Report on East Kentucky Power Cooperative's 2022 Integrated Resource Plan

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Kentucky Solar Society
Mountain Association

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1. Introduction

Kentuckians for the Commonwealth, Kentucky Solar Energy Society, and the Mountain Association engaged Energy Futures Group ("EFG") to review the East Kentucky Power Cooperative's ("EKPC" or "Cooperative") 2022 Integrated Resource Plan ("IRP"). EFG is a clean energy consulting company that performs IRP modeling and critically reviews IRPs in over a dozen states, provinces, and territories. We've reviewed over 100 integrated resource plans and similar exercises in our over 35 years of combined experience.[1] Our work in these jurisdictions involves either conducting our own simulations and/or reviewing modeling conducted using a wide variety of electric system modeling platforms.

EFG welcomes the opportunity to review, on behalf of Joint Intervenors Kentuckians for the Commonwealth, Mountain Association, and Kentucky Solar Energy Society, EKPC's 2022 IRP submitted to the Kentucky Public Service Commission ("Commission") on April 1, 2022. An IRP is an opportunity for a utility, regulators, stakeholders, and communities to take an active part in the future of their electric service and their energy outcomes. In the words of Lawrence Berkeley National Laboratory ("LBNL"), "[r]esource planning processes provide a forum for regulators, electric utilities, and electricity industry stakeholders to evaluate the economic, environmental, and social benefits and costs of different investment options. By facilitating a discussion on future goals, challenges and strategies, resource planning processes often play an important role in shaping utility business decisions."[2] Effective and meaningful IRPs do not merely serve as checklists for a set of analyses; rather, they reflect thorough and thoughtful stakeholder engagement, set forth the utility's perspective and analytical processes, clearly communicate the analyses that combine to make the IRP, are well documented and give a clear decision making path for the utility.

[1] The resumes of Ms. Sommer, Mr. White, Ms. Hotaling, and Ms. Sherwood are attached to these comments as Attachments A, B, C, and D, respectively.

[2] Karhl, Fredrich, et. al. "The Future of Electricity Resource Planning". Lawrence Berkeley National Laboratory, at 3 (Sept. 2016), https://eta-publications.lbl.gov/sites/default/files/lbnl-1006269.pdf.

In addition, well-done IRPs often discuss the ways in which the utility's next IRP might change in the future, such as how assumptions may change or further analyses the utility might conduct in preparation for its next IRP. EFG appreciated the opportunity to review the 2022 IRP and participate in two rounds of discovery with EKPC staff to better understand the IRP, the modeling, and the supporting data.

EFG submits these observations, comments, and recommendations in hopes of joining the conversation and increasing transparency, engagement, and bringing a more robust planning perspective to EKPC's IRP process.

2. Summary of Recommendations

Our recommendations are discussed in detail in the body of our report. The following presents a high-level summary of our recommendations. EFG believes that EKPC can provide a more robust IRP in future proceedings by consideration of the following:

Inputs and Modeling

- Review of the load forecasting methodology to address the gap in the first-year of the forecast from the actuals. Also, to address the divergence between the historic trend and the Cooperative's forecast of its total energy requirement.
- Use the most recently available NYMEX curve or an approach that blends the near-term NYMEX trend with long-term fundamentals forecast.
- Provide the coal, natural gas, capacity price, and the energy market on-peak and off-peak price forecasts directly in the initial IRP filing in an unredacted format where practicable.
- Use sensitivity analysis on its fuel prices to capture the market's movements and provide a robust IRP that provides confidence to stakeholders and regulators.
- Increase transparency in the IRP process and allow intervening parties to have full access to all the modeling input and output files, rather than turning over a limited set of files.
- Utilize a collaborative approach such as the one employed by the Minnesota utilities and DTE Electric to evaluate IRP modeling software options.
- Update the costs of solar resources to include the impacts from the Inflation Reduction Act ("IRA"). If market data is not available, we recommend that EKPC consider the Moderate and Conservative Capital Cost from the National Renewable Energy Lab Annual Technology Baseline ("NREL ATB") for new solar resources.

- Include battery storage resources as part of the new supply side resource options. If market price data is not available, we recommend that EKPC model battery storage resources using the most recent NREL ATB version. We also recommend that EKPC include the impacts of the IRA, which allow standalone battery storage projects to receive the Investment Tax Credit.
- Provide a clearer discussion of how emission costs are incorporated into the modeling.
- Model the Forecast Pool Requirement ("FPR") instead of the Installed Reserve Margin ("IRM") so that EKPC's planning most closely aligns with PJM's resource adequacy requirements.
- In the evaluation of the economics of a utility's existing resources, we recommend that the utility have all of the costs associated with the unit, including fixed O&M and capital expenditures, accounted for in the IRP model.
- Provide a robust economic retirement analysis of the Cooper Station units in future IRPs.

Demand Side Management and Energy Efficiency Programs

- Eliminate LED bulbs from the residential portfolio. Allocate LED funds to a comprehensive in-home audit program and expansion of measures under the Button-Up Weatherization program and incentive provided under the Heat Pump Retrofit Program.
- Promote heat pump technology that is above the minimum efficiency standard and align it with the new federally recognized efficiency rating system. Expand rebates to a tiered structure to encourage adoption of various heat pump technology options, including heat pump water heaters.
- Eliminate LED bulbs as part of the online energy audit. Provide an in-home energy audit program with direct install measures such as air and duct sealing with the option for incentives related to insulation and heat pump technology.
- Consider offering two pathways under an in-home energy audit program to promote the adoption of heat pump technology that will be rebated under the IRA funds to low-to-moderate income customers.
- Expand the energy efficiency workforce, with support from IRA funding, to increase participation for the in-home audit program and in anticipation of IRA rebates.

- Expand the residential demand response program to include opportunities for small businesses.
- Actively promote the interruptible rate tariff to commercial customers and owner-members. If the interruptible rate has a continued lack of interest, it should be revised to promote participation.
- Expand EKPC's energy efficiency webpage to include rebate levels, eligible measures, eligible contractors, and ways to participate in the programs. Develop streamlined marketing materials for use by owner-members.
- Develop a stakeholder process, based on best practices, to support the development of the DSM inputs.
- Utilize the Market Potential Study ("MPS") to inform the development of the DSM portfolio without the MPS dictating the portfolio. Consider equity in program opportunities, not only with low-income members but also for commercial and industrial members.

3. EKPC Load Forecast

The load forecast is discussed generally in Section 3.0 of the IRP. Detailed discussions of the load research program, load forecast and methodology are contained in *Technical Appendix Volume 1 - Load Forecast* ("Technical Volume 1").

EKPC uses a "bottom-up" approach to building its demand and energy forecasts. The loads of each owner-member are forecasted at the class level.[3] Residential and Small Commercial classes are forecasted using standard econometric approaches familiar across the industry. The Large Commercial and Industrial class is projected as a function of the real gross county product for the relevant service territory. The Public Street and Highway Lighting class is projected as a function of residential sales.[4]

The Cooperative produced its base forecast and several scenario cases by increasing and decreasing weather assumptions, electric price assumptions, residential and small commercial

---

[3] The load forecast was approved by the EKPC Board in December of 2020 and Rural Utilities Service ("RUS") in January 2021.

[4] 2022 EKPC IRP at 83. Seasonal and Public Building Sales are both small and account for a de minimis amount of actual or forecasted load demand.

growth.[5] [6] EKPC's forecast of its summer peak, total energy requirements, and winter peak are reproduced in this report as Figure 1, Figure 2, and Figure 3, respectively. These figures also display the Cooperative's forecasts from the 2019 IRP for comparison.

Figure 1. EKPC Summer Peak Demand 2012 – 2036, Actuals through 2020

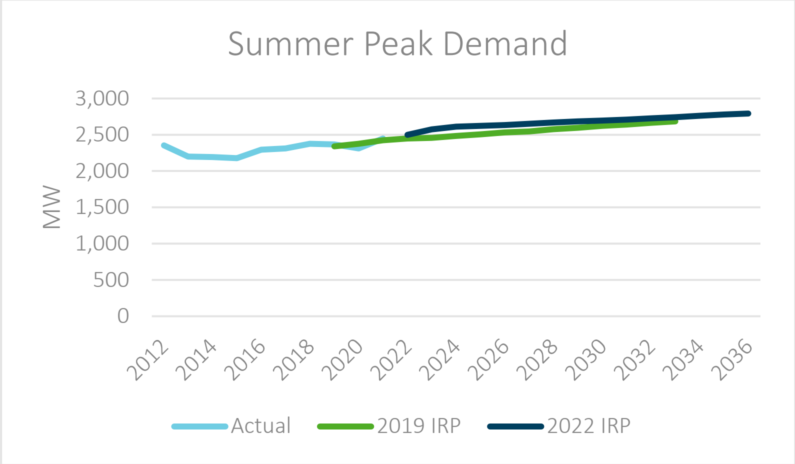
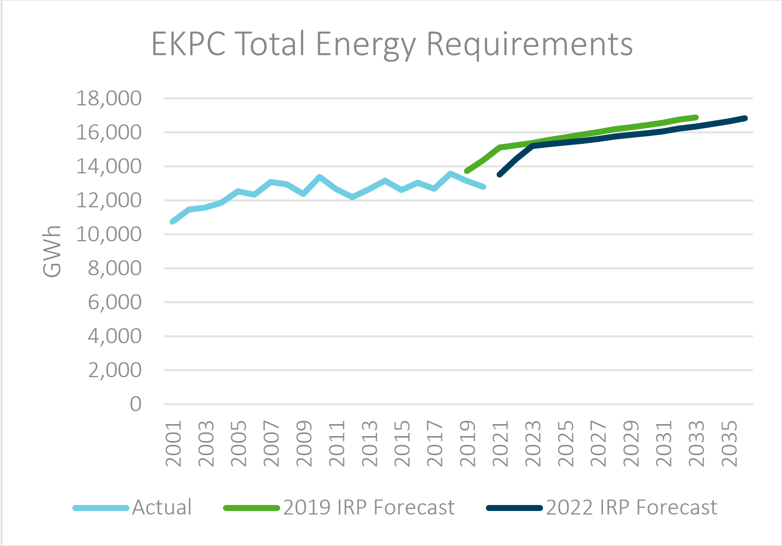


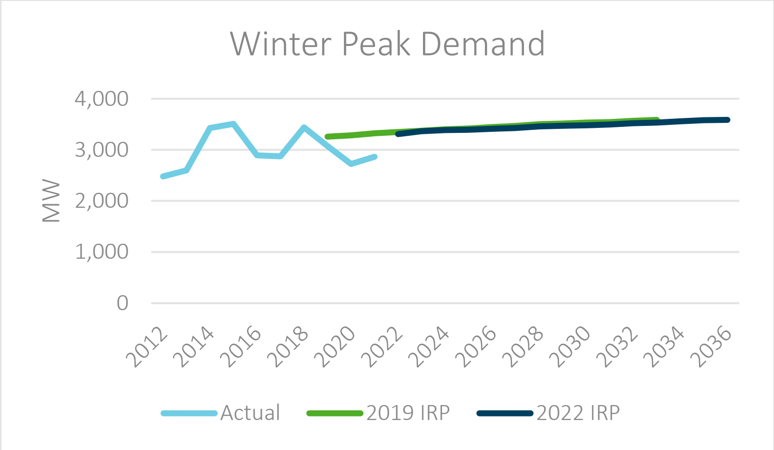
Figure 2. EKPC Total Energy Requirements



[5] Large commercial and industrial class was unchanged.

[6] Response to Joint Intervenors' Supplemental Request 50a.

Figure 3. EKPC Winter Peak Demand 2012 - 2036, Actuals through 2020



EFG compared the historic growth rates of the Cooperative's seasonal peaks and total energy requirements to the projected growth rates. Below, in Table 1, are the Compound Annual Growth Rates (CAGR) calculated for the summer peak, winter peak, and total energy requirements, respectively. The growth in EKPC's seasonal demand peaks and total annual energy requirements over the previous 10-years has been flat to declining for EKPC.

Table 1. Comparison of EKPC Actual and Projected Growth Rates

Growth Rates (Compound Annual Growth Rate)		
Category	Actual (2011-2021)	Forecast
Summer Peak	0.26%	0.80%
Winter Peak	-0.10%	0.60%
Total Energy	0.10%	1.11%

As Table 1 shows, the increase in the projected total energy requirement is higher than the actual growth rate in the Cooperative's energy sales over the ten-year period between 2011 and 2021. EKPC forecasts a CAGR of 1.1% in its total energy requirements as compared to a CAGR of 0.1% in the Cooperative's actual energy requirements. The energy requirements forecast is a primary input that will drive resource selection in IRP modeling. As such, the projected growth rate in the Company's total energy requirements diverging significantly from the historic trend may suggest the energy requirements forecast in the IRP is not reasonable. A transparent, stakeholder-engaged IRP process could help EKPC to identify these and other concerns before filing future IRPs with the Commission. EKPC's load forecast was approved nearly 18-months ago.[7] Even without the unprecedented disruptions to the economy and energy-use patterns due to COVID and its associated impacts, it would be difficult for a forecast produced with such a lag to be useful for regulators, stakeholders, or engaged community members. It does appear that EKPC's forecasts are adjusting downward. However, reviewing the first-year jump in EKPC's load forecast would be helpful.

The forecasted growth rates in energy requirements should be explained by EKPC. No explanation was provided by EKPC that would indicate the change is related to methodological changes or exogenous factors.[8] Certain refinements to consider may be shortening the load and weather history used to estimate the models. Additionally, given the structural reality of the Cooperative's load forecast for this IRP, it may provide additional value to regulators and stakeholders if EKPC used a more updated load forecast even as a sensitivity in future IRP filings.

3.1 Capacity Needs and PJM Load Obligation

EKPC states that it does not have a capacity need, and in fact has the capacity needed to meet its summer peak.

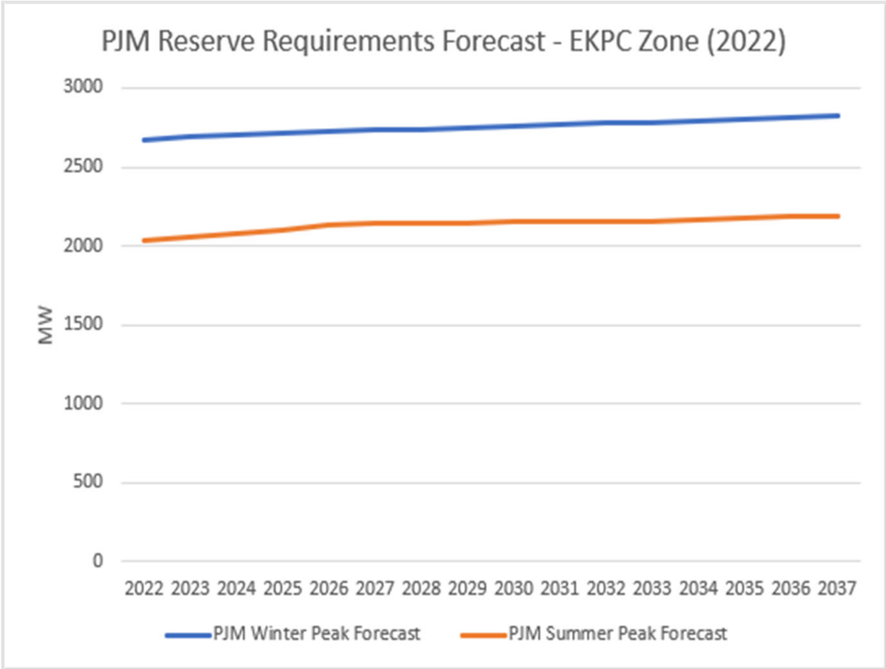
> *EKPC has sufficient capacity resources to meet its forecasted summer load peaks through the IRP study period. It expects to utilize Power Purchase Agreements ("PPAs") to cover the future winter period needs for a hedge against energy price exposure and solar PPAs to meet its sustainability goals on an economic basis.* [9]

[7] 2022 IRP, Technical Appendix Vol. 1 at 1

[8] Response to Joint Intervenors' Initial Request 7a-c.

[9] 2022 EKPC IRP at 8.

Figure 4. PJM Forecast of EKPC Zone Summer Coincident Peak and Winter Peak[10]



Further, as a member of PJM, EKPC is positioned beneficially. The utility can meet its summer peak with its own resources and procure excess energy from PJM's markets during the winter. For comparison, EKPC projects it will have approximately 3,600 MW of generating capacity through 2036, without the anticipated 395 MW of capacity additions. PJM projects that EKPC's zonal load obligation will peak at approximately 2,200 MW in 2036. Figure 4 above, graphs PJM's expectation of the seasonal peak demands in the EKPC zone.

