567/kWh in 2026, which is notably higher than the cost of energy savings through DSM-EE programs, ranging from 0.019 kWh to $0.049/kWh); Testimony of Maria Roumpani, PhD on Behalf of Joint Intervenors Appalachian Citizens' Law Center, Kentuckians for the Commonwealth, and Mountain Association, at 30-31 (Feb. 14, 2025) ("Roumpani Direct") (comparing costs per kWh saved through DSM-EE programs to avoided cost values and levelized cost of supply-side resource alternatives).

[14] Roumpani Direct at 23, 30.

[15] The TRC cost-effectiveness test "is the cost effectiveness test historically preferred by the Commission." Direct Testimony of Scott Drake on Behalf of East Kentucky Power Cooperative, Inc., Case No. 2024-00370 (Nov. 20, 2024) ("Drake Direct"), at 17:2-4. EKPC

proposed programs range from 2.21 to 7.97;[16] and the cost of energy savings for the proposed programs is notably below the avoided cost of energy standing alone (i.e., before accounting for additional avoided cost benefits, such as avoided transmission capacity needs).[17]

These are compelling cost benefits, and DSM-EE program benefits continue far beyond their least-cost character to include, for example:

- Increasing the reliability and resilience of the grid by making the system less vulnerable to outages;
- Avoiding risks related to long-lead time, capital intensive projects, which is particularly important in the current economic environment;
- Avoiding regulatory and stranded asset risks that face supply-side investments;
- Can be deployed and scaled quickly;
- Reducing exposure to fuel insecurity and fuel price volatility.[18]

These additional benefits have value, but are not included in EKPC's cost-effectiveness calculations. As a result, EKPC's cost-effectiveness scores must understate the value of savings.

Consider, for example, the value to a participant in EKPC's Button-Up Weatherization Program. Offered since the early 1990s, Button-Up Weatherization is about eliminating energy

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Witness Scott Drake defined the test as follows: "The TRC measures the net costs of a DSM/EE program as a resource option based on the total costs of the program, including both the participants' and the utility's costs. This test provides a cost-effective perspective for both program participants and non-participants. . . . Historically, the TRC cost-effectiveness test is utilized to evaluate cost-effectiveness of individual measures as determined by the 2024 Potential Study." *Id*. at 15:14-18 and 16:9-10.

[16] Roumpani Direct at 31, tbl.6. A TRC score greater than 1 indicates a measure is cost-effective as compared to alternatives, with higher scores indicating even greater cost effectiveness.

[17] According to record evidence provided by EKPC, the cost of energy savings under the proposed DSM Plan programs ranges from $0.019/kWh to $0.049/kWh, while EKPC's avoided cost of energy ranges from $0.0385/kWh to $0.0567/kWh in 2026. Roumpani Direct at 30.

[18] Roumpani Direct at 25-26.

waste by offering incentives for air sealing, insulation, and HVAC work.[19] On average, participants in Button-Up Weatherization in 2023 saved 2,428 kWh annually.[20] That's more than a reduced monthly bill; that's a coop owner-member enjoying a more comfortable, resilient home.[21] For all customers, those savings avoid higher cost generation and transmission costs, with the Button-Up Weatherization program reporting that the average cost of savings was roughly $0.03/kWh,[22] with a TRC score comfortably above 1.0.[23]

These benefits, and the dignity that accompanies them, are even more impressive in EKPC's income-qualified weatherization program. For CARES program performance, EKPC reports 120 participants in program year 2023 saved an average of 4,650 kWh annually.[24] The incremental affordability and comfort benefits afforded to those participating households cannot be overstated.

EKPC's DSM-EE programs have been successfully delivering these benefits for decades, with substantial savings potential available across residential and commercial classes. This least-cost, high-reward resource should be immediately and aggressively to maximize cost-effective potential as soon as possible.

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[19] April 22, 2025, HVT 10:55 a.m. through 10:57 a.m. (Witness Drake affirms on cross examination that improving the building shell reduces energy waste, causing EKPC staff to view the "Button-Up Program is [EKPC's] most important program").

[20] Drake Direct, Application Ex. 10, Direct Testimony of Scott Drake on Behalf of East Kentucky Power Cooperative, Inc., Case No. 2024-00370 (Nov. 20, 2024) ("Drake Direct"), Attach. SD-6, 2023 DSM DLC Annual Report at 7 (annual combined energy savings of 68,000 kWh divided by 28 participants). Note that the savings per participant reflected on page 7 of the 2023 DSM DLC Annual Report provide slightly different values for the Button-Up program and others. Joint Intervenors cannot explain these inconsistencies in EKPC's reporting.

[21] E.g., Drake Direct, Attach. SD-6, 2023 DSM DLC Annual Report at 3.

[22] *Id.* at 7.

[23] *Id.* at 10 (reporting 1.68 TRC score).

[24] *Id.* at 7 (reporting 120 participants with annual combined energy savings of 558,000 MWh).

2. *EKPC should be directed to pursue the conservatively-estimated achievable potential.*

EKPC, with support from the experts at GDS Associates, estimated the cost-effective, achievable energy and demand savings potential in EKPC's service territory. Conducted at member expense, the triennial potential study could serve as a roadmap for EKPC and its owner-members to aggressively pursue all cost-effective and reasonably achievable potential, as the Commission has previously encouraged.[25] Instead, the proposed DSM Plan aims for a fraction of the identified potential.[26]

The figures below, reproduced from Dr. Roumpani's Direct Testimony, illustrate the gap between achievable potential—maximum achievable potential in blue and reasonably achievable potential in red—and in green, the savings assumed in the proposed DSM Plan.[27] In the first five years alone, the proposed DSM Plan leaves approximately 350,000 MWh of reasonably achievable energy savings potential untapped.[28]

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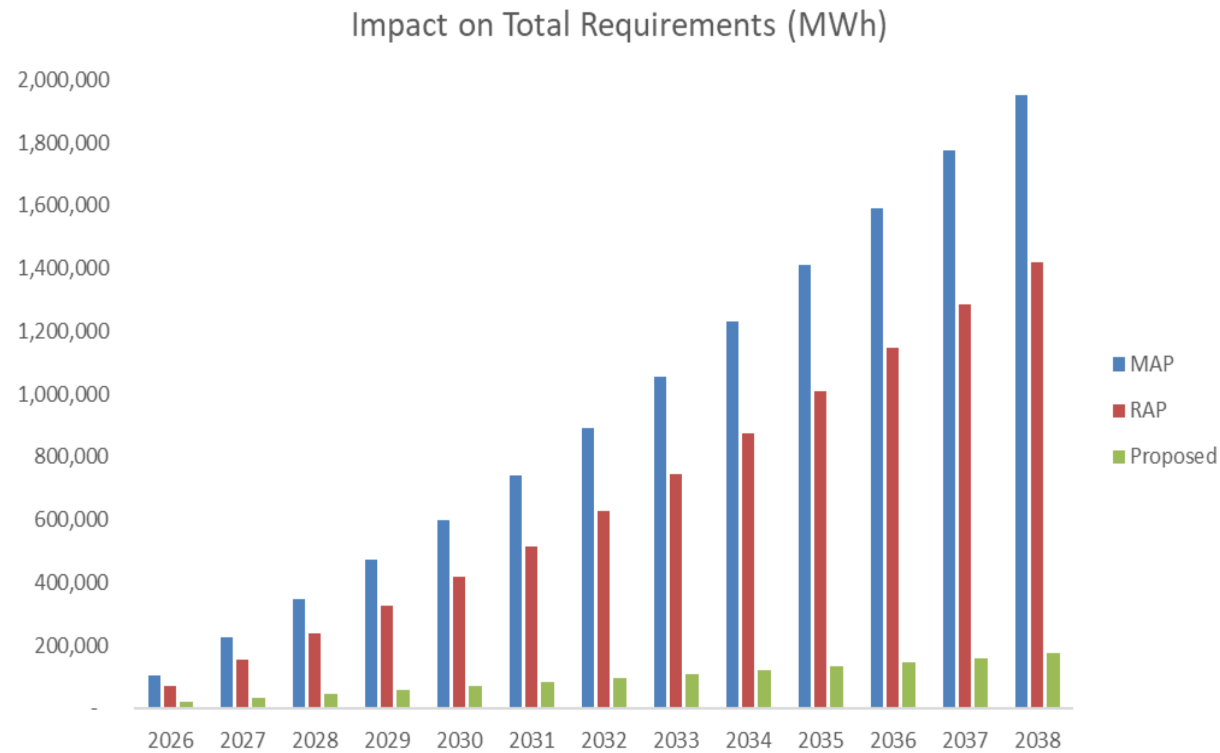
[25] Case No. 2023-00362 Dec. 15, 2023 Order at 7; Case No. 2022-00392, Jan. 6, 2023 Order at 7 (Jan. 6, 2023) ("The [Market Potential Study] will assist Kentucky Power in identifying DSM and energy efficiency programs for both residential and commercial–industrial customers that are cost-effective and avoid more expensive supply-side resources. The Commission encourages Kentucky Power to aggressively pursue all reasonable cost-effective DSM programs given the high-avoided capacity costs that will occur now that the Rockport UPA has expired.").

[26] EKPC's Rebuttal Witnesses provided no direct response to Dr. Roumpani's testimony, and identified no errors or misstatements of fact. With EKPC's rebuttal responding only to certain data responses, the direct testimony stands entirely unrebutted.

[27] As in Dr. Roumpani's Direct Testimony, reported numbers from the Potential Study are delayed two years from 2024 to 2026. Roumpani Direct at 17.

[28] *Id.*

Figure 2 - Proposed DSM Plan, MAP and RAP Impacts on Total Energy Requirements (MWh)

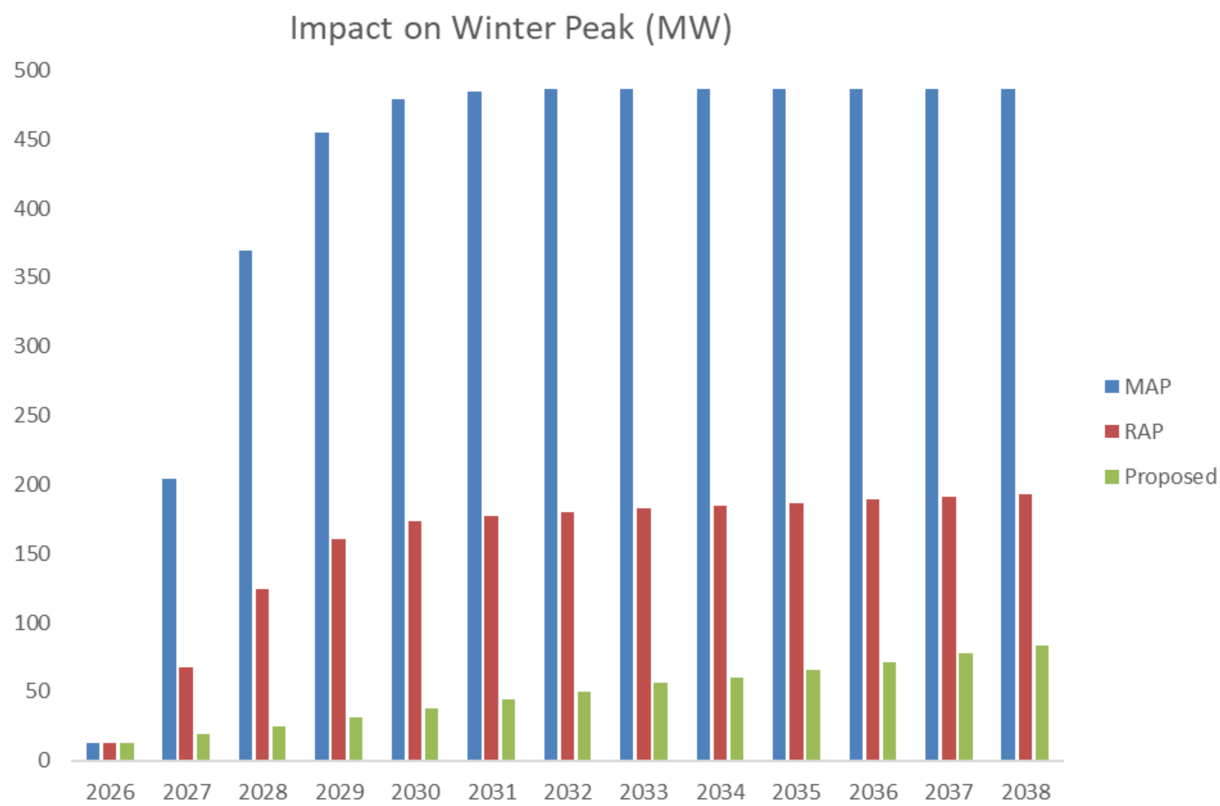


By 2030, the proposed plan targets just over 10% of what the EKPC consultants identified as realistically achievable.[29]

Similarly, as in Figure 3 below, the DSM Plan unreasonably proposes to leave 135 MW to 441 MW of potential winter capacity reductions untapped.[30] Meaning, even at a time of great concern for winter reliability, the proposed DSM Plan would pursue less than 25% of the cost-effective realistically achievable potential identified by GDS in the first five years of an expanded plan.

