COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

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

JOINT INTERVENORS' INITIAL COMMENT ON EAST KENTUCKY POWER COOPERATIVE INC.'S 2022 INTEGRATED RESOURCE PLAN

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Kentuckians for the Commonwealth, Kentucky Solar Energy Society, and Mountain Association (collectively, "Joint Intervenors") appreciate the opportunity to offer this Initial Comment on the 2022 Joint Integrated Resource Plan ("IRP") of East Kentucky Power Cooperative, Inc. ("EKPC").

INTRODUCTION

With this Initial Comment, Joint Intervenors endeavor to share our initial impressions of EKPC's 2022 IRP, with the aim of ensuring that there has been a full and fair evaluation of all potentially cost-effective resources, and also sharing recommendations to improve EKPC future planning efforts. Joint Intervenors views are informed in substantial part by the work of Energy Futures Group, whose experts independently reviewed the IRP, with a particular focus on resource modeling and demand-side management/energy efficiency potential ("DSM/EE").

In Section I, discussion begins with a high-level introduction to the experts' observations and recommendations, which Joint Intervenors incorporate and adopt as part of this Initial Comment. Section II summarizes key provisions of the recently-enacted Inflation Reduction Act, which warrants attention given its seismic changes in energy opportunities for rural cooperatives and the communities they serve. In section III, Joint Intervenors seek to further develop and clarify information related to a claimed transmission constraint that may be justifying retention of the Cooper Station units despite [[BEGIN CONFIDENTIAL] [redacted] END CONFIDENTIAL]] over the IRP planning period. Section IV addresses opportunities for EKPC to improve its support for equitable demand-side investments by its member-owner distribution cooperatives. Section V reviews the reliability, affordability, and resilience benefits of distributed energy resources, and how EKPC might better evaluate and encourage distributed power resources across its predominantly rural service territory.

Joint Intervenors' silence on any issue, analysis, or conclusion advanced in EKPC's 2022 IRP and supporting materials should not be taken as support or opposition. To the extent that EKPC, or any other party to this proceeding, is interested in discussing aspects of the 2022 IRP and implications of the Inflation Reduction Act—whether addressed or not by this Initial Comment—Joint Intervenors welcome informal dialogue and collaboration in service of our shared goal to ensure robust planning toward development of a reliable, low-cost portfolio for EKPC's owner-member distribution cooperatives and their retail customers.

DISCUSSION

I. The Energy Futures Group Report Provides a Detailed Technical Review of EKPC's Modeling, Including Practical Recommendations To Improve Future Planning And Increase Transparency.

Joint Intervenors' comments are informed in substantial part by the work of Anna Sommer, Earnest White, Chelsea Hotaling, and Stacy Sherwood of Energy Futures Group ("EFG"). The attached EFG Report reflects their independent review of EKPC's 2022 IRP and offers practical recommendations to increase the robustness and transparency of EKPC's future IRP. The EFG Report is adopted in full as part of this comment. Key observations from the EFG Report include the following:

1. EKPC's load forecast projects compound annual growth rates that significantly outpace actual historical growth rates but does not identify any methodological or exogenous factor that could explain such a change. EFG Report Sec. 3.

2. With regard to commodity forecasts, the IRP lacks transparency and relies on unreasonably stale data and opaque methodologies. EFG Report Sec. 4.

3. The IRP does not provide and did not assess economic retirement dates for any existing generating units. This lack of retirement analysis is most glaring in relation to the 1960s-vintage Cooper Station units, which EKPC projects [[BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]] throughout the planning period. EFG Report Sec. 5.

4. The IRP contains limited information and discussion of how the RTSim model was used, does not appear to factor in total system costs/profits, and does not clearly explain steps taken within the model as opposed to external to the model. EFG Report Sec. 6.

5. The IRP provides insufficient information to enable independent comparisons of the various plans evaluated on the basis of cost, emissions, or any other common metric, leaving EKPC's method of selecting a final plan opaque. EFG Report Sec. 7.

6. The IRP does not adequately evaluate cost-effective potential from behind the meter generation and does not integrate evaluation of such resources with EKPC's transmission and distribution planning. EFG Report Sec. 8.

7. The IRP appears not to appreciate the grid services and resource adequacy benefits coincident to increasing renewables on the electric grid. EFG Report Sec. 9.

8. The IRP proposes a portfolio of demand response and energy efficiency resources that is far less than what EKPC's potential study found to be cost-effective, missing a broad range of opportunities for energy savings, peak demand reductions, and customer bill savings. EFG Report Sec. 10.

In concert, these shortcomings in EKPC's 2022 IRP lead to the unfortunate conclusion that insufficient information has been provided to determine whether EKPC's resource plan identifies the lowest cost plan. Rather than proactively searching out opportunities to deliver more affordable, reliable, and resilient electric service, EKPC appears to be going through the motions, largely content to maintain the status quo, with one exception: EKPC does plan to adjust its resource portfolio by adding solar PPAs in the near-term, consistent with its adopted Sustainability Goals.

While not opposing EKPC's Sustainability Goals, Joint Intervenors urge EKPC to pause, re-evaluate, and reconsider the most cost-effective means of meeting the needs and commitments of its member-owner distribution cooperatives. To assist, the EFG Report provides specific recommendations of changes to the modeling methodology, data sources, constraints, and resource options that EKPC could apply in its re-analysis of optimal portfolio options and selection of a least-cost plan. Those Recommendation are stated here and available in Section 2 of the EFG Report:

Recommendations Specific to Inputs and Modeling

R-1. Review the load forecasting methodology to address (1) the gap in the first-year of the forecast from the actuals and (2) the divergence between the historic trend and the Cooperative's forecast of its total energy requirement.

R-2. In natural gas price forecasting, use the most recently available NYMEX curve or an approach that blends the near-term NYMEX trend with long-term fundamentals forecast.

R-3. 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.

R-4. Use sensitivity analysis on fuel prices to capture the market's movements and provide a robust IRP that provides confidence to stakeholders and regulators.

R-5. 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.

R-6. Utilize a collaborative approach such as the one employed by the Minnesota utilities and DTE Electric to evaluate IRP modeling software options.

R-7. 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.

R-8. 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.

R-9. Provide a clearer discussion of how emission costs are incorporated into the modeling.

R-10. 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.

R-11. 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.

R-12. Provide a robust economic retirement analysis of the Cooper Station units in future IRPs.

<u>Recommendations Specific to Demand Side Management and Energy Efficiency Programs</u>

R-13. 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 incentives provided under the Heat Pump Retrofit Program.

R-14. 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.

R-15. 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.

R-16. 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.

R-17. 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.

R-18. Expand the residential demand response program to include opportunities for small businesses.

R-19. Actively promote the interruptible rate tariff to commercial customers and owner-members. If interruptible rate has a continued lack of interest, it should be revised to promote participation.

R-20. 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.

R-21. Develop a stakeholder process, based on best practices, to support the development of the DSM inputs.

R-22. 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.

These recommendations, if faithfully adopted by EKPC, could dramatically improve the value and validity of its resource optimization modeling and resource planning process.

II. The Inflation Reduction Act Changes Assumptions Made in the IRP, Necessitating Further Analysis and Consideration.

The recent passage of the Inflation Reduction Act of 2022[1] ("IRA" or "the Act") provides unprecedented opportunity for funding—nearly $369 billion in direct investment to ensure energy security, reduce carbon emissions, increase energy innovation, and support environmental justice objectives. Unsurprisingly, given its scope and scale, the IRA is a complex and lengthy

[1] Inflation Reduction Act of 2022, H.R.5376, 117th Cong. (2022) ("IRA"), https://www.congress.gov/bill/117th-congress/house-bill/5376/text.

piece of legislation with significant implications for EKPC's resource planning. Joint Intervenors appreciate that EKPC could not have foreseen passage of the IRA, much less the specific contours of the enacted bill. Still, it is a game changer with such significant opportunities that it must be considered thoroughly to achieve our shared goal of least-cost planning.