We further note that EKPC's next IRP would benefit from more forthright explanation of how their forecasting method necessarily differs from that of PJM, and to what effect. PJM's forecast in the EKPC zone and EKPC's own forecast do differ, and EKPC did analyze that difference. According to EKPC, there are several reasons why the PJM load forecast and its internal load forecast are not directly comparable to each other. But those differences and EKPC's analysis are not clear on the face of the IRP and needed to be drawn out through independent investigation and information requests. EKPC provided an explanation of the difference between its forecast and PJM's. However, this is a missed opportunity for

[10] PJM, 2022 PJM Load Forecast Report, tbls. B-1. B-2 (Jan. 2022), https://www.pjm.com/-/media/library/reports-notices/load-forecast/2022-load-report.ashx.

transparency and engagement in the process. Additionally, the PJM forecast would provide regulators and stakeholders an independent and public resource against which to compare EKPC's projections. Last, as a member of PJM, a discrepancy between the grid operator and utility in expected load growth should be resolved.

> *The PJM and EKPC forecasts are not the same series. EKPC's forecast is developed according to its work plan and the requirements of Rural Utilities Service ("RUS"). Economic assumptions are based on owner-member share of county-level projections. Appliance saturations are based on an end-use survey as required by RUS. The EKPC forecast also incorporates known changes to industrial Customers. These assumptions may not be the same as the PJM load forecast. Additionally, the resulting forecasts are different. A graph of historical net total energy requirements along with the EKPC and PJM load forecast are included below. The PJM forecast is below historical actual indicating that it is not comparable to the EKPC total energy requirement forecast.*
>
> *The PJM forecast is for the load tied directly to the EKPC transmission system. It includes some load for LG&E/KU which is served from the EKPC system, and it does not include the EKPC load that is served from the LG&E/KU transmission system. The two forecasts are not directly comparable without significant modifications to the PJM forecast.*[11]

In future IRPs, EKPC should include a detailed discussion of how to reconcile these two forecasts. EKPC should distinguish its load obligation as a PJM member from any other loads it serves. EKPC should also distinguish capacity cleared against its load obligation from any excess capacity sold into the capacity market.

For example, the load obligation and capacity position values in Table 2 below are much higher than PJM's forecast of the summer coincident peak zonal obligation for the EKPC zone displayed in Figure 5.

Table 2. EKPC Reported Load Obligation v PJM Zonal Forecast

EKPC Capacity Position (MW)			
Delivery Year	Load Obligation	UCAP	PJM Forecast EKPC Zone Summer Peak
2020/2021	2605	2810	

[11] Response to Joint Intervenors' Supplemental Request 37.

2021/2022	2705	2846	
2022/2023	2791	2853	2030

4. Commodity Forecasts

In addition to the load forecast, the commodities assumptions, primarily fuel and energy market prices, are foundational to accurately forecasting costs of the considered supply-side resource options. Each unit's costs for fuel and variable operations and maintenance, as well as the energy price against which those units are dispatched, are major factors for dispatching the Cooperative's resources in modeling and in actual operations. EKPC acknowledges that current commodity prices have diverged significantly from those used in its IRP but believes the long-term trends will turn back towards its earlier price assumptions.[12] EFG works on IRPs across many jurisdictions and understands that even best-in-class IRPs are snapshots in time, built upon the best information available at the time. However, EFG makes some observations about the commodities forecasts used in EKPC's 2022 IRP.

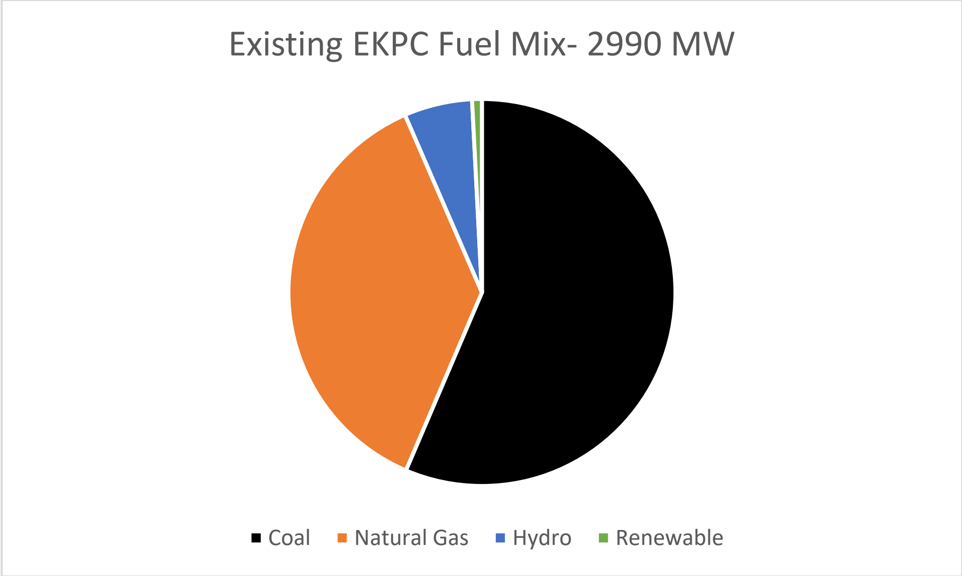
Figure 5, below, shows the Cooperative's existing generation fleet by fuel type. As the chart shows, the existing fleet is primarily coal-fired generation from John Sherman Cooper Station ("Cooper Station") and the Hugh L. Spurlock Station ("Spurlock Station") units.[13] These units have a combined capacity of 1,687 MW.[14] The primary fuel type for the rest of the existing generation fleet is natural gas.

[12] 2022 EKPC IRP at 56.

[13] Spurlock Station consists of four units, Spurlock 1, 2, and 4, as well as a third unit – Gilbert.

[14] 2022 EKPC IRP at 100.

Figure 5. EKPC Current Generation Fleet by Fuel Type[15]



4.1 Coal and Natural Gas

Under EKPC's final plan, its generation portfolio is, and will remain, heavily coal-based for the foreseeable future. Of the approximately 3,000 MW of owned and contracted generation, approximately 55% is coal-fired generation. The Cooperative also forecasts coal generation to be at least 70% of its self-generation through 2036.[16]

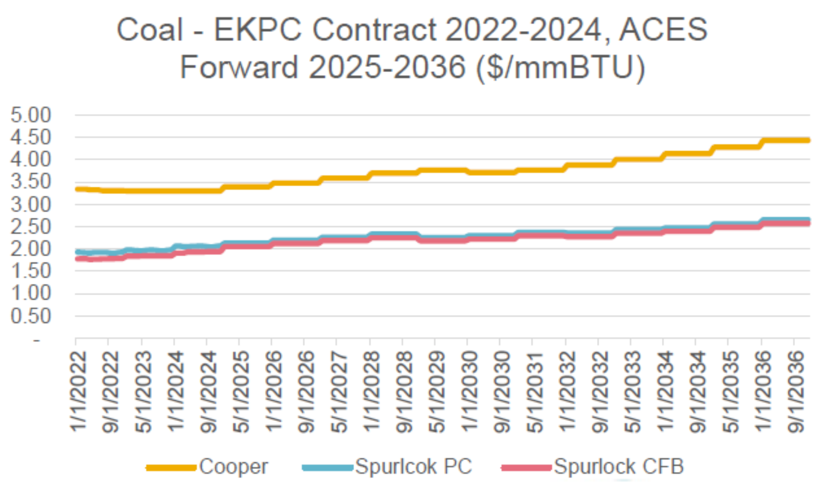
EKPC provided its coal price forecast in a graph, reproduced as Figure 6 below, for its delivered coal contract price forecast. The chart presents a relatively flat growth rate for the price of delivered coal to both of its units. The price of delivered coal for the Cooper Station and Spurlock Station Units diverge significantly. This may be because, according to S&P Global,

[15] 2022 EKPC IRP at 100–03.

[16] 2022 EKPC IRP, Corrected Table 8-10.

Spurlock Station can receive coal by barge on the Ohio River.[17] Whereas Cooper Station is supplied by truck.[18, 19]

Figure 6. EKPC Forecast of Coal Prices



Spot market coal prices have increased significantly since EKPC made its projection of future contract prices, and EKPC's forecast of delivered coal prices is unrepresentative of recently executed contracts executed.[20]

In EKPC's response to Attorney General's Supplemental Request 48, the Cooperative indicated that:

> *With spot coal in limited supply and high domestic and international demand, a coal supply agreement may need to be fully executed within hours, or the coal is at risk of being sold to another party. This immediate need for spot coal has led EKPC to utilize more Emergency Spot Purchases and Test Spot Purchases to*

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[17] Tyler Godwin, *East Kentucky Power Co-op buys 270,000 st of coal for Spurlock plant: filing*, S&P Global (June 4, 2019), https://www.spglobal.com/commodityinsights/en/market-insights/latest-news/coal/060419-east-kentucky-power-co-op-buys-270000-st-of-coal-for-spurlock-plant-filing.

[18] Archives, *Students Visit Sherman Cooper Power Plant* KPCS News (Jan. 4, 2013), https://kcps.news/district-news/students-visit-sherman-cooper-power-plant.

[19] This is also confirmed by review of EKPC's recent coal contracts and contract changes, KY PSC, Fuel Contracts (last visited Oct. 11, 2022), https://psc.ky.gov/WebNet/FuelContracts/ ("KYPSC Fuel Contracts Site").

[20] The commodities forecasts considered in the 2022 EKPC IRP were developed in the fall of 2021.

> *secure that coal supply in an effort to match the increased coal burn or simply to maintain physical coal inventory within the target levels.*

EKPC went on to state regarding long-term coal contracts:

> *EKPC is attempting to secure longer-term coal contracts. Contrary to the objectives of most utilities, for the last several years coal suppliers have been resistant to agree to a coal supply agreement for more than three years. Currently, any coal supply agreement with a term longer than three years is contingent on a market price reopener during the third delivery year to establish the coal price for the new term.*

Coal market pricing data are less readily available than data in other commodity fuel markets. Thus, transparency in the Cooperative's coal price forecast assumptions and the development of that forecast is essential to an informative IRP process. For example, only Spurlock Station's coal contracts were provided through discovery.[21] In future IRPs, EKPC should provide its coal contracts for Cooper Station as well. In addition, EKPC should explain how it developed its forecast of these prices and provide the data in an accessible and disaggregated format for stakeholders to evaluate.

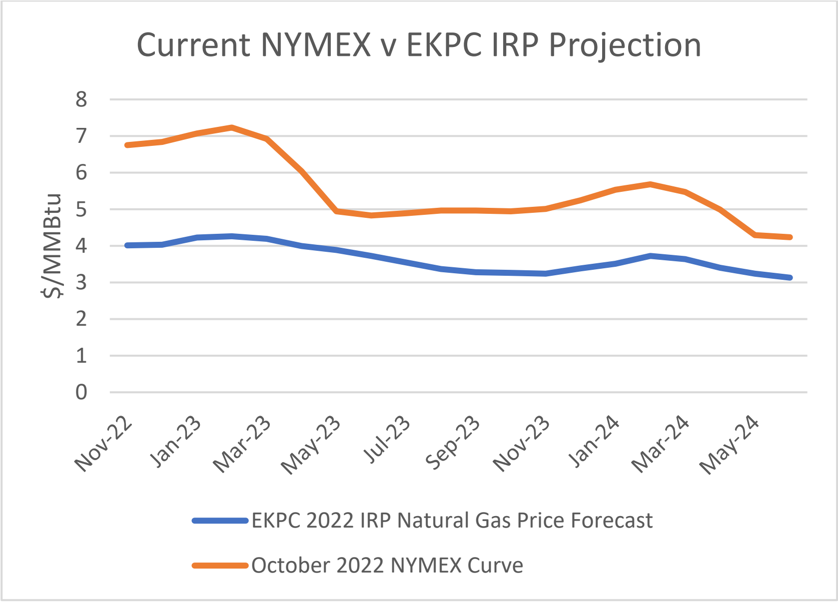
Natural Gas Prices

Natural gas prices forecast in EKPC's IRP, and reproduced below from December 2022 through June 2024 with the most recent NYMEX futures curve, as Figure 7, are also concerning. Likely due to the vintage of the forecast, EKPC is projecting the NYMEX Henry Hub price to drop dramatically below current market levels and forward projections. December 2022 is in the forecast period for the natural gas price assumptions in 2022 IRP. EKPC projected natural gas prices to be approximately $4/MMBtu at this time. Henry Hub futures are currently trading at nearly $7/MMBtu, an increase of 75% over the Cooperative's modeled assumption. Although trading is thin, the NYMEX forward curve is consistently above $4/MMBtu and near $5/MMBtu through 2024.[22] The NYMEX forward curve is readily available, and in future IRPs, we recommend that EKPC use the most recently available NYMEX curve or an approach that blends the near-term NYMEX trend with long-term fundamentals forecast.

[21] Response to Joint Intervenors' Initial Request 96.

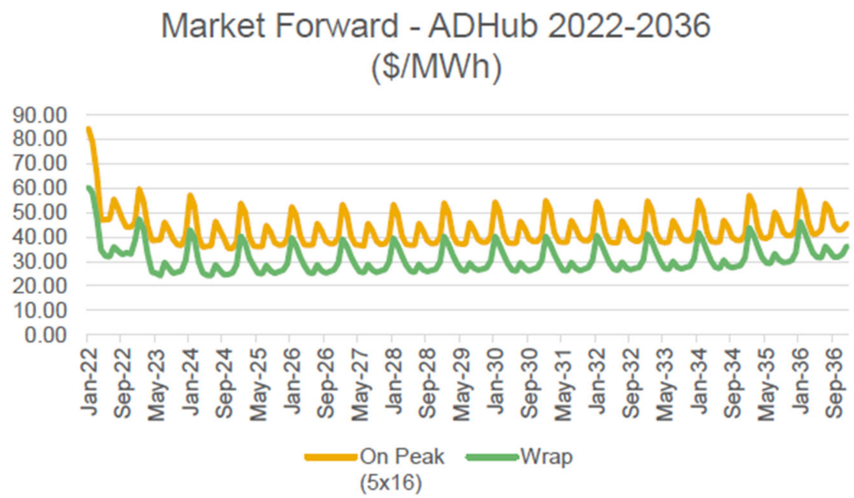
[22] Henry Hub Natural Gas Futures – Quotes, CME Group (last updated Oct. 11, 2022), https://www.cmegroup.com/markets/energy/natural-gas/natural-gas.quotes.html.

Figure 7. EKPC Natural Gas Forecast vs Current NYMEX Curve



4.2 Energy Market Price

Figure 8. EKPC Forecast of Energy Market Prices



EKPC's energy market price forecast, reproduced above as Figure 8, is also low as compared to observed market prices. For example, the year-over-year average PJM AEP-Dayton Hub Locational Marginal Price (LMP) was $63.37/MWh from September 1, 2021, to September 1, 2022. Thus far for 2022, the year-to-date average PJM AEP-Dayton Hub LMP has been $71.24/MWh. The current average of PJM AEP Dayton Hub LMPs for September 2022 is $82.28/MWh.[23] This is far above the forecasted energy market prices for both the forecasted contract prices.

4.3 Capacity Market Price

With respect to EKPC's capacity price forecast, we note two paramount concerns: first, this commonly public information has been redacted from public view, and second, EKPC's forecasted capacity prices significantly depart from credibly sourced third-party forecasts.

EKPC's capacity price forecast was marked as confidential, but this information is routinely published as part of IRPs in public forums.[24] [redacted]

[23] *Energy Markets*, PJM (Accessed September 27, 2022), https://pjm.com/markets-and-operations/energy.

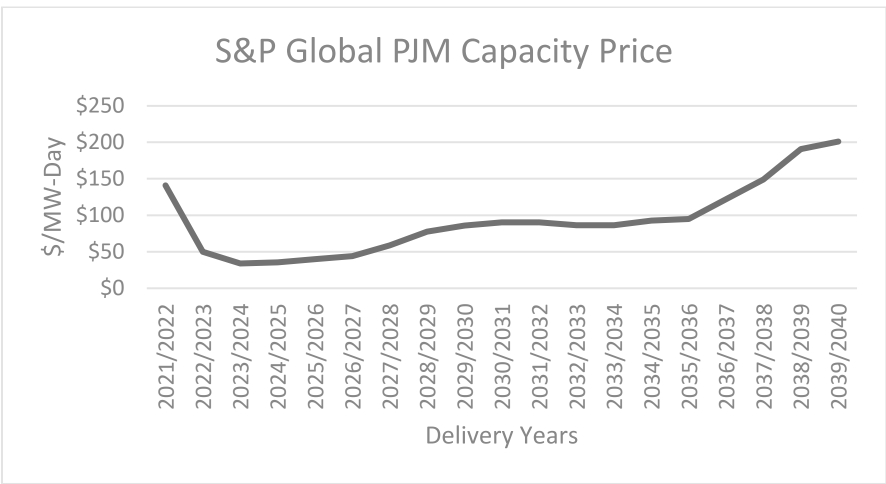
[24] *See e.g.*, Dominion Energy Virginia, 2021 IRP Update to the 2020 Integrated Resource Plan (filed Sept. 1, 2021), https://www.dominionenergy.com/-/media/pdfs/global/company/2021-de-integrated-resource-plan.pdf; Indiana

[redacted] The capacity price forecast will typically be used to compare new resources against market purchases. A capacity forecast that overestimates the cost of future capacity in the market would tend to overvalue existing resources that can clear the capacity market and receive the capacity revenues in the capacity expansion modeling.

