COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

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

O R D E R

The Commission initiated this proceeding for Commission Staff to conduct a review of the 2022 Integrated Resource Plan (IRP) filed by East Kentucky Power Cooperative, Inc. (EKPC), pursuant to 807 KAR 5:058. Attached as an Appendix to this Order is the Commission Staff's Report summarizing Commission Staff's review of the IRP. Pursuant to 807 KAR 5:058, Section 11(3), Commission Staff's Report, attached to this Order as an Appendix, shall be entered into the record of this case.

Based on the evidence of record, the Commission finds that the Commission Staff's Report represents the final substantive action in this matter. The final administrative action will be an Order closing the case and removing it from the Commission's docket. That Order will be issued after the period for comments on the Staff Report has expired.

IT IS THEREFORE ORDERED that:

1. The Commission Staff's Report on EKPC's 2022 IRP represents the final substantive action in this matter.

2. Any party desiring to file comments regarding the Commission Staff's Report on EKPC's 2022 IRP shall do so on or before March 21, 2023.

3. EKPC shall file comments with respect to the Commission Staff's Report and in response to Intervenor comments on or before April 4, 2023.

4. An Order closing this case and removing it from the Commission docket shall be issued after the period for comments on the Commission Staff's Report has expired.

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PUBLIC SERVICE COMMISSION

Chairman

Vice Chairman

Commissioner

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KENTUCKY PUBLIC
SERVICE COMMISSION

ATTEST:

Executive Director

APPENDIX

AN APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2022-00098 DATED MAR 09 2023

FORTY-FIVE PAGES TO FOLLOW

Kentucky Public Service Commission

Commission Staff's Report on the

2022 Integrated Resource Plan

of East Kentucky Power Cooperative, Inc.

Case No. 2022-00098

March 9, 2023

SECTION 1

INTRODUCTION

In 1990, the Kentucky Public Service Commission (Commission) promulgated 807 KAR 5:058 to create an integrated resource planning process to provide for review of the long-range resource plans of Kentucky's jurisdictional electric generating utilities by Commission Staff. The Commission's goal was to ensure that all reasonable options to meet projected load were being examined in order to provide ratepayers a reliable supply of electricity that is cost-effective.[1]

East Kentucky Power Cooperative, Inc. (EKPC) filed its 2022 Integrated Resource Plan (2022 IRP) on April 1, 2022. EKPC is a not-for-profit, member-owned generation and transmission cooperative located in Winchester, Kentucky.[2] EKPC provides electricity to 16 owner-member distribution cooperatives with more than 550,000 meters at homes, farms, and businesses in 87 Kentucky counties.[3] EKPC does not directly serve any retail customers.[4] Its owner-members include Big Sandy RECC, Jackson Energy Cooperative, Blue Grass Energy Cooperative, Licking Valley RECC Clark Energy Cooperative, Nolin RECC, Cumberland Valley Electric, Owen Electric Cooperative, Farmers RECC, Salt River Electric Cooperative, Fleming-Mason Energy Cooperative, Shelby Energy Cooperative, Grayson RECC, South Kentucky RECC, Inter-County Energy Cooperative, and Taylor County RECC.[5] EKPC's 2022 IRP reflects its resource plan for meeting owner-members' electricity requirements for the 2022 to 2036 planning period.[6]

EKPC owns and operates coal-fired generation at the John Sherman Cooper Station in Pulaski County (341 MW) and the Hugh L. Spurlock Station in Mason County (1,346 MW).[7] EKPC owns and operates gas-fired generation at the J.K. Smith Station in Clark County (989 MW winter rating) and Bluegrass Generation Station in Oldham County (567 MW winter rating).[8] EKPC also owns and operates Landfill Gas to Energy renewable generation facilities in Boone County (4.6 MW), Laurel County (3.0 MW), Barren County (0.9 MW), Greenup County (2.3 MW), Hardin County (2.3 MW), and Pendleton County

[1] *See* Admin. Case No. 308, *An Inquiry into Kentucky's Present and Future Electric Needs and the Alternatives for Meeting Those Needs* (Ky. PSC Aug. 8, 1990), Order at 1–3. *See also* 807 KAR 5:058.

[2] 2022 IRP, Section 1 at 1.

[3] 2022 IRP, Section 1 at 1.

[4] 2022 IRP, Section 1 at 1.

[5] 2022 IRP, Section 1 at 1.

[6] 2022 IRP, Section 1 at 3.

[7] 2022 IRP, Section 1 at 1.

[8] 2022 IRP, Section 1 at 1.

(3.0 MW).[9] EKPC owns an 8.5 MW solar generation facility in Clark County.[10] EKPC purchases 170 MW of hydropower from the Southeastern Power Administration (SEPA) on a long-term basis, generated from the Cumberland River hydropower system.[11] Laurel Dam (70 MW) historically has been a reliable resource. In total, EKPC owns or purchases 3,438 MW (winter rating) or 3,136 MW (summer rating) of generation.[12] EKPC operates within the PJM Interconnection, LLC (PJM) Regional Transmission Organization (RTO), which has more than 180,000 MW of generation capacity.[13] EKPC owns and operates a 2,968-circuit mile network of high voltage transmission lines consisting of 69 kV, 138 kV, 161 kV, and 345 kV lines, and all the related substations.[14] EKPC is a member of the Southeast Electric Reliability Council (SERC).[15] EKPC maintains 77 normally closed free-flowing interconnections with its neighboring utilities.[16]

EKPC states that its strategic objectives include (1) actively managing its current and future asset portfolio to safely deliver reliable, affordable and sustainable energy from appropriately diversified resources, and (2) working with federal and state stakeholders to ensure high reliability and economic viability while mitigating evolving regulatory challenges including possible carbon emissions reduction mandates.[17] EKPC set out the following anticipated actions designed to achieve these objectives: (1) monitoring economic and load growth conditions including distributed generation, (2) developing and promoting cost-effective Demand-Side Management (DSM) programs, (3) monitoring sustainable energy resources and obtaining resources through Power Purchase Agreements as needed to meet strategic and load driven directives, (4) evaluating energy price hedges for winter seasons and review against market and owned-generation options, (5) maximizing the operational and economic benefits realized by being a member of PJM, (6) working with federal and state stakeholders to ensure the economic viability of EKPC's existing and future resources to meet the challenges and opportunities in complying with current and proposed environmental regulations, and (7) advocating for rules and policies that resolve the current PJM interconnection queue backlog.[18]

On June 1, 2022, an Order was entered establishing a procedural schedule for the review of EKPC's 2022 IRP. The procedural schedule established a deadline for

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[9] 2022 IRP, Section 1 at 1.

[10] 2022 IRP, Section 1 at 1.

[11] 2022 IRP, Section 1 at 2.

[12] 2022 IRP, Section 1 at 2.

[13] 2022 IRP, Section 1 at 2.

[14] 2022 IRP, Section 1 at 2.

[15] 2022 IRP, Section 1 at 2.

[16] 2022 IRP, Section 1 at 2.

[17] 2022 IRP, Section 1 at 2.

[18] 2022 IRP, Section 1 at 9.

requesting intervention, two rounds of requests for information to EKPC, and an opportunity for intervenors to file written comments regarding the IRP and indicated that a hearing and additional comments from intervenors and EKPC would be scheduled. On July 28, 2022, the procedural schedule was amended to allow EKPC additional time to respond to requests for information.

The Attorney General of the Commonwealth of Kentucky, by and through the Office of Rate Intervention (Attorney General), Nucor Steel Gallatin, and Sierra Club were permitted to intervene in this matter pursuant to 807 KAR 5:001. Kentuckians for the Commonwealth, Kentucky Solar Energy Society, and Mountain Association (Joint Intervenors), who are represented by the same counsel, were permitted to jointly intervene in this matter.

EKPC responded to two rounds of request for information from intervenors and Commission Staff. Intervenors filed comments regarding EKPC's IRP on October 11, 2022, and EKPC filed comments in response on November 1, 2022. An in-person hearing was held on December 13, 2022. A post-hearing procedural schedule was issued on December 16, 2022, that set deadlines for filing additional comments and responses. EKPC and Joint Intervenors filed additional comments on February 3, 2023, and responses on February 17, 2023. Members of the general public were given the opportunity to provide oral comments at the hearing and written comments at any time throughout this case.

After reviewing the information submitted in this case, Commission Staff prepared this report summarizing Commission Staff's review and evaluation of EKPC's 2022 IRP in accordance with 807 KAR 5:058, Section 11(3), which requires Commission Staff to issue a report summarizing its review of each IRP filing and to make suggestions and recommendations to be considered in future IRP filings. Commission Staff's goals when reviewing and evaluating this IRP are to ensure that:

- All resource options are adequately and fairly evaluated;

- Critical data, assumptions, and methodologies for all aspects of the plan are adequately documented and are reasonable; and

- The report includes an incremental component, noting any significant changes from EKPC's most recent IRP filed in 2019.

The remainder of this report is organized as follows:

- Section 2: Load Forecasting—reviews EKPC's projected load growth and load forecasting methodology.

- Section 3: Demand-Side Management and Energy Efficiency (DSM/EE)—summarizes EKPC's evaluation of DSM opportunities.

- Section 4: Supply-Side Resource Assessment—focuses on supply-side resources available to meet EKPC's load requirements and environmental compliance planning.

- Section 5: Integration—discusses EKPC's overall assessment of supply-side and demand-side options and their integration into an overall resource plan.

- Section 6: Reasonableness and Recommendations—discusses Commission Staff's position regarding the reasonableness of the IRP and its assumptions and includes Commission Staff's recommendations.

SECTION 2

LOAD FORECASTING

INTRODUCTION

This Section reviews and comments on the projected load growth of the Member Cooperatives' systems and EKPC's load forecasting methodology. This section also reviews the parties' comments regarding EKPC's load and demand forecast. Commission Staff's discussion of and recommendations regarding EKPC's load and demand forecasting are discussed in Section 6 of this Report.

FORECAST METHODOLOGY

In conjunction with its 16 owner-members, EKPC prepares energy and peak demand forecasts every two years as required by the Rural Utilities Service (RUS). Regional economic views are created by aggregating owner-member service territories, which are then used for analysis and reporting purposes.[19] Individual owner-member forecasts, EKPC's own use, and transmission losses are aggregated to EKPC's total system forecast. The forecasts take into account the impacts of DSM programs, energy efficiency, and demand response programs, and form the basis for determining the level of supply-side and demand-side resources required to meet the needs the owner-members. Owner-members use their load forecasts for developing construction work plans, long range work plans, and financial forecasting. EKPC uses its load forecast for DSM and marketing analyses, transmission planning, power supply planning, and financial forecasting.[20]

Due to the COVID-19 pandemic in 2020 and the attendant drop in load, EKPC produced its 2021-2035 load forecast later in 2020 than usual. IHS Global Insight, Inc. (IHS) supplies economic data and forecasts to EKPC and provided an updated economic forecast in June 2020. EKPC used the updated economic data in its forecast. In addition, working with its owner members, EKPC had sufficient data to perform a 2020 load forecast outside its usual modeling methodology. However, in order to not skew the growth rates, 2020 was excluded from the calculations.[21]

IHS provides county level historic and projected economic and demographic variables to the owner-members and EKPC, including population, employment, and income. The county-level projections are used to derive specific owner-member service

[19] EKPC's Response to Commission Staff's First Request for Information (Staff's First Request) (filed July 29, 2022), Item 33.

[20] IRP, Section 3 at 63.