Joint Intervenors commend EKPC for taking steps to review and assess implications of the IRA,[2] and seek to be a constructive partner and resource as that effort continues. The IRA opens the door to significant tax credits for non-profit utilities, with rural cooperatives receiving special attention with unique opportunities for grants and loans, including:

(1) $9.7 billion toward Rural Cooperative Grants;
(2) Modifications and extensions of the production tax credit and investment tax credit, including direct pay of credits for non-profit utilities;
(3) $10 billion toward a revised and extended advanced energy project credit;
(4) Modifying, expanding, and extending energy efficiency credits for homes and businesses; and
(5) $10 billion to DOE building efficiency programs.
(6) Bonus incentives to the Investment Tax Credits based on projects located in "Energy Communities," which could make additional financial incentives available to many Eastern Kentucky communities for renewable energy developments.

Each of these programs, and more, warrants a closer look here, beginning with direct pay.

With Direct Pay Provisions, EKPC can take advantage of newly expanded and extended energy tax credits. As EKPC correctly notes, taxable entities have historically been able to extract more benefits from renewable energy programs than have non-taxable entities, but the

[2] Response of East Kentucky Power Cooperative to Joint Intervenors' Supplemental Discovery Requests, Question 29a-c (Mar. 25, 2022) ("Response to JI Supplemental Q").

IRA changes this calculus.[3] The IRA's direct pay provisions allow cooperatives, municipalities, and other nonprofit entities to receive payments for either investing in or producing their own zero-emission energy. Electric cooperatives, for the first time, have direct access to energy innovation tax credits and parity with for-profit and investor-owned counterparts. The direct pay provisions allow for direct funding to asset owners—cutting out the need for a tax equity middleman.

This significant development realizes a top legislative goal of the National Rural Electric Cooperative Association, with cooperatives around the nation applauding new investment opportunities for renewable energy generation, storage, and transmission.[4] EKPC is eligible and well positioned to benefit from tax incentives for a wide range of eligible projects to improve energy generation, efficiency, and residential electrification.

1. Energy Generation and Manufacturing

The IRA contains robust support for clean energy generation and domestic manufacturing of solar, wind, battery, and electric vehicle components. The IRA provides two significant tax incentives for energy generation and manufacturing in the form of a Production Tax Credit ("PTC")[5] and Investment Tax Credit ("ITC").[6] Both the PTC and ITC provide two credit values:

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[3] EKPC Response to Attorney General's Second Information Request, Request 7a (August 30, 2022) ("Response to AG Supplemental Request").

[4] *See*, Abigail Sawyer, *Rural Electric Co-ops Glad to be Included in Inflation Reduction Act Benefits*, California Energy Markets (Aug. 26, 2022), https://www.newsdata.com/california_energy_markets/regional_roundup/rural-electric-co-ops-glad-to-be-included-in-inflation-reduction-act-benefits/article_13faa71e-2581-11ed-97f1-83f1b4466002.html.

[5] The changes to Section 45 of the Internal Revenue Code, I.R.C. § 45, (extending and modifying the PTC terms) are found in Section 13101 of the IRA.

[6] The changes to Section 48 of the Internal Revenue Code, I.R.C. § 48, (extending and modifying the ITC terms) are found in Section 13102 of the IRA.

a lower base credit and a bonus rate that is equal to five times the base amount, when requirements related to prevailing wage and apprenticeship are met. Projects will have the option to choose either the ITC or PTC, with both options offering additional bonuses for meeting domestic content requirements, location in energy communities,[7] or serving qualified low-income properties. Projects that are eligible for multiple bonuses can benefit from stackable percentage increases.

The Production Tax Credit applies to the production of energy from solar, wind, geothermal, biomass, hydropower or other eligible projects,[8] providing up to 1.5 cents/kWh when prevailing wage and apprenticeship requirements are met,[9] and an additional bonus up to a maximum total incentive of 1.65 cents/kWh if domestic content requirements are met.[10]

With passage of the IRA, the Investment Tax Credit newly applies to stand-alone storage projects,[11] and provides direct pay of credits up to 30% for renewable energy projects when certain prevailing wage, apprenticeship, and domestic content requirements are met,[12] and a 10% adder available for projects in an energy community.[13]

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[7] An "Energy community" is defined as (1) a brownfield site; (2) a metropolitan or non-metropolitan area which (a) has direct employment or local tax revenues over an established percentage related to the extraction, processing, transport or storage of coal, oil, or natural gas, (b) has an unemployment rate at or above the national average; or (3) a census tract or adjoining tract in which a coal mine closed after Dec. 31, 1999, or a coal fired electric power plant was retired after Dec. 31, 2009." IRA Section 13101(g) (amending 26 U.S.C.A. § 45(b)).

[8] IRA Section 13101(a) (applying extension of PTC to geothermal, solar, biomass, hydropower, and other renewable sources).

[9] IRA Section 13101(f) (amending 26 U.S.C.A. § 45(b)).

[10] IRA Section 13101(g) (amending 26 U.S.C.A. § 45(b) to provide domestic content adder and energy community adder).

[11] IRA Section 13702(a) (adding 26 U.S.C.A. § 48E).

[12] IRA Section 13702(l).

[13] IRA Section 13702(a) (adder for energy communities).

With regards to related industrial and manufacturing facilities, the IRA provides for an Advanced Energy Project credit allocating $10 billion in tax credits, of which at least $4 billion must be allocated to projects located outside of or adjacent to census tracts where a coal mine closed after 1999 or a coal-fired power plant was retired after 2009.[14] The IRA further modifies qualifying Advanced Energy Projects to include not only manufacturing in service of production, but also any "industrial or manufacturing facility to the production or recycling of" renewable generation, including fuel cells, microturbines, energy storage systems, electric grid modernization equipment and components, and other equipment related to renewable, low-carbon, and low-emission products.[15]

Notably, the IRA also provides 10% and 20% bonus credits for certain wind, solar, and energy storage projects benefiting low-income communities.[16] Qualifying facilities must have a maximum net output of less than 5 MW and serve residents of certain housing assistance programs or provide at least half the project's financial benefits to households with an income of less than 200% of the Federal Poverty Line or less than 80% of Area Median Income.[17]

EKPC should evaluate opportunities to benefit from PTC and ITC funds as soon as possible to ensure investment opportunities are not missed.

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[14] IRA Section 13501 (expanding and modifying qualifying advanced energy projects).

[15] IRA Section 13501(b) (modifying 26 U.S.C.A § 48C(c)(1)(A)).

[16] IRA Section 13103 (amending 26 U.S.C.A. § 48 to add new subsection (e)).

[17] *Id.*

2. Energy Efficiency and Electrification

Four programs of particular interest here include the Nonbusiness Energy Property Credit, Residential Clean Energy Credit, the Energy Efficient Commercial Buildings Deduction, and the New Energy Efficient Home Credit.

Beginning in 2022, the IRA will expand and extend the nonbusiness energy property credit through 2032, by increasing the credit from 10% to 30%, with the lifetime cap replaced with a $1200 annual credit limit, with up to $2000 credit for heat pumps and biomass stoves. Qualified energy property made eligible for the credit cover a range of products, including water heaters, heat pumps, central air conditioners, hot water boilers, biomass stoves, oil furnaces, air sealing materials and systems, costs of home energy audits, and electrical panels installed to enable qualified improvements, with specific efficiency requirements for each upgrade.

Second, the residential clean energy credit will allow taxpayers to claim up to 30% credit for qualified residential energy efficiency property purchases, including battery storage with a capacity of at least 3 kWh.

Third, the energy efficient commercial buildings deduction[18] will be modified and extended to reduce the amount by which a building must increase its efficiency to qualify for the deduction from 50% to 25%, allowing for a deduction up to $2.50 per square foot if prevailing wage and apprenticeship requirements are met, and a bonus deduction of up to $0.10 for each percentage point increase in energy efficiency up to $5 per square foot.