PJM capacity market prices are the result of an administrative process and are difficult to project using traditional fundamentals forecasting methodologies. However, S&P Global's PJM capacity price forecast reproduced below provides a useful data point for comparison against the capacity price forecast EKPC used in its IRP modeling.

The above challenges to capacity market price forecasting aside, EKPC's capacity price forecast is on average almost [redacted] than S&P's PJM capacity price forecast in Figure 9 below.

Figure 9. S&P Global PJM Capacity Price[25]



Michigan Power Company 2021 Integrated Resource Planning Report (Jan. 31, 2021), https://www.in.gov/iurc/files/IndMich_2021-IRP-Report_01312022.pdf; Indianapolis Power and Light 2019 IRP (Dec. 16, 2019), https://www.in.gov/iurc/files/2019-IPL-IRP-Public-Volume-1_121619.pdf; and the Appalachian Power Company 2022 IRP (May 1, 2022), https://rga.lis.virginia.gov/Published/2022/RD206/PDF.

[25] Katherine McCaffrey, *PJM capacity prices projected to drop due to auction parameter, market updates*, S&P Global (May 10, 2022), https://www.spglobal.com/marketintelligence/en/news-insights/research/pjm-capacity-prices-projected-to-drop-due-to-auction-parameter-market-updates.

Fuel and market price forecasts are essential building blocks to an IRP and inputs to its modeling. Having access to this information is important for stakeholders and intervenors to evaluate the IRP. We recommend, in a format like the examples provided in this report, EKPC provide the coal, natural gas, capacity price, and the energy market on-peak and off-peak price forecasts directly in the initial IRP filing in an unredacted format where practicable.

To recap EFG's observations: EKPC's coal price forecasts are opaque and should be better described in its IRP. Regarding forward natural gas prices, it is unclear why EKPC limited itself to using the NYMEX forward curve from last fall for natural gas prices. This information is readily available, updated frequently, and public. Given the known volatility in natural gas prices, a more recent NYMEX forward curve would have been available when performing the IRP modeling. It is also unclear to us why the capacity market price forecast is confidential or why it should be markedly [redacted] than S&P Global's forecast.

The value of an IRP and its modeling is a function of its input assumptions as well as the choices of the modeling team, and constraints placed on the model solution. The timeliness of EKPC's forecasts themselves limit the value of this IRP to evaluate the best path forward for the utility. For example, solar resources are more than likely undervalued in an analysis with below market energy prices. This is without consideration of the provisions of the new Inflation Reduction Act.

EKPC's scenario analysis did not appear to include any commodity price sensitivities. Commodity price sensitivities would be one way to account for changes in the market that maintain value for the IRP even though situations change. As the IRP commodity price environment stands, the environment evaluated is not the environment in which EKPC will face resource decisions for the foreseeable future.

We recommend in future IRPs that EKPC present sensitivities directly to its fuel prices in addition to using the most recent commodity price forecasts available at the time of its model runs. As the load forecast is part of the RUS process, and necessarily developed some time before the IRP modeling, ensuring the near-term commodity regime reflects the near-term environment is important. Additionally, EKPC should, at a minimum, run sensitivities assuming a high- and low- band for its commodity price forecasts to maintain the IRP as a robust planning document even in volatile environments such as the one we are experiencing now.

5. Cooper Station

Cooper Station is located near Somerset on Lake Cumberland. The station has one 116 MW unit that began operating on February 9, 1965, and one 225 MW unit that began operating commercially on October 28, 1969.[26]

Considering the age of this unit, the economics of coal units generally in PJM[27], and the current state of the coal supply market[28] it is reasonable to consider the economic retirement or deactivation of thermal units in IRP planning. Yet, EKPC's IRP does not evaluate economically optimal retirement dates for its Cooper Station units or any other supply-side generation units. When asked, EKPC offered the following explanation for not considering the retirement of any of its units:[29]

> *EKPC has not assumed a retirement date on any of its units other than for calculating the depreciable life of the assets as included in the latest depreciation study filed with the Commission. It is beneficial to EKPC's owner-members and end-use retail members if a unit is able to serve until it is fully depreciated. In recent cases, some expert witnesses have suggested that the depreciable life of generation units should be extended. Unless the unit can stay in operation until it is fully depreciated, owners-members and end-use retail members must pay the sunk costs of the retired generation in addition to the cost of replacement capacity.*

There are several problems with EKPC's position. First, this refusal to consider a different course of action, *i.e.*, retiring the unit, is a classic example of the sunk cost fallacy.[30] That is, a continued commitment to a behavior or endeavor merely because prior resources have been invested. Sunk costs must be recovered regardless of whether the station continues to operate

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[26] 2022 EKPC IRP at 97.

[27] Naureen S. Malik & Will Wade, *US Coal Plants' Fate Hinges on June Power-Price Auction*, Bloomberg (June 17, 2022), https://www.bloomberg.com/news/articles/2022-06-17/us-coal-plants-could-consider-closing-when-pjm-grid-auction-results-come-out.

[28] Ethan Howland, *Coal plant owners seek to shut 3.2 GW in PJM in face of economic, regulatory and market pressures*, Utility Dive (March 22, 2022), https://www.utilitydive.com/news/coal-plant-owners-seek-to-retire-power-in-pjm/620781/; Energy Ventures Analysis, Inc., *US Coal Markets and the Current Coal Supply Shortage*, PJM (July 2022), https://www.pjm.com/-/media/committees-groups/committees/oc/2022/20220714/item-08---us-coal-markets-and-the-current-coal-supply-shortage.ashx.

[29] Response to Joint Intervenors' Initial Request 38.

[30] *Sunk Cost Fallacy*, Behavioral Economics (last visited Oct. 11, 2022), https://www.behavioraleconomics.com/resources/mini-encyclopedia-of-be/sunk-cost-fallacy/.

or not, but EKPC can still evaluate its going forward costs against alternative resources. EKPC states that it performed no analysis of the retirement of Cooper Station, and as such it was not possible through the evaluation of the IRP to determine if the cost of replacement capacity would be economic in comparison to continuing to run Cooper Station. Meaning, EKPC's IRP does nothing to assess whether continuing to operate both Cooper Station units is likely to be economically beneficial for its member-owners. The fact that a portion of the plant balance still needs to be depreciated does not establish that retaining each of the Cooper Station is the lowest-cost resource option for EKPC's member-owners.

Additionally, EKPC has carbon reduction goals: a 35% reduction by 2035 and a 70% reduction by 2050. The Cooperative states that it intends to accomplish these goals by, among other things, minimal hours of operation at Cooper Station through 2035, and ultimately the retirement of both Cooper Station and Spurlock Station in 2050.[31] EKPC did not submit any analysis of the retirement of either unit based on its current assumed retirement date because it was assumed to be out of the scope of the IRP, however EKPC did not explain why it did not evaluate earlier retirement of these units.[32]

We recommend EKPC produce retirement analyses in future IRPs of the Cooper Station units, as well as the Spurlock Station units to ensure that it is meeting the goal of developing least cost and least risk plans. Those analyses must include all going forward costs of operating those units including capital investment related to ongoing operations such as the capital projects given in response to AG Initial Request 31 as well as any potential environmental upgrades, e.g. an SCR unit at Cooper Unit 1.

According to the analyses that EKPC did perform as part of this IRP, Cooper Station has a [redacted] economic outlook. Across the planning period, Cooper Station's forecasted capacity factor is [redacted]. In fact, by EKPC's own analysis, Cooper Station [redacted]. Figure 10, taken from operational and cost data provided by EKPC through 2031, indicates that continued operation of Cooper Station will [redacted] even without accounting for fixed O&M and capital investments. This outlook accepts EKPC's analysis at face value, treating all assumptions as correct, [redacted] as well as the previously discussed commodity and load forecast assumptions. But unfortunately, [redacted]

[31] Response to Joint Intervenors' Initial Request 90c.

[32] *Id.*

[redacted] from continued operation in the energy market on an economic basis.[33]

[redacted]

Figure 10. Cooper Station Net Energy Revenue

[redacted]

[redacted]

Based on EKPC's responses to discovery, it is our understanding that the net book value plant balance for the Cooper Station is approximately $139 million dollars,[34] and EKPC intends to continue operating the unit until fully depreciated under the currently approved schedule. While the remaining cost of Cooper Station will be recovered from customers even if the plant is retired, [redacted] EFG estimated from the data provided by EKPC would also be recovered from EKPC's customers. These are all material reasons to evaluate continued operation of Cooper Station, in particular. Additionally, as Figure 11 shows, the annual average capacity factor at Cooper Station has been declining since 2012 and has only risen slightly for 2022 to date to 18%.[35]

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[33] To achieve positive net revenues for 2022, Cooper Station would have to operate a capacity factor of [redacted] To date for 2022, Cooper Station has operated at an average capacity factor of 18%.

[34] Response to Nucor's Supplemental Request 1.

[35] Response to Joint Intervenor Initial Request 29.

[redacted]

Figure 11. Cooper Station Historic Capacity Factor[36]

[redacted]

[redacted]

In its Response to Joint Intervenors' Initial Request 30, however, EKPC projected Cooper Station's annual average capacity factor for 2022 to be [redacted] through 2031. The expected annual average capacity factor at Cooper Station is projected to [redacted] which suggests that considering the retirement of this unit would be reasonable and prudent in the IRP process.

Further, EFG used the data in EKPC's Response to Joint Intervenor Initial Request 30 to project the estimated annual energy market revenues for Cooper Station. The results suggested that Cooper Station [redacted] That alone should be cause for further evaluation.

Although EKPC stated in its response to Joint Intervenor Initial Request 30 that it did not track capacity revenues at the unit level, this review of Cooper Station's operations highlights a potential importance of capacity price forecast assumptions in IRP modeling. For example, a capacity price forecast that is [redacted] other market outlooks could bias the economics of a particular unit against units that may not have

[36] Response to Joint Intervenors' Initial Request 29 and Response to Sierra Club Initial Request 12.

the same capacity accreditation such as solar or battery storage. An inflated capacity forecast could also overprice replacement capacity procured from the market. However, EKPC performed no analysis of the costs of continued operation of Cooper Station against purchased capacity from the PJM market:

> *No, EKPC has not evaluated the retirement costs of any of its thermal units. Given that none of its thermal units have been fully depreciated, any retirement in the short-term would result in ratepayers being forced to incur stranded investment costs in addition to the costs of investments of new generation.*[37]

The impact to the revenues and costs of Cooper Station are difficult to quantify. Energy market prices are high, but fuel costs have also increased substantially. This is an example of where EKPC could have performed sensitives on commodity prices in anticipation of some of these concerns. Additionally, EKPC did not provide costs for Cooper Station's coal contracts, and the cost of coal delivered to Cooper Station is significantly higher than coal delivered to Spurlock Station (*see* 4.1 Coal and Natural Gas).

EKPC states a driver in the decision not to analyze the retirement of Cooper Station is that it is needed for voltage support in the region:

> *Cooper station provides key voltage support in the transmission area throughout Southern Kentucky. The current transmission system is not configured to support the peak load periods in that region without the generation injections at Cooper Station.*[38]

Notably, EKPC has not explored multiple non-wire options including battery storage and conversion of one or more units to a synchronous condenser to address this problem. EKPC, however, states that it is currently performing an analysis though it is limited to "transmission infrastructure options to bolster voltage support in the area."[39]

We recommend that EKPC provide a robust economic retirement analysis of the Cooper Station units in future IRPs. A power flow study to evaluate operability considerations for unit retirement is a good complement to this analysis but it must be robust and consider all feasible mitigations, both generator and transmission related, as well as "right-size" those mitigations to the problem created by the retirement.

[37] Response to Joint Intervenors' Supplemental Request 55.

[38] Response to Joint Intervenors' Supplemental Request 21.

[39] Response to Joint Intervenors' Supplemental Request 22f.

A robust economic analysis of the continued operation of Cooper Station would include, but not be limited to, evaluating the cost of continued operations at Cooper Station against the replacement of Cooper Station's capacity and the most cost-effective mitigations to voltage concerns such as conversion to synchronous condensers, on-site renewables, battery storage, and so on. The need to maintain voltage support in the area may be a justification to not retire Cooper Station, but that should not preclude EKPC from studying and analyzing the retirement of Cooper Station in future IRPs.

6. Capacity Expansion and Production Cost Modeling

Capacity expansion and production cost modeling are typically used by electric utilities in developing an IRP. Capacity expansion modeling involves utilizing an optimization engine to minimize system costs given the estimated costs of new and existing resources including a simplified[40] projection of unit commitment and dispatch.[41] When the model is choosing the least cost portfolio, it will seek to minimize the cost of a plan that meets peak load plus the planning reserve margin and any additional constraints that may be added to the model.

For the production cost modeling, a portfolio of existing and new resources is fixed. The portfolio is dispatched on an 8,760 hour per year, chronological basis in each year of the planning period. Typically, the results from the production cost modeling are then combined with the capital and other fixed costs in the capacity expansion modeling to develop the total costs of the portfolios evaluated.

For this IRP, it appears that EKPC did perform capacity expansion and production cost modeling using a model named RTSim. However, the narrative of the IRP contained limited information and discussion about how the RTSim model was used, it does not appear the capital costs factored into total system cost/profits, and there were several sections in the IRP that were not clear about which steps were taken using RTSim and which were external to the model. It was also unclear how stochastic variables were incorporated into the IRP. Our critiques of EKPC's modeling approach as well as the lack of transparency related to EKPC's modeling is discussed in more detail in the following sections.

[40] In order for the model to reach a solution the "problem size" has to be manageable, a common way to limit problem size is to simulate only a handful of hours, such as two "typical" days per month in the capacity expansion step.

[41] The model can also optimize for any external market interactions.

6.1 Unclear Modeling Methodology

The IRP narrative leaves the impression that EKPC used RTSim to perform both capacity expansion and production cost modeling. EKPC seems to indicate that RTSim's Resource Optimizer was utilized to perform capacity expansion modeling. In the IRP narrative, EKPC said:

> *RTSim's Resource Optimizer was used to perform the optimization of the resource plan. The Resource Optimizer automatically sets up and runs the RTSim production cost model to perform simulations of a large number of potential resource plans to determine the optimum plan. Because the basic RTSim model is used by the Resource Optimizer model, the Resource Optimizer uses the same data and detailed analysis that is used in the production cost model simulation, except that future units are set as resource alternatives. Any future resources to be considered by the Resource Optimizer are set up with several potential future commercial operation dates.*[42]

But intervenors were not provided with any supporting capacity expansion files from EKPC. The Joint Intervenors requested[43] that EKPC provide all of the RTSim input and output files that were used in the production of the IRP. However, the input files were limited to load, market prices, and fuel prices. In addition, the single output file provided in response to this Request seemed to be from a production cost modeling run. After reviewing what EKPC provided in response to this Request, we did not see any indication of capacity expansion input or output files from RTSim.

EKPC also indicated that plans were simulated with 5 iterations,[44] where each iteration varies loads, fuel and market prices, and forced outages.[45] The response to Joint Intervenor's Initial Request 22 similarly states, "The RTSim Resource Optimizer will create a unique set of resources and perform a production cost simulation for the particular configuration. This

[42] 2022 EKPC IRP at 162.

[43] Joint Intervenors' Initial Request 40.

[44] In response to Joint Intervenors' Initial Request 22, EKPC said that "The RTSim Resource Optimizer will create a unique set of resources and perform a production cost simulation for the particular configuration. This process is repeated over the 2500 runs, with 5 iterations of the production cost model to seek out the least cost plan."

[45] 2022 EKPC IRP at 167.

process is repeated over the 2500 runs, with 5 iterations of the production cost model to seek out the least cost plan."

However, at page 162 of the IRP, EKPC states "Actual and forecasted market prices, natural gas prices, coal prices, and emission costs are correlated to the load data used in the simulation. Five hundred (500) iterations are used in the model simulations." It's not possible to verify whether EKPC performed 500 or 5 iterations on each expansion plan because the full set of modeling files were not provided to Joint Intervenors. However, the single output file that was provided[46] contains some data suggesting that 500 iterations were conducted, not 5. This is the explanation that makes the most sense to us. It would be computationally challenging to produce 2,500 unique expansion plans, but it would be much more likely and also more in line with the data that EKPC says it varied, that RTSim was used to conduct 500 unique production costing runs on each expansion plan. That is, each unique plan (and it is not clear if there are 5 or 10 of them) dispatched 500 times under different load and commodity pricing assumptions. Intervening parties were only provided with a limited set of input files for these dispatch outcomes/iterations covering fuel, market prices, and load but not forced outages. However, even for those variables with information provided, it was not clear whether these files covered all of the outcomes modeled for each iteration.