[21] IRP, Section 3 at 63.

territory projections.[22] The specific service territory boundaries provide the basis for grouping the county level data projections into seven regional territories, each with specific measures of projected economic activity.[23]

For the specific owner-member forecasting models, EKPC transforms the county level data into monthly values. Using measures of regional economic activity that are better aligned with an owner-member's specific service territory provides for more accurate customer and sales growth forecasts.[24] For each owner-member, forecast models are constructed for each customer classification as reported on RUS Form 7. The classifications include residential, seasonal, small commercial and industrial, public buildings, large commercial and industrial, and public street and highway lighting. Summing class sales and distribution losses yields EKPC's sales to owner-members. Individual preliminary forecasts are viewed by owner-members, and after making any necessary adjustments, final forecasts are reviewed and approved by the individual owner-member boards of directors.[25] EKPC's total requirements figure is the summation of sales to owner-members, plus its own use and transmission losses.[26]

KEY ASSUMPTIONS

Over the 2021-2035 forecast period, the number of EKPC residential customers is expected to grow at an annual rate of 0.7 percent, adding approximately 54,000 total residential customers to the system. Employment is also expected to grow at an annual 0.7 percent.[27] As of 2020, 76 percent of all new households had electric heating and about 86 percent had electric water heaters. Nearly all new homes will be equipped with electric air conditioning.[28] All load forecasts are based upon normal weather assumptions from the most recent twenty-year period, 2000-2019. Weather data was obtained from seven different National Oceanic and Atmospheric Administration (NOAA) weather stations, depending upon the location of the specific owner-member service territory.[29]

The load forecast models include the ongoing and projected effects of EKPC's current five-year DSM program plan only and the naturally occurring evolution of

[22] IRP, Load Forecast Technical Appendix, at 13. A geographical information system (GIS) from Environmental Systems Research Institute (ESRI) was used to map service territory and county boundaries.

[23] IRP, Section 3 at 78 and Load Forecast Technical Appendix at 12.

[24] IRP, Section 3 at 70 and Load Forecast Technical Appendix at 13.

[25] IRP, Load Forecast Technical Appendix at 11.

[26] IRP, Load Forecast Technical Appendix at 10.

[27] IRP, Section 3 at 70.

[28] IRP, Section 3 at 70.

[29] IRP, Section 3 at 71.

appliance and household efficiency gains.[30] DSM programs are tailored to meet retail customer needs and serve to delay the addition of new generation.[31] Every two to three years, EKPC conducts a residential survey gathering information on factors affecting electricity demand including electric appliances and saturations, household characteristics, and demographic information. Projections of this data are made as a function of time.[32] As a member of Itron's Energy Forecasting Group, EKPC obtains projections of appliance efficiencies from the Energy Information Administration (EIA) for the East South Central U.S. Census Division. EKPC combines appliance efficiency projections with its residential survey data for use in its residential models.[33]

ENERGY FORECAST

The residential load forecast consists of projections of both the number of customers and use per customer. Owner-member seasonal energy sales are forecast using a statistically adjusted end-use (SAE) model regression analysis. SAE models incorporate appliance end-use forecasts with time series regression analysis and require detailed data on appliance saturations, uses and efficiencies, household characteristics, and weather characteristics, as well as demographic and economic data. Specifically, residential monthly energy sales and number of customers are functions of customer and energy sales history, number of households, population density, employment, real gross county product, real total personal income, consumer price index, base 55 heating degree day (HDD), base 30 HDD, base 65 cooling degree day (CDD), and an autoregressive term.[34] SAE models categorize household energy use into Heating, Cooling, Water Heating, and Other variables. The Other variable captures everything other than heating, cooling, and water heating appliance uses.[35] These variables are used to obtain monthly and annual use per household.[36] The number of residential customers forecast is modeled as a function of population and the number of households. Owner-member results are summed to obtain total system customers and class energy sales. Dividing residential class sales by the number of customers yields total system residential use per customer.[37] EKPC forecasts residential energy sales to grow from approximately

[30] IRP, Section 3 at 65.

[31] IRP, Load Forecast Technical Appendix at 16.

[32] IRP, Load Forecast Technical Appendix at 16.

[33] IRP, Load Forecast Technical Appendix at 16.

[34] IRP, Section 3 at 82.

[35] IRP, Load Forecast Technical Appendix at 14.

[36] IRP, Load Forecast Technical Appendix at 14.

[37] IRP, Load Forecast Technical Appendix at 14.

7,205,739 MWh to 7,991,693 MWh over the 2021-2036 forecast period.[38] This represents a compound annual growth rate of 0.69 percent.

Small commercial and industrial customers are defined as having annual peak demand less than 1 MW. Small commercial and industrial sales and the number of customers is based on regression analysis, the results of which are functions of regional electricity prices, industrial sector employment, and economic activity. Total system use per customer is obtained by dividing forecasted class energy sales by forecasted number of customers.[39] Monthly small commercial energy sales and number of customers is modeled as a function of customer and energy sales history, residential customer counts, number of households, population density, employment, real gross county product, real total personal income, consumer price index, base 55 HDD, base 30 HDD, base 65 CDD, and an autoregressive term.[40] EKPC forecasts small commercial and industrial sales to grow from approximately 1,967,078 MWh to 2,256,693 MWh over the 2021-2036 forecast period.[41] This represents a compound annual growth rate of 0.92 percent.

Large commercial and industrial customers have annual peak demands greater than or equal to 1 MW. Owner-members make their own energy projections, which are based on specific key account knowledge. In addition, owner-members advise EKPC of a known customer leaving their systems or of anticipated additions.[42] EKPC forecasts large commercial and industrial class sales using regression analysis with input from the owner-members. Anticipated new customer growth is explicitly input into the forecast and is distributed among the owner-members using a probabilistic model, which assumes each new customer has a 1.5 MW load with a 60 percent load factor.[43] EKPC forecasts large commercial and industrial customer energy sales to grow from approximately 3,546,763 MWh to 5,640,411 MWh over the 2021-2036 forecast period.[44] This represents a compound annual growth rate of 3.14 percent.

Each of the following customer class sales represent a very small portion of EKPC's total energy sales. Seasonal sales include sales to vacation homes and weekend retreats and camps. Only one owner-member reports seasonal sales, which represent less than 0.1 percent of total EKPC energy sales.[45] Public building sales include sales to

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[38] IRP, Section 3, Table 3-4 at 67. See also IRP, Section 3, Table 3-3 at 66. EKPC forecasts the impact of DSM (energy efficiency and demand response programs) on energy usage as a negative 35,631 MWh in 2021 expanding to a negative 101,652 MWh in 2036.

[39] IRP, Load Forecast Technical Appendix at 15.

[40] IRP, Section 3 at 82.

[41] IRP, Section 3, Table 3-4 at 67.

[42] IRP, Load Forecast Technical Appendix at 15.

[43] IRP, Load Forecast Technical Appendix at 15.

[44] IRP, Section 3, Table 3-4 at 67.

[45] IRP, Section 3 at 87.

government buildings and libraries and account for 0.3 percent of total energy sales.[46] Only two owner-members report this sales class. Public street and highway sales are a function of residential sales and represent 0.07 percent of total energy sales. Sales have been impacted by upgrades to light emitting diode (LED) bulbs. Eleven owner-members report this sales class.[47] Taken together, EKPC forecasts these customer class energy sales to grow from approximately 48,515 MWh to 50,647 MWh over the 2021-2036 forecast period.[48] This represents a compound annual growth rate of 0.29 percent.

The table below presents EKPC's net total energy requirements beginning with the summation of owner member sales and accounting for office and facilities uses, distribution losses, and transmission losses. EKPC's net total energy requirements are forecasted to grow from 13,529,377 MWh to 16,838,980 MWh over the forecast period. This represents a compound annual growth rate of 1.47 percent.

EKPC Net Total Energy Requirements[49]

Year	Total Retail Sales (MWh)	Owner-Member Office Use (MWh)	Average Distribution Losses[1] (MWh)	Sales to Owner-Members (MWh)	EKPC Facilities Use (MWh)	Average Transmission Losses[2] (MWh)	Net Total Requirements (MWh)
2021	12,768,095	10,408	449,737	13,228,240	8,250	292,887	13,529,377
2022	13,628,162	10,408	475,329	14,113,899	8,250	298,913	14,421,062
2023	14,387,878	10,408	481,691	14,879,977	8,250	303,043	15,191,270
2024	14,494,581	10,408	481,307	14,986,296	8,273	310,207	15,304,776
2025	14,581,351	10,408	485,187	15,076,946	8,250	312,082	15,397,278
2026	14,677,212	10,408	490,330	15,177,950	8,250	314,170	15,500,370
2027	14,774,619	10,408	495,025	15,280,053	8,250	316,280	15,604,583
2028	14,908,621	10,408	501,016	15,420,045	8,273	319,172	15,747,490
2029	15,003,086	10,408	506,231	15,519,725	8,250	321,234	15,849,209
2030	15,092,974	10,408	510,397	15,613,779	8,250	323,178	15,945,207
2031	15,198,554	10,408	515,412	15,724,373	8,250	325,464	16,058,087
2032	15,357,518	10,408	522,585	15,890,511	8,273	328,896	16,227,680
2033	15,461,120	10,408	528,312	15,999,840	8,250	331,157	16,339,247
2034	15,613,616	10,408	524,589	16,148,613	8,250	334,232	16,491,095
2035	15,759,257	10,408	531,696	16,301,361	8,250	337,389	16,647,000
2036	15,939,443	10,408	539,581	16,489,432	8,273	341,275	16,838,980

1. Average distribution losses are forecast at 3.8 percent annually.
2. Average transmission losses are forecast at 2.3 percent annually.

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[46] IRP, Section 3 at 88

[47] IRP, Section 3 at 89 and Load Forecast Technical Appendix at 15.

[48] IRP, Section 3, Table 3-4 at 67.

[49] IRP, Section 3, Table 3-4. *See also* EKPC's Response to Commission Staff's Second Request for Information (Staff's Second Request) (filed Sept. 20, 2022), Items 2–4. The forecast results presented in the Load Forecast Technical Appendix did not match information presented in the IRP including Table 3-4. When EKPC reran its forecasts based upon the updated June 2020 IHS economic forecasts, those results were presented in the IRP. Updated forecast results do not appear to have been included in the technical appendix. Information presented in Section 3 of the IRP represents the most up to date forecasts.

PEAK DEMAND AND ALTERNATIVE SCENARIOS

Seasonal peak demand forecasts are a function of normalized historical peaks, summed monthly energy usages, and load factors to determine a base case forecast. For each owner-member, they are obtained by applying winter and summer load factors to forecasted total purchased power.[50] High and low scenarios are then constructed around the base case. EKPC constructs three economic scenarios. The base case economic growth scenario is based on base case economic assumptions and normal weather and is the most likely to occur. The low growth case assumes that the annual increase in energy sales falls short of the base case by the same amount by which the average annual increase in energy sales in the slowest growing ten-year period in the past 20 years falls short of the year average annual increase. The high economic growth scenario assumes that the annual increase in energy sales exceeds the base case by the same amount by which the average annual increase in energy sales in the fastest growing ten-year period in the past 20 years exceeds the 20 year average annual increase.[51]

Weather scenarios include mild and extreme winter and summer weather. The distribution of weather over the 1999-2019 period was used to identify mild and extreme temperatures and seasonal heating degree days and cooling degree days. The scenarios developed include 1-in-30 mild, 1-in-20 normal, 1-in-10 extreme, and 1-in-30 extreme.[52]

The following three tables are EKPC's forecast base case energy and seasonal peak demands and the accompanying scenario analyses results. The base case total energy requirements are forecast to grow at a compound annual growth rate of 1.47 percent ranging from 14,421 GWh to 16,839 GWh over the 2022-2036 forecast period.

EKPC Net Total Energy Requirements (GWh)[53]

Year	Pessimistic Economics Mild Weather	Pessimistic Economics Normal Weather	BASE CASE	Optimistic Economics Normal Weather	Optimistic Economics Extreme Weather
2022	13,455	14,243	14,421	14,768	15,643
2023	14,147	14,936	15,191	15,736	16,610
2024	14,169	14,957	15,305	16,035	16,909
2025	14,170	14,958	15,397	16,317	17,191
2026	14,180	14,968	15,500	16,614	17,489
2027	14,191	14,979	15,605	16,918	17,792
2028	14,238	15,026	15,747	17,269	18,143
2029	14,245	15,033	15,849	17,580	18,454
2030	14,245	15,034	15,945	17,889	18,764
2031	14,262	15,050	16,058	18,223	19,097
2032	14,330	15,118	16,228	18,626	19,500

[50] IRP, Section 3 at 82.

[51] IRP, Load Forecast Technical Appendix at 17.

[52] IRP, Load Forecast Technical Appendix at 17.

[53] IRP, Section 3, Table 3-2 at 65 and Table 3-19 at 91.