And lastly, the IRA will also increase the value of the new energy efficient home credit,[19] providing contractors with tax credits for housing units built or remodeled to reach energy-

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[18] IRA Section 13303 (amending section 26 U.S.C. § 179D).

[19] IRA Section 13304 (amending 26 U.S.C.A. § 45L).

saving specifications for a variety of home types—including a bonus credit for multifamily homes if wage requirements are met during the construction of the units.

In addition to tax incentives, the IRA also provides substantial direct investment opportunities to further increase energy efficiency and residential electrification efforts. The two most notable direct investments programs are the Homeowner Managing Energy Savings ("HOMES") rebate program and the High Efficiency Electric Home Rebate Program ("HEERA"). Under the HOMES program, the IRA provides $4.3 billion to DOE to award to state energy offices to develop and implement whole-house energy savings retrofits.[20] The HOMES program incentivizes deeper retrofits that can save families more annually by providing up to $8000 per home or 80% of project costs for low-and-moderate-income homeowners who install home energy retrofits that produce energy savings of at least 35%.[21] Similarly, the IRA provides DOE with $4.5 billion for grants to state energy offices to create electrification rebate programs for homeowners and multifamily building owners, explicitly providing point-of-sale rebates of up to $14,000 maximum total, including up to $2500 for electric wiring, $4000 for main panel upgrades, $1600 for weatherization, and up to $8000 for heat pump HVACs.[22]

A. The IRA's Climate, Energy and Environmental Investments create new grant and loan opportunities for EKPC.

In supplement to the tax incentives for clean energy generation and residential electrification, the IRA provides unprecedented direct investments in programs across more than a dozen agencies to further advance renewable energy development and energy efficiency. By

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[20] IRA Section 50131.

[21] IRA Section 50121(c)(2).

[22] IRA Section 50122.

prioritizing and directly targeting funding for environmental justice, the IRA strives to ensure that impacts will be equitable by requiring specific investments to be made in low-income communities, communities of color, and rural communities.

The USDA's assistance for rural cooperatives is especially noteworthy here. The IRA will provide $9.7 billion for loans and grants designed specifically for electric cooperatives to purchase renewable energy, renewable energy systems, zero-emission systems, and carbon capture and storage systems, to deploy such systems or make energy efficiency improvements to generation and transmission assets.[23] It is important to note that USDA is directed to prioritize projects that achieve the greatest GHG emission reductions and that will otherwise aid disadvantaged rural communities. Individual awards are capped at 25% of project costs, with maximum awards up to $970 million. As stated by Duane Highley, Tri-State Cooperative CEO, "the co-op provisions signed into law will drive investment, bolster jobs and preserve the reliable and affordable power that drives rural prosperity."[24]

The IRA will also provide $1 billion in loan subsidy under the Rural Electrification Act with forgiveness authority up to 50% of loan amount, or greater, if granted a waiver from the Secretary, including for projects that store electricity in support of renewable energy production.[25]

Additionally, the IRA will provide $1.72 billion for the Rural Energy for America Program (REAP), including $820.25 million for FY 2022, $180 million for FYs 2023-2027, and

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[23] IRA Section 22004.

[24] Press Release, *Co-op provisions in Inflation Reduction Act of 2022 Advance Tri-State Responsible Energy Plan*, Tri-State Cooperative (August 16, 2022), https://tristate.coop/co-op-provisions-inflation-reduction-act-2022-advance-tri-state-responsible-energy-plan.

[25] IRA Section 22001.

an additional $144.8 million for FY 2022 and $31.8 million for FY 2023-2027 for underutilized renewable energy technologies and program technical assistance.[26]

B. The IRA introduces significant new economic development and job growth opportunities worth considering in the course of long-range resource planning.

The IRA presents significant opportunities to spur new economic growth by facilitating investment in renewable and zero-carbon emitting resources. As investment banking company Credit Suisse stated, the IRA "definitively changes the narrative from risk mitigation to opportunity capture."[27] However, the IRA also presents significant challenges to coal- and gas-fired resources.[28] As Commission Staff recently noted, the IRA likely affected the costs of proposals and utilities should obtain updated proposals reflecting those changes so that customers are not overcharged for generation capacity.[29] EKPC should therefore reevaluate resources based on changes arising from the IRA.

As discussed in the attached EFG Report, EKPC should update the costs of solar resources to include impacts from the IRA and consider battery storage resources as part of new supply side resource options.[30] It is important for utilities to react dynamically to changed circumstances, and the IRA is an important and sweeping modification to the energy landscape

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[26] IRA Section 22002.

[27] Robinson Meyer, *The Climate Economy is About to Explode*, The Atlantic (October 5, 2022), https://www.theatlantic.com/science/archive/2022/10/inflation-reduction-act-climate-economy/671659/.

[28] The IRA amended the Clean Air Act to add a charge of $1500 by 2026 for methane emissions at certain facilities. IRA Section 60113, (c) and (e).

[29] Commission Staff's Report on the 2021 Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company Case No. 2021-00393, at 66 (Sept. 16, 2022) (**"**Staff Report on LG&E/KU 2021 IRP").

[30] EFG Report, Section 6.3.1.

that could bring significant benefits to the customers of EKPC's member cooperatives.[31] In line with Commission Staff recommendations,[32] EKPC should take advantage of newly available incentives and update its resource calculations in light of the IRA to ensure the least-cost, most reasonable resources are selected.

III. EKPC Should Be Doing More to Assess, Report, and Address Transmission Constraints—Particularly Those Impacting Reliability and Supply-Side Resource Options.

Joint Intervenors were surprised to learn through a response to the Attorney General in this proceeding that, according to EKPC, "[t]he current transmission system is not configured to support the peak load periods in [Southern Kentucky] without the generation injections at Cooper Station."[33] This transmission constraint is not identified in Section 6.0, where EKPC details its transmission upgrade and expansion plans over the next fifteen years, or anywhere else in the IRP. And it is not clear on the face of the IRP whether any of those planned transmission projects are intended to address this significant reliability issue. As Joint Intervenors probed this issue further through supplemental information requests[34] and reviewed EKPC's economic outlook for the Cooper Station units, that surprise turned to concern that EKPC has not adequately or transparently prioritized reliable, low-cost planning and, instead, has simply assumed continued long-term reliance on its 1960s-vintage Cooper units,[35] which EKPC's own

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[31] *E.g.*, EFG Report, Section 6.9.

[32] Staff Report on LG&E/KU 2021 IRP at 66.

[33] Response of East Kentucky Power Cooperative, Inc. to Attorney General's Initial Discovery Requests, Question 1c (June. 29, 2022) ("Response to AG Initial Q")

[34] *See* Response to JI Supplemental Q21-28.

[35] Response to AG Initial Q21.

analysis projects [[BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]]

In this section, Joint Intervenors will summarize the information that EKPC has disclosed, share our concerns and questions, and offer recommendations to be applied going forward. At bottom, the fact of the matter is that unexpected outages do happen, and no generating unit lasts forever—it is the responsibility of a prudent utility to plan for both eventualities and to be forthright with their regulator and stakeholders about that planning. Unfortunately, it appears on the record developed to date that EKPC has not done so.

A. If there is a transmission constraint impacting system reliability or materially limiting resource options, that constraint should be addressed in the Integrated Resource Plan.

Integrated resource plans should transparently report and evaluate transmission constraints that, in the utility's estimation, materially constrain supply-side resource options or present reliability challenges. This expectation is firmly grounded in the IRP regulation and common sense. Joint Intervenors urge Staff to Recommend that future EKPC IRPs more seriously and transparently evaluate the nexus between efficient use of transmission, distribution, and generation assets in service of maintaining reliable service at the lowest reasonably possible cost.