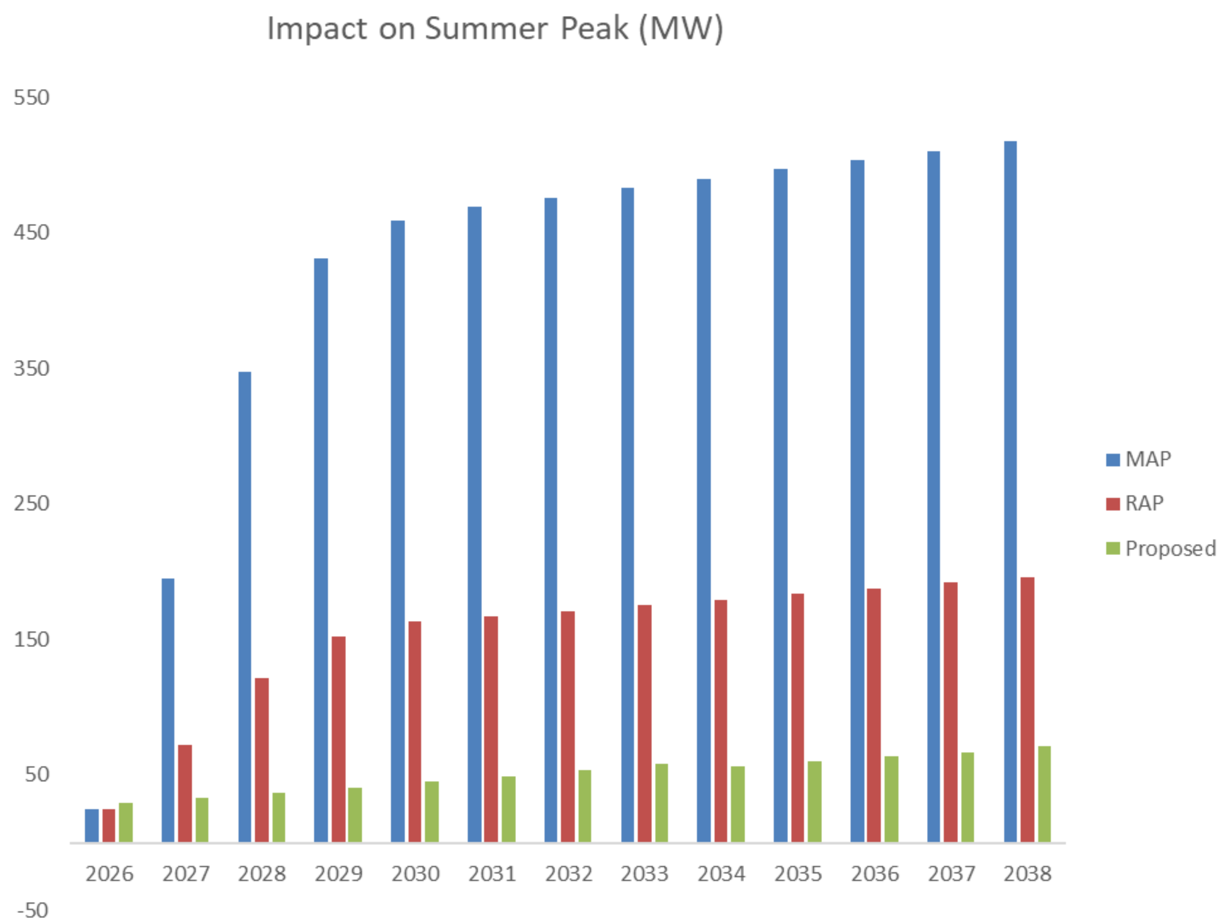
[29] *Id.* at 16.
[30] *Id.* at 18-19.

Figure 3 - Impact on Winter Peak from MAP, RAP, and EKPC Proposed DSM Plan (MW)



This pattern repeats at summer peak, with the DSM Plan proposing to pursue less than 28% of the identified summer peak demand reduction potential over the next five years, as in Figure 4 below.

Figure 4 - Impact on Summer Peak from MAP, RAP, and EKPC Proposed DSM Plan (MW)



As the foregoing figures illustrate, taking the potential study at face value, the proposed DSM Plan dramatically underperforms. Dr. Roumpani recommends, and it would be reasonable for the Commission to require, that EKPC develop demand side management and energy efficiency programs that pursue the reasonably achievable potential identified by GDS: cumulative savings of 400,000 MWh by 2030, and winter peak savings of 173 MW.[31]

[31] Roumpani Direct at 20.

3. *EKPC has the Roadmap, Resources, and Wherewithal to Achieve Higher Levels of Energy and Demand Savings.*

Using its recent potential study and internal expertise, EKPC is capable of intentionally designing a DSM Plan that will maximize identified savings potential without arbitrary constraint. Dr. Roumpani's unrebutted direct testimony identified "low-hanging fruit" that could cost-effectively and quickly ramp to support greater participation and greater energy savings. Several examples related to budget and untapped savings potential are highlighted here, and JI PH Brief Attachment 2 (attached hereto) comprehensively collects Dr. Roumpani's observations and recommendations.

Budgets need to be increased to support higher levels of participation in cost-effective programs.[32] For example, a 50% budget increase for demand response programs would yield three times the savings.[33] That cost-effective scaling of demand response programs delivers winter demand savings at a cost of only $75.65/kW (and $30.83/kW summer demand savings)—far below EKPC's avoided generation capacity cost ($175.60/kW-yr) and avoided costs overall.[34]

As budgets expand, EKPC should prioritize programs targeting end-uses with the greatest amount of cost-effective potential and ability to shave winter peaks.[35] To that end, the potential study supports ramping up existing programs and incentives for building shell and HVAC measures beyond proposed levels. In addition to being the leading end-use categories for cost-

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[32] *Id.* at 21-22.
[33] *Id.* at 22.
[34] Drake Direct, Attach. SD-8. Additional details for seasonal values and annual escalation are provided in EKPC's Response to JI Q1-57, and additional discussion is provided in Dr. Roumpani's Direct Testimony at 22-23.
[35] Roumpani Direct at 27-28.

effective residential savings, building shell and HVAC measures "can have a dramatic impact on winter peak demand," making them especially valuable in serving EKPC's identified winter capacity needs.[36]

Additionally, program budgets should be more closely aligned to energy savings potential. For example, the Bring Your Own Thermostat Program and new High Efficiency Heat Pump Programs, as proposed, aim to achieve cumulative savings of roughly 2,800 MWh, despite the Potential Study identifying combined cumulative potential that's 29 to 57 times greater (82,929 MWh (RAP) and 161,665 MWh (MAP)).[37] Such unreasonably large departures from estimated achievable potential should be corrected.

More low-hanging-fruit to quickly ramp up cost-effective savings is collected in Dr. Roumpani's testimony, and can be further developed based on the data and analysis already set forth in the 2024 Potential Study. As a least-cost resource that provides real benefits for all customers, EKPC should be directed to make changes to maximize savings. Joint Intervenors urge Dr. Roumpani's recommendations in their entirety, and as restated in Attachment 2 with this brief.

C. EKPC's decision to forego achievable potential unreasonably increased need for higher-cost alternatives and tainted the load forecast.

The shortcomings of the DSM Plan have effects beyond the potential accessibility of demand-side programs for end-users. By largely ignoring the identified achievable potential, the DSM Plan undermines the reasonableness of the 2024 Long-Term Load Forecast, and by extension, undermines EKPC's claimed need and the validity of the offered supply-side

[36] *Id.* at 28.
[37] *Id.* at 29.

analysis.[38] These shortcomings started in planning; continued despite EKPC having been cautioned as recently as its 2022 IRP that a different approach was needed and expected; and will continue causing higher costs of service while providing fewer customer benefits.

With reasonable planning, as older generation approaches retirement, EKPC could have invested aggressively toward building up cost-effective EE and DR programs that would have more significantly reduced, delayed, or offset more costly supply-side resources.[39] But EKPC did the opposite: EKPC slashed DSM/EE program budgets down from $5.5 million in 2019 to less than $4 million annually in 2021-2024;[40] skipped evaluating DSM/EE program impacts as part of its 2022 IRP "beyond those in the [then-] current approved suite of programs";[41] and undermined the 2022 IRP's load forecast and analysis of the supply-side needs by excluding the achievable potential identified by third-party experts.[42] Staff's Report on the 2022 IRP observed that EKPC's DSM-EE planning was not integrated into its resource analysis, and that EKPC did not assess DSM-EE resource potential on the same basis as new generation resources, despite EKPC having a modeling tool capable of doing exactly that.[43]

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[38] *See* Order Attaching Commission Staff's Report*, In the Matter of Electronic 2022 Integrated Resource Plan of East Kentucky Power Cooperative, Inc*., Case No. 2022-00098, at 34 (March 9, 2023) ("By not including future cost-effective DSM programs that were shown to have positive Maximum Achievable Potential (MAP) and Realistically Achievable Potential (RAP) scores, the [2022 IRP] load forecast and, by extension, the supply-side analyses were not at as informative as they could have been.").

[39] Roumpani Direct at 26.

[40] Responses to Staff's Post-Hearing Request to East Kentucky Power Cooperative, Inc. Dated April 24, 2024, Case No. 2024-00370, Question 6 (May 2, 2025) ("EKPC Resp. to Staff PH-6").

[41] Case No. 2022-00098, March 9, 2023 Order Attaching Commission Staff's Report, at 34 (Mar. 9, 2023).

[42] *Id.*

[43] *Id.* at 38.

Notwithstanding the 2022 IRP reminder to EKPC that "generation resources and DSM/EE programs should be analyzed together as part of the same modeling runs," and "on the same basis,"[44] no such analysis occurred in support of this DSM Plan proposal or any of the supply-side resource proposals. But the record does confirm that the cheapest kilowatt hour is the one that does not need to be generated by EKPC at a new gas-fired unit.

Dr. Roumpani's Direct Testimony highlighted the relative cost-effectiveness of EKPC's DSM programs over three years (2021-2023) as compared to the avoided cost values used to determine cost-effectiveness in the potential study and the proposed DSM Plan.[45] For illustrative purposes, Dr. Roumpani also offered a comparison of the Cooper CCGT costs to a DSM-EE program portfolio capable of avoiding a comparable level of energy and demand savings.[46] The result, summarized below shows that operating a 745 MW CCGT at a 40% capacity factor, would cost $172 million per year over 35 years.[47] A DSM portfolio could deliver the same magnitude of demand and energy savings (2,610 GWh/yr) for a $110 million annual budget.[48] While not offered as a full alternative to the Cooper CCGT, Dr. Roumpani explained that such analysis helps demonstrate that "a proper evaluation of both supply-side and demand-side resources would have resulted in a portfolio with more DSM resources and a lower supply-side capacity need (this could mean a smaller size CCGT, or a delayed need for that resource)."[49]

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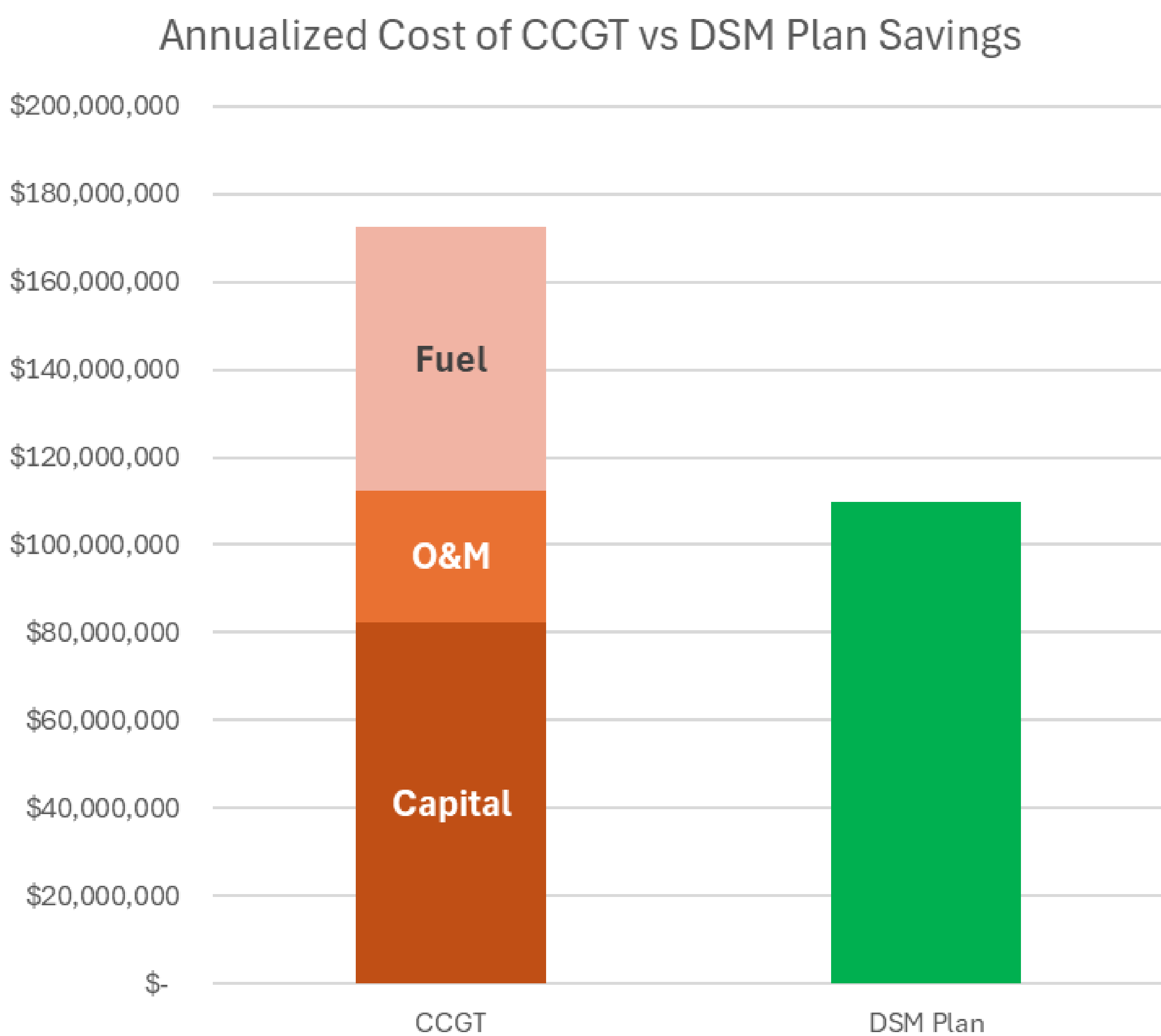
[44] *Id.*
[45] Roumpani Direct at 23.
[46] *Id.* at 23-24.
[47] *Id.* at 24 (providing full set of assumptions, which include application of PJM's Effective Load Carrying Capability Class Ratings, discount rates, and other price assumptions, all of which are consistent with cost estimates provided by EKPC).
[48] *Id.* at 25-26.
[49] *Id.*

Figure 5 - Annualized Cost of CCGT vs DSM Plan Savings



This comparison remains undisputed. Reasonable minds should agree generally, and in this particular case, that least-cost portfolios result from integrated evaluation of supply- and demand-side resources, followed by the pursuit of identified achievable savings potential.