2033	14,343	15,131	16,339	18,969	19,844
2034	14,392	15,180	16,491	19,365	20,240
2035	14,444	15,233	16,647	19,773	20,647
2036	14,523	15,309	16,839	20,245	21,116

The scenario analyses create a lower bound (pessimistic economics and mild weather) and an upper bound (optimistic economics and extreme weather) around the Base Case. In 2022, the lower and upper bounds range from 13,455 GWh to 15,643 GWh, which gradually widens to 14,523 GWh to 21,116 GWh by 2036.

The winter peak demand is forecast to grow at a compound annual rate of 1.51 percent from 3,309 MW to 3,586 MW over the forecast period. The scenario analyses create a forecast range around the Base Case ranging from 2,902 MW to 3,824 MW in the 2021-2022 winter heating season and widening to 2,863 MW to 4,816 MW by the 2035-2036 heating season.

EKPC Net Winter Peak Demand (MW)[54]

Year	Pessimistic Economics Mild Weather	Pessimistic Economics Normal Weather	BASE CASE	Optimistic Economics Normal Weather	Optimistic Economics Extreme Weather
2021 - 22	2,902	3,297	3,309	3,414	3,824
2022 - 23	2,904	3,300	3,363	3,476	3,893
2023 - 24	2,904	3,300	3,384	3,538	3,962
2024 - 25	2,893	3,287	3,391	3,586	4,016
2025 - 26	2,890	3,284	3,409	3,646	4,083
2026 - 27	2,889	3,283	3,427	3,708	4,153
2027 - 28	2,896	3,291	3,457	3,783	4,236
2028 - 29	2,890	3,284	3,470	3,841	4,301
2029 - 30	2,882	3,275	3,480	3,897	4,364
2030 - 31	2,876	3,268	3,494	3,957	4,431
2031 - 32	2,880	3,272	3,520	4,032	4,515
2032 - 33	2,873	3,265	3,533	4,093	4,584
2033 - 34	2,874	3,266	3,556	4,167	4,667
2034 - 35	2,875	3,267	3,578	4,241	4,750
2035 - 36	2,863	3,253	3,586	4,302	4,816

The Base Case summer peak demand is forecast to grow at a compound annual growth rate of 0.88 percent from 2,500 MW to 2,794 MW over the forecast period. The scenario analyses create a forecast range from 2,236 MW to 2,947 MW in 2022 with the range widening to 2,233 MW to 3,752 by 2036.

[54] IRP, Section 3, Table 3-2 at 65 and Table 3-20 at 92; EKPC's Response to Staff's First Request, Item 13.

EKPC Net Summer Peak Demand (MW)[55]

Year	Pessimistic Economics Mild Weather	Pessimistic Economics Normal Weather	BASE CASE	Optimistic Economics Normal Weather	Optimistic Economics Extreme Weather
2022	2,236	2,541	2,500	2,631	2,947
2023	2,221	2,524	2,574	2,659	2,978
2024	2,240	2,546	2,612	2,729	3,057
2025	2,236	2,541	2,623	2,772	3,105
2026	2,233	2,537	2,634	2,816	3,154
2027	2,233	2,538	2,651	2,866	3,210
2028	2,235	2,540	2,669	2,919	3,269
2029	2,234	2,539	2,684	2,969	3,325
2030	2,230	2,534	2,695	3,016	3,378
2031	2,227	2,531	2,707	3,064	3,432
2032	2,229	2,533	2,726	3,121	3,495
2033	2,229	2,533	2,742	3,176	3,557
2034	2,231	2,535	2,761	3,234	3,622
2035	2,233	2,537	2,780	3,293	3,688
2036	2,231	2,534	2,794	3,351	3,752

INTERVENOR AND RESPONSE COMMENTS

Joint Intervenors collectively filed comments including a report prepared by Energy Futures Group. Joint Intervenors suggested that EKPC's load forecast projects growth rates that outpace historical growth without explanation.[56] They also recommend that the forecasting methodology address a "gap in the first-year of forecast from the actuals."[57]

EKPC responded that its load forecast made a significant jump due to its largest industrial customer expanding its operations with a new smelting line in 2022, doubling its operations load.[58] Otherwise, the remainder of the load growth was very much in line with current load trends.

[55] IRP, Section 3, Table 3-2 at 65 and Table 3-20 at 93. EKPC's Response to Staff's First Request, Item 13.

[56] Joint Intervenors' Initial Comments at 2 (filed Oct. 11, 2022).

[57] Joint Intervenors' Initial Comments at 4.

[58] EKPC's Response Comments at 7–8 (filed Nov. 1, 2022).

SECTION 3

DEMAND-SIDE MANAGEMENT AND ENERGY EFFICIENCY

INTRODUCTION

Depending on the circumstances, the IRP regulation permits demand-side resources to be assessed as options that could be selected to meet projected load or based on their projected effects on load.[59] This section briefly describes EKPC's existing DSM/EE programs, summarizes how existing programs were reflected in the IRP, and discusses DSM/EE programs EKPC reviewed to meet projected load. This section also reviews EKPC's response to Commission Staff's recommendations regarding DSM/EE in its 2018 IRP and the parties' comments specifically regarding EKPC's DSM/EE programs. Commission Staff's discussion of and recommendations regarding EKPC's DSM/EE forecasting are in Section 6 of this Report.

CURRENT DSM/EE PROGRAMS

EKPC analyzed their DSM/EE program plans for 2022 by including qualitative and quantitative research, which includes member acceptance, demand and energy impacts, savings potential, and cost-effectiveness. The DSM portfolio includes seven energy efficient programs and one demand response program. This section currently includes the following programs:[60]

1. Button-Up Weatherization: This program is designed to increase the energy efficiency of a home's shell by reducing heat loss. Air sealing and attic insulation are the most cost-effective methods to improve a home's energy performance. An incentive is paid based on heat loss reduction which is then measured in British Thermal Units per Hour (BTUH). Homes must be greater than two years old and the primary source of heat must be electricity for customers to be eligible for this program.

2. CARES – Low Income Weatherization: Working with Kentucky Community Action Agencies (CAA), the CARES program provides an incentive to enhance the weatherization and energy efficiency of low-income customers' homes. The program provides installation of weatherization including insulation, air sealing, duct sealing, and a water heater blanket to single family or multi-family homes. Customers with and without a heat pump are eligible for the program and the maximum incentive per household is $2,000.

3. Heat Pump Retrofit: This program provides an incentive to customers to replace their old heat source such as electric furnace, ceiling cable heat, baseboard heat, or electric thermal storage with a more energy efficient heat pump. The program provides a rebate incentive for both centrally ducted systems and mini-split

[59] *See* 807 KAR 5:058, Section 7(3).

[60] 2022 IRP Technical Appendix Volume 2, Exhibit DSM-5at 1–11.

systems. The rebates range from $250 to $750 depending on the equipment type installed.

4. Touchstone Energy (TSE) Home: This program is designed to improve the energy performance of new residential homes by encouraging homes to be built to higher standards for thermal integrity and equipment efficiency as well as installing a more energy efficient heat pump. New residential homes must undergo a variety of inspections and specifications before approval, receive greater than or equal to a 75 on the Home Energy Rating System (HERS), and pass the 2009 International Energy Conservation Code. Homes must be located within the EKPC service territory of a participating owner-member system in order to be eligible.

5. ENERGY STAR® Manufactured Home: This program is designed for customers to purchase an energy efficient manufactured home. EKPC will pay incentives in the form of rebates for electric heated homes that qualify for the ENERGY STAR® label. The building must have an ENERGY STAR® certification in order to be eligible.

6. Residential Energy Audit: This program is for education purposes as it provides information to customers on how to manage their energy use and save energy. EKPC uses the Billing*Insights* software tool to analyze energy usage and make recommendations to customers. The customers who complete the audit through Billing*Insights* receive a free LED light bulb.

7. Residential Efficient Lighting: This program is designed specifically for improving the efficiency of residential lighting by distributing LED light bulbs to the customers.

8. Direct Load Control (Residential) – AC Switch or Bring Your Own Thermostat (BYOT): This program is designed to shift loads during peak times to reduce EKPC's capacity loads during PJM peaks. EKPC accomplishes this by reducing demand and energy uses through direct load control devices on air conditioners and heat pumps. EKPC offers $10 per year for each water heater and $20 per year for each air conditioner under its control.

The following table provides the projected annual energy, summer peak demand, and winter peak demand load impacts of all existing DSM programs.[61] Total energy requirements will increase by an average if 1.1 percent while winter and summer net peak demand will increase by approximately 0.6 percent and 0.8 percent.[62]

Year	Impact on Energy Requirements (MWh)	Impact on Winter Peak (MW)	Impact on Summer Peak (MW)
2022	-7,058	-2.0	-3.3
2023	-15,016	-4.1	-6.6
2024	-22,523	-6.1	-9.8
2025	-30,031	-8.2	-13.1

[61] 2022 IRP Technical Appendix Volume 2, DSM-19, Table DSM-5

[62] 2022 IRP, Section 8.3 at 161.

2026	-37,539	-10.2	-16.4
2027	-44,800	-12.2	-19.6
2028	-52,061	-14.2	-22.8
2029	-59,323	-16.2	-26.1
2030	-66,584	-18.1	-29.3
2031	-73,845	-20.1	-32.5
2032	-81,106	-22.1	-35.7
2033	-88,368	-24.0	-38.9
2034	-95,629	-26.0	-42.2
2035	-102,890	-28.0	-45.4
2036	-110,151	-29.9	-48.6

The following tables provide the summer peak demand and winter peak demand load impact of each individual existing DSM program:[63]

Impact on Winter Peak (MWh)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Button-up Weather-ization	(0.4)	(0.9)	(1.3)	(1.8)	(2.2)	(2.6)	(3.1)	(3.5)	(4.0)	(4.4)	(4.8)	(5.3)	(5.7)	(6.1)	(6.6)
CARES – Low Income	(0.5)	(1.0)	(1.5)	(2.0)	(2.5)	(3.0)	(3.5)	(4.0)	(4.5)	(5.0)	(5.5)	(6.0)	(6.5)	(7.0)	(7.4)
Heat Pump Retrofit	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Touchstone Energy Home	(0.9)	(1.9)	(2.8)	(3.8)	(4.7)	(5.7)	(6.6)	(7.6)	(8.5)	(9.5)	(10.4)	(11.4)	(12.3)	(13.3)	(14.2)
ENERGY STAR® Manu-factured Home	0.0	(0.1)	(0.1)	(0.2)	(0.2)	(0.3)	(0.3)	(0.4)	(0.4)	(0.5)	(0.5)	(0.6)	(0.6)	(0.7)	(0.7)
Residential Energy Audit	(0.1)	(0.2)	(0.2)	(0.3)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)
Residential Lighting	0.0	(0.1)	(0.1)	(0.2)	(0.2)	(0.2)	(0.3)	(0.3)	(0.3)	(0.4)	(0.4)	(0.5)	(0.5)	(0.5)	(0.6)
Direct Load Control: Residential Air Conditioner – Bring Your Own Thermostat (BYOT)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Impact on Summer Peak (MWh)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Button-Up Weather-ization	(0.1)	(0.3)	(0.4)	(0.5)	(0.7)	(0.8)	(0.9)	(1.1)	(1.2)	(1.3)	(1.5)	(1.6)	(1.7)	(1.9)	(2.0)
CARES – Low Income	(0.2)	(0.5)	(0.7)	(1.0)	(1.2)	(1.5)	(1.7)	(2.0)	(2.2)	(2.5)	(2.7)	(3.0)	(3.2)	(3.5)	(3.7)
Heat Pump Retrofit	(0.2)	(0.3)	(0.5)	(0.7)	(0.8)	(1.0)	(1.1)	(1.3)	(1.5)	(1.6)	(1.8)	(2.0)	(2.1)	(2.3)	(2.5)
Touchstone Energy Home	(0.2)	(0.5)	(0.7)	(0.9)	(1.1)	(1.4)	(1.6)	(1.8)	(2.0)	(2.3)	(2.5)	(2.7)	(2.9)	(3.2)	(3.4)

[63] 2022 IRP Technical Appendix Volume 2, Exhibit DSM-6at 1–5

ENERGY STAR® Manu-factured Home	0.0	0.0	(0.1)	(0.1)	(0.1)	(0.1)	(0.2)	(0.2)	(0.2)	(0.2)	(0.3)	(0.3)	(0.3)	(0.3)	(0.4)
Residential Energy Audit	(0.1)	(0.1)	(0.2)	(0.2)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)
Residential Lighting	0.0	(0.1)	(0.1)	(0.1)	(0.1)	(0.2)	(0.2)	(0.2)	(0.2)	(0.3)	(0.3)	(0.3)	(0.4)	(0.4)	(0.4)
Direct Load Control: Residential Air Conditioner – Bring Your Own Thermostat (BYOT)	(2.4)	(4.8)	(7.2)	(9.6)	(12.0)	(14.4)	(16.8)	(19.2)	(21.6)	(24.0)	(26.4)	(28.8)	(31.2)	(33.6)	(36.0)

DSM-EE PROGRAM COST-EFFECTIVENESS AND ENERGY SAVINGS

EKPC stated that it selects DSM programs to offer on the basis of meeting customer needs and resource planning objectives in a cost- effective manner.[64] EKPC analyzes DSM measures and programs using both qualitative and quantitative criteria.[65] These criteria include customer acceptance, measure applicability, savings potential, and cost-effectiveness.[66] The cost-effectiveness of DSM resources is analyzed in a rigorous fashion using the California tests for cost-effectiveness.[67] EKPC is not suggesting any changes in its DSM programs from its 2019 IRP.