The 500 iterations were conducted using Monte Carlo simulations that EKPC says tested several input variables:

> *The RTSim model uses a Monte Carlo simulation to capture the statistical variations of unit forced outages and deratings, load uncertainty, market price uncertainty, and fuel price uncertainty. Monte Carlo simulation requires repeated simulations (iterations) of the time period analyzed to simulate system operation under different outcomes of unit forced outages and deratings, load uncertainty, market price uncertainty, and fuel price uncertainty. The production cost model is simulating the actual operation of the power system in supplying the projected customer loads using a statistical range of inputs.*[47]

[46] Response to Joint Intervenors' Initial Request 40.

[47] 2022 EKPC IRP at 162.

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With regard to the load uncertainty, the IRP narrative indicates that a statistical load methodology was used for the modeling in RTSim:

> *For this study, the model used the statistical load methodology. There is one set of load data in the model, which was created from the EKPC Load Forecast. Around this forecasted load, a range of distributions created four additional loads to define the high and low range of the potential loads to be examined. The model draws load data a few days at a time from the different forecasts (to represent weather patterns) to assemble the hourly loads to be simulated. Each iteration of the model draws a new load forecast to simulate. Actual and forecasted market prices, natural gas prices, coal prices, and emission costs are correlated to the load data used in the simulation. Five hundred (500) iterations are used in the model simulations.*[48]

It appears, though it is not clear, that EKPC employed this "statistical load" methodology in what were effectively production cost runs. In response to Joint Intervenor's Supplemental Request 42, EKPC said "The RTSim model provides stochastic and deterministic methodologies. Stochastic varies the load, while deterministic does not."[49]

6.1.1 Incomplete Modeling Files

In the output file that EKPC provided in response to Joint Intervenors' Initial Request 40, the information contained within the file indicated that the monthly load is the same across all 500 iterations contained within the file. Based on the review of this output file, we cannot see how the load was varied according to the statistical load methodology outlined in the IRP. It is important for intervening parties to be able to review the modeling methodologies utilized by utilities for the development of the IRP. Not providing a clear description of modeling methodologies and limiting stakeholders' ability to review this information reduces transparency and replicability, effectively preventing peer review.

In instances when a utility has not clearly articulated the modeling methodology utilized for the IRP, we are usually able to discern each step in their analysis through detailed independent review of modeling files. This was largely the case, for example, in LG&E/KU's most-recent IRP,

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[48] *Id.*

[49] EKPC Response to Joint Intervenors' Supplemental Request 42.

where LG&E/KU both provided their modeling files (amounting to several hundred or more discrete files) and informally conferred with the EFG team to ensure the information provided was clear and complete. EFG was afforded the opportunity to ask members of the LG&E/KU team questions on the modeling steps undertaken by LG&E/KU. This type of exchange was extremely helpful for us to facilitate our understanding of the modeling methodology – it allowed us to glean that fact that LG&E/KU had optimized capacity additions only to a single year – and helped to address questions we had about the process used by LG&E/KU. We find exchanges like this to be invaluable for enhancing transparency and facilitating the exchange of information between the utility and stakeholders.

Request 40 from the Joint Intervenors' Initial Request asked EKPC for "the RTSim input and output files used in the production of this IRP." In response to this request, EKPC provided a set of limited inputs, which included fuel, market price, and load values. EKPC also provided a single modeling output file, a spreadsheet in the .xslx format (Microsoft Excel). After reviewing these files, it was apparent that input and output files were missing. For example, other modeling inputs that should have been provided with this response include the reserve margin constraint, the cost of the new supply side resources offered to the model, any constraints applied to the selection of new resources, operating parameters for existing resources, costs of existing resources, emission constraints, and emission costs, etc. One of the most important inputs for the capacity expansion optimization is the reserve margin constraint. Based on the IRP narrative, it seems as if the RTSim model does not model a specified reserve margin, but instead sees a "minimum and maximum amount of capacity to be added by the model" and that corresponds to a specified reserve margin.[50] This is an example of an important input that intervenors should have access to since it heavily influences the capacity expansion modeling results.

The costs of new supply side resources are another important modeling input missing from the files EKPC produced in response to Joint Intervenors' information request. In the IRP, EKPC provided information on the capital costs considered for new resources, but then indicated that within RTSim the annualized fixed costs for capital are included.[51] Intervening parties did not receive access to the annualized fixed costs that were modeled for new supply side resources. There are several important inputs that flow into the development of the annualized fixed

[50] 2022 EKPC IRP at 166.

[51] 2022 EKPC IRP at 162-63.

costs, which include the capital cost, the book life of the resource, and the capital recovery factor.

Further, EKPC provides no meaningful information about the costs of these plans in its IRP. It provided limited “system profit” information in response to Staff's Initial Request 27c. However, it is not clear whether this information actually includes capital costs both for new and existing units or whether it is merely a comparison of revenue to generators less payments by load for energy and the variable costs of operating those generators.

Staff submitted Initial Request 27 to EKPC which asked for EKPC to “Provide an outline of the input constraints used in the Resource Optimizer to obtain the five cases and final plan in the Tables 8-4 and 8-5.” In response to Staff, EKPC did not provide any information about the input constraints. Instead, EKPC said:

> *The RTSim Resource Optimizer utilizes an expected load requirement range over the study period. This guides in the creation of the unique resource additions to meet the requirement in each of the runs. The system creates a selection of resources and performs several iterations of the RTSim production cost model to arrive at the least cost configurations.*[52]

The constraints Staff asked after are critical, and Joint Intervenors attempted to draw out this information as well through Supplemental Request 44a. Taking a different approach, that request asked EKPC to explain how an external reviewer could “review the model constraints that were used, e.g., reserve margin requirements, new build constraints, etc.” Again, EKPC did not directly answer the question asked, and instead pivoted to say that “[t]hese inputs are not direct drivers for the constraints referenced.” Through Joint Intervenors’ counsel, we sought clarification of this response, and others, but EKPC declined to discuss, correct, or supplement its earlier responses.

In order to review the modeling that a utility performs for the IRP, it is imperative that intervening parties have access to all of the modeling input and output files, as well as transparency around constraints used in the model. We recommend that EKPC foster increased

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[52] Response to Staff’s Supplemental Request 27.

transparency in the IRP process and allow intervening parties to have full access to all of the modeling input and output files, rather than turning over a limited set of files.

6.1.2 Inability to Replicate Runs for Intervening Parties and Lack of User Manual

As discussed in the above section, EKPC provided intervenors with a limited set of modeling input and output files. Not allowing intervenors to have access to all the modeling input and output files makes it challenging for intervenors to understand the modeling that EKPC conducted and reduces transparency for all parties. Neither did EKPC provide intervenors with access to the RTSim model manual. In response to Joint Intervenors' Initial Request 41, EKPC stated that "RTSim is a proprietary product of Simtec, Inc., and as such, EKPC is not at liberty to share such proprietary information."[53] Typically, these kinds of commercial concerns can be overcome through the use of a non-disclosure agreement. It is EFG's position that the use of information or tools that cannot be subject to regulatory oversight makes them unfit for use to produce regulatory work products.

Each capacity expansion and production cost model has its own setup for model inputs that may be different than other models used for similar purposes. As a result, the model documentation becomes invaluable for users who are trying to interpret the meaning of different inputs. There were several fields in the input files and the output file provided in response to Joint Intervenors' Request 40 that were unclear. However, it was challenging to ask clarification on these given the discovery turnaround time frame, which is significantly longer than the time it would take to simply check the model manual. For instance, there was a field called "Weather Day-Dist. Draw Count" in the modeling output file and it was not clear from the output file how that field was applied within the model.

Not only were intervening parties limited in the review and understanding of the IRP modeling, but without the full set of modeling files, intervening parties did not have the ability to re-run EKPC's assumptions within RTSim nor the opportunity to make changes to input assumptions to complete alternate modeling runs. In other jurisdictions where modeling transparency has been addressed, e.g., in Michigan, South Carolina, and Arizona among others, utilities have been able to engage with the model vendor to negotiate discounted project licenses for intervening parties with those costs typically absorbed by the utility.

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[53] EKPC Response to Joint Intervenors' Initial Request 41.

6.1.3 Similarities to Commission Concern with LG&E/KU's Use of PROSYM

The concerns we have about the transparency of EKPC's modeling seem to mirror concerns that the Commission documented in Case No. 2020-00349 and Case No. 2020-00350 regarding LG&E/KU's use of the PROSYM model. The Commission stated:

> *Based upon a review of the record and being otherwise sufficiently advised, the Commission finds that LG&E/KU's avoided energy cost proposal is reasonable but lacks transparency. The Commission concurs that it is reasonable to estimate avoided energy costs from different technologies using forecasted hourly energy costs developed in PROSYM. However, the proprietary nature of the production cost model limits the Commission's ability to assess its reasonableness. The full range of LG&E/KU's assumptions, inputs, and outputs was inaccessible to other parties and to the Commission without several rounds of discovery. Additionally, parties and the Commission could not re-run the model with alternate inputs to explore variations on LG&E/KU's assumptions. This lack of transparency will likely become increasing problematic as renewable energy penetrations increase and modeling assumptions become more complex and important.*
>
> *For this reason, the Commission finds that, in future cases, including those updating LG&E/KU's IRP and QF rates, LG&E/KU should improve the transparency of their avoided energy and any other costs that are calculated using proprietary software by increasing access to the software, inputs, and assumptions relied upon. While the Commission will not at this time prescribe a method for doing so, LG&E/KU should submit, within 90 days of the entry of this Order, a filing that details how LG&E/KU will increase the transparency of their modeling to the Commission. At a minimum, LG&E/KU's plan should allow for one model re-run per intervening party and the Commission per proceeding, upon a party's request, and for the provision of inputs and assumptions to the models in native formats within the initial filing.*[54]

The Commission expressed similar concerns about the transparency for the PROSYM model that we have related to the RTSim model. These concerns include a lack of access to the full set

[54] Case Nos. 2020-00349 and 2020-00350, Order at 29–30 (Ky. PSC Sept. 24, 2021).

of assumptions, inputs, and outputs, in addition to the inability for the Commission and other intervening parties to be able to re-run the model.

EKPC's response to Joint Intervenors' Supplemental Request 46 suggests that it has a different interpretation of the ability of RTSim to avoid the transparency pitfalls of PROSYM. It is important to distinguish between what's nominally possible and what's practically possible, however. For example, despite EKPC's claim otherwise, we do not have the modeling files necessary to execute capacity expansion and production cost runs.[55]

Nor do stakeholders have a way to contact RTSim's vendor, Simtec, to discuss the possibility of licensing the model on a project basis (rather than the annual license that EKPC likely holds). The RTSim website, https://rtsim.com/, gives no contact information.

Through Joint Intervenors' counsel, we communicated our impression that a complete set of modeling input and output files has not been provided, asked EKPC to confirm that it had produced all intended files, and if so, asked EKPC to informally confer to ensure that we were correctly understanding the contents of the files that had been produced. EKPC responded, through counsel, that it was unwilling to supplement its earlier responses with additional files and was not agreeable to a telephone conference.

6.2 Improving Model Transparency

Due to the transparency concerns outlined above, we recommend several steps that EKPC should take to improve the transparency of its next IRP, as necessary to enable independent review by Commission Staff and stakeholders alike:

1. Provide all modeling input and output files to intervening stakeholders;
2. Allow intervening stakeholders the opportunity to pursue low or no cost, project-based licenses of RTSim so that those parties to be able to execute runs;
3. Allow intervening parties the ability to access the RTSim model manual

If it is not possible for EKPC to improve model transparency while using the RTSim model, then we would recommend that EKPC engage in a collaborative stakeholder process to select a new model that would be able to provide an adequate degree of transparency. EKPC could emulate

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[55] *See supra* Section 6.1.2.

other jurisdictions that have used a collaborative process to determine which capacity expansion and production cost model to adopt. EFG has been a part of three such collaborative processes in Minnesota, with DTE Energy (MI), and with Dominion Energy South Carolina. We discuss the Minnesota and DTE processes in more detail in the following subsection.

6.2.1 IRP Model Selection in Other Jurisdictions

When the Minnesota[56] utilities sought a model to replace Strategist and System Optimizer, which were being phased out by their vendor, they decided to issue a Request for Information ("RFI") to solicit information from model vendors. Many stakeholders were also involved in this process, including the utilities, Commission Staff, the consumer advocate, and environmental intervenors and provided input on the questions to ask and the models to which the questions would be submitted. The stakeholders then evaluated those responses and selected four finalists who gave presentations to the stakeholders. The list was then whittled down to two models that were tested by each participating utility. Ultimately, the final model selected was up to each utility, but all four utilities decided to choose Anchor Power Solutions' EnCompass software.

Following its last IRP, DTE Electric conducted a modeling software collaborative that involved DTE Electric, Michigan Staff, stakeholders involved in DTE's IRP case, employees of Michigan utilities including Consumers Energy and Upper Peninsular Power Company, Xcel Energy, and a representative from Electric Power Research Institute ("EPRI"). DTE also sought to identify a new IRP model to replace Strategist. DTE hosted this collaborative as a technical stakeholder workshop over two days where all participants were able to learn about the potential models and ask questions. DTE started with nine software programs and narrowed them down to four and asked the vendors for those four programs to give presentations so that stakeholders could learn more about each software. DTE developed 33 ideal model attributes grouped into five categories including model capabilities, model transparency, functionality, value and IRP process efficiency, and "nice to have". These criteria are outlined in Table 3, below.

[56] Minnesota utilities including Xcel Energy, Minnesota Power, Otter Tail Power, and Great River Energy.

Table 3. DTE Evaluation Criteria for Software Consideration[57]

Model Capabilities
Ability to optimize to emission limits
Capable of optimizing a broad range of retirement dates
Captures accurate long-term costs of different lived alternatives
Accepts a non-linear escalation rate and negative escalation rates
Chronological model instead of using a load duration curve simplification for better renewable and storage modeling
Storage logic can handle more than once a day charging and discharging as well as long term storage modeling over weeks, seasons
Ability to tie storage charging to a specific technology
Ability to model ancillary service markets and assign benefits to specific technologies
Ability to accurately model economic reserve shutdowns (start-up cost, min down time, run time)
Model Transparency
Availability of manual to stakeholders (without a license preferred)
Provide transparency into modeling; access to software inputs, outputs (without a license preferred)
Licenses available at reasonable cost
Functionality
Ability to change the granularity (down to sub-hourly resolutions) and type of commitment logic depending on purpose of run (build plan generation or detailed dispatch)

[57] DTE Electric Company's Integrated Resource Plan Modeling Software Collaborative Summary Report at 28–29, Michigan Public Service Commission Case No. U-20471 (June 18, 2020).

Ability to run stochastics or other risk analysis on different types of runs including retirement analysis
Ability to coordinate the IRP modeling with the Distribution Operations long-term plan
Ability to optimize fuel blending
Specific storage technology properties such as degradation, storage level
Ability to design a simpler, more transparent, yet still robust approach to IRP modeling by reducing the number of software programs
Market Price forecasting
Value and IRP Process Efficiency
Best value of the cost over entire lifecycle, for DTE and stakeholders
Intuitive interface making it easy to transition from current model
Dedicated software support
Reasonable model run time
Additional server not preferred
Large user base
Nice to Have
Data visualization within the software
Straightforward error checking (messaging or other notification)
Program that may also work for other DTE modeling groups (e.g. Gen Ops)
Uncomplicated data import capabilities
Automatic reporting
Ability to track who makes the change to a database

Batch Running, ability to use macros and scripts
Easy exporting of input and outputs with no use of text files

Given that the purpose of IRP (and related) modeling is regulatory, one of the most important model characteristics is transparency. A number of jurisdictions including South Carolina, Arizona, New Mexico and others have adopted requirements that allow stakeholders to review all modeling files including model settings, access the model manual and even execute modeling runs using the same platform as the utility. This access bolsters the case record and brings greater scrutiny to the analytical work that underpins IRPs.

We recommend that EKPC utilize a collaborative approach such as the one employed by the Minnesota utilities and DTE to evaluate potential IRP model candidates. In the report that DTE issued on its collaborative, DTE stated that "DTE Electric, Software suppliers, and Michigan stakeholders had an open robust dialogue that will inform our final selection of a new IRP modeling software."[58] We believe that the kind of open and robust dialogue that was able to take place in the DTE software collaborative would also benefit EKPC in selecting a more transparent modeling software.

6.3 Supply Side Resources Modeled

Table 8-2 in the IRP provides the type of new supply side resources included for this IRP. It appears that EKPC modeled two different solar resources. One that EKPC considers an "Intermittent" capacity type while EKPC considers the other to be a "Power Purchase". We have concerns with the intermittent solar capital cost reported in Table 8-2 as well as concerns about EKPC's decision to not evaluate battery storage resources. The following subsections discuss both concerns in more detail.

6.3.1 Intermittent Solar Costs

EKPC seems to distinguish between the Intermittent and Power Purchase solar resources modeled in this IRP by saying:

[58] DTE Electric Company's Integrated Resource Plan Modeling Software Collaborative Summary Report at 4, Michigan Public Service Commission Case No. U-20471 (June 18, 2020).