EKPC, however, appears needlessly stuck in a pattern of disintegrated planning that under-prioritizes demand-side potential, resulting in higher costs and bills for owner-members. However the Commission resolves the requested supply-side costs, first and foremost, an order in this proceeding should demand serious efforts to help cut energy waste, improve efficiency, and reduce peaks by pursuing at least the identified achievable DSM-EE Program Potential.

III. Certificates of Public Convenience and Necessity

A. Legal Standard

A certificate of public convenience and necessity must be obtained from the Commission prior to the construction or acquisition of any facility seeking to be used in providing utility service to the public.[50]

To obtain the requested certificates for new gas resources, the Companies must demonstrate a "need" for such facilities and show an "absence of wasteful duplication" resulting from each resource addition.[51]

As the party seeking Commission approval in this proceeding, the Companies bear the burden of proof by clear and satisfactory evidence that both need and an absence of wasteful duplication has been sufficiently established.[52]

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[50] KRS 278.020(1)(b) (Upon filing of an application for a certificate, the Commission may issue the certificate, refuse to issue, or issue in part and refuse in part).

[51] Final Order, *In re Electronic Application of East Kentucky Power Cooperative Inc. for a (1) CPCN for the Construction of Transmission Facilities in Madison County, Kentucky; and (2) Declaratory Order Confirming That a CPCN Is Not Required for Certain Facilities*, Case No. 2022-00314, at 7 (Feb. 23, 2023); 807 KAR 5:001 Section 15(2) (specifies what a utility must submit with its application for a CPCN, which, among other things, includes "[t]he facts relied upon to show that the proposed construction or extension is or will be required by public convenience or necessity," "[t]he manner in detail in which an applicant proposes to finance the proposed construction or extension," and "[a]n estimated annual cost of operation after the proposed facilities are placed into service."); *see also Ky. Utils. Co. v. Pub. Serv. Comm'n*, 252 S.W.2d 885, 890 (Ky. 1952) (determination of public convenience and necessity requires both "a finding of the need for a new service system or facility from the standpoint of service requirements, and an absence of wasteful duplication resulting from the construction of the new system or facility").

[52] Order, *In re Electronic Application of Kentucky Utilities Company for a CPCN for the Construction of Transmission Facilities in Hardin County, Kentucky*, Case No. 2022-00066, at 23 (July 28, 2022) ("The Commission's consideration . . . in CPCN proceedings generally[] is

1. Need for new capacity and/or energy

A CPCN requires the utility to show "a demand and need for the service sought to be rendered."[53] To establish "need," a utility must: "first [make] a showing of a substantial inadequacy of existing service, involving a consumer market sufficiently large to make it economically feasible for the new system or facility to be constructed and operated" and second, show that "the inadequacy . . . [is] due either to substantial deficiency of service facilities, beyond what could be supplied by normal improvements in the ordinary course of business; or to indifference, poor management or disregard of the rights of consumers, persisting over such a period of time as to establish an inability or unwillingness to render adequate service."[54]

2. An absence of wasteful duplication

The requirement to avoid wasteful duplication discourages "an excess of capacity over need, an excessive investment in relation to productivity or efficiency, or an unnecessary multiplicity of physical properties, such as rights of ways, poles and wires."[55] This requirement necessarily goes beyond showing a need.

The Commission has explained that to demonstrate that a proposed facility does not result in wasteful duplication, "the applicant must demonstrate that a thorough review of all

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limited to its review of the evidence provided to determine whether a utility met its burden of proof that, after finding the presence of need, a proposal does not result in wasteful duplication.").

[53] KRS 278.020(5).

[54] *Iola Cap. v. Pub. Serv. Comm'n of Kentucky*, 659 S.W.3d 563, 571 (Ky. Ct. App. 2022), review denied (Feb. 8, 2023) (quoting *Ky. Utils. Co. v. Pub. Serv. Comm'n of Kentucky*, 252 S.W.2d at 890).

[55] *Ky. Utils. Co. v. Pub. Serv. Comm'n*, 390 S.W.2d 168, 173 (Ky. 1965).

reasonable alternatives has been performed."[56] The Commission has made clear that "[t]he fundamental principle of reasonable least-cost alternative is embedded in such an analysis."[57]

B. EKPC has not shown a need for the proposed "Plan in Total."

1. The Proposed Cooper CCGT and Liberty RICE Units Are Intended to Address a Forecasted Winter Peak Need that is Unsupported and Very Likely Inflated.

While EKPC contends that the "genesis" of the Cooper CCGT and Liberty RICE units was Winter Storm Elliott, the actual peak load that the projects are purportedly needed to meet was apparently not quantified until the 2024 Long Term Load Forecast ("2024 LTLF") and EKPC's decision to add a 7% winter reserve margin to that forecast. As compared to the Company's 2022 LTLF, the 2024 LTLF and 7% reserve margin combine to significantly increase EKPC's forecasted winter capacity needs and, therefore, the Company's claimed winter capacity shortfall over the coming years that is used to claim a need for the projects. As discussed in the testimony of Joint Intervenors witness Dr. Elizabeth Stanton,[58] however, the

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[56] Case No. 2022-00314, Final Order at 8, *supra* note 51; *see also* Order, *In the Matter of Electronic Application of East Kentucky Power Cooperative, Inc. for a Certificates of Public Convenience and Necessity and Site Compatibility Certificates for the Construction of a 96 MW (Nominal) Solar Facility in Marion County, Kentucky, and a 40 MW (Nominal) Solar Facility in Fayette County, Kentucky and Approval of Certain Assumptions of Evidences of Indebtedness Related to the Solar Facilities and Other Relief*, Case No. 2024-00129, at 3 (Dec. 26, 2024).

[57] Final Order, *Electronic Joint Application of Kentucky Utilities Company and Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity and Site Compatibility Certificates and Approval of a Demand Side Management Plan and Approval of Fossil Fuel-Fired Generating Unit Retirements*, Case No. 2022-00402, at 11 (Nov. 06, 2023).

[58] Joint Intervenors witness Elizabeth Stanton has a PhD in Economics and more than 12 years of experience providing technical expertise and consulting services on energy economics and related issues in more than a dozen PUCs across the country. Stanton Direct Testimony at 1-3 and Ex. EAS-1. In her rebuttal testimony, EKPC witness Tucker launches a spurious attack claiming that Dr. Stanton lacks a "keen understanding" of load forecasting issues because she uses the term "demand" to refer to energy use or sales. Tucker Rebuttal Testimony at 10-11. In Ms. Tucker's telling, "demand" refers only to capacity expressed in kW or MW, and not to energy use or sales expressed in kWh or MWh. April 22, 2025 HVT at 2:40 p.m.. At hearing, however, Ms. Tucker essentially conceded that this criticism was baseless. In fact, the definition of "demand" from North American Electric Reliability Corporation ("NERC") that

2024 LTLF is unsupported and likely overstated in some key ways, and the new 7% winter reserve margin has not been justified. While EKPC may have a need for some new capacity, the available evidence does not support the contention that a new 745 MW Cooper CCGT and 214 MW Liberty RICE units, along with preservation of Cooper Unit 2 through the gas co-firing proposal, are all needed to ensure reliable service to EKPC's Owner-Members and their customers.

a) EKPC Is Projecting Significantly Higher Winter Capacity Needs Than in Its 2022 IRP.

EKPC's 2024 LTLF, which was completed more than a year after the Company had started down the path of proposing a new CCGT and RICE units and finalized after this CPCN application was filed, projects higher winter loads than previous forecasts. In particular, Table 1, below charts the forecasted winter peak load for 2025, 2029, and 2031 in the 2024 LTLF compared to EKPC's 2022 LTLF.

Table 1 - 2022 vs 2024 LTLF Winter Peak Load Forecasts in MW[59]

	2022 LTLF	**2024 LTLF**	**2024 vs 2022**
2025	3,370	3,517	+147
2029	3,467	3,727	+260
2031	3,504	3,760	+256

EKPC then supplemented its 2024 LTLF winter peak load forecast with a new 7% reserve margin, which added 246 to 263 MW of load beyond what the 2024 LTLF forecast for the winter peak demand. As shown in Table 2, with the added 7% reserve margin, EKPC is

Ms. Tucker cites in her testimony references "energy . . . averaged over any designated interval of time," which is exactly what a MWh or kWh is. Similarly, witness Tucker acknowledged that the PJM glossary defines "energy" as to "usage or consumption of electricity on a power system. Demand is generally expressed in kilowatt-hours or megawatt-hours." https://www.pjm.com/Glossary#index_D. April 22, 2025 HVT at 2:43 p.m. to 2:45 p.m.

[59] Attachment JJT-3.

planning for more than 500 MW of additional winter peak load in 2029 and 2031 than was projected in its 2022 LTLF.

Table 2 - 2022 LTLF vs. 2024 LTLF + 7% Reserve Margin in MW

	2022 LTLF	**2024 LTLF + 7% Reserve Margin**	**2024 vs 2022**
2025	3,370	3,763	+ 393
2029	3,467	3,988	+ 521
2031	3,504	4,023	+ 519

b) EKPC Is Proposing More New Generation Capacity Than Needed to Meet Its Own Claimed Winter Capacity Shortfall.

Growing out of its higher forecasted winter peak load needs, EKPC claims winter capacity shortfalls of 454 MW in 2026, increasing to 723 MW by 2031, and 800 MW by 2035.[60] In its Application, EKPC assumed that 300 MW of that shortfall would be met through a hydropower PPA starting in 2026 through 2035 that the Company was in the process of negotiating.[61] So, at the time of its Application, EKPC was proposing 959 MW of new capacity to address a claimed shortfall that, after the assumed 300 MW hydropower PPA, ranged from 134 MW to 500 MW. Even without the hydropower PPA, which EKPC did not successfully negotiate, the 959 MW of proposed new capacity exceeds the Company's forecasted winter peak load plus the new 7% reserve margin by 236 MW in 2031, and at least 159 MW through 2035.

[60] Attachment JJT-4 to Application Ex. 3, Direct Testimony of Julia J. Tucker on Behalf of East Kentucky Power Cooperative, Inc., Case No. 2024-00370 (Nov. 20, 2024) ("Tucker Direct").

[61] *Id*. *See also* Responses to Staff's First Information Request to East Kentucky Power Cooperative, Inc. dated December 20, 2024, Case No. 2024-00370, Question 5 (Jan. 3, 2025) ("EKPC Resp. to Staff 1-5").

c) The 2024 LTLF Projects Higher and Faster Growing Winter Peak Load than PJM's Recent Long-Term Load Forecast for the EKPC Zone.

As witness Stanton explained,[62] EKPC's winter load forecast is inconsistent with PJM's recent long-term load forecast for the EKPC Zone. First, the PJM forecast shows much lower winter peak load than EKPC's forecast does. For example, for the winter of 2024-25, EKPC forecasts a peak of 3,517 MW,[63] while the PJM forecast shows a 2025 winter peak below 2,800 MW.[64] Second, PJM forecasts annual winter load growth of 0.3% per year over the next 10 years, and 0.4% per year over the next 15 and 20 years.[65] By contrast, EKPC forecasts 0.8% growth per year in winter peak demand,[66] leading to a 2031 forecasted winter peak load that is 243 MW higher than that forecasted for 2025.[67]

In rebuttal, EKPC witness Tucker attempts to explain the discrepancy between the PJM and EKPC load forecasts by noting that they cover somewhat different sets of load.[68] In particular, Ms. Tucker explains that the EKPC Zone forecasted by PJM does not include load that is served by EKPC but located on AEP, KU/LG&E, or Duke Energy Ohio Kentucky's systems. Conversely, PJM's forecast includes load that is located on the EKPC system but served by AEP or KU/LG&E rather than EKPC.