The projected cost savings for the DSM/EE 15-year program demand and energy impacts and cost-effectiveness are provided below. The values listed below are the benefits in the Total Resource Cost (TRC) test[68] and are the present value of the future stream of costs using a five percent discount rate:[69]

Program Name	Program Cost Savings (Present Value)	Total Resource Cost Test Benefit/Cost Ratio (TRC)
Button-Up Weatherization	$9,251,697	1.68
CARES – Low Income	$16,059,558	1.15
Heat Pump Retrofit	$26,955,443	1.60

[64] 2022 IRP, Section 5 at 111.

[65] 2022 IRP, Section 5 at 111.

[66] 2022 IRP, Section 5 at 111.

[67] 2022 IRP, Section 5 at 111.

[68] A TRC score of over one is generally considered cost-effective.

[69] 2022 IRP Technical Appendix Volume 2, DSM-4, Table DSM-1. *See also* 2022 IRP Technical Appendix Volume 2, Exhibit DSM-7, page 4, Table 8. (3)(e)(4). *See also* 2022 IRP Technical Appendix Volume 2, Exhibit DSM-7at 5, Table 8. (3)(e)(4).

Touchstone Energy (TSE) Home	$16,870,385	2.10
ENERGY STAR® Manufactured Home	$1,575,665	1.62
Residential Energy Audit	$906,126	0.45
Residential Efficient Lighting	$2,020,012	3.93
Direct Load Control – Residential: AC Switch or Bring Your Own Thermostat (BYOT)	$34,634,303	2.17

RECOMMENDATIONS FROM THE 2019 IRP

- EKPC should continue to report, annually, on its DSM programs' energy savings and peak demand deductions.
- EKPC should continue to scrutinize the results of each existing DSM program measure's cost-effectiveness test and provide those results in future DSM cases, along with detailed support for future DSM program expansions and additions. EKPC should also be mindful of the increasing saturation of EE products and be watchful for the opportunity to scale back on programs offering incentives for behavior that may be dictated by factors other than the incentive.
- The Commission recommends that EKPC continue the stakeholder process through the Collaborative and strive to include recommendations and inputs from the stakeholders. These meetings should be more than informational and entail fluid dialog between all vested parties. Any changes to the DSM programs must be discussed in full, including a transparent analysis of the cost and benefits input.
- As required by the IRP regulations 807 KAR 5:058, Section 7(4)(d), EKPC should continue to define and improve procedures to evaluate, measure, and verify both actual costs and benefits of energy savings based on the actual dollar savings and energy savings.
- EKPC should continue to report on updates to bidding its peak savings from DSM programs into the PJM capacity markets.

INTERVENOR COMMENTS

Joint Intervenors comments related to DSM/EE included the assertion that EKPC's planned portfolio of demand response and energy efficiency resources was 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.[70] Joint Intervenors recommended elimination of LED bulbs from DSM/EE plans and expansion or promotion of heat pump technology, small business demand response programs, interruptible rate tariff, Inflation Reduction Act of 2022 (IRA) rebates for the energy efficiency workforce, EKPC's EE website, stakeholder support of DSM inputs, and market potential studies, and equity in program opportunities.[71]

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[70] Joint Intervenors' Initial Comments at 3.

[71] Joint Intervenors' Initial Comments at 5–6.

SECTION 4

SUPPLY-SIDE RESOURCE ASSESSMENT

INTRODUCTION

This section reviews EKPC's supply-side assessment and its integration of supply and demand-side assessments and load to produce a resource acquisition plan. This section also reviews the parties' comments regarding EKPC's supply-side assessment and integration. Commission Staff's discussion of and recommendations regarding those issues are discussed in Section 6 of this Report.

SUMMARY OF EXISTING CAPACITY

Currently, EKPC owns and operates coal, natural gas, fuel oil, landfill gas, and solar generation resources. Additionally, EKPC maintains firm rights to hydro generation with SEPA. In total, EKPC has access to approximately 3,437MW of winter capacity, plus 170 MW purchased from SEPA on a long-term basis for a total of 3,607 MW.[72] Capacity is from the following sources:

- Coal-fired generation production from Cooper Station and Spurlock Station. Cooper Station includes two units with a combined generation capacity of 341 MW; Unit 1 entered production in 1965 and Unit 2 in 1969. Spurlock Station includes four units with a combined generation capacity of 1,346 MW; Unit 1 entered production in 1977, Unit 2 in 1981, Unit 3 in 2005, and Unit 4 in 2009.[73]

- Gas/fuel oil fired generation includes nine combustion turbine (CT) generating units at Smith Station, totaling 753 MW of summer capacity and 989 MW of winter capacity.[74] EKPC also owns and operates Bluegrass Generation Station in Oldham County, which consists of three CT units with a total summer capacity of 501 MW and winter capacity of 567 MW.[75] In 2020, EKPC retrofitted all three of its Bluegrass Generation station units for use of fuel oil as a secondary fuel supply.

- Six landfill gas generating facilities located throughout Kentucky of various sizes, which contribute up to 16.1 MW of capacity.[76]

- The Cooperative Solar Farm One facility located in Winchester, Kentucky, is made up of 60 acres featuring 32,300 solar panels and has a nameplate capacity of 8.5

[72] IRP, Section 4 at 97–98.

[73] IRP, Section 4 at 97.

[74] IRP, Section 4 at 98, 101–102 (Tables 4-2 and 4-3).

[75] IRP, Section 4 at 98, 103 (Table 4-5).

[76] IRP, Section 4 at 99, 102 (Table 4-4).

MW.[77] As of the end of 2021, EKPC stated there were 242 subscribers with 1,492 panels licensed in the Cooperative Solar Farm One.[78]

EKPC is a member of the National Renewables Cooperative Organization (NRCO). NRCO provides its members with evaluations on renewable projects, facilitating transmission constraint analysis, Renewable Energy Certificates (REC) market analysis, and engineering studies. This enables EKPC to better evaluate the efficacy of renewable generation projects, evaluate possible participation in projects, access aggregated information for renewable project pricing, and evaluate REC market prices without the added expense of dedicated staff. NRCO assisted EKPC in the request for proposals, contracting, and installation process for its Cooperative Solar Farm One project.[79] EKPC has participated in the evaluation of possible out-of-state wind projects through NRCO but has currently not found any current opportunities that fit its generation expansion needs.[80]

EKPC currently has six existing landfill gas-to-energy (LFGTE) facilities located through Kentucky with a produced output of 99,977 MWh in 2021.[81] EKPC continues to work to improve the performance of its LFGTE facilities by updating to more modern technology, eliminating obsolete controls, and ensure that each unit undergoes yearly overhaul maintenance.[82] EKPC has a single cogeneration partner and purchased 1,357 MWh in 2021.[83] Companies are hesitant to join due to the long payback periods and large capital investments needed to add new combined heat and power projects. EKPC reported that one of its owner-members is pursuing hydro generation via a power purchase agreement (PPA) with a local developer. One facility was completed in 2021 and is rated at 2.64 MW while a second facility rated at 3.04 MW is projected to be online in 2022.[84] As a result of owner-member net metering programs, EKPC's system includes approximately 9,023 kW of solar photovoltaic (PV) capacity, as well as 24 kV of capacity from small wind turbine installations.[85]

Several industrial end-use customers have reached out to their respective distributive owner-member cooperatives to express a corporate interest in securing

[77] IRP, Section 4 at 99, 103 (Table 4-6).

[78] IRP, Section 4 at 99.

[79] IRP, Section 8 at 163–164.

[80] IRP, Section 8 at 164.

[81] IRP, Section 8 at 164.

[82] EKPC's Response to Staff's First Request, Item 25a.

[83] IRP, Section 8 at 164.

[84] IRP, Section 8 at 164.

[85] IRP, Section 8 at 164–165.

renewable energy resources or renewable energy certificates (RECs).[86] EKPC and its owner-member cooperatives worked jointly to develop programs and tariffs to support the objective of offering renewable resources and/or RECs to end-use commercial and industrial (C&I) customers without cross-subsidization from or to non-participants. The Renewable Energy Program tariff was expanded to include two new renewable energy options: Option B – Long-Term Renewable Resources; and Option C – C&I RECs.[87] At the time of the current IRP filing, one large C&I end-use customer has agreed to participate in the long-term renewable energy program, while another has agreed to an REC-only purchase and is offsetting ten percent of its monthly consumption through RECs.[88]

SUMMARY OF NEW GENERATION CONSIDERED

EKPC considered and included the following generation resources in its resource optimizer modeling software: 100 MW LMS100CT, 225 MW 7F SCGT, 418 MW Combined Cycle, 150 MW Solar, 100 MW Solar PPA, and 100 MW PPA Winter Seasonal Market.[89] EKPC indicated that wind was excluded from the screening due to the lack of significant wind resources in PJM's EKPC zone, as noted on NREL wind speed maps, and the cost of a PPA with wind resources located in other areas of the PJM region. Specifically, EKPC stated that transmission costs and impact of settling the PPA at the PJM AEP-Dayton Hub and then at the EKPC zone was cost prohibitive as compared to solar located in the EKPC zone.[90] EKPC stated that battery storage was considered for potential pilot applications but was ultimately excluded due to the limited duration and initial cost at this time.[91]

SUMMARY OF MAINTENANCE PLANS FOR EXISTING UNITS

EKPC has a formal maintenance planning process to keep its existing units operating in a safe and reliable manner, to comply with environmental regulations, and to maintain optimal unit performance and reliable service to owner-members.[92] This plan is reviewed and evaluated annually by various experts in order determine if new plans or revisions of existing plans are warranted. New plans are subject to a cost-benefit analyses, which consider such factors as safety and regulatory requirements. Major projects must be Board approved.[93] Projects that cost below $5 million do not require

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[86] IRP, Section 8 at 165.

[87] IRP, Section 8 at 165.

[88] IRP, Section 8 at 165.

[89] IRP, Section 8 at 163.

[90] IRP, Section 2 at 57.

[91] IRP, Section 2 at 57.

[92] IRP, Section 7 at 143

[93] IRP, Section 7 at 143–144.

authorization by the Board and can be approved by the EKPC president and CEO.[94] EKPC provided a list of major projects at each of its generation stations for the period 2022-2026.[95]

SUMMARY OF THE TRANSMISSION SYSTEM AND TRANSMISSION PLANNING

EKPC's transmission system is comprised of approximately 2,968 circuit miles at voltages ranging from 69 kV to 345 kV and 77 interconnection points with neighboring utilities.[96] EKPC's system is designed to provide adequate capacity in order to deliver electric generation to its 16 owner-member cooperatives in order to meet the needs of their end-use customers. The EKPC planning and design criteria require meeting projected customer load demands during normal conditions and even during events such as possible simultaneous outages of a transmission facility and a generating unit at peak load conditions anytime throughout the year.[97] Interconnections with PJM and neighboring utilities have helped to improve the reliability of EKPC's transmission system and allow access to external generation resources for economic and/or emergency purchases. EKPC has established two new interconnections since its previous IRP Report, a 69kV interconnection with Louisville Gas & Electric Company (LG&E) in 2021; and a 161 kV interconnection with Tennessee Valley Authority (TVA) in 2022.[98] These interconnections are needed to improve the reliability of the electric system in the area.