Beginning with the IRP regulation, its purpose is to ensure that adequate planning is regularly undertaken to ensure "an adequate and reliable supply of electricity at the lowest possible cost," and consistent with all applicable state and federal laws and regulations.[36] To that end, the regulation requires integrated analysis of supply- and demand-side resources, as well as

[36] 807 KAR 5:058, Necessity, Function, and Conformity.

transmission and distribution resources, in the development of a long-term resource plan.[37] The IRP regulation directs all regulated utilities, including EKPC, to "describe and discuss all options considered for inclusion in the plan including: (a) Improvements to and more efficient utilization of existing utility generation, transmission, and distribution facilities . . ."[38]

These requirements make sense. Identification of the lowest-cost collection of generation, demand-side management, and transmission resources can only happen after robust and integrated evaluation of all potentially cost-effective options.[39] Joint Intervenors assume EKPC would agree with this common-sense principle, including the significance of transmission in long-range resource planning.[40]

EKPC stewards substantial transmission resources, spanning "roughly the eastern two-thirds of Kentucky."[41] This makes fulsome integration of transmission needs in long-range resource planning especially critical to the efficiency of its own system and the efficiency of the regional power system. At first look, it appears EKPC made an attempt to do that in this IRP, as detailed across almost twenty pages in Section 6.0 in the 2022 IRP.[42] EKPC provides a narrative description of its existing system, explains its membership in PJM and SERC, reports on

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[37] 807 KAR 5:058, Section 8(2).

[38] 807 KAR 5:058, Section 8(2)(a).

[39] *See e.g.*, Staff Report on LG&E/KU 2021 IRP at 53.

[40] *See e.g.*, EKPC Response to Joint Intervenors' Initial Request for Information, Request 81d (agreeing that regional transmission planning processes are an important component of ensuring reliability and minimizing costs of transmission expansion or upgrades needed to enable greater levels of renewable generation).

[41] 2022 Integrated Resource Plan of East Kentucky Power Cooperative, Inc., at 123 (Apr. 1, 2022) ("2022 IRP").

[42] *Id.* at 123-141.

transmission expansion activities from 2019–2021, and announces planned improvements to the transmission and distribution systems across the planning period.

But no section of the IRP appears to disclose a long-languishing transmission constraint in southern Kentucky that both undermines reliability and appears to be at least part of the motivation for retention of generation units that EKPC's own modeling shows [[BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]]. These shortcomings may have persisted unnoticed or unaddressed across multiple planning cycles.[43] If EKPC's goal in integrated resource planning is transparent planning for low-cost, reliable service, that needs to change with this IRP.

B. EKPC discovered a transmission constraint impacting reliability in 2007, but appears not to have directly studied the issue since, until recently.

Though not stated in the IRP, according to one of EKPC's initial responses to the Attorney General, "the current transmission system is not configured to support the peak load periods" in southern Kentucky "without the generation injections at Cooper Station."[44] EKPC continued to explain that, because of this constraint on its "current transmission system," the conventional resources at Cooper Station continue to be "required to facilitate the transition to renewable and low/no carbon emitting resources."[45] Further, this transmission constraint appears to be part of EKPC's justification for not routinely using resource optimization modeling to

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[43] *E.g.*, Case No. 2009-00106, 2009 Integrated Resource Plan of East Kentucky Power Cooperative, Inc (Public), Volume I, Section 5, Plan Summary (containing no mention of the then-recent discovery of critical voltage support provided by Cooper Station units); *id.* at 8-2 to 8-8 (summarizing transmission system without mention of critical voltage support provided by Cooper Station units); Case No. 2012-00149, 2012 Integrated Resource Plan of East Kentucky Power Cooperative, Inc. (Public), Volume I at 25–31 (same).

[44] Response to AG Initial Q1c.

[45] *Id.*

determine an economical retirement horizon for the Cooper Station units as part of its integrated resource planning.[46] After delving further on this issue, Joint Intervenors must express concern that it seems EKPC is either not taking due care to study and address this reliability issue, or EKPC has not been transparent and forthright about such efforts in this proceeding. In either case, EKPC's approach frustrates least-cost planning and fails to demonstrate that the company is taking reasonable and prudent action to ensure system reliability.

Joint Intervenors' concern is rooted in the knowledge that EKPC first recognized this constraint on its "current transmission system" in 2007,[47] but it persists today, fifteen years later. The constraint was not identified in the ordinary course of EKPC's transmission planning, but rather in response to the possibility that both Cooper Station units and the Wolf Creek Dam[48] could be forced offline for an extended period as the Army Corps of Engineers lowered levels at Lake Cumberland to enable dam maintenance.[49] That event caused EKPC to perform targeted power flow analyses, which in turn identified significant risks of cascading outages.

EKPC Witness James C. Lamb, Jr., summarized those risks in support of a CPCN application seeking authorization for modifications to Cooper Station's cooling water intake to account for lower lake levels. His observations and conclusions are sobering:

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[46] *Id.*; *see also* Response of East Kentucky Power Cooperative, Inc. to Sierra Club's Initial Discovery Requests, Question 6g–h (June. 30, 2022) ("Response to Sierra Club Initial Q") (stating that EKPC has not undertaken retirement analyses).

[47] Response to JI Supplemental Q21b.

[48] The Wolf Creek Dam, owned and operated by the U.S. Army Corps of Engineers, is a multi-purpose dam on the Cumberland River in Russell County, KY. The dam is equipped with six 1950s-vintage hydroelectric generating units with a combined installed capacity of 270 MW.

[49] *Id.* at Q21a ("The criticality of the voltage support provided by the Cooper units was recognized in early 2007 when EKPC was notified by the U.S. Army Corps of Engineers that the water levels in Lake Cumberland could be reduced below the intake levels for necessary cooling water for the units.").

> System problems may occur with or without a contingency[50] and with or without north-south transfers[.]…
>
> Load shedding up to a level of approximately 175 MW may be required for the most critical single-contingency/transfer combination[.]
>
> …
>
> Based upon the findings summarized above, EKPC concludes that a substantial risk of transmission system problems in the south-central Kentucky area exists if the Cooper and Wolf Creek generating units are unavailable during high load periods. Depending on system loads and transfer patterns, the problems could be severe enough to cause facilities to trip. **This could cause cascading outages in the area, resulting in localized blackouts. A nine-county area stretching from Adair County to Clay County could be impacted by these outages. In order to avoid loss of most or all customers in this area, some controlled load shedding may be necessary to minimize the number of customers out of service and to maintain the integrity of the local transmission grid**.[51]

Surely, this warranted immediate and serious attention, and it appeared at the time that such efforts were possible and underway. For example, referring to the possibility of a simultaneous outage of both Cooper Station units during the summer, EKPC Witness Lamb insisted that "[t]he transmission system must be designed to withstand an additional contingency for this scenario."[52] While there was not sufficient time to address all system problems—making capital investment in cooling water intake more necessary—EKPC Witness Lamb did explain that "[s]ome of the system problems can possibly be mitigated through upgrades of the facilities in a relatively short timeframe . . ..”[53]

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[50] While undefined in Witness Lamb's testimony, in this context, "contingency" would refer to "[t]he unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch or other electrical element." North American Electric Reliability Corp. ("NERC"), Glossary of Terms Used in NERC Reliability Standards at 9, https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf.

[51] Response to JI Supplemental Q21b (Excerpts from the 2007 Lamb Testimony Exhibit 1 (emphasis added)).

[52] *Id.*

[53] *Id.*

Yet, all this time later, EKPC continues to report that its "current transmission system is not configured to support the peak load periods" in southern Kentucky "without the generation injections at Cooper Station."[54] Perhaps even more concerning, it appears EKPC may not have subsequently studied this transmission constraint in the intervening fifteen years, until now. When asked to produce each analysis of this issue since it was first discovered, EKPC produced no documents and responded only to say that:

> An analysis of potential transmission-system modifications to address low-voltage and thermal-loading issues due to the unavailability of the generating units at Cooper Station is currently in progress. Power-flow analysis results are still in the process of being reviewed by EKPC staff.[55]

Joint Intervenors find this response perplexing and concerning. Either EKPC has not acted over the past fifteen years to evaluate and address a known transmission constraint with significant reliability and generation cost implications, which would be irresponsible and imprudent; or EKPC has not been forthcoming in response to information requests in this informal, non-adversarial IRP proceeding.