While Ms. Tucker's contention is accurate, it does not fully explain why EKPC's forecast is higher, and increasing faster, than PJM's. As noted above, the EKPC winter peak forecast for

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[62] Stanton Revised Direct at 14-15.
[63] Tucker Direct Attachment JJT-3.
[64] Stanton Revised Direct, Ex. EAS-2 at 33.
[65] *Id.*
[66] Tucker Direct, Attachment JJT-2 at 2.
[67] Attachment   comparing 2024 LTLF forecast for winter 2024-25 to winter 2030-31.
[68] Rebuttal Testimony of Julia J. Tucker on Behalf East Kentucky Power Cooperative, Inc., Case No. 2024-00370 at 6 (Mar. 31, 2025) ("Tucker Rebuttal").

2025 is more than 717 MW higher than PJM's forecast. In January 2025, the amount of load served by EKPC that is in other zones and, therefore, not included in PJM's forecast, was 710 MW.[69] While that amount should be added to the PJM forecast, to make the two forecasts comparable one also needs to subtract the amount of load included in the PJM forecast that is not served by EKPC.[70] In January 2025, that amount was [redacted],[71] leading to a net impact of the differences between the EKPC and PJM load forecasts of [redacted].[72] As such, PJM's forecast remains significantly lower than EKPC's even when adjusted for the somewhat different loads identified by witness Tucker. Therefore, Dr. Stanton's opinion holds that the lower PJM load forecast raises concerns that EKPC may be overestimating its winter peak needs.[73]

d) The 2024 LTLF Relies on a Forecasted Significant Increase in Large Commercial Load that Is Unverified and Opaque.

EKPC's 2024 LTLF shows that much of its forecasted increase in peak load and energy requirements is the result of projected growth in large commercial customer load in the "short-term period," which EKPC defines as through 2029.[74] For example, the 2024 LTLF forecasts that winter peak load will increase by 210 MW between 2025 and 2029.[75] Over that same period,

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[69] Hearing Ex. JI-4; April 22, 2025 HVT at 3:25 p.m. to 3:27 p.m.

[70] April 22, 2025 HVT at 3:28 p.m.6:33.

[71] Hearing Ex. JI-3, Confidential JI8 – 2020-2025 Foreign Demand on EKPC Transmission at line 62. The [redacted] figure was calculated by adding together the load amounts identified in Columns C through F of line 62.

[72] 710 MW – [redacted] = [redacted]

[73] Stanton Revised Direct at 18.

[74] EKP sp. to I 2-22.

[75] Tucker Direct, Attachment JJT-3, comparing 2024 LTLF forecast for winter 2024-25 to winter 2028-29.

EKPC forecasts that it will add 182 MW of demand from new large commercial customers.[76] Similarly, the 2024 LTLF forecasts that total annual energy sales will increase by 1,360,138 MWh from 2025 to 2029,[77] with new large commercial customer load expected to add 1,052,205 MWh in energy sales over that time period.[78]

Especially given the significant role that large commercial load plays in the forecasted increases in energy and peak demand that EKPC claims creates a need for the Cooper CCGT and Liberty RICE units, one would expect a transparent and verifiable evaluation of such load. As Dr. Stanton detailed in her Direct Testimony, however, EKPC's short-term large commercial load forecast is opaque and cannot be verified on this record.[79]

The load forecast for most customer classes in the 2024 LTLF is based on data-driven regression analysis that uses historic and projected regional economic data, sales trends, appliance saturation, weather impacts, and other factors to forecast future energy needs.[80] Such approach is used for residential customers, small commercial customers, and long-term (i.e. post-2029) large commercial customer load.[81] For short-term large commercial customer load, however, EKPC relies on the "input of the owner-members" and their knowledge about "key accounts," the presence of industrial parks, changes to existing customer loads, and the potential arrival of new customers or departure of existing customers.[82] After receiving such input, EKPC

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[76] EKPC Resp. to JI 1-31.
[77] Tucker Direct, Attachment JJT-3, comparing 2024 LTLF forecast for 2025 to 2029.
[78] EKPC Resp. to JI 1-31.
[79] Stanton Revised Direct at 11-12.
[80] Tucker Direct, Attachment JJT-2 at 12-14.
[81] *Id.* at 15-16.
[82] *Id.* at 16.

then revises its preliminary forecast "based on mutual agreement of EKPC staff and owner-member's President/CEO and staff."[83]

It, of course, makes sense to incorporate on-the-ground knowledge about existing and potential new large commercial customers into a load forecast. The problem arises when, as here, there is no transparency around what inputs were provided, how it was decided whether a potential new customer is or is not included in the forecast, or the amount of load that should be assumed for such new customer. Instead, EKPC rebuffed multiple data requests seeking insight into the short-term large commercial load forecast with conclusory statements that input was provided based on negotiations with large commercial customers and that all such input is confidential and cannot be disclosed.[84] The concerns about the lack of transparency into the large commercial customer load forecast are heightened by the fact that the forecast is based on owner-member input for the first five or six years (2024-2025 through 2029),[85] while EKPC's own Load Forecast Workplan states that "beyond the three year horizon," regression analysis should be used for such customer class.[86]

In rebuttal, EKPC witness Tucker first erroneously suggests that Dr. Stanton recommends ignoring known changes to the large commercial class, stating that "Excluding known changes to the large commercial class poses a risk to planning and reliability."[87] Dr. Stanton, of course, did no such thing. Instead, as she explained in response to a Staff data request:

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[83] *Id.* at 12.

[84] *See* EKPC Resps. to JI 1-31, 1-35, 2-22.

[85] EKPC Witness Tucker explained at the hearing that the 2024 data in the 2024 LTLF was a combination of actual and forecast data, so the short-term was somewhere between five and six years. April 22, 2025 HVT at 3:13 p.m.

[86] Attachment to EKPC Resp. to JI 1-30 at 9, "JI 1-30_2025-2039 Load Forecast Work Plan".

[87] Tucker Rebuttal at 3; April 22, 2025 HVT a 2:46 p.m. to 2:48 p.m.

> EKPC should base its short-term forecast of new large customer load on concrete evidence that there is a high likelihood that such load will actually come online, while discounting or excluding possible large customer load that is merely speculative or has a low likelihood of materializing. Such concrete evidence includes whether the potential new large customer has submitted permit applications, acquired necessary real estate, initiated construction, and entered into contracts for electric service. With regards to existing large customers, increases in load should be accounted for only on the basis of documented claims that such customers have concrete plans to increase operations or otherwise have a reasonable basis to conclude that their load will increase. Conversely, if there is a high likelihood that an existing large customer will reduce or cease operations in the short-term, that load should accordingly be subtracted from the short-term forecast.
>
> It is unclear the extent to which the above differs from the basis of EKPC's short-term large customer load forecast because, as explained in my testimony, that short-term forecast is "unverified and opaque." . . . . While EKPC provided aggregate projected new large customer counts, demand, and energy use, see EKPC Response to JI 1.31(c), it has not identified what, if any, steps EKPC or its owner-members took to determine whether there was a high likelihood that such new large customer load would actually come online. Notably, however, EKPC conceded that none of the large commercial class customers projected to come online in 2025, 2026, and 2027 had executed any contracts with EKPC or its owner-members for any of those years. EKPC Response to JI 1.35(c).[88]

In her rebuttal, witness Tucker next tries to paper the record with a series of press releases announcing some large commercial customer projects proposed in eastern Kentucky.[89] Press releases, of course, do not always become operating projects, and no information has been provided as to how much new load those projects would represent or the likelihood of the projects actually coming online. In addition, a number of the press releases date from 2018, 2021, or 2022, which raises questions about how many of the referenced projects are reflected in the new large commercial customer load growth forecast in the 2024 LTLF for 2024-2025 through 2029, as opposed to already baked into actual data from earlier years.

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[88] Joint Intervenors response to Staff 1-1.
[89] Tucker Rebuttal at 3-4 and Tucker Rebuttal Attachment JJT-1.

Finally, witness Tucker points to the significant growth in large commercial customer energy sales in 2022 and 2023 as supporting the reasonableness of the significant projected growth in that customer class in 2025 through 2029.[90] But past load growth is relevant to a regression analysis, not to an on-the-ground assessment of what potential customers in the service territory are likely to do in the future. As such, simply pointing to past load growth does nothing to change the fact that EKPC has provided no information upon which its forward-looking assessment can be evaluated and verified.

What the 2022 and 2023 large commercial customer energy sales levels that Ms. Tucker highlights do show is how EKPC has overestimated such energy use in the past. For example, the 353,692 MWh increase in large commercial customer energy sales in 2022 that witness Tucker references was well below the 1,403,630 MWh increase for that year that EKPC had projected in its load forecast accompanying its 2022 IRP.[91] The 2023 large commercial energy sales were also below forecast.[92] Similarly, the load forecast accompanying the 2022 IRP projected that average annual energy use per large commercial customer would increase from a 2019 level of 21,111 MWh to 28,473 MWh in 2023 and remain over 27,000 MWh through 2035.[93] In fact, that forecasted increase did not occur, as the actual 2023 level was 21,774 MWh.[94] That forecasting track record calls into question EKPC's claim in the 2024 LTLF that the average annual energy

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[90] Tucker Rebuttal at 2-3; April 22 HVT at 2:50 p.m. to 2:52 p.m.

[91] EKPC 2022 RP, Technical Appendix Vol. 1, *In the Matter of Electronic 2022 Integrated Resource Plan Of East Kentucky Power Company*, Case No. 2022-00098, at 37 (filed Apr. 1, 2022) ("EKPC 2022 IRP, Technical Appendix Vol. 1")..

[92] EKPC Resp. to JI 1-36.

[93] EKPC 2022 IRP, Technical Appendix Vol. 1 at 37.

[94] Tucker Direct, Attachment JJT-2 at 39.

use per large commercial customers will increase to 26,061 MWh in 2027 and remain around 25,800 MWh in 2028 and 2029.[95]

e) EKPC Has a Pattern of Overestimating Future Energy Sales.

In her testimony, Dr. Stanton explained that the reliability of the 2024 LTLF is further called into doubt by EKPC's track record of overestimating future energy sales.[96] From 2010 through 2020, EKPC's actual annual energy sales ranged from the low 12 million MWh to mid-13 million MWh.[97] In both its 2020 and 2022 LTLFs, EKPC forecasted that it would break out of this pattern and exceed 14 million MWh in sales in 2022 and 15 million MWh in 2023.[98] The projected jump in sales did not occur and remained below 14 million MWh in both 2022 and 2023.[99] Now, the 2024 LTLF forecasts 2024 sales of 14,597,314 MWh, increasing to more than 15 million MWh in 2025, clearing 16 million MWh per year in 2026 through 2031, and then exceeding 17 million MWh per year thereafter.[100] The 2024 LTLF is already off to a bad start for EKPC, as actual 2024 sales remained below 14 million MWh.[101]

2. EKPC Has Not Justified Its Decision to Add a 7% Reserve Margin to Its Winter Peak.

As noted previously, in determining its winter resource need EKPC added a 7% reserve margin to its forecasted winter peak. The Company acknowledges that this is a "significant change" from its previous practice, reflected in its 2022 IRP, of assuming a 0% winter reserve

[95] *Id.*
[96] Stanton Revised Direct a 8-10.
[97] Tucker Direct, Attachment JJT-3.
[98] *Id.*
[99] *Id.*
[100] *Id.*
[101] EKPC Resp. to JI 2-35.

margin.[102] It also presumably had a significant impact on EKPC's generation resource proposals, as the 7% reserve margin adds 246 to 263 MW to the Company's claimed winter need for 2025 through 2031 (and increasing thereafter),[103] which is greater than the 214 MW Liberty RICE units and roughly equivalent to the capacity of Cooper Unit 2. Unfortunately, the analytical rigor behind the 7% winter reserve margin does not come close to matching the significance of its impact.

EKPC explains that its new 7% winter reserve margin is intended to address the higher than expected peak demand on its system experienced during Winter Storms Elliott and Gerri, and to account for generator outage probability.[104] The Company estimated that the actual peak load during those storms was 12% higher than its winter peak forecast. While some of that increase is reflected in the higher winter peak load forecast in the 2024 LTLF, EKPC determined that an additional 7% margin was needed based on an assumption that similar winter storms would happen for 48 hours every two years.[105] According to the Company, that margin is needed to both ensure reliability and provide a hedge against high PJM market energy prices during winter storms.[106]

On this record, EKPC has not met its burden of establishing that a 7% winter reserve margin is either needed to ensure reliability or a lowest cost option for its Member-Owners and their customers. With regards to reliability, EKPC is a winter peaking utility that is a member of PJM, which is a summer-peaking Regional Transmission Organization. As a result, EKPC has

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[102] Tucker Direct at 14.
[103] Tucker Direct, Attachment JJT-4.
[104] Tucker Direct at 14.
[105] *Id.*
[106] *Id.* at 14-15.

been able to plan for no or only a minimal winter reserve margin since joining PJM. In fact, as recently as July 2024 the Company noted with regards to the benefits and costs if EKPC were to leave PJM:

> EKPC is currently able to cover its winter peak load plus a minimal reserve margin because the PJM RTO has more than 20% capacity reserves during the winter peak period. As a stand alone entity, EKPC previously planned to maintain a minimum of 12% capacity reserve margin in the winter. EKPC would have to purchase and/or construct additional capacity to maintain an acceptable winter peak operating reserve level.[107]

As witness Stanton explained in her direct testimony, that membership, along with EKPC's existing generation, was more than sufficient to keep the lights on during both Winter Storms Elliott and Gerri.[108] In the wake of those storms, PJM made changes to its reliability modeling, planning processes, and capacity assumptions to provide further reliability assurance.[109] And PJM once again kept the lights on during Winter Storm Enzo in January 2025, when PJM met an all-time winter demand record of 145,000 MW and still managed to export 8,000 MW to neighboring regions.[110] Despite this track record of success, the Company has provided no modeling or other analysis suggesting that its system reliability would be at risk if it continued its practice of having no or only a minimal winter reserve margin.