As a participating member of the PJM RTO, EKPC closely coordinates its transmission planning activities with PJM to comply with applicable PJM reliability criteria.[99] PJM's long-term regional planning process provides a broad, interstate perspective that identifies the most effective and cost-efficient improvements to ensure reliability and economic benefits on a system wide basis. After EKPC has completed its own system transmission planning activities, the plans are submitted to PJM for review, approval, and inclusion in the Regional Transmission Expansion Plan (RTEP) process.[100] Similarly, projects identified by PJM are submitted to EKPC for incorporation into its own plans to ensure continuity. As a member of SERC, EKPC supplies data for and participates in load flow reliability studies relating to potential problems with the interconnected bulk transmission system.[101] EKPC adheres to the guidelines related to generation and transmission planning, and operations as set forth by SERC.[102] In

[94] EKPC's Response to Staff's First Request, Item 23b.

[95] IRP, Section 7 at 145–156 (Tables 7-1, 7-2, 7-3, 7-4, and 7-5).

[96] IRP, Section 6 at 123.

[97] IRP, Section 6 at123.

[98] IRP, Section 6 at126.

[99] IRP, Section 6 at123.

[100] IRP, Section 6 at124–125.

[101] IRP, Section 6 at 125–126.

[102] IRP, Section 6 at 125; Section 8 at 170.

addition, EKPC participates in Available Transfer Capability studies that are performed by PJM, Independent Transmission Organizations, and Reliability Coordinators such as TVA.[103]

EKPC provided a list of transmission expansion and improvement projects completed over the three-year period prior to the submission of the current IRP. These projects included station modifications and upgrades, circuit switching and breaker additions, existing line construction and reconductoring, and new line construction.[104] Construction of new transmission lines within the EKPC system generally has resulted in reduction of system losses. EKPC also provided a list of future planned transmission projects for the 2022-2036 period.[105] These projects include the new construction or upgrading of existing transmission lines and substations, installation of new switching stations, upgrading transformers, and terminal facility upgrades. Included in the 2022-2036 planned transmission expansion projects is the construction of 31.1 miles of new 69 kV line that is expected to have a net overall reduction in system losses.[106] In order to enhance system reliability and efficiency, transmission plans are evaluated and updated annually using power flow analyses and reliability indicators.[107]

EKPC routinely assesses the ability to import power from external sources into the EKPC load zone. As a member of SERC, EKPC performs import capability studies as part of SERC's annual system assessments. EKPC reports that its transmission system is designed with the ability to import a minimum of 500 MW.[108] Import studies indicate that EKPC's interfaces with its neighboring utilities and regions meet that criteria. EKPC's import capability from the LG&E/KU interface ranges up to 850 MW, and up to 450 MW with TVA depending upon the time and season.

SUMMARY OF THE DISTRIBUTION SYSTEM AND PLANNING

EKPC owns and operates the distribution substations connecting the transmission system to the 16 owner-members' distribution systems. EKPC works with its owner-members to monitor peak demand transformer loads and to identify potential problems. EKPC, in conjunction with its owner-members, uses a "one system" four-year planning horizon and cost basis to evaluate potential substation issues.[109] Over the previous 2019-2021 period, EKPC and its owner-members completed 15 projects ranging from

[103] IRP, Section 6 at 132.

[104] IRP, Section 6 at 127.

[105] IRP, Section 6 at 137–139 (Tables 6-2, 6-3, 6-4, 6-5, 6-6, and 6-7).

[106] IRP, Section 6 at 129.

[107] IRP, Section 6 at 128.

[108] IRP, Section 6 at 132

[109] IRP, Section 6 at 133.

constructing new substations to adding and upgrading transformers.[110] In addition, during the 2019-2021 period, EKPC was able to improve its delivery points through the construction of new substations, as well as through upgrades of existing substations, in order to enhance reliability, improve system efficiency, and to meet growing member demand in certain areas. Over the 2022-2025 period, EKPC anticipates upgrading or rebuilding another 32 existing substations, and constructing four new substations.[111] EKPC and its owner-members continually work to improve power factors at the distribution level.

SUMMARY OF COMPLIANCE PLANNING

In order to maintain a strategic plan, EKPC evaluates potential future rules, whether they be in draft, proposed, or finalized. The Environmental Protection Agency (EPA) annually releases a strategic plan. The most recent EPA plan sets forth goals such as improving air and water quality and preventing contamination. EKPC states that its goals are in alignment with the strategic plan published by the EPA.

EKPC is currently in compliance with various environmental rules and requirements, including the Clean Air Act (CAA) and its various amendments, as well as the Clean Water Act (CWA) and the Resource Conservation and Recovery Act (RCRA).[112]

CAA rules that EKPC is in compliance with are as follows:

- New Source Performance Standards (NSPS)
- New Source Review (NSR)
- Title IV of the CAA
- Title V of the CAA
- Clean Air Interstate Rule (CAIR)
- Cross-State Air Pollution Rule (CSAPR)
- National Ambient Air Quality Standards (NAAQS)
- Mercury Air Toxics Standards (MATS)
- Affordable Clean Energy Rule (ACE), formerly known as Clean Power Plan (vacated by the D.C. Circuit).

EKPC also is currently in compliance with the following CWA rules:

- Section 316(a-b)
- Effluent Limitations Guidance (ELG)
- Waters of the US (WOTUS)

[110] IRP, Section 6 at 134.

[111] IRP, Section 6 at 134, 140. Tables 6-10 and 6-11 provide a listing of EKPC's planned distribution expansion projects for the 2022-2025 period.

[112] IRP, Section 9 at 177.

Finally, EKPC complies with the Coal Combustion Rule (CCR) of the RCRA.

President Biden issued Executive Order 14008 that creates a goal of carbon-free electrical generation by 2035.[113] EKPC and members of the power industry are working with several groups including the Electric Power Research Institute (EPRI) to develop reasonable and practicable timelines in order to meet expected goals set by the administration. On October 1, 2021, the EPA released a draft 2018-2026 strategic plan that provides highlights of the new initiatives.[114] Included in the EPA plan was the additional goals of tackling climate change and ensuring environmental justice for underserved communities.[115] EKPC's service area includes a significant number of residential end-users in economically distressed communities that could benefit from increased funding directed toward bringing energy and efficiency programs to those areas, through RUS electric programs.[116]

INTERVENOR AND RESPONSE COMMENTS

The Attorney General commented that EKPC's IRP did not take into account the effects of the IRA and the resulting availability of opportunities for federal funding for infrastructure.[117]

Joint Intervenors agreed that EKPC should explore several opportunities provided by the IRA.[118] Suggested opportunities included new renewable energy tax credits, including credits for siting in energy communities, and low-cost loans for electric infrastructure improvements.[119] Joint Intervenors also commented that EKPC should update solar resource costs based on IRA impact and include battery storage resources in supply-side options.[120] They also noted that EKPC's IRP did not include any generating unit retirement dates.[121] Joint Intervenors further asserted that EKPC did not integrate evaluation of "behind the meter generation" with EKPC's transmission and distribution

[113] IRP, Section 9 at 178.

[114] IRP, Section 9 at 178.

[115] IRP, Section 9 at 178.

[116] IRP, Section 9 at 179.

[117] Attorney General's Comments (filed Oct. 11, 2022) at 13.

[118] Joint Intervenors' Initial Comments at 14; Joint Intervenors' Post-Hearing Comments (filed Feb. 3, 2023) at 1–2.

[119] Joint Intervenors' Post-Hearing Comments at 2–10.

[120] Joint intervenors' Initial Comments at 4.

[121] Joint intervenors' Initial Comments at 3.

planning.[122] They also stated that the IRP did not take into account grid services and resource adequacy benefits involved in increasing renewables.[123]

EKPC responded that implementation of IRA tax credits and other IRA effects were not presently possible because the U.S. Treasury Department and other agencies had not promulgated the regulations necessary to determine the impact of these credits and other effects.[124]

EKPC submitted post-hearing comments indicating EKPC is in the process of studying "potential impacts and possible mitigating system upgrades" with regards to transmission system performance for Cooper Station and the retirement of the E.B. Brown Station.[125]

EKPC further clarified that EKPC's reserve requirement is based on its pro-rata share of the PJM summer reserve requirements and hedges its winter energy exposure for price stability, but has no winter capacity obligation to satisfy its PJM load-serving requirement.[126] EKPC also clarified that solar PPA's capacity and energy attributes are monetized regardless of whether they are behind the meter, and that these PPAs can provide energy in addition to capacity if EKPC negotiates for energy as well.[127] Last, EKPC noted that its IRP does not include resource descriptions required by 807 KAR 5:058, Section 8(3), because this regulation is not intended to apply to regional transmission organizations like PJM, and even if it did, it does not purchase 50 percent or more of its energy from PJM. [128]

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[122] Joint Intervenors' Initial Comments at 3.

[123] Joint Intervenors' Initial Comments at 3.

[124] EKPC's Post-Hearing Response Comments (filed Feb. 17, 2023) at 1–4.

[125] EKPC's Post-Hearing Comments (filed Feb. 3, 2023) at 2.

[126] EKPC's Post-Hearing Comments at 2.

[127] EKPC's Post-Hearing Comments at 3.

[128] EKPC's Post-Hearing Comments at 3–4.

SECTION 5

INTEGRATION

INTRODUCTION

A goal of the IRP process is to integrate supply-side and demand-side options to achieve an optimal resource plan. This section will discuss the integration process and the resulting EKPC plan.

PRODUCTION COST MODEL

EKPC utilizes the RTSimm production cost model and resource optimizer which simulates actual system operation to satisfy forecast load requirements to develop its resource plan. This model calculates the hourly operation of the generation system including:

- unit hourly generation and commitment;
- power purchases and sales, including economy and day-ahead transactions in the PJM energy market; and
- daily and monthly options.

Individual generating unit inputs include:

- expected outages;
- Monte Carlo probability algorithm simulated forced outages;
- unit ramp rates; and
- unit start-up characteristics.[129]

Monte Carlo simulations are used to analyze system operation outcomes under different circumstances including forced outages and derates, load uncertainty, market price uncertainty, and fuel price uncertainty.[130] The model operates by drawing a few days at a time from the base case and the four alternative load forecasts to simulate weather patterns to create hourly loads to be simulated. Then, actual and forecast market prices, natural gas and coal prices, and emissions costs are correlated to the created load data used in the simulation. Five hundred iterations are used for each simulation.[131]

CAPACITY POSITION

The table below illustrates EKPC's existing capacity position based upon its current resources.

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[129] IRP, Section 8 at 162.

[130] IRP, Section 8 at 162.

[131] IRP, Section 8 at 162.

EKPC Projected Capacity Needs (MW)[132]

Year	Projected Peaks		Reserves*		Total Req. = Peaks + Req.		Existing Resources		Capacity Needs Or Excess Gen.	
	Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum
2022	3,309	2,500	0	75	3,309	2,575	3,434	3,132	125	557
2023	3,363	2,574	0	77	3,363	2,651	3,434	3,132	71	481
2024	3,384	2,612	0	78	3,384	2,690	3,434	3,132	50	442
2025	3,391	2,623	0	78	3,391	2,701	3,434	3,132	43	431
2026	3,409	2,634	0	79	3,409	2,713	3,434	3,132	25	419
2027	3,427	2,651	0	79	3,427	2,730	3,434	3,132	7	402
2028	3,457	2,669	0	80	3,457	2,749	3,434	3,132	-23	383
2029	3,470	2,684	0	80	3,470	2,764	3,434	3,132	-36	368
2030	3,480	2,695	0	80	3,480	2,775	3,434	3,132	-46	357
2031	3,494	2,707	0	81	3,494	2,788	3,434	3,132	-60	344
2032	3,520	2,726	0	81	3,520	2,807	3,434	3,132	-86	325
2033	3,533	2,742	0	82	3,533	2,824	3,434	3,132	-99	308
2034	3,556	2,761	0	82	3,556	2,843	3,434	3,132	-122	289
2035	3,578	2,780	0	83	3,578	2,863	3,434	3,132	-144	269
2036	3,586	2,794	0	83	3,586	2,877	3,434	3,132	-152	255

* Reserves are based on PJM reserve requirements

OPTIMIZATION

The Resource Optimizer (Optimizer) routine within the RTSimm model was used to optimize the resource plan. The Optimizer constructs a resource expansion plan to meet forecast requirements, then simulates the plan to calculate the present value of the plan as compared to doing nothing.[133] Alternative plans satisfying future resource requirements are evaluated on a present worth of revenue as well as a cash flow basis.[134] The Optimizer utilizes minimum and maximum forecast capacity needs, annualized fixed costs of alternative resources, and potential in-service dates. EKPC ran 2,500 optimization simulations.[135] The Table below contains the top five lowest costs plans (i.e., Plans 1-5).[136]

[132] IRP, Section 8, Table 8-6 at 170. The original Projected Peak data was replaced with Projected Peak data from Table 3-2 at 65.