Unfortunately, though Joint Intervenors tried to ask after this issue in a variety of ways through our supplemental requests, we cannot reconcile EKPC's responses and are frankly unsure what to make of them. On one hand, the above-quoted response to Joint Intervenors' 21c, as well as EKPC's Response to Supplemental Request No. 24b,[56] suggest EKPC's response to

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[54] Response to AG Initial Q1c.

[55] Response to JI Supplemental Q21c (Asked whether EKPC analyzed transmission system changes necessary to support peak load in region with Cooper Station unit, and if so, to produce each such analysis, EKPC answered that such an analysis "is currently in progress" and produced no other analysis. From this, Joint Intervenors can only assume that EKPC performed no such analysis beyond the one currently in progress).

[56] *Id.* at Q24b ("A study of potential transmission-system modifications to address low-voltage and thermal-loading issues due to the unavailability of the generating units at Cooper Station is currently in progress.").

the Attorney General concerning its “current transmission system” is based solely on the 2007 power flow analysis used to support its CPCN application, with no subsequent analyses. On the other hand, in response to Supplemental Request 21f, EKPC reports that “[b]eginning in 2015, a simultaneous outage of Cooper Units 1 and 2 was considered to be a single generating unit scenario in EKPC’s transmission planning process . . ..” Which is it? Is EKPC only just now analyzing modifications necessary to maintain reliable service if both Cooper Station units are simultaneously unavailable, such that it has no studies since Witness Lamb’s 2007 CPCN testimony to produce in response to Request 21c? Or has EKPC been studying simultaneous unavailability of both Cooper Station units in its ordinary transmission planning process for the last seven years, but failed to produce those analyses on request for independent review by its regulator and stakeholders?

In another example, EKPC’s response to Supplemental Request 21f states that “EKPC has taken steps to design the system to withstand a single transmission element outage in the area along with both Cooper Units offline, based on assumed system conditions in available power-flow models.” If the system has been designed to withstand this scenario, why did EKPC represent in response to the Attorney General that “[t]he current transmission system is not configured to support the peak load periods in [Southern Kentucky] without the generation injections at Cooper Station”?[57]

In a third example, referring to EKPC’s representations to the Attorney General regarding the inadequacy of the “current transmission system,” Joint Intervenors asked EKPC to describe the extent of load shedding EKPC expects would result without both Cooper Station units.[58] In

[57] Response to AG Initial Q1c.

[58] Response to JI Supplemental Q21e.

response, EKPC referenced Witness Lamb's 2007 study, noting that power flow analysis "indicate[d] that a nine-county area stretching from Adair County to Clay County could be impacted by cascading transmission outages and localized blackouts, and the estimated load shedding that could be required was as high as 175 MW."[59] Again, this response appears to suggest that (1) EKPC has not taken steps to design its system to withstand a loss of both Cooper Station units, contrary to Supplemental Response 21f; and (2) EKPC is basing its conclusions about "the current transmission" on a fifteen-year old study of the problem. The transparent resource planning process required by the IRP regulation necessitates EKPC setting the record straight on this issue.

C. EKPC should be using up-to-date analyses to identify, disclose, and expeditiously remedy transmission grid conditions that threaten reliability or lead to inefficient generation decisions interfering with least-cost planning.

Setting aside the confusion sown by EKPC's inconsistent responses, Joint Intervenors respond further based on our best understanding of the information EKPC has disclosed: namely, that EKPC's 2007-vintage power flow analysis seems to be its only data source attempting to quantify the extent of load shedding requirements that might result without both Cooper Station units online,[60] a risk that persists to this day.[61] If this is indeed the case, Joint Intervenors express concern that EKPC's understanding of its current transmission system, and by extension, implications for its generation resources, is based on wildly out-of-date information, able to support only spurious conclusions.

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[59] *Id.*

[60] Response to JI Supplemental Q21e.

[61] Response to JI Supplemental Q21c; Response to AG Initial Q1c.

Given the paramount importance of reliability and least-cost planning, EKPC should be pursuing more frequent analysis of this issue using the most-recent data available and in service of realizing increased efficiencies and reliability in its provision of electric service.[62] Once EKPC had an analysis indicating "that a nine-county area stretching from Adair County to Clay County could be impacted by cascading transmission outages and localized blackouts," with estimated load shedding as high as 175 MW,[63] Joint Intervenors would expect to see some indication that EKPC continued routine analysis of that reliability risk and prioritized transmission upgrades and expansions addressing it.

Further, Joint Intervenors question the reasonableness of EKPC's continued reliance on that 2007 analysis in light of the many changes since that time. As EKPC would know better than anyone (except perhaps PJM), a robust list of projects to maintain and expand its transmission system have been implemented since 2007.[64] In the intervening fifteen years, EKPC has also added and expanded interconnections with neighboring systems and joined PJM's system.[65] Perhaps these changes explain why, for example, EKPC did not experience a load shedding event when both Cooper Station units tripped offline in February 2021 during a major ice storm that also caused several transmission line outages in the area[66]—the then-current

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[62] 807 KAR 5:058 Section 5(4); *id.* Section 8(2)(a).

[63] Response to JI Supplemental Q21e.

[64] *E.g.* Response to JI Supplemental Q25b (listing transmission projects EKPC placed in service in the Southern Kentucky area since the 2007 power flow analysis provided in evidence in KY PSC No. 2007-00168).

[65] *See* 2022 Integrated Resource Plan of East Kentucky Power Cooperative, Inc (Public), Section 6, Transmission and Distribution Planning at 124, 126-127 ("EKPC 2022 IRP").

[66] Response to JI Supplemental Q21e.

transmission system and resources connected to EKPC's system were quite different than they were at the time of Witness Lamb's 2007 testimony.

Beyond its stale character, Joint Intervenors note that the 2007 power flow analysis does not appear to have analyzed isolated simultaneous outages of the Cooper Station Units, with the Wolf Creek Dam generators remaining online. Based on Witness Lamb's summary, it appears that the 2007 power flow analysis assumed simultaneous outages of Cooper Unit 1, Cooper Unit 2, and the Wolf Creek Dam generating units, and that Witness Lamb's final projection of widespread outages may apply only in that more extreme scenario.[67] Clarification on that point from EKPC would be helpful, so that the Commission, Staff, and stakeholders have a clearer understanding of these reliability challenges. Also helpful for purposes of present-day resource planning, EKPC should be performing power flow analyses that evaluates transmission system implications if and when either Cooper Station unit, or both Cooper Station units, are retired.

Whatever has or has not taken place over the past fifteen years to relieve this transmission constraint, Joint Intervenors are encouraged to know that EKPC is currently undertaking an analysis of potential transmission-system modifications to address it.[68] Whenever EKPC's staff completes its review of those power-flow analysis results,[69] Joint Intervenors further encourage EKPC to submit those results into the record of this integrated resource plan proceeding. That information is critical to meaningful integrated resource planning in all IRP

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[67] Response to JI Supplemental Q21b (noting that reduced water levels would simultaneously make hydroelectric generating units at Wolf Creek Dam unavailable; and that "[a]nalysis of potential voltage collapse issues in the area for double contingencies with the Cooper and Wolf Creek generating units off has also been performed"; and finding that "a substantial risk of transmission system problems int eh south-central Kentucky area exists if the Cooper and Wolf Creek generating units are unavailable during high load periods").

[68] Response to JI Supplemental Q21c.

[69] *Id.*

iterations, but particularly so here in light of EKPC's economic outlook for the Cooper Station units, the units' advanced age, and significant market- and operational-headwinds for coal-fired power.[70]

D. Especially in light of Cooper Station's economic outlook, integrated analysis of and action to relieve this particular transmission constraint should be undertaken without delay.