With regards to the 7% winter reserve margin serving as an energy market hedge, EKPC correctly notes that market energy prices were high during Winter Storm Elliott. But the cost of building, acquiring, and/or maintaining generation needed to meet the additional reserve margin

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[107] Joint Intervenors Hearing Ex. JI 2 at 4, *In the Matter of the Application of East Kentucky Power Cooperative, Inc. to Transfer Functional Control of Certain Transmission Facilities to PJM Interconnection, LLC, P.S.C. Case No. 2012-00169 - Annual Report of East Kentucky Power Cooperative, Inc.* (dated July 31, 2024).

[108] Stanton Revised Direct at 31.

[109] *Id.*

[110] *Id.*

can also be high. As noted previously, the 7% reserve margin is larger than the 214 MW Liberty RICE units and about the same size as Cooper Unit 2. The former would cost nearly $500 million to build, while the costs of Cooper Unit 2 have exceeded its revenues for at least the past five years.[111] To know whether establishing a new 7% winter reserve margin is an economically beneficial option for EKPC and its Member-Owners customers, one would have to evaluate and compare the costs of meeting that reserve margin versus the costs of EKPC continuing to have no or only a minimal winter reserve margin. Yet when asked in discovery, EKPC did not identify any such cost comparison and, instead, simply referenced its 2024 Long-Term Financial Forecast which only purports to evaluate the rate impact of the full portfolio of generation projects that EKPC has proposed.[112] Such a broad analysis does nothing to answer the question of whether the new 7% winter reserve margin is an economically beneficial proposition.

3. EKPC Has Not Shown a Transmission Reliability Need for the Cooper CCGT.

Claims that the Cooper CCGT is needed for transmission reliability are unsupported and riddled by wasteful duplication. EKPC's longstanding transmission constraints in the southeastern portion of its service territory may be real, but a $1.317 billion dollar CCGT at Cooper Station is an unnecessary and duplicative fix.

EKPC already proposed a new generation project necessary to improve reliability concerns in the area when generation is not available: the Liberty RICE units. Wasteful duplication looms where multiple projects are advanced in response to the same need, as EKPC

[111] *Id.* at 46, and Joint Intervenors Response to Staff 1-5; *see also* EKPC Attachment Staff Response 4-2 New_Gen.xlsx which EKPC provided in response to Staff 4-2, and which shows production costs for the entire Cooper plant exceeding total revenues from PJM for the plant in all but one year between 2014 and 2024.

[112] EKPC Resps. to JI 1-21, 1-11, and 2-14.

has done here in proposing multiple fixes to its 2007-era transmission constraint.[113] Lacking quantitative analysis showing multiple generation additions are each needed on an independent basis, EKPC has not carried its burden of showing an absence of wasteful duplication.

Instead, the record appears to confirm that, if the Liberty RICE CPCN is granted, no additional generation is needed to maintain bulk power system reliability on EKPC's system. Recently, after two winter storms, EKPC restudied transmission alternatives that would need to be in place if Cooper Unit 1 and 2 generation was not available long term.[114] The results offer a reassuring perspective on transmission reliability in the studied circumstances: "Initial results showed there is no <u>immediate</u> [transmission] impact to the study area due to the retirement of Cooper 1&2 along with the RICE installation at the Liberty site."[115]

Still, the study continued to evaluate six transmission projects that would increase EKPC's load serving ability in the region without generation units at Cooper Station.[116] Those alternatives include the addition of a 53 MVAR capacitor bank on EKPC's Cooper 69 kV line, improving EKPC's load serving ability in the region by 32%, or 288.5 MW:

> The analysis results show that the installation of the capacitor bank at Cooper Station in conjunction with the Liberty RICE facility will support an additional 288.5 MW of EKPC load beyond the forecasted base amount (50/50 load probability) of 906.7 MW for EKPC in the region.[117]

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[113] Compare Case No. 2024-00310, EKPC Application at 5; and EKPC Cooper Combined Cycle CPCN Application, Case No. 2024-00370, (Nov. 20, 2024) at ¶¶ 4, 15, 16.

[114] April 22, 2025 HVT at 9:19:00 a.m. – 9:20:30 a.m. (Mr. Adams explaining request from Mr. Mosier to the Transmission Planning team).

[115] Attachment provided in Response to JI 1-23(c), *Cooper Generation Unavailability Tra ssion Analysis*, at slide 6.

[116] Mr. Adams helpfully clarified how to interpret the values reported in the "Cooper Generation Unavailability Transmission Analysis" at the hearing, beginning at approximately 9:27 a.m. on April 22, 2025, and continuing for four minutes.

[117] EKPC Resp. to JI 2-2.

Regardless of the outcome on the requested Liberty RICE CPCN, this capacitor bank addition is going forward: the project is expected to cost $1 Million,[118] will be completed by the end of 2026, and will "provide additional reliability and reactive-power margin for the region for high-load periods when one or both Cooper units are not operating."[119]

If there is some remaining transmission reliability problem or need even after the Liberty RICE or capacitor bank additions, EKPC has not quantified or characterized it with any specificity. Without that, all EKPC is really saying about reliability here is that more is more: with more generation additions and more transmission projects the bulk power system will be more reliable. That's true, but it does not mean there is an actual inadequacy in EKPC's existing system, or that any such an inadequacy would persist after the addition of a $1 Million capacitor bank next year, or after the addition of Liberty RICE units, if approved.

If there indeed is a persistent transmission issue that needs to be addressed, there would still be the question of whether a $1.317 billion dollar CCGT is a necessary, least-cost means to address that issue without wasteful duplication. Instead of answering that question, the record suggests that alternatives were inadequately considered. Specific to transmission reliability issues, the record includes several more transmission solutions that would meaningfully improve transmission system capacity in the region at lower cost than the Liberty RICE units or Cooper CCGT, but no indications that these alternatives were evaluated against generation additions broadly or the Cooper CCGT in particular, on equal footing and in a quantitative fashion.

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[118] Attach provided in Response to JI 1-23(c), *Cooper Generation Unavailability Transmission Analysis*, at slide 6; *see also* EKPC Resp. to JI 2-2(

[119] EKPC Resp. to JI 2-2(a); April 22, 2025 HVT 9:33:00 a 9:33:30 a.m. (Mr. Adams affirms).

To highlight one alternative here: the record does not reflect any direct analysis of pursuing the Cooper CCGT to address reliability versus proceeding with a new 345 kV line to the LG&E/KU Alcalde substation. That 345 kV line project, with an estimated cost of $70M, would take approximately 4 years to bring online, and "in conjunction with the Liberty RICE facility" EKPC determined that the project would support an additional 405.7 MW of load beyond the base forecast amount.[120]

With insufficient evaluation of potentially reasonable and cost-effective transmission alternatives, EKPC cannot carry its burden to show that the Cooper CCGT is necessary to address a transmission reliability concern and not duplicative of other efforts already underway, or reasonable alternatives.

C. EKPC has not shown that wasteful duplication would not result from its "Plan in Total."

1. EKPC Has Failed To Present a Meaningful Analysis of Alternatives to, and the Economics of, the Proposed Cooper CCGT.

Once a need has been identified, the most prudent and cost-effective plan for meeting that need should be developed through a searching and sophisticated analysis of the best combination of supply and demand side options. The record is clear, however, that no such analysis occurred. Instead, by early to mid-2023, EKPC had brought Burns & McDonnell onboard to develop the project scoping and siting, preliminary design, and cost estimates for the new CCGT and RICE units that the Company had already settled on pursuing. Meanwhile, as Dr. Stanton details in her testimony, EKPC dismissed any supply side alternatives based on a simplistic qualitative process of elimination.[121] Demand side resources – i.e. demand response and energy efficiency – were

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[120] EKPC Resp. to JI 1-23, JI 2-2.
[121] Stanton Revised Direct at 19-21, 23-25.

not even considered as potential parts of the solution to EKPC's claimed need.[122] In essence, EKPC presents the Cooper CCGT (and Liberty RICE units) as a fait accompli, rather than the result of a searching and sophisticated analysis of the most prudent and cost-effective combination of options for meeting its needs.

Joint Intervenors explain elsewhere in this brief the unreasonableness of EKPC's cursory dismissal of storage, alone or paired with solar, from its analysis (see Section III.C.3, below), and the missed opportunity of EKPC's failure to even consider increased demand response and energy efficiency to help meet or reduce its claimed need (see Section II.C., above). Here, we address EKPC's failure to carry out the type of rigorous analysis of the selection and cost of the Cooper CCGT (and Liberty RICE units) that is needed before the Company can be approved to spend more than $1.8 billion of customer money on what would be a long-term commitment to significant gas infrastructure.

EKPC failed to carry out the type of resource optimization modeling that the company acknowledges is typical in the industry. Rather than the simplistic qualitative process of elimination carried out by EKPC, the Company should have determined the appropriate mix of resources to meet its needs through long-term optimization modeling. As Dr. Stanton explains, such modeling, which is sometimes referred to as a "resource expansion" modeling, "compares a utility's expected supply- and demand-side capacity resources to its customer demand, and performs optimization modeling to identify a least-cost portfolio of resources that meets all regulatory or legal requirements."[123] In contrast to the simplistic qualitative process of elimination employed by EKPC, optimization modeling provides a quantitative assessment of

[122] *Id.* at 19-20.
[123] *Id.* at 22.

how various combinations of options would perform in EKPC's system that can be provided and subjected to review by the Commission, Staff, and intervening parties.[124] EKPC's failure to carry out such modeling here renders its proposal for the $1.317 billion CCGT and $500 million Liberty RICE units insufficiently supported to allow for approval.

In response to discovery, EKPC acknowledges that optimization modeling is typical industry practice, noting that "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."[125] The Company, however, tries to excuse its failure to follow this typical practice in two ways, neither of which holds water.

First, EKPC contends that such practice "is predicated on having ample time to meet the expected need" but that the new winter peak loads during winter storms "expedited the need for new generation" and, therefore, did not leave time to carry out optimization modeling.[126] This lack-of-time excuse is meritless. The "genesis" for EKPC's proposals – Winter Storm Elliott – happened in December 2022, which was 21 months before the filing of the Liberty RICE CPCN application, and 23 months before the Cooper CCGT CPCN application. EKPC had identified and started project scoping work on both of those projects by early to mid-2023, submitted the CCGT project into the PJM interconnection queue in January 2024,[127] and carried out a single production cost modeling run of the projects in May 2024. There is simply no basis upon which

[124] *Id*. at 24-25.
[125] EKPC Resp. to JI 1-10.
[126] *Id.*
[127] Application Ex. 6, Direct Testimony of Darrin Adams on Behalf of East Kentucky Power Cooperative, Inc., Case No. 2024-00370, at 10 (Nov. 20, 2024) ("Adams Direct").

one could conclude that EKPC could not have carried out optimization modeling at some point in that more than 20-month timeline.

Second, EKPC claims that optimization modeling would have been pointless because a new gas CCGT is the only dispatchable resource that feasibly could have been selected.[128] In support, EKPC witness Tucker highlights statements from the head of PJM and the Chair of the Federal Energy Regulatory Commission calling for more gas CCGTs and other dispatchable resources.[129] While those statements are interesting, they do not change the need at issue here – how to ensure that EKPC can continue providing adequate service during the limited number of hours when winter storms push total load above the Company's current installed capacity. Those statements also do not obviate EKPC's responsibility to determine what combination of resources provide the least cost option for meeting the needs of its member-owners and their customers. As Dr. Stanton opines, given the relatively limited duration of the winter peaks at issue here, it is not clear that a new baseload facility such as the Cooper CCGT is the most responsive option.[130] Regardless, it is certainly not the only option, as storage, solar plus storage, increased demand response, and continued reliance on PJM or short-term or seasonal PPAs in lieu of the new winter reserve margin, could all help meet the identified need.[131] As such, optimization modeling of the range of available and feasible options is not only not pointless, it is necessary to determine what is the most reasonable and prudent combination of options that should be pursued here. EKPC's failure to provide such standard analysis renders its Cooper CCGT CPCN request not approvable on this record.

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[128] EKPC Resp. to JI 1-10; Tucker Rebuttal Testimony at 16-20.
[129] Tucker Rebuttal Testimony at 16-19.
[130] Stanton Revised Direct at 17-18, 29.
[131] *Id.* at 18.