[133] IRP, Section 8 at 167.

[134] IRP, Section 8 at 160.

[135] IRP, Section 8 at 167.

[136] IRP, Section 8, Table 8-5 at 168; EKPC's Response to Staff's First Request, Item 27c. The top five lowest cost plans actually yielded a positive net present value system profit ranging from Plan 1 a system profit of $146,459, 040 to Plan 5 with a system profit of $7,970,816.

In order to obtain its optimal Final Plan, EKPC focused on Plan 1 as the basis for incorporating its corporate sustainability goals.[137] EKPC's sustainability goals are as follows:[138]

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

Because the Optimizer selected the renewable resources (solar PPAs) on economics, EKPC's Power Supply staff including the Senior Vice President and supporting staff used those resources as a basis for applying the timing of its sustainability goals.[139] The new renewable energy was applied to Plan 1 based on possible in-service dates. Plan 1 was modified to include the amount of solar PPAs to meet renewable sustainability goals. In addition, it was modified on a production cost basis to limit the amount of carbon dioxide to the sustainability targets. When necessary to meet reduction goals, generation would be restricted.[140] In addition to the top five most cost-effective plans, the optimal Final Plan is listed in the table below.

Select Data from Resource Optimizer Plan Summary (MW)[141]

Year	Type	Plan 1	Plan 2	Plan 3	Plan 4	Plan 5	Final Plan
2022	Peaking						
	Intermediate						
	Renewable						
	Seasonal PPA	100	100	100	100	100	100
2023	Peaking						
	Intermediate						
	Renewable						110
	PPA						
2024	Peaking						
	Intermediate						
	Renewable						200
	Seasonal PPA					100	
2025	Peaking						
	Intermediate						
	Renewable						
	PPA						

137 EKPC's Response to Staff's First Request, Item 27b.

138 EKPC's Response to Staff's Second Request, Item 12a.

139 EKPC's Response to Staff's Second Request, Item 12d; EKPC's Response to Staff's First Request, Item 28. The renewable additions are intended to be annual products. The seasonal PPA is intended to be a winter price hedge.

140 EKPC's Response to Staff's Second Request, Item 12d–e.

141 IRP, Section 8, Table 8-5 at 168.

2026	Peaking						
	Intermediate						
	Renewable						200
	Seasonal PPA						
2027	Peaking						
	Intermediate						
	Renewable						200
	Seasonal PPA	100					
2028	Peaking						
	Intermediate						
	Renewable					100	
	Seasonal PPA						
2029	Peaking						
	Intermediate						
	Renewable		100				
	Seasonal PPA						
2030	Peaking						
	Intermediate						
	Renewable					100	
	Seasonal PPA						
2031	Peaking						
	Intermediate						
	Renewable		200		100		200
	Seasonal PPA						
2032	Peaking	225			225		225
	Intermediate						
	Renewable						200
	Seasonal PPA						
2033	Peaking		225			225	
	Intermediate						
	Renewable		100		100		
	Seasonal PPA				100		
2034	Peaking			225			
	Intermediate						
	Renewable					200	
	Seasonal PPA						
2035	Peaking						
	Intermediate						
	Renewable			100			
	Seasonal PPA		100				
2036	Peaking				225	225	
	Intermediate						
	Renewable						
	Seasonal PPA						

The table below shows EKPC's projected total capacity and reserve margins based upon the Final Plan which embodies its sustainability goals. There is a mismatch between the reserve margin/excess generation in the table below (IRP Table 8-6 page 170) and the reserve margins based upon updated IRP Table 3-2 page 65. Generally using existing resources, the winter reserve margin based upon Table 3-2 is higher, ranging from six MW (125 MW minus 119 MW) in 2022, and growing to 43 MW (255 MW minus 109 MW) in 2036. However, the summer reserve margin based upon Table 3-2 is generally lower, ranging from two MW (559 MW minus 557 MW) in 2022 to 18 MW (273 MW minus 255 MW) in 2036. These differences do not alter EKPC's winter capacity deficit beginning in 2028

EKPC Final Plan Projected Additions and Reserves (MW)[142]

Year	PPA Energy Additions	Peak / Intermed Capital Add		Total Capacity = Existing + Additions		Tot. Cap. minus Requirements or Excess Generation	
		Win	Sum	Win	Sum	Win	Sum
2022	100			3,534	3,132	225	557
2023	110			3,534	3,198	171	547
2024	200			3,534	3,318	150	628
2025				3,534	3,318	143	617
2026	200			3,534	3,438	125	725
2027	200			3,534	3,558	107	828
2028				3,534	3,558	77	809
2029				3,534	3,558	64	794
2030				3,534	3,558	54	783
2031	200			3,534	3,678	40	890
2032*	200	225	170	3,659	3,968	139	1161
2033				3,659	3,968	126	1144
2034				3,659	3,968	103	1125
2035				3,659	3,968	81	1105
2036				3,659	3,968	73	1091

* 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, not to add "capacity."

Even though EKPC stated that the PPA seasonal and renewable energy additions are not for the purpose of adding capacity, but to hedge prices, it accrues seasonal capacity over the forecast period. The 100 MW 2022 seasonal PPA increases winter by 100 MW. Renewable PPAs are solar additions and increase summer capacity at a 60 percent capacity factor. Summer capacity increases 290 MW from 2031 to 2032. As with previous solar PPAs, assuming that the 200 MW solar PPA increases summer capacity by 60 percent (120 MW), that leaves the 170 MW summer peaking addition as adding to capacity by 170 MW; a 100 percent capacity factor. Winter capacity is needed in 2028 and summer capacity is never needed.

INTERVENOR AND RESPONSE COMMENTS

The Attorney General's comments focused on the "plan for providing an adequate and reliable supply of electricity to meet forecasted electricity requirements at the lowest

[142] Select information from Updated Table 8-6 in EKPC's Response to Staff's Second Request, Item 16f. The reserve margins are based upon projected peaks from IRP, Section 3, Table 3-2 at 65. In addition, IRP, Table 8-7 at 171 did not show that EKPC required any base load generation over the forecast period.

possible cost."[143] The Attorney General cautioned against premature replacement of fossil fuel baseload generation with wind and solar power, which are intermittent, and could therefore affect reliability. The Attorney General and EKPC agreed that conventional resources will continue to be necessary and should not be retired until adequate renewables are installed, battery technology matures, and these resources prove they can supply the real-time energy for system reliability at a reasonable cost.[144]

The Attorney General also stated that the IRP data indicated that the sum of forecasted generation and purchased energy resulted in a decrease in energy supply despite an increase in forecasted demand.[145] The Attorney General cautioned EKPC against relying too heavily on PJM market purchases due to rising PJM prices.[146]

Joint Intervenors commented on fuel cost forecasting and modeling. Joint Intervenors asserted that EKPC's commodity forecasts lacked transparency and relied on unreasonably stale data and opaque methodologies.[147] They recommended that natural gas price forecasting should use the most recently available New York Mercantile Exchange (NYMEX) curve or an approach that blends the near-term NYMEX trend with long-term fundamentals forecast.[148] Joint Intervenors also suggested the use of sensitivity analysis on fuel prices.[149]

Regarding modeling, Joint Intervenors wanted EKPC to allow intervenors full access to modeling input and output files, and to not redact fuel prices, capacity price, and the energy market on-peak and off-peak price forecasts.[150] Joint Intervenors commented that the IRP contained limited discussion of how the RTSimm model was used, specifically concerning a purported lack of factoring in total system costs and profits,[151] as well as emission costs.[152] Joint Intervenors suggested a collaborative approach to evaluate modeling software options.[153] They also recommended that EKPC model the Forecast Pool Requirement instead of the Installed Reserve Margin so that

[143] Attorney General's Comments at 3 (quoting 807 KAR 5:058, Section 8(1)).

[144] Attorney General's Comments at 4.

[145] Attorney General's Comments at 11.

[146] Attorney General's Comments at 11–12.

[147] Joint intervenors' Initial Comments at 2.

[148] Joint intervenors' Initial Comments at 4.

[149] Joint intervenors' Initial Comments at 4.

[150] Joint intervenors' Initial Comments at 4.

[151] Joint Intervenors' Initial Comments at 3.

[152] Joint intervenors' Initial Comments at 5.

[153] Joint intervenors' Initial Comments at 4.

EKPC's planning more closely aligns with PJM's resource adequacy requirements.[154] Joint Intervenors recommended that fixed operation and maintenance costs and capital expenditures should be taken into account for units in the model.[155] Joint Intervenors also asserted that EKPC's method of comparing plans included insufficient information to understand how EKPC selected a final plan.[156] Post-hearing, Joint Intervenors noted the lack of integration between analysis of transmission, supply-side resources, and demand-side resources.[157] Joint Intervenors also sought greater diligence, coordination and transparency from EKPC in developing its IRP. Joint Intervenors noted that EKPC was unaware of the retirement of the E.B. Brown station, had failed to attempt to analyze a significant transmission constraints, and refused to produce modeling inputs and outputs.[158] Lastly, Joint Intervenors asserted the need for EKPC to analyze retirement of Cooper Station.[159]

EKPC responded to Joint Intervenors' comments stating that their experts appeared not to have any experience with the RTSimm model.[160] EKPC noted that IRP's filed in other states also keep fuel prices and capacity price redacted.[161] EKPC also stated that its commodity forecasts use standard index values.[162] Regarding attention to transmission constraints, EKPC pointed out that PJM controls much of its decision-making regarding transmission, and that Joint Intervenors have not suggested any cost-effective solutions to transmission issues.[163] In response to transparency complaints, EKPC disputes that it failed to produce the information necessary for Joint Intervenors to analyze the modeling.[164]

[154] Joint intervenors' Initial Comments at 5.

[155] Joint Intervenors' Initial Comments at 5.

[156] Joint Intervenors' Initial Comments at 3.

[157] Joint Intervenors' Post-hearing Comments at 11–12.

[158] Joint Intervenors' Post-hearing Comments at 17–20; Joint Intervenors' Response to EKPC's Supplemental Post-Hearing Comment (filed Feb. 17, 2023) at 2–3.

[159] Joint Intervenors' Post-hearing Comments at 25.

[160] EKPC's Initial Comments at 2.

[161] EKPC's Initial Comments at 3.

[162] EKPC's Initial Comments at 8.

[163] EKPC's Post-Hearing Response Comments at 12.

[164] EKPC's Post-Hearing Response Comments at 10.

SECTION 6

REASONABLENESS AND RECOMMENDATIONS

INTRODUCTION

Some aspects of EKPC's 2022 IRP, including some of the methodologies and assumptions used to produce the IRP, are reasonable and consistent with 807 KAR 5:058. However, there are areas in which EKPC could improve its IRPs going forward, including issues with certain methodologies and assumptions that affected the reasonableness of the 2022 IRP. This section discusses the reasonableness of EKPC's 2022 IRP and the issues and areas for improvement and makes recommendations for EKPC's next IRP.

REASONABLENESS OF LOAD FORECASTING

EKPC's assumptions and methodologies for load forecasting are generally reasonable. However, there are areas in which the load forecasting portion of EKPC's IRP could be improved.