Only generation added for the purpose of covering summer peak load capacity obligations is considered 'capacity' additions. All other intermittent or seasonal purchases are made to hedge the energy price exposure to the EKPC system and not to supply 'capacity' to its portfolio or the PJM system.[59]

The capital cost reported for the Intermittent Solar resources in Table 8-2 are [redacted] the sources that EKPC references for this table. The references for the capital costs[60] are noted by EKPC to be the 2021 National Renewable Energy Lab Annual Technology Baseline ("NREL ATB") and the 2021 Energy Information Administration ("EIA") Annual Energy Outlook ("AEO"). The capital cost reported in Table 8-2 is [redacted] than what was reported for the capital cost of solar in the 2021 NREL ATB and the 2022 EIA AEO.[61] The capital cost reported by EKPC in Table 8-2 is actually [redacted] the solar plus battery storage costs reported in the NREL ATB and the EIA AEO. It seems as though EKPC may not be relying on the sources that were referenced in the IRP for the capital cost of the Intermittent Solar sources. We recommend that in the absence of market data obtained through a Request for Proposals ("RFP"), that EKPC consider the Moderate or Conservative Capital Cost from the NREL ATB for new solar resources. We also recommend that EKPC update the costs of solar resources to include the impacts from the Inflation Reduction Act ("IRA").

6.3.2 Battery Storage Resources Not Evaluated

For this IRP, EKPC chose not to evaluate battery storage resources as a new supply side resource option. In the IRP, EKPC said:

Battery storage has been considered for potential pilot applications, but the limited duration and initial cost has excluded batteries at this time. As the

[59] 2022 EKPC IRP at 166 n12.

[60] Reported in 2020 dollars.

[61] U.S. Energy Information Administration, *Cost and Performance Characteristics of New Generating Technologies,* Annual Energy Outlook 2022 (Mar. 2022), https://www.eia.gov/outlooks/aeo/assumptions/pdf/table_8.2.pdf

technology continues to develop and mature, EKPC anticipates further research and possible consideration of battery capacity as part of the resource portfolio.[62]

EKPC's rationale for not including battery storage resources is surprising, given the significant cost declines and technological advancements that have taken place. It is not uncommon for utilities to be evaluating four-hour or longer duration battery storage resources as part of IRP modeling. The PJM Interconnection Queue[63] indicates that several battery storage projects are in the queue and seek to interconnect to EKPC's transmission system.

We recommend that EKPC include battery storage resources as part of the new supply side resource options. If market price data is not available, then we recommend that EKPC model battery storage resources using the most recent NREL ATB version. We also recommend that EKPC include the impacts of the IRA, which allow standalone battery storage projects to receive the Investment Tax Credit ("ITC").

6.4 Emission Costs

In the response to Joint Intervenors' Initial Request 44 on how the Guidehouse carbon prices were incorporated into the IRP modeling, EKPC stated that "The Guidehouse carbon prices were utilized in the Demand Side Analysis, as well as ensuring that the market costs developed from those scenarios were encompassed in the RTSim iterations."[64] The IRP narrative did not provide a discussion on how emission costs were incorporated into the model. The output file provided in response to Joint Intervenors' Initial Request 40 indicates that a cost was modeled for an emission labeled as "COx" in the modeling file. It did not appear that this cost was included in the total system cost, but it is not clear how this cost influenced the RTSim model. We typically see emission costs modeled as either a dispatch adder, that is included in the cost of operating the unit, or as an externality cost that is added to the Present Value of Revenue Requirements ("PVRR") as a post-processing adjustment. The IRP narrative indicated that Guidehouse had prepared four different carbon price forecasts. Since we were only provided with one modeling file, it was not clear if the emission costs included in the modeling file

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[62] 2022 EKPC IRP at 58.

[63] New Services Queue, PJM (last visited Oct. 11, 2022), https://www.pjm.com/planning/services-requests/interconnection-queues.aspx.

[64] Response to Joint Intervenors' Initial Request 44.

corresponded to the Guidehouse forecasts. We recommend that EKPC provide a clearer discussion of how emission costs are incorporated into the modeling.

It is also not clear why a cost was not assigned to the NOx emissions in the model. This would have been especially important for EKPC's coal units. Figure 12 below shows the annual NOx emissions from EKPC's coal plants.

[redacted]

Figure 12. NOx Emissions (lbs) from EKPC Coal Plants[65]

[redacted]

[redacted]

Current NOx allowance prices have risen significantly in reaction to an increase in gas prices, which has made coal more economic and driven up demand for allowances, as well as in reaction to a proposed update to EPA's NOx rule.[66] Even if EKPC is not short allowances itself,

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[65] Response to Joint Intervenors' Initial Request 40.

[66] Thomas Hancock, *2022 ozone season NOx prices rise with natural gas prices*, S&P Global (July 14, 2022), https://ihsmarkit.com/research-analysis/2022-ozone-season-nox-prices-rise-with-natural-gas-prices.html ; *e.g.*, Direct Testimony of Mark Valach at 7, WV PSC Case No. 22-0793-E-ENEC, *Monongahela Power Company and The Potomac Edison Company's Petition and General Investigation to determine reasonable rates and charges on and after January 1, 2023* (Aug. 25, 2022) (explaining that the cost of NOx allowances "has increased from approximately $150/credit in 2020 to $40,000/credit as of today").

dispatching NOx emitting units represents an opportunity cost and therefore it makes sense to include NOx emissions costs in its modeling.

6.5 Modeling the PJM Installed Reserve Margin versus the Forecast Pool Requirement

PJM performs an annual Reserve Requirement Study to develop the following year's planning reserve margin requirement, or the Forecast Pool Requirement ("FPR").[67] Table 4 below shows the Recommended FPR from the 2021 Reserve Requirement Study. For the modeling performed for the 2021 IRP, EKPC has developed its reserve margin requirements based on the numbers reported in the "Recommended IRM" column of the table. The "Recommended FPR" column reflects the IRM adjusted for the Equivalent Forced Outage Rate Demand ("EFORd").

Table 4. PJM 2021 Reserve Requirement Study Summary Table[68]

RRS Year	Delivery Year Period	Calculated IRM	Recommended IRM	Average EFORd	Recommended FPR
2021	2022 / 2023	14.93%	**14.9%**	5.08%	**1.0906**
2021	2023 / 2024	14.76%	**14.8%**	5.04%	**1.0901**
2021	2024 / 2025	14.68%	**14.7%**	5.02%	**1.0894**
2021	2025 / 2026	14.66%	**14.7%**	5.02%	**1.0894**

The IRM is higher than the FPR because, just as the accredited value of a generator is discounted for its forced outage rate, the PRM is correspondingly lower as well. It's much more difficult to understand EKPC's capacity position relative to its obligations when planning is done on a partial or fully ICAP basis. We recommend that EKPC model the FPR instead of the IRM so that EKPC's planning most closely aligns with PJM's resource adequacy requirements.

When asked about this approach, EKPC stated that:

> *Thermal units are modeled in RTSim with their installed capacity and the expected forced outage rate. The model makes many iterations to develop a robust expectation of production costs. Each iteration takes a draw for forced outages to reach the expected percentage value for the year. In one draw, an*

[67] FPR = (1+ IRM) * (1-EFORD)

[68] PJM, *2021 PJM Reserve Requirement Study*, tbl. I-1 (Oct. 12, 2021), 2021-pjm-reserve-requirement-study.ashx.

> *outage might occur during winter peak conditions, in another iteration, an outage might occur in the summer, and so forth. By placing the forced outage rate and installed capacity in the model a more accurate view of potential production cost scenarios are developed. If the unforced capacity value (UCAP) is used then all hours of the year have reduced capacity available. That is not reflective of how the system is actually operated.*[69]

Most other IRP models have the ability to distinguish between a unit's nameplate and its accredited capacity so that the accredited capacity does not unduly influence the dispatch of that unit. This may be another consideration for EKPC to weigh as it explores using a different modeling tool.

6.6 Modeling Winter Peak versus Summer Peak

Further, EKPC does not appear to be modeling the summer peak.[70] The reserve requirement projected in the IRP does not match the system peak in the Cooperative's modeling output files. The data in the Cooperative's modeling files more closely approximates the data from EKPC's internally produced forecast for the winter peak. For example, in EKPC's modeling output file the forecasted system peak for 2025 is [redacted].[71] However, EKPC forecasts its summer peak to be 2,613 MW in 2025.[72] Without greater transparency in its modeling, it is difficult to know if EKPC is considering the appropriate reserve margin or target in its planning.

EKPC states that it based the reserve requirement on PJM's reserve margin, which is based on the summer peak.[73] We recommend EKPC model the PJM summer reserve requirement, in future IRPs. EKPC is a winter peaking utility and a sensitivity that considers meeting the winter peak load with existing capacity may be informative for EKPC and stakeholders. However, as a member of PJM, and as EKPC states in the IRP, leveraging the difference between its summer

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[69] Response to Joint Intervenors' Supplemental Request 47.

[70] As a member of PJM, EKPC is responsible for its pro-rata load share of the system's summer coincident peak. Leveraging the diversity between PJM's system peak and a member utility's non-coincident peak is a part of the PJM value proposition.

[71] Response to Joint Intervenors' Initial Request 40.

[72] 2022 EKPC IRP at 170.

[73] *Id.*

peak and winter peak within the framework of PJM is a significant portion of the PJM value proposition for EKPC's customers.

6.7 Level of Owned Versus Purchased Generation

Based on the information presented in Tables 8-8 and 8-10 in the IRP and our review of the modeling output file, it appears that EKPC's Preferred Plan is projecting higher forecasted energy requirements, a decline in EKPC's existing generation, and an increase in market purchases over the planning period. Table 5 shows the monthly modeled capacity factors for Cooper Station 1 and Cooper Station 2 which shows the [redacted] capacity factor for both units. [redacted]

Table 5. Cooper Station Modeled Monthly Capacity Factors[74]

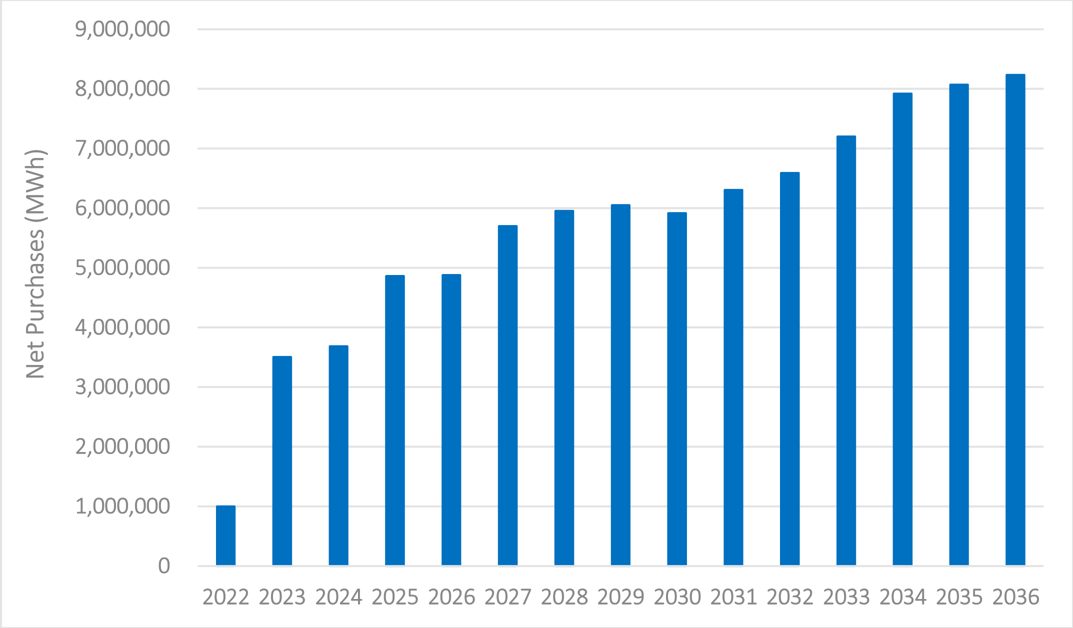
[redacted]

[74] Response to Joint Intervenors' Initial Request 40.

[redacted]

In combination with the [redacted] in the operations of the Cooper units, EKPC is forecasting higher energy requirements, which means that EKPC expects that a decreasing proportion of its needs will be met by its own generation. In order for the model to meet the energy requirements and not have any shortfall periods, the model purchases more energy from the market. Figure 13 shows the modeled net purchases for EKPC over the planning period, which indicates an increasing level of market purchases.

Figure 13. EKPC Modeled Net Purchases (MWh)



In response to Joint Intervenor Request 49, EKPC stated, "EKPC hedges its exposure to high market prices by ensuring it has adequate resources to cover its load. When the market prices are lower than EKPC's resources, then EKPC purchases from the market and its resources are not dispatched. When the PJM market price is higher than the EKPC resources, then the EKPC generating resources are dispatched into the market. This allows the EKPC owner-members to be hedged against the high market prices."

But EKPC does not seem to have considered the option of a different mix of generators to supply a great proportion of energy needs even under its expected case energy prices. This is a missed opportunity to understand the possibilities to reduce cost risk for its owner-members and their retail customers.

6.8 Modeled Costs for Thermal Generators in RTSim

Our review of the modeling output file provided in response to Joint Intervenors' Initial Request 40 indicated that the fixed operations and maintenance ("Fixed O&M") and capital expenditures were not included as a separate cost from Variable O&M in the RTSim model. When asked about this in Joint Intervenors' Supplemental Request 50f, EKPC said "The dispatch of units is driven by only variable costs. Fixed costs are incurred regardless of amount of run time. The fixed costs are considered when looking at new resources but not existing resources."[75] While EKPC's response is accurate in that fixed costs do not influence the dispatch, the fixed costs and projected capital expenditures are important to accounting for all the costs of a unit to evaluate the economics of the unit. Figure 14. Cooper Station Projected Fixed CostsFigure 14 shows the projected fixed O&M cost for the Cooper Station units throughout the planning period based on the Fixed O&M cost that EKPC reported for each unit in the IRP.

In the evaluation of the economics of a utility's existing resources, we recommend that the utility have all of the costs associated with the unit, including fixed O&M and capital expenditures, accounted for in the IRP model. These are critically important inputs into the total system cost typically evaluated in an IRP.

[redacted]

Figure 14. Cooper Station Projected Fixed Costs[76]

[redacted]

[redacted]

[75] Response to Joint Intervenors' Supplemental Request 50f.

[76] 2022 EKPC IRP at 104.

6.9 Commitment to Addressing Changed Circumstances

The dynamics of energy prices and the unusual state of the U.S. economy, make long-term predictive analyses like IRPs difficult to keep relevant. That is why it's particularly important for utilities to react dynamically to changed circumstances. The Inflation Reduction Act is an important and sweeping modification to the energy landscape and leveraging its tax incentive, direct pay, and rebate provisions could bring significant benefits to the customers of EKPC's member cooperatives. As such, we were disappointed to see EKPC's response to Joint Intervenors' Supplemental Request 30b, which stated that "EKPC utilized the data known at the time for this filing. New data [such as direct pay tax incentives] will be reflected in future filings." We would prefer to see an indication from EKPC that it is talking to the Kentucky Office of Energy Policy about the rules that would need to be written to enable the state to take advantage of certain IRA provisions, that it is planning to reevaluate all its supply-side options given the impact of the IRA provisions on its recently issued RFP,[77] etc. It may be that EKPC merely interpreted Joint Intervenors' Supplemental Request 30b narrowly and is doing those things. If so, we would welcome that clarification as well as an understanding of how that work can be made transparent to the stakeholders in this docket.

7. Developing a "Final Plan"

Very little information is provided about any of EKPC's evaluated plans. Section 8.0 does not allow the reader to compare plans on the basis of cost, emissions, or any other common metric. It leaves the Cooperative's approach to developing a final plan very opaque indeed. Any IRP ought to be supported by robust and well-reasoned analysis that is well explained and well-documented—particularly in response to discovery questions. An IRP's purpose is both internal and external and if independent review of the IRP cannot be conducted, particularly in the regulatory context, it's very difficult to ascertain whether the preferred plan represents the least cost and least risk option for the utility.

[77] Response to Joint Intervenor Supplemental Request 56.

As EKPC noted in its IRP, the Staff's report on its prior IRP directed EKPC to:

> *provide more robust and detailed explanations of the modeling results between the demand side and supply-side modeling. For example, as brought out in the Hearing, the differences between the peak load demand forecasts in Table 3-19 and those used as supply-side inputs in Table 8-6, are well reasoned, but not obvious. In addition, there should be more discussion of specific steps taken by the models to ultimately obtain a preferred least cost plan, the interactions between the RTSim models, and tying results listed in tables to discussions more closely.*[78]

In response to this recommendation, EKPC states that it "has provided all of its data and the sources of that data in the appropriate sections throughout the IRP. EKPC has also discussed its view of uncertainty in appropriate sections throughout the IRP. The RTSim model is discussed in the Integrated Resource Planning section."