As summarized in the attached EFG Report, independent review of EKPC's modeling reveals that EKPC expects both Cooper Station units to [[BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]].[71] Remarkably, even after forecasting [[BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]] from operation of those units, EKPC did not undertake to evaluate whether its member-owners might obtain a net benefit by retiring those units and replacing them with more economically-competitive generation and non-wires solutions.[72] Doubly so in light of the fact that EKPC has sufficient capacity through the year 2032 (perhaps even 2034), and that capacity position holds up even against forecasted load growth that dramatically exceeds compound annual growth rates on EKPC's system at any time over the last decade.[73] Meaning, even if we accept EKPC's forecasts and modeling results at face value, it appears they could meet their capacity obligations over the coming decade at a lower overall cost without the Cooper Station units.

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[70] EFG Report, sec. 4.1 (addressing coal price forecasts generally) and 5 (addressing economic outlook for Cooper Station); *see also* Response to AG Initial Q21s ("The coal market is currently tight, putting upward pressure on price . . ."); Response to AG Supplemental Q38a.

[71] EFG Report, sec. 5

[72] Response to JI Initial Q38; Response to Sierra Club Initial Q6 ("There have been no studies for unit retirements of the EKPC fleet.")

[73] EFG Report, sec. 3 (addressing load forecast).

Despite that outlook, two factors appear to be driving EKPC decision not to evaluate an economically optimal retirement horizon for Cooper Station: (1) its long-known but apparently never addressed transmission constraint;[74] and (2) Cooper Station units' undepreciated net book value.[75] Remedies for both factors are at hand, and should be actively evaluated without delay. With respect to transmission upgrades, there are myriad options capable of providing additional voltage support, for example: upgrades to existing transmission line(s); upgrades to existing transformer(s); new transmission line(s); new substation(s); and static volt-ampere reactive compensators ("SVC") or fast-switched capacitor bank(s). Through our data requests, the Joint Intervenors inquired about each of these options, and EKPC is currently studying benefits of a new transmission line, which may include expanded or new substations, and a fast-switched capacitor bank or SVC.[76] Upgrades to existing transmission lines or transformers appear to have been ruled out without study.[77]

Regarding the possible transmission solutions EKPC is studying, preliminary cost estimates look promising. In response to Joint Intervenors' Supplemental Request 22c, EKPC provided a bulleted list of seven specific transmission line projects, with planning-level cost

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[74] Response to JI Supplemental Q21a.

[75] Response of East Kentucky Power Cooperative, Inc. to Nucor Steel Gallatin's Initial Discovery Requests, Question 1 (August 30, 2022) ("Response to Nucor Supplemental Q").

[76] Response to JI Supplemental Q22c-e.

[77] Response to JI Supplemental Q22a ("**EKPC has not studied the potential** to upgrade an existing transmission line to provide adequate voltage support if Cooper Station generating units are retired. Due to the widespread nature of the voltage support required, **EKPC is not aware of** any single transmission line (or even a set of a few transmission lines) that could be upgraded to provide adequate voltage support.") (emphasis added); Response to JI Supplemental Q22b ("**EKPC has not studied** the potential to upgrade existing transformers to provide adequate voltage support if Cooper Station generating units are retired. Due to the widespread nature of the voltage support required, **EKPC is not aware** of any existing transformers that could be upgraded to provide adequate voltage support.") (emphasis added).

estimates ranging from $27 million to $110 million.[78] The four lowest cost options are $40M or less, ballpark.[79]

Also of note, EKPC need not limit itself to its current focus "on transmission infrastructure additions that could bolster support in the area."[80] There are also demonstrated non-wires solutions that merit study, and Joint Intervenors would encourage EKPC to evaluate those potentially cost-effective options as well. For example, EKPC might study the potential to convert the Cooper Station units into synchronous condensers, as FirstEnergy did roughly eight years ago at its Eastlake coal generating units in Ohio.[81]

EKPC should also evaluate the potential to deploy utility-scale storage behind Cooper Station's point of interconnection, which standing alone or along with additional transmission upgrades, could enable EKPC to use stored energy to meet peak demands. Importantly, and contrary to the expectations at the time EKPC completed its IRP, passage of the Inflation Reduction Act makes direct pay of tax credits for storage resources available to EKPC, along with a number of stackable adders EKPC could likely qualify for, as summarized in Section II above. IRA Section 22001 also makes USDA Section 317 Loans newly available for storage resources, backed with a one-billion-dollar authorization, and direction to the USDA to develop

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[78] Response to JI Supplemental Q22c (note that planning-level cost estimates refers to +100/-50% accuracy).

[79] *Id.*

[80] Response to JI Supplemental Q22f.

[81] Press Release, FirstEnergy Corp., FirstEnergy Completes Transmission Projects to Boost Electric Reliability in Northern Ohio (June 1, 2015), https://investors.firstenergycorp.com/investor-materials/news-releases/news-details/2015/FirstEnergy-Completes-Transmission-Projects-to-Boost-Electric-Reliability-in-Northern-Ohio/default.aspx.

guidelines for loan forgiveness.[82] These and other non-wires solutions should be evaluated, and EKPC should carefully track USDA's progress on the development of loan forgiveness criteria under this program.[83]

Turning to the second challenge of Cooper Station—its undepreciated book value—the EFG report addresses this issue in detail and emphasizes the importance of analyzing the early retirement of these generators. The Inflation Reduction Act again offers opportunities for EKPC. IRA Section 50144 creates an Energy Infrastructure Reinvestment Loan Program, administered by the Department of Energy, that may provide an avenue for EKPC to refinance its remaining Cooper Station debt as part of a project to replace those units with zero-emitting generation or storage resources.[84] This looks to be a well-funded program, enabling up to $250 billion in low-cost loans to generation asset owners across the country. These DOE loans will only be available through 2026.[85] EKPC needs to take action now to explore whether this financing opportunity could enable the cost-effective retirement of Cooper Station and open the door to lower-cost power for its member-owners and not miss out on economic development opportunities for the communities its member-owners serve.[86]

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[82] *Supra* Section II; IRA Section 22001 (amending 7 U.S.C.A § 8103(h)(1) to require that loans under the Rural Electrification Act "shall be forgiven in an amount that is not greater than 50 percent of the loan based on how the borrower and the project meets the terms and conditions for loan forgiveness" and directed the establishment of criteria for waiving that 50 percent limitation, creating potential for full loan forgiveness).

[83] Response to JI Supplemental Q22f.

[84] *Supra* Section II; IRA Section 50144 (appropriating funds, creating commitment authority in the Secretary of Energy, and amending 42 U.S.C.A. § 16517).

[85] IRA Section 50144(a).

[86] *See e.g.*, Christian Fong, et al., *The Most Important Clean Energy Policy You've Never Heard About*, Rocky Mountain Institute (Sept. 13, 2022), https://rmi.org/important-clean-energy-policy-youve-never-heard-about/.

In sum, Joint Intervenors hope that EKPC is able to clarify the record and reconcile its inconsistent and concerning responses, providing adequate reassurance that reliable service and least-cost planning do in fact guide its long-range planning. Joint Intervenors further urge Commission Staff to recommend that EKPC's future IRPs take care to evaluate the integrated nature of transmission, distribution, generation, and demand-side investments. Where transmission and distribution limitations constrain generation decisions or present reliability challenges, EKPC should transparently discuss those issues, commence studies based on the best-available information, and undertake implementation of the most cost-effective solutions, which may include some combination of wires-based and non-wires solutions.

IV. Equitable Utility Investments Can Help Households and Small Businesses Take Advantage of Efficiency Opportunities, and Now Is a Great Time For EKPC to Re-Double Its Support.

Like EKPC, Joint Intervenors recognize the significant and urgent need for greater affordability and economic opportunity across eastern Kentucky and in the territories of EKPC's member-owner distribution cooperatives. Mountain Association, in particular, is dedicated to serving these same communities and contributing to meeting these urgent needs. To that end and in partnership with EKPC, Mountain Association has long-supported equitable utility investments directly to retail customers through the How$mart (aka Kentucky Home Energy Retrofit Rider) program. With expanded federal funding newly available to households across eastern Kentucky, pairing rebates with equitable utility investments can be a critical means of bridging the affordability gap to make weatherization and efficiency upgrades possible for many. Here, Joint Intervenors will summarize EKPC's experience and role with respect to this tool given its structure as a generation and transmission cooperative, and share a vision of what EKPC could do to further support its owner-members in this regard.