First, EKPC conducted additional demand- or supply-side analyses out of its normal sequence. Specifically, IHS Global Insight produced new forecasts, and EKPC reran its load forecast using the updated data. EKPC's updated load forecast was presented in Section 3 of the IRP, but the load forecast information presented and utilized in the Load Forecast Technical Appendix and in Section 8, Integration, was based on the original load forecast.[165] This resulted in the presentation of inconsistent results that caused confusion and cast doubt on the veracity of the whole analysis. EKPC should strive to present internally consistent data and to explain any inconsistencies in narrative form.

EKPC did not include any DSM/EE program impacts beyond those in the current approved suite of programs. By not including future cost-effective DSM programs that were shown to have positive Maximum Achievable Potential (MAP) and Realistically Achievable Potential (RAP) scores, the load forecast and, by extension, the supply-side analyses were not as informative as they could have been.

EKPC indicated that it made no attempt to identify future cogeneration opportunities.[166] Further, the effects of cogeneration and behind-the-meter solar and other customer-owned, distributed energy resources (DERs) were barely discussed in the IRP, and no methodology for projecting the effects of those resources during the planning period was provided in the IRP.[167] However, as Louisville Gas and Electric Company and Kentucky Utilities Company (LG&E/KU) noted in their most recent IRP, those resources

[165] EKPC's Response to Staff's First Request, Item 13.

[166] Hearing Video Transcript (HVT) of the Dec. 13, 2022 Hearing at 14:41:20–14:42:50.

[167] *See* 2022 IRP, Section 8 at 163–166, 173–174.

have the potential to materially affect load during the planning period as the cost of customer-owned solar is expected to decrease over the next ten years,[168] and as EKPC has acknowledged, certain industrial and commercial customers have incentives other than the cost of energy to own and operate solar and other renewable generation. Given the likely expansion of such resources and their potential effect, EKPC should have projected the extent to which its customers will adopt those resources during the planning period, projected the effects that adoption could have on load, and fully explained the methodology and assumptions used to make such projections. Further, to the extent possible, EKPC should have used its modeling software to project the adoption of such resources to ensure that factors used to assess DER adoption are the same as those used to assess traditional resource additions by EKPC.

REASONABLENESS OF DEMAND AND SUPPLY SIDE RESOURCE ASSESSMENTS

Limitations on Supply-Side Resource Options in Model

Pursuant to 807 KAR 5:058, Section 8(1), a utility's IRP must include 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." The plan is required to include an "assessment of potentially cost-effective resource options available to the utility."[169] Further, the plan must 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;
> (b) Conservation and load management or other demand-side programs not already in place;
> (c) Expansion of generating facilities, including assessment of economic opportunities for coordination with other utilities in constructing and operating new units; and
> (d) Assessment of nonutility generation, including generating capacity provided by cogeneration, technologies relying on renewable resource, and other nonutility sources.[170]

EKPC's resource assessment model was only permitted to select 100 MW simple cycle units, 225 MW simple cycle units, a 418 MW combined cycle units, 100 MW seasonal PPAs, and 100 MW energy only, solar facilities.[171] However, the resource assessment portion of EKPC's IRP simply identifies those resources as being included

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[168] Case No. 2021-00393, *Electronic 2021 Joint Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company* (filed Oct. 19, 2021), 2021 IRP, Vol. I, Section 5 at 29-30, Figure 5-15 (showing qualifying facilities and customer owned solar would reduce peak demand by several hundred MWs without the 1 percent cap permitted by HB 100).

[169] 807 KAR 5:058, Section 8(1).

[170] 807 KAR 5:058, Section 8(2).

[171] 2022 IRP, Section 8 at 162–163.

without an explanation for why they were chosen.[172] Further, EKPC's IRP never discusses nuclear energy or pumped storage,[173] whether operated by EKPC or through a partnership, as resource options, and excludes other resources, such as hydroelectric and out-of-state wind facilities, with very little to no explanation.[174] Thus, it was not clear from EKPC's IRP how it chose the potential supply-side resources to include in the model and in particular why any specific generation resource was excluded from the model, including whether it was excluded for qualitative or economic reasons.

Excluding or limiting the model's ability to select certain resources for qualitative reasons may be appropriate in certain circumstances, but such exclusions or limitations should be fully explained and justified. Further, utilities should not generally exclude potential resources from their resource expansion models due to costs, given the number of variables that could ultimately affect the resource selected, and should fully explain and justify the exclusion of any potential resource due to the cost of the resource.

Partnership Opportunities

EKPC's witnesses indicated at the hearing that they would be open to partnership opportunities for constructing and operating new generating units but that they did not assess such opportunities as part of their IRP.[175] As noted above, the IRP regulation requires the assessment of such opportunities. Further, some Kentucky utilities have indicated that they are seeking partnerships in order to reduce the cost of generating units through economies of scale.[176] Partnership opportunities could also allow EKPC to access generation technologies with which it has less or no experience.[177] Finally, investor-owned utilities could access different, potentially lower cost financing options by partnering with EKPC or other cooperatives.[178] Given those potential benefits and the

[172] 2022 IRP, Section 8 at 162–163.

[173] Commission Staff understand that resources like nuclear generation may not be, or rather, probably are not practical for EKPC at this time, especially as an independently owned and operated resource. However, the IRP should reflect that EKPC is considering potential resources and should explain why such resources are not practical or cost effective. This allows Staff and the public to ensure that utilities are considering all options and to track changes in assumptions regarding resources through successive IRPs in the event a utility ultimately decides to include and select a new type of resource.

[174] *See* 2022 IRP, Section 8 at 163–164.

[175] HVT of Dec. 13, 2022 Hearing at 14:41:20-14:42:50; 15:05:23-15:06:29; 16:18:20-16:20:20.

[176] *See* Case No. 2020-00299, *Electronic 2020 Integrated Resource Plan of Big Rivers Electric Corporation* (Ky. PSC Nov. 22, 2021), Commission Staff's Report on the 2020 Integrated Resource Plan of Big Rivers Electric Corporation at 43.

[177] For instance, Duke Energy Kentucky, Inc., which indicated that partnering on a generation unit would allow it to achieve savings through economies of scale, has affiliates that have or are in the process of constructing new nuclear and pumped hydroelectric units.

[178] HVT of Dec. 13, 2022 Hearing at 15:04:30-15:05:13 (discussing electric cooperatives lower cost of capital as compared to investor owned utilities); *see also* HVT of Dec. 13, 2022 Hearing at 18:18:30-18:19:02 (indicating that cooperatives would not likely be prohibited from using their financing to fund a generation facility in conjunction with an investor owned utility).

requirements in the regulation, EKPC should have explored potential partnerships with neighboring utilities and the possibility of a partnership should have, at minimum, been considered and discussed when determining what resources to model.

More broadly, since EKPC and other utilities are dependent on their neighbors, in part, to regulate frequency and provide voltage support on their systems, EKPC should engage more with neighboring utilities regarding generation and transmission planning and should review the IRPs of other Kentucky utilities to ensure that they are consistent with EKPC's understanding of the utilities' plans. For instance, during the course of this IRP, EKPC acknowledged that Cooper Station Units 1 and 2 could be unavailable at the same time and that an outage of those units could affect its ability to serve load in that area,[179] but EKPC indicated that as long as LG&E/KU's Brown Unit 3 was operating that they would not expect a loss-of-load event.[180] However, EKPC's witness acknowledged that he was unaware that LG&E/KU had been planning for a number of years to close Brown Unit 3 in or about 2028, and therefore, EKPC had been planning based on an inaccurate assumption regarding its neighboring utility that could directly affect EKPC's ability to serve load.[181] Commission Staff concludes EKPC should communicate more with neighboring utilities to avoid such issues and should further review other utilities' public filings regarding transmission and generation planning to ensure it has accurate information.

Improvements to Current Transmission Assets

EKPC does not appear to engage in transmission planning that looks specifically at whether transmission options could provide access to lower-cost generation or energy from PJM's market to meet its load.[182] The IRP regulation, at minimum, requires that transmission options be considered. Further, while economic transmission planning may be difficult, EKPC should consider transmission options to meet its load at a lower cost, including whether additional transmission capacity could lower locational marginal pricing within EKPC's PJM zone in a way that reduced costs to customers or could provide access to additional energy from other PJM zones when necessary at a lower cost than constructing or maintaining additional reserve generation. If EKPC contends that such planning is not possible or practical, Commission Staff would recommend that EKPC explain why in its next IRP.

Reliability Issues Associated with Winter Storm Elliot

During Winter Storm Elliott (Elliott), several utilities experienced an inability to obtain natural gas deliveries for generators. The problem was compounded by an inability to import power to make up for the generation shortage. This may have been due, in part, to neighboring entities (RTOs or individual utilities) imposing transmission line

[179] EKPC's Response Comments at 9.

[180] HVT of Dec. 13, 2022 Hearing at 9:59:15–10:02:43.

[181] HVT of Dec. 13, 2022 Hearing at 10:10:10-10:11:07.

[182] *See* HVT of Dec. 13, 2022 Hearing at 9:47:23–9:57:59.

releases prioritizing their own load or other transmission related issues. The end result was rolling blackouts during Elliott. Since the purpose of the IRP planning process is to meet future demand with an adequate and reliable supply of electricity at the lowest possible cost, the causes and potential solutions to any reliability issues that arose during Elliott should be addressed in EKPC's next IRP as discussed below.

REASONABLENESS OF INTEGRATION ASSESSMENT

Avoided Costs for DSM/EE

EKPC's analysis of new DSM/EE programs was thorough standing alone, but EKPC's analysis could be improved through better integration with the rest of the IRP. As noted above, the results of EKPC's DSM/EE program analysis were not integrated into the ultimate IRP plan, because new cost-effective programs were not used to reduce projected load or treated as a resource that could be used to meet load. Further, by analyzing the cost-effectiveness of new potential DSM/EE programs separately from new generation resources, i.e., outside of the modeling software used to assess generation resources, the DSM/EE programs were not assessed on the same basis as new generation resources. EKPC acknowledged that new DSM/EE programs could be assessed like generation resources using the RTSimm Resource Optimizer.[183]

To ensure that new DSM/EE programs and new generation resources are assessed on the same basis, including that the cost of new generation be consistent with the avoided costs for DSM/EE programs, generation resources and DSM/EE programs should be analyzed together as part of the same modeling runs, using the same cost and other inputs, to the extent practical. If EKPC contends it is not practical for it to do so, then EKPC should explain why it is not practical and explain in detail how DSM/EE programs and new generation are being evaluated based on the same costs. Finally, even if the cost effectiveness of DSM/EE programs are analyzed separately, the effects of cost-effective programs should be reflected in the final plan, either based on their effect on load or as a general resource that can be used to meet load.

EKPC's Sustainability Goals

EKPC explained that it developed its final plan by reviewing the optimal plans produced by the Resource Optimizer and including EKPC's Sustainability goals.[184] EKPC stated in response to questions in this case that "[t]he recommended plan is a combination of the best cases shown in Table 8-4, which also meets EKPC's defined need for resources based on load and sustainability goals."[185] However, it was not clear from the IRP whether or how EKPC's sustainability goals were used to develop the final plan or whether EKPC was justified in applying its sustainability goals to develop the final plan. Thus, while application of the sustainability goals appeared to have limited effect, a

[183] HVT of Dec. 13, 2022 Hearing at 10:10:0–10:11:07.

[184] EKPC's Response to Staff's First Request, Item 27.

[185] EKPC's Response to Staff's First Request, Item 50.

person reviewing the IRP could not assess EKPC's sustainability goals to determine if it were reasonable to apply them or whether they were applied in a reasonable way.

Among other things, a utility's resource assessment and acquisition plan must include:

> (a) General methodological approach, models, data sets, and information used by the company;
> (b) Key assumptions and judgments used in the assessment and how uncertainties in those assumptions and judgments were incorporated into analyses;
> (c) Criteria (for example, present value of revenue requirements, capital requirements, environmental impacts, flexibility, diversity) used to screen each resource alternative including demand-side programs, and criteria used to select the final mix of resources presented in the acquisition plan.[186]

Based on those requirements, and to ensure that the bases for its resource decisions were clear, EKPC should have at minimum identified and explained each of its sustainability goals, explained each assumption or assessment that formed its basis for adopting those goals, and explained how those sustainability goals were used to develop the optimal plan. More broadly, EKPC should identify and explain each constraint or assumption reflected in each modeling run and criteria used to evaluate plans outside the modeling run.