2. *EKPC Has Not Provided a Meaningful Analysis of the Economics of the Proposed Cooper CCGT.*

EKPC will presumably argue that its failure to meaningfully consider alternatives can be ignored because the plant would purportedly be profitable in the energy markets and require only small rate increases on customers. Any such argument should be rejected because EKPC has not provided a meaningful analysis of the economics or rate impacts of the proposed Cooper CCGT.

First, because EKPC failed to complete any quantitative analysis of alternatives, the record is bereft of any evidence of the economics or rate impacts of the Cooper CCGT compared to other potential alternatives. As noted above, even EKPC agrees that the typical industry practice would be to develop a Present Value of Revenue Requirements ("PVRR") analysis which, as Dr. Stanton explains, "facilitate[s] comparisons across resources and, in so doing, identif[ies] preferred or least-cost resources."[132] EKPC did not carry out a PVRR analysis in this proceeding, offering the same excuses for such failure as it offered for its failure to do optimization modeling.[133] Those excuses fail for the same reasons as discussed above.

In lieu of a PVRR analysis, EKPC offers a "Thermal Unit Net Cost Benefit" analysis that purports to show a bit more than $1 billion in net operating revenues for the Cooper CCGT unit from 2030 through 2039.[134] This analysis was an output from the production cost modeling run that EKPC carried out in May 2024. Thorough review of that modeling was hindered by the fact that, in response to multiple requests seeking production of all modeling input and output files, EKPC produced only a single modeling input file and a single modeling output file. As discussed

[132] Stanton Revised Direct at 27.
[133] EKPC Resp. to JI 1-10.
[134] Attachment JI1-24e.xlxs, produced by EKPC in response to JI 1-24(e). Note that Attachment JI1-24e.xlxs is a replacement for Attachment JJT-5, which erroneously included the exact same net cost benefit values for each of the years 2030 through 2033.

more in Section IV, below, however, in response to a post-hearing data request, EKPC produced on May 2 an additional 47 modeling input files, which of course was too late to allow for any meaningful review or questions about such files. Regardless, at least two significant shortcomings in the Thermal Unit Net Cost Benefit analysis stand out. First, the analysis reflects only the difference between the variable cost of operating the plant versus a forecasted market price and, therefore, does not reflect the $1.317 billion capital cost of building the plant, or any fixed operating costs or ongoing capital costs needed to keep the plant in operating condition.[135] Second, the analysis is based on only a single production cost modeling run, which means that no information is provided about how the economics would change if, for example, actual market energy prices or gas prices end up being higher or lower than assumed in the modeling.[136] In short, a single production cost modeling run that does not test for a range of potential market conditions provides information that is of only limited value in assessing the potential economics of a more than $1.3 billion investment.

The information provided by EKPC regarding the potential rate impacts of the Cooper CCGT is also of limited value. In response to discovery requests seeking such information, EKPC repeatedly noted that it did not model its proposed projects individually, but instead only as a package that included the Cooper CCGT, Liberty RICE units, the Spurlock and Cooper 2 gas co-fire projects, and NewERA Renewables.[137] According to EKPC, all those projects could be completed with "modest rate increases, averaging less than 2% per year over the next 20 years."[138] When asked for support for that claim, EKPC identified its 2024 Long-Range

[135] April 22, 2025 HVT at 3:56 p.m. – 3:58 p.m.
[136] April 22, 2025 HVT at 3:58 p.m. – 4:00 p.m.
[137] *See, e.g.*, EKPC Resp. to JI 1-11.
[138] *Id.*

Financial Forecast, a summary of which was produced as a confidential document.[139] While Joint Intervenors also requested any modeling input or output files supporting that projection, no such files were produced in advance of the hearing. At hearing, however, witness Stachnik acknowledged that he had received input files for the Financial Forecast, which turned out to be the outputs from the single production cost modeling run discussed above.[140] Regardless, by evaluating all of the proposed projects and, presumably, EKPC's existing operations all together, the Financial Forecast says little about the rate impact of the Cooper CCGT or any other specific project alone. As such, the question of how a new $1.317 billion CCGT project would impact the utility rates and bills of the member-owners' customers remains unanswered on this record.

3. *EKPC Has Not Met its Burden for a CPCN for Spurlock 3 & 4.*

a) Considerable cost and operational risk with an "unproven," "first-of-its kind" design has not been sufficiently researched, documented, or disclosed to the Commission.

EKPC has failed to prove that the co-firing of the Spurlock Units 3 & 4 is technically and economically feasible, much less that the plan would avoid wasteful duplication by avoiding the "excessive investment in relation to productivity."[141]

The record in this case shows that for Units 3 and 4 the Spurlock Co-Fire Project rests on shaky technological footing. One of EKPC's stated reasons for proposing the Spurlock Co-Fire Project is to bring Spurlock Units 1-4 into compliance with the U.S. EPA's Greenhouse Gas rule ("GHG Rule") which requires, among other things, coal-fired generating units that intend to

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[139] EKPC Resp. to JI 2.8 and attachments Confidential-JI2.8.c1.pdf and Confidential-JI2.8.c2.xlsx.

[140] April 21, 2025 HVT at 3:56 p.m.

[141] *Ky. Utils. Co.*, 390 S.W.2d at 173.

operate past January 1, 2032 but retire before January 1, 2039 to co-fire with natural gas.[142] In 2023, EKPC submitted to the U.S. EPA comments on the proposed GHG Rule, noting that Units 3 and 4 of the Spurlock plant are circulating fluidized bed ("CFB") units, and 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.[143]

These comments demonstrate that, at least as recently as August 2023, EKPC believed that co-firing at Spurlock Units 3 & 4 was not possible.

In developing the Spurlock Co-Fire Project, EKPC contracted with Burns & McDonnell ("BMcD") to prepare a scoping report for the project. Throughout that report, BMcD raises serious concerns about the feasibility of gas co-firing at Spurlock Units 3 and 4. The report notes that such gas co-firing "requires novel design solutions that are unproven," which "could lead to design activities taking longer than anticipated and design rework as information is discovered throughout the design process."[144] The report also specifies that "the proposed co-firing modifications have not been executed to BMcD's knowledge," which could lead to "[h]ot commissioning activities taking longer than expected."[145] Crucially, the scoping report states that the project's "'first of it[']s kind' design for CFB boilers of this type / size" is a "major risk[]."[146]

The BMcD report further states that, "to increase confidence in the feasibility of the conceptual design, BMcD subcontracted with Reaction Engineering, Inc. (REI) to create a CFD

[142] Young Direct.
[143] JI Hearing Ex. 1 at 29.
[144] Young Direct, Attach. BY-3, Spurlock Station Units 1-4 Co-fire Project Scoping Report (Rev. 4), at p. 1-7 (Oct. 2024) ("BY-3").
[145] *Id*. at p. 1-10.
[146] *Id*. at p. 7-8 & Appendix P, line 039.

model of the Unit 3 furnace."[147] The BMcD report provides no details about the results of the REI modeling beyond stating that the "model results show" that co-firing the units on gas "appears technically feasible."[148] In response to discovery, EKPC stated that "no additional engineering studies or research" besides the BMcD report and the REI modeling was carried out by BMcD or EKPC to determine if the gas co-firing at Spurlock 3 and 4 was feasible.[149] As of the submission of this Brief, EKPC has refused to produce the REI report, precluding Joint Intervenors and the Commission from being able to verify the feasibility of co-firing at Units 3 & 4.[150] EKPC has only produced a one-page document that claims to *summarize* the findings of the REI report.[151] This one-page document was not prepared by REI and is dated February 10, 2025, meaning that it was compiled well after Joint Intervenors asked EKPC to produce the actual REI report in their January 17, 2025 Second Information Request.[152] The one-pager provides no means for assessing and verifying EKPC's claim that co-firing at Spurlock Units 3 & 4 is feasible, and the Commission should not rely on it as evidence of feasibility.

At the April 21 hearing, EKPC Witness Young stated that he was not aware of any other CFBs that have co-fire capability at the scale of the proposed Spurlock co-firing project.[153] Witness Young went on to state that he was aware of smaller co-firing installations at CFB units.[154] In response to a post-hearing request for information, EKPC for the first time identified

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[147] *Id.*
[148] *Id.* at p. 7-2.
[149] EKPC Resp. to JI 2-47.
[150] *See* Joint Intervenors' Motion to Compel (Apr. 24, 2025) and Joint Intervenors' Reply in Support of Motion to Compel (May 1, 2025).
[151] EKPC Resp. to JI 2-47(c), "Response 47c REI CFD Report Summary" (Confidential).
[152] *See* Joint Intervenors' Second Information Request to East Kentucky Power Cooperative, Inc., Case No. 2024-00370, Question 47(c) (Jan. 17, 2024) ("JI 2-47(c)").
[153] Apr. 21, 2025 HVT at 1:42 p.m. – 1:43 p.m.
[154] *Id*.

a single CFB unit that was converted to natural gas co-firing: Green River Energy's Spiritwood Station.[155] Spiritwood Station's capacity for generating electricity is significantly smaller in scale than Spurlock Units 3 and 4, with a capacity of only 99 MW electric,[156] compared to 268 net MW each for Spurlock Unit 3 and 4.[157] Given the significant difference in size, and the fact that the Spiritwood conversion happened before EKPC and BMcD's statements raising concerns about the ability to co-fire Spurlock Units 3 and 4, EKPC's last-minute reference to the Spiritwood Station does not ameliorate concerns as to the feasibility of EKPC's co-fire plan.

Without verifiable evidence that co-firing at Spurlock Units 3 & 4 is technologically feasible, EKPC cannot satisfy its burden of avoiding wasteful duplication through excessive investment in relation to productivity.

b) Gas supply issues alone come with significant stranded cost risk to EKPC member-owners.

Despite the uncertainty of the feasibility of this project, EKPC proposes not only to spend the capital costs on this unproven technology, but also to commit its member-owners to paying for a significant pipeline extension. The significant cost associated with the gas pipeline must be considered in determining a least cost reasonable alternative as well, but EKPC hasn't put forward any analysis of alternatives to the pipeline as proposed.

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155 EKPC Resp. to JI PH-11. Note that although EKPC's Response to JI PH-11 reports that Spiritwood Station "is a 275 MW total (90 MW electric plus process) unit," the cited 2023 Great River Energy IRP describes the unit as having "the capacity to generate up to 99 MW of electricity." *Id.* n.2. Also of note, EKPC stated that it was also aware of a CFB unit that was converted to natural gas firing, rather than co-firing. *Id.*

156 *Id.*

157 Young Direct, Attach. BY-3 at p. 1-2.

EKPC began the process of selecting a natural gas pipeline lateral and interconnection through a request for proposals ("RFP") issued December 5, 2023.[158] After receiving final bids from two interstate pipeline companies for the lateral, a final interstate pipeline company was chosen in August, 2024.[159] The pipeline selected would be approximately 40 miles long,[160] and run from approximately Morehead to Maysville, through Rowan, Fleming, and Mason Counties. The final estimated cost of the pipeline to Spurlock is estimated at over $357 million,[161] and was originally estimated by EKPC to be between $400 to $450 million,[162] the amount stated at hearing.[163] That cost will be paid upfront by the interstate pipeline company, but EKPC is committed to paying that cost back over a period of 20 years,[164] and anticipates building that cost into its base rates.[165] The cost, however, was not included in the capital cost estimates for the projects proposed to the Commission.[166] Additionally, the cost assumes a possible future expansion,[167] overbuilding the pipeline to serve as much as seventy percent more natural gas than required at start-up.[168]

158 Application Ex. 8, Direct Testimony of Mark Horn on Behalf of East Kentucky Power Coopera , Inc., Case 2024-00370, at 4 (Nov. 20, 2024) ("Horn Direct").
159 *Id.* at 5.
160 April 21, 2025 HVT at 9:30:00 a.m. – 9:30:35 a.m.
161 EKPC Resp. to JI 1-44(a).
162 JI Hearing Exhibit 1 at 30; April 21, 2025 HVT at 10:01:50 a.m. – 10:01:30 a.m. , and 4:01:45 p.m. – 4:02:05. p.m.
163 April 21, 2025 HVT at 9:30:00 a.m. – 9:30:35 a.m.
164 EKPC Resp. to JI 1-44(a).
165 EKPC Resp. to JI 2-38(a)(i).
166 EKPC Resp. to JI 1-45(b).
167 Horn Direct, Attachment MH-2 at 6.
168 EKPC Resp. to Staff PH-3, Attachment *Confidential-StaffPHDR-3-Amended and Restated Pulaski Project Precedent Agreement.pdf* at 3.

Effectively, therefore, EKPC has not applied for a project that will cost its owner-members $187 million as stated in their application,[169] but between $544 million and $637 million dollars.[170] This represents substantially more investment, and risk, to be borne by EKPC's owner-members, and ultimately their ratepayers, than originally represented to the Commission in the application. Given the considerable cost and operational risk with an "unproven," "first-of-its kind" design for two of the Spurlock units described above, the cost of constructing an oversized pipeline only adds to the stakes. EKPC itself admits that construction of a pipeline larger than needed can add to costs,[171] however it has not presented to the Commission any cost-effectiveness analysis of pursuing the gas infrastructure expansion projects to supply just Spurlock 1 & 2, as compared to the pipeline to serve all four Spurlock units plus an additional speculative future expansion, all with significant local opposition, including from local government.[172]

4. EKPC Has Not Justified Its Refusal to Meaningfully Consider Battery Storage.

EKPC has also failed to demonstrate an absence of wasteful duplication, because it has not performed a thorough review of battery storage. Instead, EKPC has sought to replace the required thorough review of alternatives with conclusory declarations that battery storage would not be a viable alternative to new gas generation.