In our view, the data provided do not meet the spirit of the Staff's recommendation. For example, the IRP lacks a "discussion of specific steps taken by the models to ultimately obtain a preferred least cost plan." The IRP merely states that five plans were created and evaluated in RTSim.[79] However, none of these plans were EKPC's preferred plan, a fact that is not explicitly stated in the IRP. EKPC lightly alludes to this by saying "These five plans were reviewed to determine if the operation dates of the near-term resources were in fact achievable based on recent experience."[80] In response to Staff's Supplemental Request 27b, EKPC adds some clarification, saying that "The top plan as determined by the Resource Optimizer was the foundation for the creation of the optimal plan. Review of the top plans, and the inclusion of the EKPC Sustainability goals, was performed to provide the final plan." However, when asked to provide documentation of this process, EKPC said:

> *All five top cases show a need for a Seasonal Purchase, see Table 8-4 on page 167 of the IRP. All five cases show a need for a Peaking Resource in the 2032 to 2034 time frame. Four of the five cases show one or more intermittent resources as being economic.*
>
> *EKPC took those results and compared the needs for the system based on seasonal peaks and existing resources, as shown on Table 8-6 on page 170 of the*

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[78] 2022 EKPC IRP at 57.

[79] 2022 EKPC IRP at 167.

[80] 2022 EKPC IRP at 169.

IRP. When the economic resources were supplied to meet peak load and sustainability requirements, the resultant plan is shown on Table 8-7 on page 171 of the IRP. There are no spreadsheets associated with the process as it is housed within RTSim and related simple ".txt" input and output files. [81]

Whether the final plan is a result of the RTSim modeling or some other, external criteria, it is good practice to fully document that plan. This includes describing in more detail, within the IRP, the steps that were taken to develop the final plan and the analytics behind the plan development. EKPC's response to Staff's Supplemental Request 12a is significantly more descriptive of its process of developing the final plan. There, Staff's Supplemental Request drew out the specific EKPC Sustainability Goals applied to the plans selected by the model to reach the "final plan":

The EKPC Sustainability Goals for Energy and the Environment are:

a. Transition to cleaner resources:

i. 10% energy from new renewables by 2030

ii. 15% energy from new renewables by 2035

b. Reduction in greenhouse gases:

i. 35% reduction in total carbon dioxide emissions by 2035

ii. 70% reduction in total carbon dioxide emissions by 2050

…

The EKPC Sustainability Goals were only applied to the final plan.

…

Four of the top five plans shown on page 167 of the IRP indicate that the

Intermittent Resource (i.e. solar PPA) was an economic alternative chosen by the optimizer. Based on the fact that the optimizer chose the solar PPAs solely on economics, EKPC then took those resources and applied them to match the timing needed to also meet its sustainability goals. Specifically, the percentage

[81] Response to Joint Intervenor s' Supplemental Request 51a-d.

amount of renewable energy that was targeted to be supplied throughout the plan. [82]

Even if all these steps could be captured in RTSim, which would be unusual, that documentation was not provided as discussed in Section 6 of this report. The single output file given by EKPC only corresponds to the final plan[83] and not to any of the other runs conducted. This makes it difficult for stakeholders to fully vet the Cooperative's modeling results.

In addition, the IRP does not address Staff's Recommendation of "tying results listed in tables to discussions more closely." For example, it's not obvious that Table 8-7, reproduced below, contains the same plan as the "Final Plan" in Table 8-5 because it's not clear what is meant by "energy additions."

Figure 15. Reproduction of "Table 8-7 EKPC Projected Additions and Reserves (MW)"

Year	Energy Additions	Base Load Capacity Additions		Peaking/ Intermediate Cap. Additions		Total Capacity		Reserve Requirements[13]		Reserve Margin	
		Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum
2022	100					3,434	3,136	0	75	4%	25%
2023	110					3,434	3,198	0	77	2%	22%
2024	200					3,434	3,318	0	78	2%	20%
2025						3,434	3,318	0	78	2%	20%
2026	200					3,534	3,438	0	79	1%	19%
2027	200					3,534	3,558	0	79	1%	19%
2028						3,534	3,558	0	80	0%	18%
2029						3,534	3,558	0	80	0%	17%
2030						3,534	3,558	0	80	0%	17%
2031	200					3,534	3,678	0	81	0%	16%
2032[14]	200			225	170	3,659	3,968	0	81	5%	22%
2033						3,659	3,968	0	82	5%	21%
2034						3,659	3,968	0	82	4%	20%
2035						3,659	3,968	0	83	4%	19%
2036						3,659	3,968	0	83	3%	19%

Further, a number of tables are included but never discussed, such as Tables 8-3 (which is also exactly the same as Table 8-7) and 8-5.

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[82] Response to Staff's Supplemental Request 12.

[83] Response to Joint Intervenors' Supplemental Request 50a.

8. Behind the Meter Generation

While not as frequently the subject of economic evaluation in IRPs as energy efficiency, behind the meter ("BTM") generation and in particular distributed solar and battery storage may have the ability to play an important role in the Cooperative's resource mix, ought to have been evaluated here, and should be evaluated in future IRPs. Section 6.0 on Transmission and Distribution Planning notes that EKPC plans certain distribution substation improvements to "meet growing member demand in certain areas, enhance system reliability, and improve the efficiency of the system." Where those improvements are intended to accommodate growing demand, we would encourage EKPC to consider non-wires alternatives[84] ("NWA") to those upgrades as a more cost-effective option for its members. NWA options would include energy efficiency and demand response as well as between the meter generation and storage.

Furthermore, FERC Order 2222 and PJM's compliance filing in response to that order pave the way for distributed energy resources to participate in PJM's energy, capacity, and ancillary services markets, which open up new pathways to compensate those resources.

Distributed solar and battery storage resources also have a potential role to play as a community-based resource to help address energy affordability for low-income customers. Projects less than 5 MW in size and serving eligible communities qualify for a bonus adder to the PTC or ITC.

In addition, there are a number of tools available, such as NREL's D-Gen model, that would allow EKPC to create supply curves of distributed solar and their associated incentive costs. That curve can be offered to the IRP model as one of many resources to choose from.

Distributed solar may also offer complementary benefits to the utilities' system in the form of increased bulk level reliability and the ability to shave the summer peak.

In future IRPs, DERs, including customer-owned generation, should be evaluated alongside conventional supply-side and demand-side resources, on an equal footing, and treated as legitimate resources for meeting energy and capacity requirements. This analysis should include scenarios in which net metering is permitted to expand beyond the 1% threshold. As the utilities have the discretion under statute to allow net metering to continue beyond the 1%

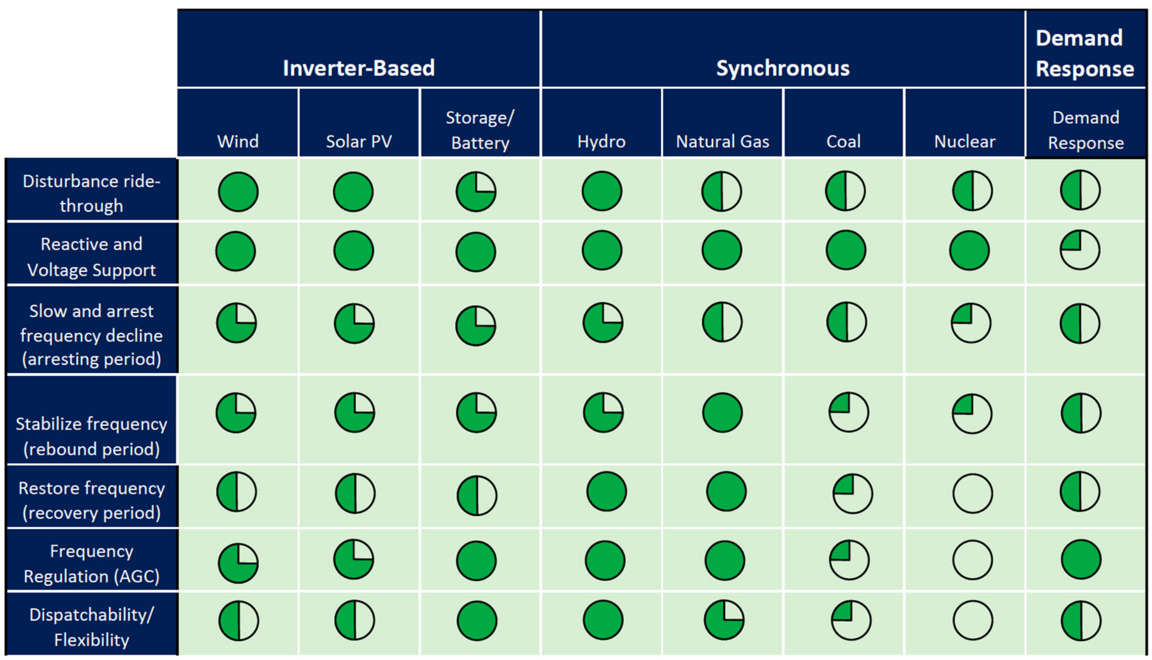
[84] *See e.g.*, Brenda Chew et al., N*on-Wires Alternatives: Case Studies from Leading U.S. Projects*, E4TheFuture (Nov. 2018), https://e4thefuture.org/wp-content/uploads/2018/11/2018-Non-Wires-Alternatives-Report_FINAL.pdf (several case studies of non-wires alternatives):

threshold, this should be evaluated as a potential opportunity to help EKPC to meet its customers' needs at the lowest cost.

9. Grid Services and Resource Adequacy with Increasing Renewables

As increasing levels of renewables are added to the grid, there can sometimes be misconceptions about the impact of those resources on grid operations and on resource adequacy. On the operational side, renewables generally represent an opportunity to enhance grid services. For example, inverter-based resources can provide reactive power through their power electronics even when they are not operating, something that most synchronous generators are not capable of – they must be committed and dispatched to provide this service.

Figure 16. Summary of Grid Services by Technology Type[85]



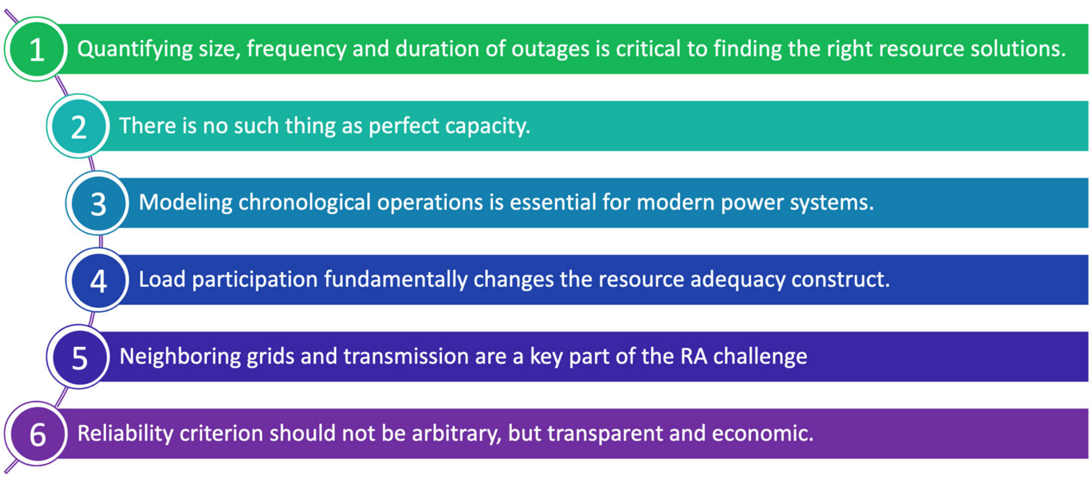
[85] Michael Milligan, *Sources of grid reliability services,* The Electricity Journal, at tbl. 1 (2018), https://reader.elsevier.com/reader/sd/pii/S104061901830215X?token=81116DED9291AD176607AD9CFE3582CA7CF6F3EC82EE4F9A7AB1E78559914CF133FBD230B38EFD33E5F6C00FE4B8B6F8&originRegion=us-east-1&originCreation=20220929173601

Notably, Figure 16 was created before the adoption of grid-forming inverter technology which can help provide other grid needs not listed in this figure such as black start capability and short circuit strength.

Higher penetrations of variable energy resources (primarily wind and solar) change the risks to the electrical system and necessitate different approaches to ensuring reliability and resource adequacy. On the reliability front, utilities and grid operators have used enhanced flexibility (battery storage, improved generator flexibility, etc.), revamped approaches to acquiring system services (such as using automatic generation control systems, incentivizing frequency and voltage support when needed, etc. and improved renewable forecasting to ensure reliability as risk periods change.[86]

On the resource adequacy ("RA") front, new evaluation approaches are needed not merely because the generator mix is changing but because the climate is changing as well. RA analyses now need to contend with correlated events such as weather induced thermal generator outages and renewable production impacts as well as more extreme events such as flooding or extreme cold. Ideally, those analytical approaches will follow these principles articulated by the Energy Systems Integration Group in Figure 17.

Figure 17. Six Principles for Modern Resource Adequacy[87]



[86] Energy Systems Integration *Group Reliability in Power Grids with High Levels of Wind and Solar*, https://www.esig.energy/wp-content/uploads/2020/06/Maintaining-Reliability-in-Power-Grids-with-High-Levels-of-Wind-and-Solar-2.pdf.

[87] Taken from Telos Energy, *Redefining Resource Adequacy for Modern Power Systems*, at 15 (May 26, 2021), https://pubs.naruc.org/pub/3D827A62-1866-DAAC-99FB-47C1762CAC55.

Some key principles to highlight include the first principle in this chart. In order to right-size the resources acquired to address anticipated shortfalls it is important to understand what those loss of load events look like. Are they long duration or just a few hours? Are they likely to occur in the winter or summer? Do they occur under many weather years or just a handful? Electrical systems are not typically planned to be perfectly adequate because acquiring that level of reliability is very expensive. And even those utilities operating in RTO footprints can make decisions about whether to acquire capacity in reaction to potential reliability risks. The second principle is an important reminder that all capacity is at risk of failure or being unavailable, no technology is capable of ensuring reliability all the time. The fourth principle is easily overlooked, but load and the activities to reduce load such as energy efficiency and demand response are all weather dependent. Typically in resource adequacy analyses, load varies with weather but demand-side reduction does not despite its important contribution to reliability. And oftentimes, flexible loads are not even explicitly modeled in resource adequacy studies. The sixth principle is an important one – reliability has a tradeoff with cost and decisions about acquiring more or less reliability should be transparently made in concert with its effects on system cost.

10. DSM

10.1 Summary of Key Findings

1. EKPC proposes a DSM portfolio that is far less than the potential study found to be cost-effective. Essentially failing its customers by not maximizing its achievement of cost-effective energy efficiency and the much-needed benefits.
2. EKPC projects that it will obtain significant portfolio savings from residential efficient lighting; however, increased federal lighting standards will preclude reporting of the majority of planned savings for lighting.
3. EKPC fails to propose any commercial energy efficiency or demand response programs, including small business programs. This results in unnecessary constraint on supply side resources.
4. EKPC's Heat Pump Retrofit program relies upon measures that are considered the federal minimum efficiency, leaving limited to no savings for customers.
5. EKPC should offer a comprehensive pathway for its home retrofit programs to encourage deeper savings through the combination of air and duct sealing, insulation, heat pump retrofit, and demand response wi-fi thermostats.
6. EKPC should offer multiple pathways under the energy audit program to support the IRA eligibility requirements.
7. EKPC lacks sufficient marketing and customer awareness about the benefits of energy efficiency and its DSM programs.

10.2 Overview of DSM Programs

EKPC's 2022 demand side management ("DSM") portfolio for the IRP proposes seven energy efficiency ("EE") programs and one demand response ("DR") program. EKPC's portfolio was developed from an EE and DR market potential study ("MPS"), conducted by GDS Associates, Inc, for EKPC's service territories over a 15-year period from 2021 through 2036. The MPS assessed the potential to reduce electric consumption and peak demand through the implementation of DSM program for residential, commercial, and industrial facilities. Utilizing an annual budget of $3 million for residential energy efficiency, EKPC developed its participation estimates and conducted a cost-effectiveness analysis using the Total Resource Cost ("TRC") test.

The portfolio, designed solely for residential customers, is projected to cost $63.8 million (2022$). There are no commercial programs included as part of EKPC's DSM portfolio. By 2036, the 15-year program period, the residential portfolio is projected to reduce energy usage by 110,151 MWh and lower winter and summer peak load by 29.9 MW and 48.6 MW, respectively. Overall, the portfolio of programs is projected to be cost-effective, with only one program, Residential Energy Audit, projected to have a total resource cost ("TRC") ratio less than 1.0.