First, Joint Intervenors address the appropriateness of EKPC considering equitable utility investments in its long-range generation and transmission planning. Although EKPC's IRP does not directly address the equitable utility investment program of several of its owner-members—currently, the Kentucky Energy Retrofit Rider—the program's impact bears directly on EKPC's load forecast, and by extension, its future sense of energy and capacity needs. This relationship to load forecasts and peak demands is practically similar to the effect of investment in energy efficiency programs generally. The difference, of course, is that in a service territory where so many households have limited incomes, pairing direct investment in those homes is often needed to make energy efficiency programs accessible. EKPC can play a role in supporting its owner-members in relation to this program as a means of reducing or deferring the need to invest in supply-side generation.

At the same time, Joint Intervenors acknowledge that the Kentucky Energy Retrofit Rider has not been deployed to a scale that would make it likely, in the near-term, to contribute significantly to deferring or avoiding capital investment in supply-side resources.[87] Nevertheless, it still warrants attention in EKPC's IRP because there is a role for EKPC in its implementation by member-owners, and this existing model is a potentially cost-effective means of reducing load through retail customer energy savings.[88] For example, Ouachita Electric Cooperative in Arkansas credited equitable utility investments as a key contributor to a 4.5% decrease in rates, after implementing a three-year Pay As You Save efficiency program that reached 10% of its residential members, with those members averaging a greater than 16% reduction in monthly

[87] Response to JI Initial Q92.

[88] 807 KAR 5:058 Section 8(1)–(2).

bills.[89] This example illustrates the potential for this model to contribute to meeting shared goals of offering safe, reliable, and affordable energy to customers.

As it stands today, several of EKPC's owner-members offer equitable investments to retail customers through the Kentucky Energy Retrofit Rider: Big Sandy Rural Electric Cooperative ("RECC"), Farmers RECC, Fleming-Mason Energy, Grayson RECC, Jackson Energy Cooperative, and Licking Valley RECC.[90] These owner-members are among a set of utilities across ten states that have collectively leveraged in excess of $50 million directly to customers, which has indirectly supported manufacturers, distributors, and installers of DSM measures.[91] Collectively, the cost recovery rate of these programs exceeds 99.5%.[92] In effect, the Kentucky Energy Retrofit Rider lets participating owner-members invest in efficiency and energy waste reduction as if it were a supply-side resource.

With that model, the Kentucky Energy Retrofit Rider is a gap-filler, reducing barriers to customer adoption of demand-side management resources and barriers to participation in utility-sponsored DSM/EE programs by providing access to low-cost capital directly to customers. It is well-known that some customers especially need that up-front help, and without it are less able to maintain affordable monthly electric bills. Renters, low-income households, and fixed-income

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[89] National Rural Utilities Cooperative Finance Corporation News, *Solar + Efficiency + Innovation = Lower Rates for Arkansas Co-op Members* (Dec. 16, 2019), https://www.nrucfc.coop/content/nrucfc/en/news/stories/solar---efficiency---innovation---lower-rates-for-arkansas-co-op.html.

[90] Response to JI Initial Q92.

[91] Energy Efficiency Institute Inc., 2022 PAYS Status Update, http://www.eeivt.com/wp-content/uploads/2022/03/2022-PAYS-Status-Update_3_29_22.pdf .

[92] *Id.*

households are disproportionately prevented from making efficiency improvements without assistance.

Substantial federal investment in weatherization and efficiency rebates, surveyed above in Section II, are real, but by themselves will not reach some of the most vulnerable and energy insecure households in the country or the commonwealth. Through its member cooperatives, EKPC serves a great many households in that category. As EKPC recently explained, many of the retail customers served by its assets "literally, are faced with a regular choice between food, electricity and medicine."[93] By EKPC's estimates, it serves 40 counties experiencing persistent poverty; and roughly 42% of its customers are elderly, many dependent on government assistance, on fixed incomes, and living in "energy-leaking mobile homes."[94]

With its six owner-members showing the path, EKPC can be a difference-maker across its service territory for these customers.[95] Joint Intervenors encourage EKPC's continued collaboration in developing administrative and outreach support to make its Kentucky Energy Retrofits Rider easy for all its owner-members to take up.

EKPC can also be a critical partner in supporting and facilitating the small-businesses that its owner-members will rely on to implement and carry this model forward to more households. To date, Mountain Association has been able to assist with that practical implementation piece, and Mountain Association has been upfront about its inability to take these programs to scale. Mountain Associations' vision for these programs is to drive both

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[93] *E.g.*, EKPC Comments on Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone NAAQS Proposed Rule, at 3 (June 22, 2022) Docket EPA-HQ-OAR-2021-0668-0372, https://www.regulations.gov/comment/EPA-HQ-OAR-2021-0668-0372.

[94] *Id.*

[95] *Id.* ("EKPC has a strong interest in keeping energy affordable to assist its 16 Owner-Member cooperatives in serving people facing the harsh realities of today's economy.").

customer affordability *and* small-business development and job growth across eastern Kentucky. Mountain Association's success in this will be measured by its ability to step back from direct implementation, with home-grown, for-profit enterprises taking over.

V. EKPC's IRP Should Fully Evaluate Distributed Energy Resources On-Par With Traditional Supply- and Demand-Side Resources.

Following review of EKPC's 2019 IRP, Staff recommended that EKPC provide discussion of battery storage and distributed energy resources,[96] and the current IRP does include a responsive discussion.[97] That discussion is appreciated, but the current IRP could do more to assess the potential benefits of distributed energy resources to EKPC's system, particularly with respect to battery storage. EKPC should better incorporate distributed energy resources ("DERs") into their resource planning and modeling, taking care to evaluate DERs on par with traditional supply- and demand-side resources.[98] Section 8 of the attached EFG Report provides technical observations and recommendations for consideration by EKPC and Commission Staff, and here, Joint Intervenors offer brief additional comment on these resources.

Although DERs played a less prominent role in electric service and markets when the Commission adopted the IRP regulation as compared to today, the regulation includes provisions calling for their consideration in the course of integrated resource planning. First, as a general

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[96] IRP at 38.

[97] IRP at 38–56.

[98] 807 KAR 5:058 Section 8(2)(d) ("The utility shall describe and discuss all options considered for inclusion in the plan including . . . (d) assessment of nonutility generation, including generating capacity provided by cogeneration, technologies relying on renewable resources, and other nonutility sources."); *id* Section 8(3)(d) ("The following information regarding the utility's existing and planned resources shall be provided. . . . (d) Description of existing and projected amounts of electric energy and generating capacity from cogeneration, self-generation, technologies relying on renewable resources, and other nonutility sources available for purchase by the utility during the base year or during any of the fifteen (15) forecast years of the plan.").

matter, the IRP regulation is expansively written, calling on utilities to search out a "resource assessment and acquisition plan for providing an adequate and reliable supply of electricity to meet forecasted electricity requirements at the lowest possible cost," including assessment of potentially cost-effective resource options.[99] Within a non-exhaustive list of potentially cost-effective resource options, Section 8 continues to require an "[a]ssessment of nonutility generation, including generating capacity provided by cogeneration, technologies relying on renewable resources, and other nonutility sources."[100] Nonutility generation should include customer-owned distributed generation, including solar and storage resources.

Joint Intervenors emphasize that analysis of DERs is worthwhile because these resources have the potential to offer significant energy and peak demand savings, and contribute to a more reliable, resilient grid. These benefits can be achieved at a very low cost to the utility when the investment is made by the customer, who also covers all operational and maintenance costs, as occurs with net metering for distributed solar resources, Qualifying Facilities, on-site storage, and many energy efficiency measures. Far from being a threat to reliability or resilience, strategically deployed DERs can maintain service to critical loads, provide energy self-sufficiency, and increase Kentucky's resilience against natural disasters.[101]

EKPC's IRP notes that approximately 9,023 kW of solar photovoltaic installations currently participate in its member cooperatives' net metering tariffs, observing that installations

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[99] 807 KAR 5:058 Section 8(1).