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[169] Tucker Direct at 33; Young Direct at 17.

[170] *See* Young Direct at 17 and Confidential EKPC Resp. to JI 1-44(a). $187 million capital cost for retrofit + $357 million = $544 million; $187 million + $450 million from JI Hearing Exhibit 1 = $637 million.

[171] EKPC Resp. to JI 2-38(c).

[172] See attachment to Comments of Tom Galbreath and George Watson, April 17, 2025; Minutes of the Fleming County Fiscal Court meeting at 1, 4 (Apr. 08, 2024).

EKPC's failures to meaningfully assess battery storage alternatives are numerous. EKPC did not present a cost comparison of battery storage compared to its proposed resources or include battery storage in its CPCN production cost modeling.[173] EKPC did not perform an "optimization run . . . to consider new generation and retirements of existing units," including for battery storage.[174] Nor did EKPC issue a battery storage request for proposals ("RFP") to establish current real-world costs and operational characteristics.[175] In her rebuttal testimony, EKPC Witness Tucker appeared to disagree with the very need for such a thorough review of alternatives, claiming that "[a] detailed optimization model is not needed to qualitatively ascertain what generating options should be considered."[176] But wasteful duplication cannot be avoided by such subjective judgments, and EKPC's failure to meaningfully consider battery storage is a defect in its application.

In her Direct Testimony, Dr. Stanton identified numerous limitations in EKPC's reasoning for excluding battery storage.[177] These include the aforementioned failure to meaningfully assess battery storage alternatives through production cost modeling, optimization modeling, or an RFP.[178] Dr. Stanton likewise rebutted EKPC's claim that battery storage is "relatively new and unproven,"[179] highlighting that battery storage is used as a capacity resource throughout the United States, with 16,653 MW of BESS resources operating across 41 states,

[173] Revised Direct Testimo f Elizabeth A. Stanton, PhD, at 33:3-8 (Feb. 14, 2025) ("Stanton Revised Direct").
[174] EKPC Resp. to Staff 1-7.
[175] EKPC Resp. to JI 1-14(a).
[176] Tucker at 19:26-27.
[177] *See* Stanton Revised Direct at 32:18-41:14.
[178] *Id*. at 33:3-11 and 37:7-10.
[179] EKPC Resp. to JI 2-28(a).

and another 46,950 MW of proposed resources.[180] Dr. Stanton also submitted evidence demonstrating that battery storage has been proven to support reliability during winter peaks in regions such as ERCOT.[181] Finally, Dr. Stanton highlighted issues with EKPC's cost estimate for battery storage, including that EKPC failed to account for potential mechanisms for lowering cost, such as the Investment Tax Credit ("ITC") for energy storage provided under the Inflation Reduction Act.[182]

In EKPC Witness Tucker's rebuttal testimony, she did not refute Dr. Stanton's specific points regarding EKPC's failure to meaningfully assess battery storage. Instead, Witness Tucker simply cited Congressional testimony from PJM Interconnection President and Chief Operating Officer Manu Asthana, in which he called for adding more generation, along with comments from FERC Chairman Mark Christie.[183] As Witness Tucker noted, Mr. Asthana testified that "[a]lthough today the category of dispatchable generators largely refers to fossil-fuel based resources, longer-duration batteries and potentially other technologies could also serve in this role in the future to the extent they can become more cost-effective and be deployed at scale."[184] Witness Tucker's rebuttal testimony seems to suggest that Mr. Asthana's comments should serve as a blanket excuse for not assessing the viability of BESS in EKPC's service territory. But in Mr. Asthana's next sentence, he clarifies that "PJM is resource agnostic and works to facilitate the entry of all resources onto the system."[185] Elsewhere, PJM has indicated that it believes that

[180] Stanton Revised Direct at 38:1-4.
[181] *Id.* at 39:1-11.
[182] *Id.* at 34:9 through 37:6 and 41:6-14.
[183] Tucker Rebuttal at 16:9-20:16.
[184] *Id.* at 18:2-5 (quoting Tucker Rebuttal, Attach. JJT-3, U.S. House of Representatives Committee on Energy & Commerce, Subcommittee on En gy, *Testimony of Manu Asthana, President and CEO, PJM Interconnection*, at 6 25, 2025) ("Asthana Testimony")).
[185] Asthana Testimony at 7.

battery storage can help support reliability and address near-term electricity demand growth, with PJM announcing on May 2, 2025, that it was selecting five battery projects with a combined 2,275 MW energy to take part in its Reliability Resource Initiative.[186] In this context, Mr. Asthana's remarks should have served as a call to meaningfully assess the cost-effectiveness and dispatchability of BESS. At the very least, they cannot serve to rebut Dr. Stanton's detailed testimony regarding EKPC's failure to fully consider battery storage as an alternative to new gas generation.

The North American Electric Reliability Corporation's ("NERC") 2024 Long-Term Reliability Assessment, which EKPC submitted into the record in response to Staff Request 1.3(b), suggests that EKPC should have given a significantly harder look at whether battery storage could fill at least some of its demand needs:

> Energy storage development continues in PJM. As solar generation increases in PJM, growth of storage is expected to follow since storage devices are frequently co-located with solar projects. Efficient grid operations in an era of rapid renewable energy resource growth will require greater system flexibility. Energy storage can offer grid operators another tool to maintain stable power supply under varying wind and solar power output driven by weather conditions or unit outages. Storage can also improve grid efficiency by increasing utilization of existing transmission lines. PJM continues to work with members, Department of Energy (DOE) national laboratories, and other industry entities to advance the use of energy storage and, in particular, enable its participation in PJM markets.[187]

At the April 22 hearing, in response to questions about the 2024 Long-Term Reliability Assessment, Witness Tucker appeared to walk back her previous position that battery storage

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[186] PJM, *News Release, PJM Chooses 51 Generation Resource Projects to Address Near-Term Electricity Demand Growth* (May 2, 2025), https://www.pjm.com/-/media/DotCom/about-pjm/newsroom/2025-releases/20250502-pjm-chooses-51-generation-resource-projects-to-address-near-term-electricity-demand-growth.pdf.

[187] NERC, 2024 Long-Term Reliability Assessment, at 93 (Dec. 2024) ("2024 Long-Term Reliability Assessment"), provided as EKPC Resp. to Staff 1-3(b).

technology is "relatively new and unproven"[188] and admitted that EKPC does not dispute that battery storage is technologically feasible.[189] Rather, Witness Tucker claimed that EKPC took issue with the cost of battery storage, and Witness Tucker further claimed that battery storage would not serve EKPC's specific needs during winter peak periods.[190] EKPC has not introduced sufficient evidence to support either claim.

In its Application, EKPC relied on a cost per MWh figure for battery storage from the National Renewables Cooperative Organization ("NRCO").[191] This reliance is misplaced. As EKPC Witness Mosier admitted at hearing, NRCO has not assisted any of its members in procuring or installing a battery storage system, and its cost per MWh figure did not include the ITC from the Inflation Reduction Act.[192] As Dr. Stanton testified, assuming prevailing wage and apprenticeship requirements are met, a battery storage project would be eligible for a 30% ITC, and if the project is located in an energy community or meets other criteria, the project could be eligible for 10% tax credit adders.[193] For its part, EKPC acknowledged that it also "did not evaluate the impact of the Inflation Reduction Act's ITC on the cost of a utility-scale BESS."[194] Particularly given the limitations in NRCO's cost figures, EKPC should have conducted further analysis or issued an RFP to determine a reasonable range of costs for battery storage.

EKPC also admits that it did not apply for New ERA funding to potentially reduce the cost of battery storage, even though, as Witness Mosier stated at the April 21 hearing, a battery

[188] EKPC Resp. to JI 2-28.
[189] Apr. 22, 2025 HVT at 4:16 p.m. – 4:18 p.m.
[190] Apr. 22, 2025 HVT at 4:18 p.m. – 4:19 p.m.
[191] *See* EKPC Resp. to JI 1-14(a).
[192] Apr. 21, 2025 HVT at 10:26 a.m. – 10:27 a.m.; EKPC Response to JI 1-14(b).
[193] Stanton Revised Direct at 36:4-10.
[194] EKPC Resp. to JI 2-10.

storage project paired with solar or another renewable resource could have been eligible for New ERA funding.[195] Dr. Stanton also testified to the fact that the U.S. Department of Agriculture announced six New ERA awards for projects that included battery storage in December 2024.[196] If EKPC had applied for New ERA funding for battery storage or evaluated the impact of the ITC, it may have arrived at a significantly lower cost estimate than NRCO's.

In response to post-hearing requests for information, EKPC pointed to NREL's 2023 cost projections for utility-scale battery storage, which provides an estimated cost of $443,000/MWh in 2024.[197] Here too, EKPC has failed to justify its choice in cost estimate. First, EKPC has not explained why this estimate would not also be inflated due to not considering the ITC or potential New ERA funding. Second, EKPC ignores the fact that NREL's report shows storage costs decreasing substantially over time: the report projects costs to decrease to $351,000/MWh by 2028 and $326,000/MWh by 2030,[198] which are the proper years of comparison, as those are the years when the Liberty RICE unit and the Cooper CCGT would respectively come online.[199]

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[195] Apr. 21, 2025 HVT at 10:25 a.m. – 10:26 a.m.

[196] Stanton Revised Direct at 34:17-35:3 (citing Exhibit EAS-3, U.S. Dept. of Agric., *USDA Announces Another Round of Historic Investments to Increase Access to Clean, Affordable Energy Across the Country: Investments in Rural Electric Cooperatives Will Lower Costs and Support Jobs in Rural Communities* (Dec. 19, 2024)).

[197] EKPC Resp. to JI PH-6 & Responses to Nucor's Post-Hearing Request to East Kentucky Power Cooperative, Inc. Dated April 25, 2025, Question 2 (May 2, 2025) ("EKPC Resp. to Nucor PH-2") (citing Wesley Cole & Akash Karmaker, *Cost Projections for Utility-Scale Battery Storage: 2023 Update*, NREL, at 13 (June 2023), https://www.nrel.gov/docs/fy23osti/85332.pdf .

[198] Cole & Karmaker at 13, *supra* note 197.

[199] Application Ex. 2, Direct Testimony of Don Mosier on Behalf of East Kentucky Power Cooperative, Inc., *In the Matter of Electronic Application of East Kentucky Power Cooperative, Inc. for 1) a Certificate of Public Convenience and Necessity to Construct a New Generation Resource; 2) a Site Compatibility Certificate; and 3) Other General Relief*, Case 2024-00310, at 8:22-23 (Sept. 20, 2024) ("Mosier Direct in Case No. 2024-00310"); Application Ex. 2, Direct Testimony of Don Mosier on Behalf of East Kentucky Power Cooperative, Inc., Case No. 2024-00370, at 19:3-4 (Nov. 20, 2024).

Third, EKPC ignores the fact that Dr. Stanton already compared NRCO's cost estimate to costs that NREL published in 2024, and Dr. Stanton demonstrated that NREL's 2024 costs are meaningfully lower than NRCO's.[200] Witness Tucker did not rebut these points in Dr. Stanton's testimony. As a result, EKPC cannot now rely on NREL's 2023 cost estimates to justify its inflated battery storage cost estimate.[201]

Turning to EKPC's claim that battery storage could not support EKPC's needs during winter peak periods, EKPC primarily relies on the performance of *pumped*—not battery—storage resources during Winter Storm Elliott.[202] EKPC simply claims that "[b]attery resources *could* be susceptible to this same type of constraint and render them extremely limited in operation during peak load periods."[203] But as Dr. Stanton noted in her testimony, EKPC did not provide any evidence that battery storage with or without solar is subject to the same operation constraints as pumped storage, and EKPC has not sought to verify this potential constraint through modeling or other analysis.[204] Furthermore, NERC's 2024 Long-Term Reliability Assessment that EKPC submitted into evidence weighs against this concern, providing that

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[200] Stanton Revised Direct at 36:11-37:6 (citing Nat'l Renewable Energy Lab., 2024 Annual Technology Baseline [Workbook] (June 25, 2024): ps://data.openei.org/files/6006/2024%20v2%20Annual%20Technology%20Baseline%20Workbook%20Errata%207-19-2024.xlsx [retrieved from Nat'l Renewable Energy Lab., Electricity Annual Technology Baseline (ATB) Data Download, https://atb.nrel.gov/electricity/2024/data (last visited Feb. 14, 2025)]).

[201] EKPC has also recently referred to the potential cost of an LG&E battery storage project proposed in Case No. 2025-00045. *See* EKPC Resp. to NUCOR PH-3. But the Commission and other parties in that proceeding have not yet weighed in on the reasonableness of LG&E's cost estimate, and LG&E's proposed storage project is a self-build project that was not the result of an RFP process. *See* Apr. 21, 2025 HVT at 10:27 a.m. – 10:28 a.m.

[202] *See* Responses to Attorney General's First Information Request to East Kentucky Power Cooperative, Inc. Dated December 16, 2024, Question 10 (Jan. 1, 2025) ("EKPC Resp. to AG 1-10").

[203] *Id*. (emphasis added).