Further, while not everything can be quantified or assessed through the Resource Optimizer or other modeling software, EKPC's modeling software should be used to the extent possible to assess resource options and potential scenarios that are likely to materially affect the resources selected. For instance, if EKPC's sustainability goals are based on the risk of carbon or some other regulation that would cause existing units to be closed or increase the cost of new or existing units, then EKPC should identify that risk and include additional modeling runs that address that risk. EKPC could then develop and discuss a final plan based on the relative costs of the various plans produced by the model in scenarios with and without that risk and EKPC's analysis of the relative likelihood of the various scenarios. Such an analysis would be more effective at producing an adequate and reliable, least-cost plan.

<u>Accounting for Regulatory Risk</u>

EKPC's IRP included a useful summary of current and projected changes to environmental regulations, and EKPC should include similar discussions in future IRPs. However, as discussed above with respect to EKPC's sustainability plan, it was not always clear whether or how the regulatory risks were incorporated into the analysis.

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[186] 807 KAR 5:058, Section 8(5).

For instance, EKPC noted that due to revisions to the Cross-State Air Pollution Rule, which EKPC expected to be proposed in February 2022, could require, among other things, "the installation of NOx SCR control systems on any remaining coal-fired power plants without these state-of-the-art controls."[187] However, there was no discussion of how that scenario would affect resource decisions such as the cost of bringing EKPC's existing resources into compliance with the rule or whether the least-cost option in the event of that regulation would be to retire existing units early. Similarly, EKPC included the risk of carbon regulation when assessing its DSM/EE programs and discussed it generally in the broader IRP, but other than incorporating its sustainability goals into the final plan after the model runs, EKPC did not account for the risk of carbon regulation when it developed its final plan.

EKPC should spend additional time discussing the likelihood of the regulatory risks they identified and how those risks would affect existing and potential resources if they occurred. Further, as discussed above with respect to the sustainability goals, the Resource Optimizer or other modeling software should be used to the extent possible to assess resource options and potential scenarios that are likely to materially affect the cost of resources (e.g., a scenario that assessed the costs of upgrading existing units to comply with the potential revisions to the Cross-State Air Pollution Rule).[188]

<u>Cost of Current Units</u>

EKPC explained that it expected its current fleet of generation resources to be available through the planning horizon, so it did not permit the Resource Optimizer to select the economic retirement of any existing units.[189] EKPC acknowledged that unless there was a change in regulation, this meant that additional expected costs necessary to keep existing units operating during the planning period were not considered against the cost of simply replacing the unit to determine which generation resource would result in the lowest cost to customers.[190] EKPC's witness argued that keeping those units operating acts as a hedge against higher energy prices in the PJM market.[191]

Commission Staff agrees that it is reasonable for EKPC to maintain generation assets to hedge against higher costs within the PJM market. However, to ensure that it

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[187] 2022 IRP at 204.

[188] Staff concludes that if EKPC had made a model run under that scenario that allowed additional costs for current units to comply with a regulation to be compared against new units that EKPC could have used the results of such a model run along with the risk that the regulation will occur to assess the best options moving forward. For instance, if the risk of regulation is high and the cost of meeting it is not significantly different than EKPC's expected costs in the absence of regulation, then it may be reasonable for EKPC to pursue the option that would comply with the regulation. Conversely, if the cost of complying with a regulation would be significant, then it may better to push out any major decision as long as possible, so the ultimate decision could be made with better information.

[189] HVT of Dec. 13, 2022 Hearing at 14:23:35–14:24:30, 14:26:40–14:27:07.

[190] HVT of Dec. 13, 2022 Hearing at 14:24:30–14:26:08, 14:29:12–14:31:55.

[191] HVT of Dec. 13, 2022 Hearing at 14:26:00–14:26:40.

is planning its generation assets on a least-cost basis, EKPC should allow the Resource Optimizer to assess the economic retirement of existing units, especially when capital costs are necessary to keep existing units operational. Assuming EKPC maintained the same reserve margin for planning and accurately assesses the availability of units, this analysis would simply select the least-cost plan to maintain the same hedge EKPC would have with its existing units, which potentially would be selected by the model in any case. This method should more effectively produce an adequate, reliable and least-cost plan.

PRESENTATION OF PLAN

When EKPC presented its resource assessment and acquisition plan, it primarily did so through a number of tables in Section 8 of its IRP. However, without reading between the lines or asking follow-up questions, it was not clear what some of the planned acquisitions were referring to, because they were only vaguely described or resources that were intended to be energy only were reflected as adding to EKPC's capacity.[192] Further, Commission Staff notes that it is difficult to reflect certain resources, such as improvements to current resources and transmission resources, in table format. Thus, while the summary tables are useful, it would also be beneficial for EKPC to describe in narrative form the current and new resources that it will use to meet its projected load to provide context to any summary table.

RECOMMENDATIONS

Load Forecast

- EKPC should strive to present internally consistent data and to explain any differences in similar data such as the different load forecasts based on the original and updated IHS Global Insight data.[193]
- EKPC did not include any DSM/EE program impacts beyond those in the current approved suite of programs. As discussed above and below, EKPC should analyze DSM/EE programs and generation resources together as resources that may be selected in the same modeling runs to meet projected load, using the same cost and other inputs, to ensure that new DSM/EE programs and generation resources are assessed on equal footing. However, if EKPC is not able to assess new DSM/EE programs using the modeling software, EKPC should at minimum project the effect of new cost-effective DSM/EE programs on load during the planning period and explain how it did so.

Demand-Side Management:

- EKPC should continue to report, annually, on its DSM programs' energy savings and peak demand deductions.

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[192] *See* HVT of Dec. 13, 2022 Hearing at 15:59:00-16:02:31.

[193] *See* EKPC's Response to Staff's First Request, Item 13.

- EKPC should identify and assess all potential cost-effective DSM options.
- Any changes to the DSM portfolio should be discussed in full including a transparent analysis of the cost and benefits inputs.
- EKPC should describe and discuss all new DSM programs that they considered, and if a program was considered but ultimately not included in any model or format, EKPC should explain each basis for excluding the program.
- EKPC should continue the stakeholder process through the EKPC DSM Collaborative meetings and strive to include recommendations and inputs from the stakeholders in its DSM assessment.
- EKPC should consider making AMI usage data that is more closely aligned to real-time data available to customers.
- EKPC should consider pilot programs, peak time rebate programs, time-of-use rates, and prepay options for AMI customers.
- EKPC should continue to define and improve procedures to evaluate, measure, and verify both actual costs and benefits of energy savings based on the actual dollar savings and energy savings.
- EKPC should continue to report on updates to bidding its peak savings from DSM programs into the PJM capacity markets.
- EKPC should thoroughly examine and fully discuss the cost-saving possibilities involved in the proliferation of C&I interruptible rate options.

Supply-Side Resources

- EKPC should provide a more robust discussion of potentially viable supply-side resources and should assess all potentially cost-effective resources using the resource expansion modeling software.
- EKPC should describe and discuss all supply-side resources that were considered, including variations of the same resource (e.g., NGCC with and without CCS), and if a resource was considered but ultimately not included in the model, EKPC should explain each basis for excluding the resource, including the specific information used to support each basis such as engineering concerns that resulted in a resource being excluded based on a determination that it is not feasible.
- EKPC should consider interconnection costs and the cost of necessary network upgrades to the extent possible when assessing resources both in and outside its service territory and should describe and discuss how such costs were considered, whether and how such costs were included in the modeling software, uncertainties associated with how such costs were considered, and if applicable, why such costs could not be included in the modeling software.
- EKPC should consider and discuss savings, if any, that could be achieved by obtaining resources owned and operated through partnerships with other utilities.

- EKPC should consider and discuss opportunities, or the lack thereof, to partner with nearby utilities to gain experience with or access to new generation resources.

- EKPC should generally be in communication with other Kentucky electric utilities and review their IRPs when conducting planning.

- To the extent possible, EKPC should consider whether transmission options would allow it to serve load at a lower cost, including whether additional transmission capacity could lower locational marginal pricing within EKPC's PJM zone in a way that will reduce costs to customers or could provide access to additional energy from other PJM zones when necessary at a lower cost than constructing or maintaining additional reserve generation.

- In its next IRP, EKPC should provide a discussion of each cause of any reliability issues that arose on its system during Elliott; how EKPC could improve its current generation and transmission facilities to address reliability issues in a cost effective manner; the risks presented by multiple Kentucky utilities relying on the same natural gas transmission network and how they can be mitigated; and how EKPC changed its assessment of resources based on Elliott, e.g. whether it increased the risk of forced outages for certain resource for planning purposes. EKPC should also discuss long-term and short-term options to improve reliability if it is not able to run gas generators coupled with the possibility of not being able to import power, including whether it would be reasonable to plan for such a scenario. To the extent EKPC has any bilateral contracts to provide or receive power during an emergency, the discussion should include whether the contracts protect EKPC if it is unable to provide backup power and what obligation the counterparty has to provide power to EKPC.

<u>Integration</u>

- The Preferred Plan was not determined by the production cost/optimization model (RTSimm). EKPC's Sustainability Goals were layered by committee consensus in on the top least cost plan (Plan 1). If EKPC reflects its sustainability goals in the next IRP, EKPC should at minimum identify and explain each of its sustainability goals, explain each assumption or assessment that formed its basis for adopting those goals, and explain in detail how those sustainability goals were used to develop the final plan.

- As an alternative for comparison purposes and clarity, the sustainability goals, or rather the basis for the sustainability goals, should be given to RTSimm and the model should be allowed to determine the least-cost way to achieve the goals. EKPC could then develop and discuss a final plan based on the relative costs of the various plans produced by the model in scenarios with and without the sustainability goals and EKPC's analysis of the relative likelihood of the various scenarios.

- Carbon prices were excluded from load forecasting but were included in DSM modeling. EKPC should consistently include or exclude carbon prices or any other carbon limitation across different modeling methods.

- EKPC should spend additional time discussing the likelihood of the regulatory risks it identified and how those risks would affect existing and potential resources if they occurred. Further, as above, the modeling software should be used to the extent possible to assess resource options and potential scenarios that are likely to materially affect the resources selected, e.g., a scenario that assessed the costs of upgrading existing units to comply with the potential revision to the Cross-State Air Pollution Rule. EKPC could then develop and discuss a final plan based on the relative costs of the various plans produced by the model in scenarios with and without the potential regulation and EKPC's analysis of the relative likelihood of the various scenarios.

- EKPC should use the full functionality of RTSimm, or its chosen modeling software, to examine the economic and practical viability of available and near-market-ready resources, including:
    - Economic addition or retirement of generation resources;
    - Behind the meter DERs and other customer owned generation;
    - Cogeneration opportunities to the extent these exist or can be anticipated and modeled; and
    - DSM/EE programs: To the extent possible, EKPC should analyze generation resources and DSM/EE programs together as resources that may be selected in the same modeling runs to meet projected load, using the same cost and other inputs, to ensure that new DSM/EE programs and new generation resources are assessed on equal footing.

- If EKPC is not able assess the adoption of customer owned generation using its modeling software, EKPC should project the extent to which its customers will adopt customer owned resources, including qualifying facilities, customer owned solar, and other customer owned DERs, during the planning period of its next IRP and should project the effects those resources are likely to have on load, and EKPC should fully explain the methodology and assumptions used to make those projections.

- Each of the five lowest cost plans and the optimal plan had multiple additions of solar PPAs in various years. For the next IRP, if a similar pattern emerges which includes EKPC's sustainability goals, there needs to be a discussion of how each of EKPC's generation resources will operationally function such that the overall resource mix as determined by the RTSimm models is the least-cost plan.

- EKPC's should consider the likelihood of PJM changing its solar capacity credit as a variable in future modeling.

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REASONABLENESS

While its proposed plan was not necessarily unreasonable, EKPC's plan and analysis were often difficult to understand and assess due to the manner in which information was presented and gaps in some of the information. EKPC's IRP would be improved significantly if EKPC fully explained its methodology and assumptions in a narrative form and in a logical order. Further, as discussed above, EKPC could improve its methodology in several ways to more effectively produce an adequate and reliable, and least-cost plan. Depending on the circumstances, those methodology changes might have resulted in EKPC selecting a different final plan in this matter.

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