[100] 807 KAR 5:058 Section 8(2).

[101] *See, e.g.*, Smart Electric Power Alliance, *Commonwealth of Kentucky Regional Microgrids for Resilience Study* at Section 0.0 Executive Summary (April 2021), https://eec.ky.gov/Energy/Documents/SEPA%20Kentucky%20Regional%20MG%20Study_April%202021.pdf (summarizing potential to serve critical facilities via distributed resources).

"continue[] to grow as solar voltaic prices continue to decrease."[102] However, the IRP does not appear to provide any specific attempt to forecast adoption rates or provide substantive discussion on the avoided cost benefits associated with customer-owned generation. Joint Intervenors encourage EKPC to model growth rates for solar, and DERs generally, under multiple scenarios. With passage of the IRA, the availability of tax credits for solar and storage resources—whether combined or on a stand-alone basis—will make these resources even more affordable and advantageous for individual customers.

In future IRPs, the growth rates of DERs should be modelled under multiple scenarios, including those in which net metering is allowed to expand above the 1% minimum required by statute.[103] Importantly, there is no statutory cap on net metering prescribed under Kentucky law. Rather, KRS 278.466 requires all regulated utilities to provide net metering up to 1% of the supplier's single hour peak load, leaving availability of net metering beyond that point to the discretion of each utility.[104] Consistent with general obligations to provide reliable, low-cost service, each utility should be analyzing system benefits up to and beyond the 1% minimum, and such analysis should be incorporated into integrated resource planning. Without this analysis, EKPC may overlook the potential for DERs to reduce system costs and more cost-effectively meet their customers' energy needs. Ignoring DERs within the IRP process could lead a utility to overstate its peak load, energy requirements, and capacity needs.

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[102] IRP at 164–65.

[103] KRS § 278.466.

[104] KRS § 278.466(1) ("If the cumulative generating capacity of net metering systems reaches one percent (1%) of a supplier's single hour peak load during a calendar year, the supplier shall have no further obligation to offer net metering to any new customer-generator at any subsequent time.").

For example, in Louisville Gas & Electric and Kentucky Utilities Companies' ("LG&E/KU") Joint 2021 IRP, LG&E/KU provided a forecast of distributed generation resources under multiple scenarios, including a scenario where net metering was offered above the 1% minimum required by law.[105] In LG&E/KU's forecast, with expanded net metering, adoption of distributed solar generation significantly increased, rising from below 100 MW to over 500 MW by 2030.[106] To be sure, EKPC's service territory is distinct, and this example is not intended to be a demonstration of what one might expect within EKPC's territory. Rather, it reflects the value of attempting to analyze the question, in furtherance of long-range resource planning.

A comprehensive benefit-cost analysis can identify the value that DERs provide to EKPC, its member cooperatives, and their customers. This benefit-cost analysis should be conducted following the principles identified by the Commission in the Kentucky Power Co. rate case no. 2020-00174[107], and the methods detailed in the *National Standard Practice Manual for Benefit Cost Analysis of Distributed Energy Resources* ("NSPM-DER").[108] The NSPM-DER "provides objective, policy- and technology-neutral, and economically sound guidance for developing jurisdiction-specific approaches to benefit-cost analyses of distributed energy resources."[109]

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[105] Louisville Gas and Electric Company and Kentucky Utilities Company Joint 2021 Integrated Resource Plan, Vol. I at 5-29, Case No. 2021-00393 (Oct. 19, 2021).

[106] *Id.*

[107] Order at 21–24, *In the Matter of Elec. Application of Ky. Power Co. for a Gen. Adjustment of Its Rates for Elec. Serv.*, Case No. 2020-00174 (May 14, 2021).

[108] National Standard Practice Manual For Benefit-Cost Analysis of Distributed Energy Resources, (Aug. 2020), www.nationalenergyscreeningproject.org/national-standard-practice-manual/ ("NSPM-DER").

[109] NSPM-DER at i.

The Commission recently applied the following principles to evaluation of Kentucky Power Company's net metering tariff, *inter alia*: Those principles are:

- Evaluate eligible generating facilities as a utility system or supply side resource.
- Treat benefits and costs symmetrically.
- Conduct forward-looking, long-term, and incremental analysis.
- Avoid double counting.
- Ensure transparency.
- The Order noted the additional principles of stability and simplicity.

While the immediate context of that case was net metering, these principles are generally applicable to all distributed resources, and useful in determining a consistent methodology to account for DER costs and benefits in resource planning.

Lastly, Joint Intervenors note that distributed energy resources can strengthen the grid, improving both reliability and resilience. These are legitimate resources, deserving of a hard look in integrated resource planning. By way of example, with funding from the U.S. Department of Energy's State Energy Program, and support of the Kentucky Energy and Environment Cabinet Office of Energy Policy, the Smart Electric Power Alliance recently undertook a study of in-state potential to deploy nanogrids and community microgrids in high-risk areas.[110] While the Joint Intervenors do not endorse the report in its entirety, nonetheless, it may serve as a resource to EKPC in evaluating its own potential role in developing distributed energy resources and microgrids in its territory. For example, the authors provide criteria to consider with respect to

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[110] Smart Electric Power Alliance, *Commonwealth of Kentucky Regional Microgrids for Resilience Study* at Section 0.0 Executive Summary (April 2021), https://eec.ky.gov/Energy/Documents/SEPA%20Kentucky%20Regional%20MG%20Study_April%202021.pdf.

strategic placement of distributed resources, including proximity to critical infrastructure, areas with high natural hazard risks, areas with known reliability challenges, and areas with notably high energy burdens for retail customers, among others.[111]

Also of note, the economic potential to develop microgrids and site distributed energy resources in critical locations across EKPC's territory improved with passage of the IRA. Just as the IRA makes investment and production tax credits for renewable resources (including storage) available to EKPC as a non-profit cooperative, other tax-exempt entities like hospitals, schools, and non-profits are newly able to take advantage of those tax credits and adders as well. Working in partnership with member distribution cooperatives and the communities they serve, there is considerable potential for EKPC to strategically encourage distributed energy resources. It makes sense to discuss and evaluate that potential in the course of integrated resource planning.

In sum, DERs encompass a wide range of resources, including on-site generation, storage, and energy efficiency measures, which provide well-known benefits and services to the utility and their customers. These resources are becoming much more widespread, their technologies are advancing, their costs are falling, and they are increasingly supported by incentive programs such as the Inflation Reduction Act. EKPC's IRP process should thoroughly evaluate DER's and the opportunity to leverage private investment in combination with Federal incentives to help supply their customers with reliable, affordable, and clean electricity services.

CONCLUSION

Joint Intervenors appreciate this opportunity to provide initial comments and recommendations related to EKPC's 2022 Integrated Resource Plan. As this proceeding

[111] *Id.* at 1–2.

continues, Joint Intervenors hope to come to greater understanding of the state of EKPC's long-range planning efforts through constructive dialogue and informal collaboration. As noted above, Joint Intervenors share EKPC's goal of providing reliable, low-cost service to the communities its generation and transmission assets ultimately serve, and look forward to the significant opportunities for supply- and demand-side resources on EKPC's system and the associated economic development and job growth opportunities for Kentucky.

Respectfully submitted,

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CERTIFICATE OF SERVICE

In accordance with the Commission's July 22, 2021 Order in Case No. 2020-00085, Electronic Emergency Docket Related to the Novel Coronavirus COVID-19, this is to certify that the electronic filing was submitted to the Commission on October 11, 2022; that the documents in this electronic filing are a true representations of the materials prepared for the filing; that no hard copy of this filing will be made; and that the Commission has not excused any party from electronic filing procedures for this case at this time.

Ashley Wilmes