[204] Stanton Revised Direct at 38:8-12.

"[e]nergy storage can offer grid operators another tool to maintain stable power supply under varying wind and solar power output driven by weather conditions or unit outages."[205] Finally, as Dr. Stanton testified, battery storage has been proven to support reliability during extreme events elsewhere.[206] For instance, in ERCOT, battery storage prevented blackouts and averted load shedding during September 2023 emergency conditions, as well as allowing additional gas generation and saving an estimated $750 million in system costs during the January 2024 winter freeze.[207]

EKPC has not sufficiently assessed the potential for battery storage as a viable option that should have been included in an evaluation of the best combination of resources to address the needs claimed in this proceeding, and it has not substantiated the alleged limitations of battery storage. For these reasons, EKPC has not avoided wasteful duplication in its Application.

IV. EKPC Must Be Reminded of the Obligation to Produce Complete Sets of Modeling Files in Response to Data Requests.

Incomplete disclosure of modeling files should not be an issue, but it lately has been in EKPC proceedings. This proceeding marks the third time in as many years[208] that EKPC neglected to produce modeling files in response to timely and legitimate data requests, then erroneously assured the requesting party that no additional files existed, before ultimately admitting otherwise and disclosing additional files after the close of discovery or after hearing. Responding parties have an obligation to provide accurate and complete responses to legitimate

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[205] 2024 Long-Term Reliability Assessment at 93.

[206] Stanton Revised Direct at 39:1-11.

[207] *Id*. (citing Exhibit EAS-4, Connor McMann, *Role of Battery Energy Storage Systems (BESS) in the ERCOT Market*, Aurora Energy Research (May 2024)).

[208] Joint Intervenors cannot rule out additional instances, but make no unfavorable assumptions in that regard.

data requests,[209] and EKPC needs to be reminded of that obligation with respect to modeling files in particular.

Here, EKPC did not produce the complete set of modeling files underlying its supply-side generation project proposals despite multiple legitimate requests for those files and informal follow-ups with EKPC counsel. Instead, after providing a single file in response to earlier requests, EKPC's post-hearing data requests yielded 47 additional RTSim modeling input files.[210]

Although EKPC's post-hearing response claims that those 47 previously withheld files were newly provided "[s]ince they are specifically requested," that excuse fails. It is beyond dispute that parties requested "all modeling input and output files" for "each modeling run carried out as part of this CPCN,"[211] as Joint Intervenors asked for exactly that:

> **JI Request 1-2.** 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.

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[209] 807 KAR 5:0001, Section 3(12)(d) (requiring (1) sworn statements that each response is "true and accurate to the best of [the respondent's] knowledge, information, and belief formed after a reasonable inquiry"; (2) timely amendments if the respondent "obtains information that indicates that the response was incorrect when made or, though correct when made, is subsequently incorrect in any material respect"; and explanations from the respondent upon failing or refusing to furnish all or part of the requested information).

[210] EKPC Resp. to JI PH-3.

[211] Tendered Initial Requests For Information of Appalachian Citizens Law Center, Kentuckians for the Commonwealth, Kentucky Solar Energy Society, and Mountain Association to East Kentucky Power Cooperative, Inc., Request 2 (Dec. 20,2024). Commission Staff's First Request for Information to East Kentucky Power Cooperative, Inc., Request 19 (Dec. 20, 2024) (seeking an explanation of "the modeling assumptions and supporting calculations in excel spreadsheet")

> 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.

It should not take multiple follow-ups or multiple requests to receive complete responses to legitimate requests for "all modeling input and output files."

Yet, that was needed in this proceeding, as it was needed in the Liberty RICE CPCN and 2022 IRP proceedings. In the Liberty RICE CPCN proceeding, EKPC produced no modeling files in response to Sierra Club data requests asking for the same.[212] After conferring, Sierra Club did successfully urge EKPC to provide modeling files, and EKPC supplemented its response with one confidential input file and one confidential output file. But that unfolded too late, *after* the deadline for submission of intervenor testimony and the close of pre-hearing discovery.[213]

In the 2022 IRP review proceeding, EKPC provided a limited set of input values and a single output file in response to a straightforward, timely, and legitimate request for modeling files.[214] Expecting more, Joint Intervenors, through counsel, informally sought production of additional modeling files,[215] but EKPC stonewalled until the hearing, when an EKPC witness admitted that additional modeling files existed, but had not been produced.[216] As in this case, only after the hearing, in response to post-hearing data requests, did EKPC produce a more complete set of modeling files.

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[212] Case No. 2024-00310, Sierra Club's Emergency Motion for Leave to Submit Supplemental Requests for Information and the Option to Submit Direct Testimony at 3-4 (Feb. 20, 2025).

[213] *Id.* at 5.

[214] Case No. 2022-00098, Initial Data Requests of Joint Intervenors, Question 40 (June 30, 2022) ("Please provide, in spreadsheet format with all formulas and links intact, the RTSim input and output files used in the production of this IRP.").

[215] Case No. 2022-00098, Joint Intervenors Post-Hearing Comment on EKPC's 2022 IRP, at 21 (Feb. 3, 2023).

[216] Case No. 2022-00098, Dec. 13, 2022 HVT at 1:30 p.m. – 1:35 p.m.

This recurring practice flouts the Commission's rules, stymies the orderly development of the record, and cannot continue. With a mere eight-month timeline to reach reasoned, well-supported decisions capable of withstanding appeal, CPCN cases depend on all parties' good faith engagement with the discovery process to advance the orderly and efficient development of the record. If instead, key evidence supporting a utility's CPCN proposal continues to be dropped into the record after testimony filings and after hearings, any order granting the CPCN will have due process and sufficiency of the evidence issues baked in for appeal.

Regulated utilities should expect that they will need to marshal their evidence in support of requested relief in proceedings before this Commission, and that should include complete and prompt disclosure of modeling files in response to legitimate requests. At least, a reminder from the Commission of the expectation for responding parties to provide complete responses to legitimate data requests could change the course of future proceedings for the better.

V. Conclusion

For the foregoing reasons, Joint Intervenors respectfully request that the Commission grant the relief requested in the testimonies of Dr. Roumpani and Dr. Stanton.

In line with Dr. Roumpani's testimony, Joint Intervenors request that the Commission approve the proposed DSM plan for program years 2025, 2026, and 2027, with the modifications proposed in Dr. Roumpani's testimony to achieve greater degrees of cost savings and efficiency. In order to achieve reasonable least-cost service, Joint Intervenors also request that the Commission order EKPC to: (1) develop, within six months of a final order, an updated DSM Plan proposal that pursues all realistically achievable DSM programs (2) develop, within twelve months of a final order, an updated Potential Study or other serious analysis correcting flaws and shortcomings identified in Dr. Roumpani's testimony; (3) propose, by January 2027, an updated

DSM Plan that incorporates and utilizes the updated Potential Study; and (4) perform integrated analysis of DSM potential on equal footing with supply-side resources in future resource planning.

Because EKPC has not proven that the proposed Cooper CCGT would serve a legitimate need and avoid wasteful duplication, and in line with Dr. Stanton's testimony, Joint Intervenors request that the Commission reject EKPC's CPCN application for Cooper CCGT, or, if the Commission finds it necessary to approve the Cooper CCGT CPCN, require EKPC to file within one year a re-evaluation of the CCGT project. Finally, because EKPC has also not proven that the Cooper 2 and Spurlock co-firing projects are needed and avoid wasteful duplication, Joint Intervenors request that the Commission reject EKPC's CPCN application for the Cooper 2 and Spurlock co-firing projects.

[Signature and Certificate on following page]

Respectfully Submitted,

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CERTIFICATE OF SERVICE

In accordance with the Commission's July 22, 2021 Order in Case No. 2020-00085, *Electronic Emergency Docket Related to the Novel Coronavirus COVID-19*, this is to certify that the electronic filing was submitted to the Commission on May 06, 2025; that the documents in this electronic filing are a true representation of the materials prepared for the filing; and that the Commission has not excused any party from electronic filing procedures for this case at this time.

Byron L. Gary

JI PH Brief Attachment 1

Table 1: Programs Included in EKPC's Proposed DSM Plan

Program Name	Summary Description	Proposed Changes
New Programs		
High Efficiency Heat Pump (Residential)	Provides incentives to homeowners replacing a heat pump with a more efficient heat pump.	n/a
Commercial Advanced Lighting	Provides an incentive for small commercial businesses to replace inefficient light bulbs or light fixtures with LED lighting.	n/a
Commercial and Industrial Thermostat	Provides an incentive to qualifying businesses to replace traditional thermostats with self-learning thermostats.	n/a
Back-up Generator Control (Residential)	Provides annual incentive to retail participant in exchange for EKPC managing permanently installed whole-home back-up generators during peak energy events.	n/a
Existing Programs - with proposed changes		
Button-Up Weatherization (Residential)	Provides incentives to participants with existing homes focused on building envelope measures including insulation and air sealing.	Add incentives for new measures. Increase incentives due to increased measure costs.
CARES (Residential)	Income-qualified weatherization assistance program administered by Community Action Agencies and Affordable Housing Organizations; focus on insulation, air sealing, and heat pump measures.	Increase incentives due to increased measure costs.
Heat Pump Retrofit (Residential)	Provides incentives to participants with existing homes using electric resistance heat to convert to using a heat pump.	Increase incentives due to increased measure costs.
Existing Programs - without changes		
Touchstone Energy® Home Program (Residential)	Provides incentives to home builders to increase home energy efficiency by 25% above minimum standards.	None
Direct Load Control (Residential)	Provides annual incentive to participants in exchange for EKPC managing water heater, center air conditioners or heat pumps, or thermostats during peak load events.	None
Electric Vehicle Home Charging Pilot (Residential)	Provides incentive to participants to encourage off-peak EV charging.	None

JI PH Brief Attachment 2

DSM-EE Plan Recommendations[1]

- Approve the proposed DSM Plan for program years 2025, 2026, and 2027, with immediate modifications:
    - Extend the plan's budget to at least $11.4 million (reflecting the High scenario developed in the 2024 Potential Study), ensuring that programs are available to more customers.
    - Modify the Demand Load Control ("DLC") Bring Your Own Thermostat ("BYOT") program to allow for winter peak reduction.
    - Offer the DLC and Back-up generator programs to Commercial & Industrial ("C&I") customers.
    - Increase the incentives provided for all residential programs, especially those of shell programs.
- Order EKPC to develop, within six months of a final order in this proceeding, an updated DSM Plan proposal that will aggressively pursue all realistically achievable DSM programs as identified in the 2024 Potential Study.
    - The proposal should pursue at least the RAP savings as projected in the 2024 Potential Study, namely 400,000 MWh of energy efficiency and winter peak demand reductions of 173 MW by 2030.
    - Explore additional programs that at minimum include:
        - Residential and Commercial Energy Assessments and programs targeting behavioral changes.
        - Additional Residential programs targeting inefficient electric heating, and water heating equipment.
        - Programs tailored for manufactured housing.
        - New Commercial programs targeting savings from heating, motors, and refrigeration uses, all of which can also deliver winter demand savings.
        - Non-residential EV charging plans.
    - Explore financing opportunities and new program designs in line with national best practices to overcome persistent barriers to participation, e.g., Pay-As-You-Save Program ("PAYS®") model, also referred to as on-bill financing ("OBF") or Inclusive Utility Investment ("IUI") programs, to overcome high upfront cost barriers.

[1] Reproduced from Direct Testimony of Maria Roumpani at 3-5, 60-61.

  - Evaluate the impact of increasing incentives for programs including, at minimum, the following programs:
    - DLC;
    - Commercial Advanced Lighting;
    - All residential heating, ventilation, and air conditioning ("HVAC") equipment and shell programs.

- Order EKPC to provide, within twelve months of a final order in this proceeding, an updated Potential Study or other serious analysis correcting for the flaws and shortcomings identified here to provide more accurate estimates of cost-effective, achievable potential. The updated analysis should include at least the following adjustments:
  - Determination of optimal incentives that aim to maximize energy and cost savings, without over-relying on unjustified limits on incentive and/or spending levels.
  - The assessment of the potential of distributed solar and energy storage resources.
  - The assessment of emerging technologies, including but not limited to bidirectional charging, and the types of technologies and program delivery mechanisms in the Exhibits MR-2, MR-3, MR-4, MR-5.
  - Together with the Potential Study, EKPC should provide a third-party process evaluation and feasibility study for implementing Time-of-Use ("TOU") and Critical Peak Pricing ("CPP") rates across its member utilities.

- Order EKPC to propose, by no later than Jan. 2027, an updated DSM Plan that will utilize and observe the updated potential study to pursue re-assessed achievable programs and include additional programs and measures recommended. That updated DSM Plan should also propose guidelines for the stakeholder collaborative process as well as EKPC's (and owner-members') in-house evaluation of the Potential Study findings in the development of the proposed DSM plan. Guidelines should ensure a transparent process and outline evaluation criteria for programs, design principles, and documentation of process and results (including program elimination or rejection decisions).

- Direct EKPC to perform integrated analysis of DSM potential on equal footing with supply-side resources in all future resource planning, including but not limited to Integrated Resource Plan ("IRP") and Certificate of Public Convenience and Necessity ("CPCN") proceedings. This should include allowing DSM resources to be a selectable resource together with supply-side resources in resource optimization modeling.