Table 6. EKPC Proposed DSM Programs

Customer Class	Program Name	Program Description
Residential	Button-Up Weatherization	Incentives provided for the installation of insulation and air sealing measures
Residential	CARES – Low Income	EKPC provides up to $2,000 per households to Community Action Agencies to leverage funding for weatherization and heat pumps to qualified homes
Residential	Heat Pump Retrofit	Rebates for the installation of heat pumps which targets homes with electric resistance heating

Residential	Touchstone Energy (TSE) Home	Rebates for new home construction built to a Home Energy Rating System ("HERS") Index of 75 or lower than the Kentucky standard new home (HERS Index of 105)
Residential	ENERGY STAR Manufactured Home	Incentives provided to members who install a new manufactured home that meets Energy Star requirements
Residential	Residential Energy Audit	An online audit which analyzes energy usage and makes recommendations to lower energy. Those who complete the audit receive LEDs through the mail
Residential	Residential Efficient Lighting	LEDs provided to customers through Annual meetings or the Residential Energy Audit
Residential	Direct Load Control – Residential: AC Switch or Bring Yor Own Thermostat	Incentives provided to customers who enroll their central air conditioner unit or hot water heater into the peak shaving program

10.3 Federal Lighting Standards

Recommendation: Eliminate LED bulbs from the residential portfolio. Allocate funds to a comprehensive in-home audit program and expansion of measures under the Button-Up Weatherization program and incentive provided under the Heat Pump Retrofit Program.

EKPC reports significant lighting savings from its Residential Efficient Lighting Program and Residential Energy Audit Program. The former program provides members with rebates for qualified light-emitting diode ("LED") purchases and the latter mails LED bulbs to members who complete an online energy audit. Additionally, LED bulbs are provided to members that attend their respective cooperative's annual meeting, with the savings claimed under the DSM portfolio.[88]

However, on April 26, 2022, the United Stated Department of Energy ("DOE") adopted new rules for general service lamps ("GSLs) which require nearly all screw-based bulbs to meet the minimum efficiency standard of 45 lumens per watt.[89] Non-compliant bulbs can only legally be sold until July 2023, at which point enforcement actions will be taken. These rules eliminate the halogen and incandescent baseline for lighting savings calculations. As a result, LED bulbs will become the residential baseline, eliminating energy savings reductions that can be claimed by residential energy efficiency programs.

The GDS 2021 market potential study ("MPS"), which EKPC based its portfolio forecasts on,[90] was completed prior to the implementation of the lighting rule changes and therefore it is understandable that the MPS did not consider the impact. However, EKPC should adjust its portfolio to reflect these changes. EKPC will not be able to claim the lighting savings after July 2023 and therefore should not provide lighting rebates or offer LED bulbs through any of its programs after that date.[91]

Per EKPC's Response to Joint Intervenors' Supplemental Request 9c, EKPC recognizes that once a technology becomes the baseline, it will result in a program with a high rate of free ridership, which in turn is "an inefficient allocation of resources." Therefore, funding currently allocated for residential lighting measures should be reallocated to the other programs. The funding should be reallocated to a revised and enhanced version of an in-home energy audit program, that provides expanded measures and rebates like those in the Button-Up Weatherization program. This recommendation is further discussed in the next two subsections of the report.

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[88] Response to Joint Intervenors' Initial Request 10.

[89] *Energy Conservation Program: Backstop Requirement for General Service Lamps*, 86 Fed/ Reg. 70775 (Dec. 13, 2021), https://www.federalregister.gov/documents/2021/12/13/2021-26807/energy-conservation-program-backstop-requirement-for-general-service-lamps.

[90] 2022 EKPC IRP at 4.

[91] The one exception to the claiming savings from LED bulbs is for direct install provided through an income qualified program; however, the claimed savings from such efforts should be limited to one year of savings. However, it is my understanding that the program does not offer LEDs under an income qualified program.

It is important to allocate the LED funds to efforts that provide deeper, comprehensive savings as it can reduce administrative costs while rendering higher savings opportunities. This is necessary as the LED program is highly cost-effective, with a projected TRC of 3.93, and contributes meaningfully to the DSM portfolio's overall cost-effectiveness. Therefore, to continue a cost-effective portfolio, deeper savings per project must be obtained.

10.4 Heat Pump Retrofit Program

Recommendation: Promote heat pump technology that is above the minimum efficiency standard and align it with the new federally recognized efficiency rating system. Expand rebates to a tiered structure to encourage adoption of various heat pump technology options, including heat pump water heaters.

In 2021, the Heat Pump Retrofit Program offered tiered rebates for heat pumps with a seasonal energy efficiency ratio ("SEER") of 14 and 15 when replacing electric resistance heat and a central air conditioner. EKPC plans on continuing these tiered incentives for the same efficiency ratings in its 2022 DSM portfolio. While we strongly support this program concept, we have concerns with the program's design that should be addressed.

1. An air conditioner or heat pump with a rating of SEER 14 is the lowest efficiency rating that complies with minimum federal standards in the south. Therefore, for several years, EKPC has been claiming savings for units that are considered standard and would have been purchased without the incentive because there is not a less efficient option.
2. The SEER 14 and 15 heat pump efficiency levels are lower than those modeled in the MPS. GDS considered the costs and savings associated with the adoption of a 16 or 17 SEER heat pump from the current federal efficiency standard of 14 SEER for air conditioners, heat pumps, and packaged units.[92]
3. In 2023, the federal efficiency standard for residential cooling will increase from 14 SEER to 15 SEER for air conditioners and heat pumps, 14.5 for packaged units and air conditioners exceeding 45,000 BTU/hour.

[92] Technical Appx. Vol. 2, Ex. DSM-1, Appendix A-1 Residential Measures Detail.

4. In 2023, the rating system will transition from SEER to SEER2. The current rating system, SEER, measures the total cooling capacity during normal periods of operations by the total energy input and as such, the higher the SEER the less electricity is required. The SEER2 rating, developed in 2016, is more stringent than the SEER rating as it raises the external static pressure testing conditions to more closely replicate a real world, typical ducted system.

The proposed heat pump rebates would be for minimum efficiency equipment that would result in limited to no savings for EKPC's customers. Energy efficiency programs should be designed to encourage participants to choose measures that are more efficient than the baseline (federal, state, and local regulations) because that will save them money on their electricity bills while also reducing system operating costs. Incentives should be large enough to help customers afford the more expensive high efficiency equipment.

The heat pump retrofit program should continue to offer tiered incentives, but beginning at the SEER2 equivalent of a 16 SEER heat pump, as was modeled in the MPS. Furthermore, there should be tiered incentives established for the various types of heat pump equipment as the project costs can vary based upon the technology. This includes centrally ducted heat pump systems, ductless single zone heat pumps, ducted/ductless multizone heat pumps, ground source heat pumps, and should be expanded to include heat pump water heaters. Additionally, the program should be co-promoted with the demand response efforts through the installation of Wi-Fi-enabled thermostats.

The Heat Pump Retrofit program should be coordinated and offered along with the Residential Energy Audit and the Button-up Weatherization programs. While members should have the option to participate in any of the programs, establishing a comprehensive pathway will encourage members to take advantage of the many residential energy efficiency and demand response offerings. In-home audits can include savings through the installation of direct install measures, such as air sealing and duct sealing, during the first visit while also identifying incentives opportunities for insulation to reduce air leaks and encourage the installation of properly sized heat pump equipment. Combining these program efforts, especially from the customer perspective, can allow for comprehensive and deeper savings, that would otherwise not be addressed. Furthermore, the Button-up Weatherization program should include duct sealing and extend its insulation rebates for ceiling insulation to also include wall and basement ceiling insulation, as well as an option for a demand response enabled wi-fi enabled smart thermostat.

10.5 Residential Energy Audit Program

Recommendation: Eliminate LED bulbs as part of the online energy audit. Provide an in-home energy audit program with direct install measures such as air and duct sealing with the option for incentives related to insulation and heat pump technology.

The Residential Energy Audit Program can be an excellent program to help members understand the importance of energy efficiency in the context of their own home. However, the program is only offered online, resulting in an expensive marketing effort that is leaving potential savings opportunities on the table. In 2021, the program had 34 online participants at a cost of $133,000, equivalent to $3,912 per participant. While the online audit does mail LED bulbs to participants, as mentioned above those savings will be minimal going forward.

The online audit can still be continued as a marketing tool; however, no LED bulbs should be mailed. Additionally, the program should be transitioned to provide in-home audits, including for manufactured homes. To offset the cost of the in-home audit, direct install measures such as air sealing and duct sealing can be offered. The audit can identify rebate opportunities for insulation, heat pumps, and heat pump water heaters. Providing in-home audits can identify and lead to significant per home savings, in addition to offering a personalized experienced for participants and grow the audit industry. As discussed further below, expansion of the audit program will positively impact economic development throughout the service territory. The MPS identified that the leading savings potential, approximately 40 percent, comes from HVAC shell (air sealing, duct sealing, and insulation) and the HVAC equipment.[93]

To increase cost-effectiveness of this effort, program eligibility could be targeted to high energy use homes and/or target older homes. To be clear, this does not mean that other homes should be excluded, rather EKPC and the owner-members should concentrate marketing efforts to homes or neighborhoods which meet these criterions. Another way to increase savings opportunities is to require an audit be completed for behind-the-meter solar, combining two programmatic efforts.

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[93] Technical Appx. Vol. 2, Ex. DSM-1 EKPC 2021 Potential Study, Figure 4-4 Residential Potential by End-Use and Building Type – RAP 2036.

10.6 Demand Response

Recommendation: Expand the residential demand response program to include opportunities for small businesses. Actively promote the interruptible rate tariff to commercial customers. If interruptible rate has a continued lack of interest, it should be revised to promote participation.

The MPS indicates that there is potential for EKPC to reduce its forecasted demand by 430 MW over a 15 year period through a comprehensive residential and commercial demand response effort.[94] Investing in this level of demand response would require an investment of $68 million over the 15 year period; however, it would produce benefits of more than $470 million in that same time frame, producing a TRC ratio of 6.94.[95] This indicates that demand response could serve as a cost-effective alternative to supply. While projected to be highly cost-effective, the level of total demand response savings actually proposed by EKPC is grossly anemic compared to the level identified in the MPS. Most of the demand reduction cannot be realized as there are no commercial demand response programs available or planned. Second, the residential demand response portfolio excludes cost-effective demand reduction opportunities related to critical peak pricing and electric vehicle charging.

In 2021, the residential demand response program had a total of 31,464 participants, with a potential summer demand reduction of 25.6 MW. This is almost equivalent to the RAP demand reductions identified from direct load control devices. Therefore, the residential demand response portfolio should be expanded to include tariff efforts related to time-of-use pricing strategies such as critical peak pricing and for electric vehicle charging. Shifting demand use to other periods can be extremely effective in reducing supply side constraints and costs. Per EKPC's Response to Joint Intervenors' Supplemental Request 8, EKPC and its owner-members are considering piloting an electric vehicle charging pilot. This should be included as part of is DSM portfolio.

There are two commercial opportunities that EKPC should implement to reduce demand. First, leveraging the residential system, EKPC should offer small businesses the opportunity to participate in the direct load control thermostat and water heater programs. EKPC identified

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[94] Technical Appx. Vol. 2, Ex. DSM-1 EKPC 2021 Potential Study Table 6-7 Demand Response MAP & RAP Potential – Residential Programs and Table 8 Demand Response MAP & RAP Potential – C/I Programs.

[95] Technical Appx. Vol. 2, Ex. DSM-1 EKPC 2021 Potential Study RAP scenario provided in Table 6-9 NPV Benefits and Costs MAP & RAP Demand Response Potential – 2036.

that it does not currently offer this because it "feels this could be confusing and potentially frustrating to many commercial members."[96] However, this can easily be avoided by providing targeted marketing to those on a specific tariff and including marketing that explicitly states what is eligible. This exact opportunity is offered throughout the country by utilities. Furthermore, the level of cost-effective demand reduction from this commercial sector will likely offset the marketing costs and will leverage the same system currently implemented for the residential demand response effort, effectively lowering the cost per customer.

A second opportunity for commercial demand response is through an interruptible rate, which could reduce demand by almost 300 MW per the MPS.[97] EKPC offers Rate D Interruptible Service as a rider to all rates, which provide a per kilowatt demand monthly bill credit for customers that respond within thirty minutes to the interruption notice.[98] The level of the demand credit is based upon the annual number of hours of interruption. EKPC's response to Joint Intervenors' Supplemental Request 17, this interruptible tariff is administered by EKPC Staff, which is common, but does not have any participants. If EKPC is going to offer an interruptible service tariff, it should work with its owner-members to develop a tariff that will encourage participation and development of demand response programs at the owner-member level. One way to encourage participation in this program is to provide varying levels of demand credits based upon increased notice time prior to an interruption.

10.7 Federal Funding Opportunity

Recommendation: Consider offering two pathways under an in-home energy audit program to promote the adoption of heat pump technology that will be rebated under the IRA funds to low-to-moderate income customers. Expand the energy efficiency workforce, with support from IRA funding, to increase participation for the in-home audit program and in anticipation of IRA rebates.

[96] Response to Joint Intervenors' Supplemental Request 13.

[97] Technical Appx. Vol. 2, Ex. DSM-1 EKPC 2021 Potential Study Table 6-8 Demand Response MAP & RAP Potential – C/I Programs.

[98] KY PSC, East Kentucky Power Cooperative, Inc. of Winchester, Kentucky: Rates, Rules and Regulations for Furnishing Wholesale Power Service at Various Locations to Rural Electric Cooperative Members Throughout Kentucky, P.S.C. No. 35, First Revised Sheet No. 23 Effective Oct. 10, 2021), https://psc.ky.gov/tariffs/Electric/East%20Kentucky%20Power%20Cooperative,%20Inc/Tariff.pdf.

In the CARES Low-Income Weatherization Program EKPC provides matching funds for the installation of heat pumps to Community Action Agencies ("CAAs"). EKPC does not implement a stand-alone weatherization program for low-income customers, nor does it support insulation and air sealing to make homes more efficient. The program provides up to $2,000 per home to reduce the costs of a heat pump installation.[99] Without funding from EKPC, the rules the CAAs must operate under preclude them from installing heat pumps in the homes of these vulnerable customers. This effort by EKPC to strengthen the CAA's weatherization efforts and expand the long-term savings for eligible customers should be applauded.

While the rules related to how the IRA funds can be utilized are still being clarified, there is an interpretation that the IRA funds cannot be stacked with other federal funds, such as those received for federal weatherization assistance program. The IRA sets forth substantial rebate opportunities for low-to-moderate income customers. However, there is not an established workforce network to support the rebate opportunities and EKPC does not offer a comprehensive pathway or programs to support the rebate opportunities under IRA. As rules are clarified, EKPC should work with the State's Office of Energy Policy to support the delivery of the programs.

One way that EKPC can directly support this effort before the funds are distributed is to redesign its energy audit program, as suggested above. That potential redesign could be expanded to include two pathways in order to leverage that one program rather than creating two distinct programs. The two pathways could be one for higher income homes and a second to match the IRA eligibility requirements for the low-to-moderate income customers. The low-to-moderate income pathway could assist in addressing health and safety measures that may prevent homes from taking advantage of the IRA rebates. If EKPC offers this pathway, it is likely that it could claim the savings under its DSM portfolio from the IRA rebates. The attribution of savings will likely need to be discussed with Kentucky's Office of Energy Policy; however, if EKPC provides the pathway for owner-members to take advantage of the federal rebate funds, it would seem appropriate for EKPC to claim the savings.[100]

[99] Funding can be used for the cost of the heat pump and/or installation labor.

[100] Attribution will not impact the planning for IRP purposes but can impact the level of savings recognized under the DSM programs.

Based upon the limited participation to date, any increased weatherization and HVAC measure installations related to IRA rebates for residential customers may be detrimental to EKPC's programs. This is because contractors may be focused on IRA-related work rather than promoting the EKPC's program given the limited energy efficiency workforce and current supply constraints for items such as HVAC equipment. EKPC can eliminate such concerns by proactively expanding the weatherization and HVAC work forces within its service territory by ramping up the investment in its energy efficiency programs over the next few years, rather than maintaining its current low steady participation rate. Additionally, EKPC should consider a budget which increases over time to accommodate changes to technology baselines, opportunities for federal funding, emerging technologies, and program redesign. With these factors considered, there is potential for greater savings to be recognized under the EKPC DSM portfolio with minimal additional investment needed.

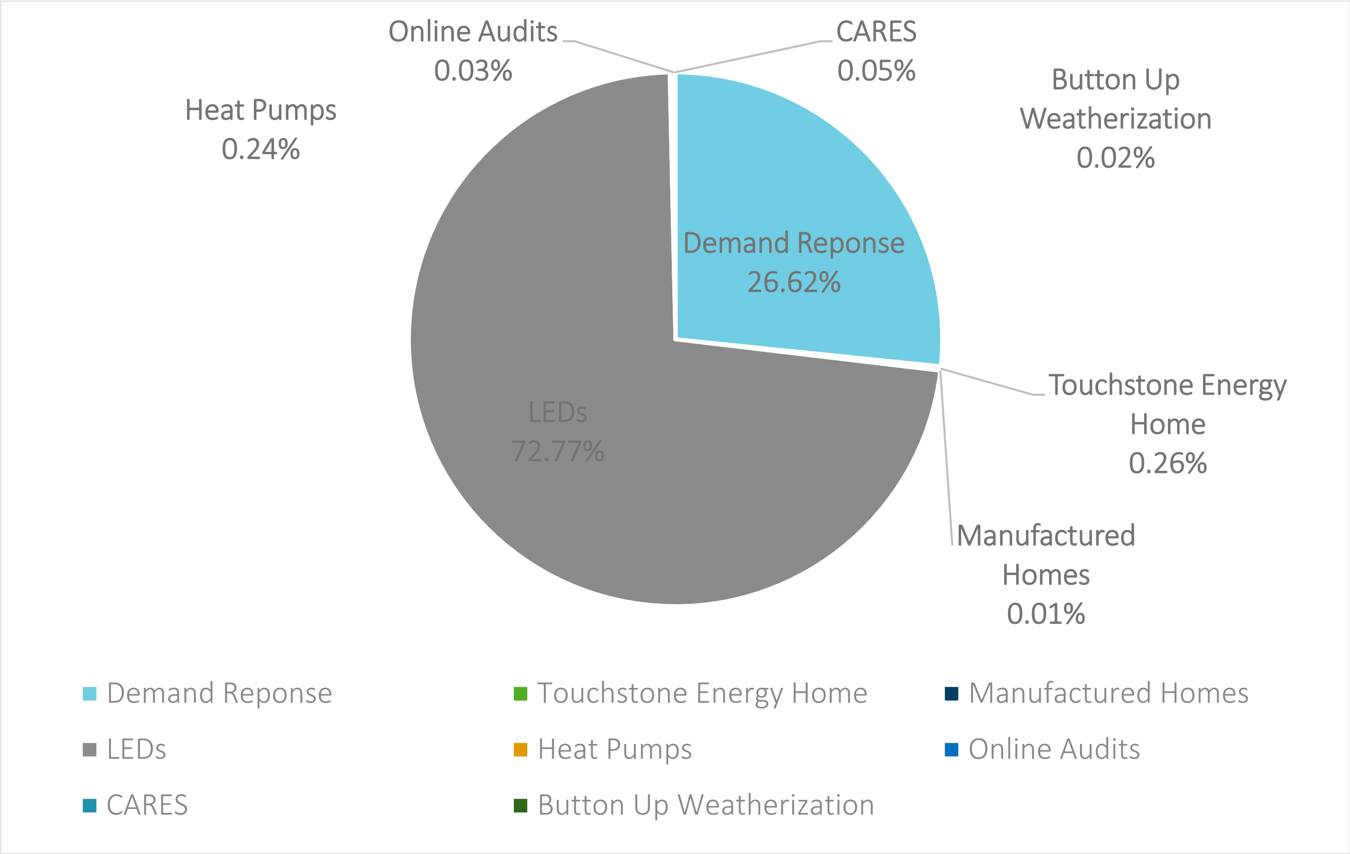
Furthermore, expansion of the energy audit program can be used to spur economic development within EKPC's service territories. Expanding the energy audit program beyond the online component will encourage workforce expansion for energy auditors, insulators, and HVAC contractors. Furthermore, by encouraging the expansion of the work force, it will help to support the adoption of weatherization and HVAC measures rebated under the IRA funding. Additionally, with IRA funding earmarked for workforce training through state energy offices, EKPC will not need to absorb a significant portion of the expense to expand the energy efficiency workforce. Overall, a redesign of the energy audit program, coupled with the IRA rebates and energy tax credits will result in more job opportunities and provide a positive economic impact throughout the EKPC service territory.

10.8 Awareness Marketing Efforts

Recommendation: Expand EKPC's energy efficiency webpage to include rebate levels, eligible measures, eligible contractors, and ways to participate in the programs. Develop streamlined marketing materials for use by owner-members.

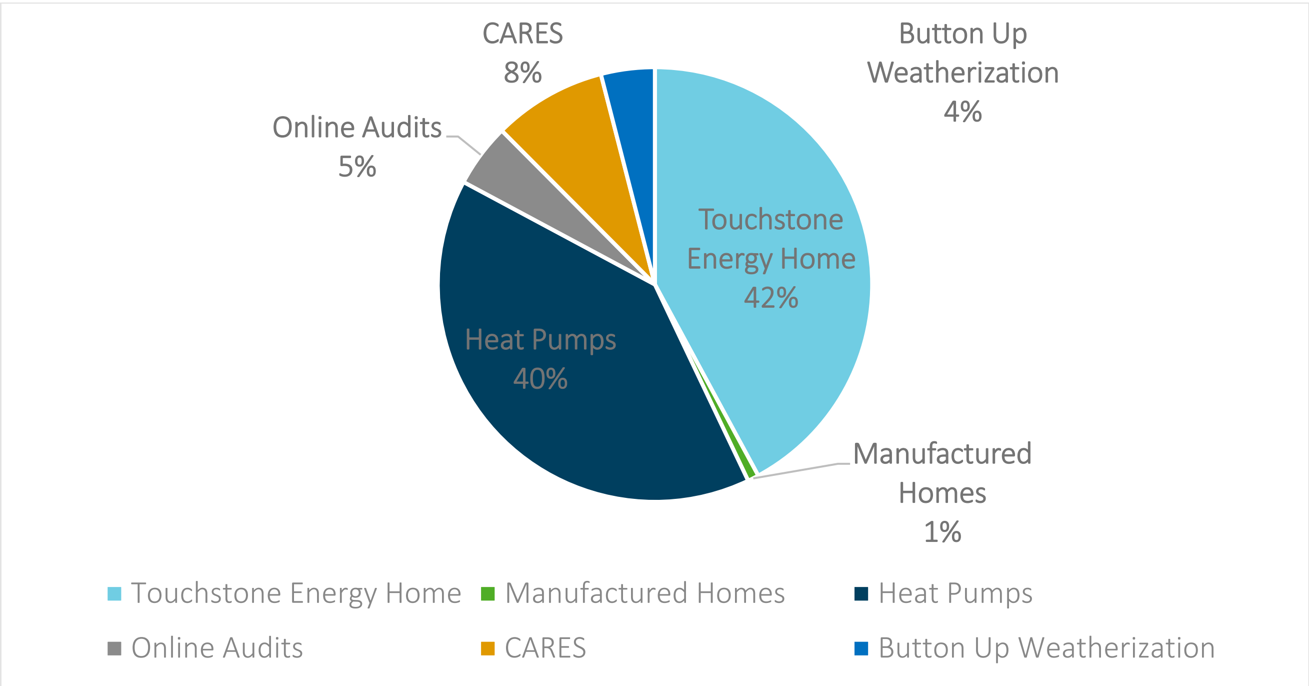
EKPC's residential DSM programs have minimal participation per year when compared to the total number of customers. Figure 18 below shows the level of participation by program. LEDs and demand response contribute almost all of the 2021 participation, with all other programs accounting for 0.61% of participation.

Figure 18. Participation by Program



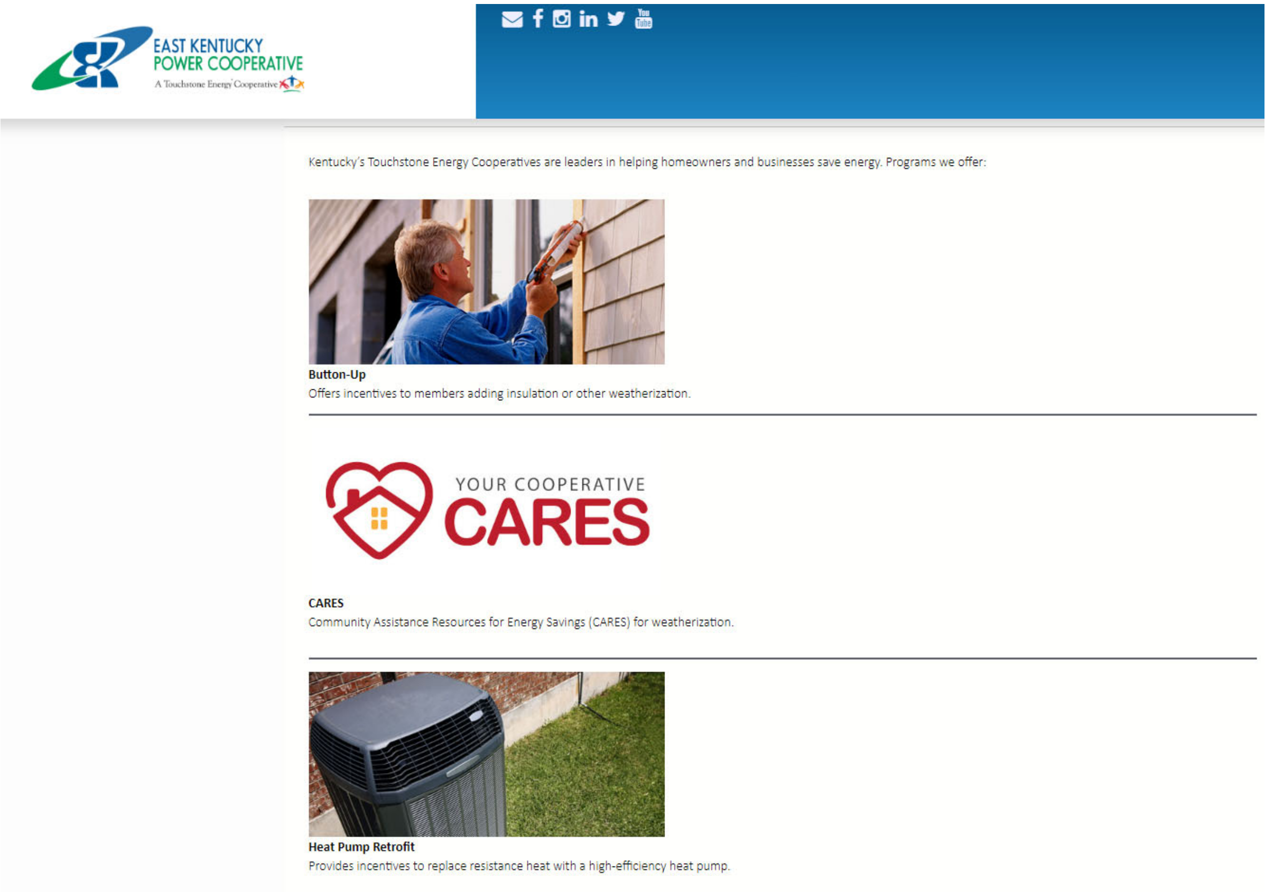
Outside of the LED and the demand response effort, the Heat Pump Retrofit Program and Button-Up Weatherization programs are the only programs that implement energy efficiency in existing homes. The CARES, Touchstone Energy Home, and Manufactured Homes programs rely on the cooperatives working with CAAs and manufacturers/builders, respectively. Based upon the breakdown in Figure 19, this means that only 44% of the 0.61% of the participation identified in Figure 18 is with owner-members. The reason for the lack of participation in the energy efficiency programs is likely two-fold. First, as identified above, the rebates are for minimum efficiency standards and therefore do not support the adoption of more efficient technology. There is no incentive for customers to choose higher efficiency options and the rebate levels are not offsetting the cost of the higher efficient technology. Second, there is a lack of marketing of the energy efficiency and demand response programs.

Figure 19. Participation Excluding LEDs and Demand Response



One recommendation is to increase the content on EKPC's energy efficiency webpage. This page includes a list of the programs with a one-sentence description. However, it lacks information on how to participate in the programs, rebate levels, eligible contractors and measures, and the benefits of energy efficiency. At a minimum, EKPC should revise its website, referenced in Figure 20, to include the information identified above and provide links to its member cooperatives to allow for members to find out how to participate.

Figure 20. EKPC's Energy Efficiency Webpage



In addition to the website, EKPC could create streamlined marketing materials for its member-owners to utilize to promote the programs at various community events, mailings, and annual meetings. The materials could be customized with the logo of the member cooperative, along with EKPC. This would be a way to extend marketing funds further and would be an economical way to increase program participation and savings.

Finally, with the addition of IRA funding, it would be beneficial for EKPC to provide a general awareness campaign around electrification and energy efficiency. Increasing awareness of the benefits of energy efficiency, dispelling the myths of heat pumps, and increasing awareness of weatherization can increase program participation and savings captured under the program. Although savings from an awareness campaign may be limited as to what EKPC can claim, it could result in a decrease in energy usage and load, which will directly impact the IRP.

10.9 Market Potential Study

Recommendation: Develop a stakeholder process, based on best practices, to support the development of the DSM inputs into the MPS and IRP. Utilize the MPS to inform the development of the DSM portfolio but without the MPS dictating the portfolio. Consider equity in program opportunities, not only with low-income members but also for commercial and industrial members.

EKPC based the development of its DSM portfolio on the $3 million scenario provided in the MPS. That scenario did not include the following:

1. Any new programs from those offered by EKPC at the time the study was conducted.
2. Any commercial or industrial programs, including lighting or demand response.
3. Residential demand response programs. This program is projected to cost $22.5 million in administrative and rebates costs over 15 years.
4. Heat pumps with a SEER 14 or 15. This program is projected to cost $10 million in administrative and rebate expenses over 15 years to install baseline efficient technology.

While these offerings were not included as part of that MPS scenario, EKPC still included a residential demand response program and a heat pump program with baseline efficient technology. One can gather from this that EKPC used the MPS to inform the design of their DSM portfolio; however, EKPC did not fully rely on the $3 million MPS scenario. Therefore, the portfolio design should be viewed as an opportunity for inclusion of cost-effective measures outside of that MPS scenario. Furthermore, EKPC should not exclude from its DSM portfolio highly cost-effective savings, such as that from commercial lighting and demand response opportunities. Energy Efficiency and demand response serve as the least cost supply side option and should be leveraged when cost-effective to delay or prevent the building of additional capacity.

On the commercial side, the MPS identified that under the RAP scenario the potential for 22,000 MWh of incremental annual energy savings and almost 5 MW of annual incremental demand reduction. Yet, EKPC does not offer ANY commercial or industrial programs as part of its DSM portfolio. Although residential lighting standards are changing, there is still ample opportunity for lighting savings from the commercial sector, especially from small businesses. EKPC argues that it observed more commercial members were opting for the most efficient LEDs, regardless of the utility incentive; however, there are still opportunities to encourage the adoption of LEDs in the commercial market.[101] Additionally, the saving attributed to the adoption of commercial high efficiency LEDs can be claimed by EKPC, unlike with residential lighting. Given the elimination of low-cost residential lighting savings, an increased annual investment in energy efficiency of approximately $1 million for commercial lighting could aid in the overall cost-effectiveness of the DSM portfolio.

Additionally, as identified above, the demand response program should be extended to include commercial opportunities, including small business direct load control devices and active marketing of interruptible tariffs for the commercial customers.

On the residential side, the MPS reviewed the measures based upon EKPC's program design at the time of the study but failed to consider how a redesign of the residential programs, including administrative and marketing, could promote a deeper, comprehensive approach to whole home weatherization and adoption of energy efficient measures. Currently the weatherization and HVAC measures are siloed and do not offer comprehensive options from a participant's perspective, nor does it promote the development of a comprehensive weatherization workforce.

DSM was only evaluated at one level, the GDS Potential Study $3 million scenario, with minor modifications from EKPC for demand response and level of measure efficiency. To fully evaluate DSM potential and its impact on supply side planning, EKPC should have reviewed multiple levels of savings within the context of the IRP to determine the appropriate level of investment in DSM. Not only should EKPC have considered the various level of savings and investment identified in the GDS Potential Study, but it should have included levels of costs and savings associated with all cost-effective energy efficiency. Based on the limited review of energy efficiency and demand response potential, it is likely that EKPC is leaving alternative supply side cost-effective savings out of its portfolio. In addition to the recommendations throughout the DSM portion of the report, we would like to recommend some best practices for consideration in the development of future EKPC DSM portfolios which are included in the IRP. These best practices are based upon EFG Staff's participation in stakeholder processes to develop DSM inputs for the IRP in other jurisdictions.

1. Utilize a stakeholder process to support development of DSM inputs for the IRP.

2. Reduce program costs by including avoided transmission and distribution benefits.
3. Convert energy savings to the generation level by using marginal in place of an average line loss rate.
4. Bundle savings consistent with a coherent program or portfolio design.
5. Model differing levels of savings, beyond RAP and MAP, with the intent to capture all cost-effective energy efficiency and demand response savings.
6. Give the IRP model two or three opportunities to select a differing level of savings so that the change in saving can be both stable for several years and better match up with need for new generation.
7. Model levelized program costs instead of as-spent costs to ensure that DSM is modeled on a level playing field as new supply side resources.
8. Avoid double-counting savings by excluding naturally occurring savings, (e.g., residential lighting), that are already captured in the load forecast.