COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC 2023 INTEGRATED RESOURCE PLAN OF BIG RIVERS ELECTRIC CORPORATION	)))	CASE NO. 2023-00310

<u>O R D E R</u>

The Commission initiated this proceeding for its Staff to conduct a review of the 2023 Integrated Resource Plan (IRP) filed by Big Rivers Electric Corporation (BREC), 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. This Staff Report is being entered into the record of this case pursuant to 807 KAR 5:058, Section 11(3).

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 BREC's 2023 IRP shall represent the final substantive action in this matter.

2. Any party desiring to file comments regarding the Commission Staff's Report on BREC's 2023 IRP shall do so on or before September 6, 2024.

3. 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.

[REMAINDER OF PAGE INTENTIONALLY LEFT BLANK]

PUBLIC SERVICE COMMISSION

Angie Hatton
Chairman

Vice Chairman

Signed on behalf of Chair w/ permission

Mary Pat Regan
Commissioner

ENTERED
AUG 20 2024
rcs
KENTUCKY PUBLIC
SERVICE COMMISSION

ATTEST:

For
Executive Director

APPENDIX

AN APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2023-00310 DATED AUG 20 2024

FIFTY PAGES TO FOLLOW

Kentucky Public Service Commission

Commission Staff’s Report on the

2023 Integrated Resource Plan of

Big Rivers Electric Corporation

Case No. 2023-00310

August 2024

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]

Each electric generating utility is required by 807 KAR 5:058, Section 2, to file an Integrated Resource Plan (IRP) every three years. This plan requires the utility to (1) forecast its load, or expected demand, for the following 15 years;[2] (2) identify existing and potential supply-side and demand-side resources;[3] and (3) determine how to meet its demand in a way that minimizes cost while maintaining reliable service. The load forecast is compared to existing resource generation capacity, and the utility must establish a plan for meeting any capacity shortfall for each year. Modern generation planning involves complex software modeling systems in which the utility includes available resources as variables and the model is intended to output the most cost-effective[4] generation portfolio for each of several scenarios combining variables such as variance from forecasted load, fuel costs, changes to reserve margin requirements, changes in environmental regulation, and capital expenditures.

Big Rivers Electric Corporation (BREC) is a member-owned generation and transmission cooperative headquartered in Owensboro, Kentucky.[5] BREC provides wholesale electricity to owner-members Jackson Purchase Energy Corporation (Jackson Purchase), Kenergy Corporation (Kenergy), and Meade County Rural Electric Cooperative Corporation (Meade County RECC).[6] These member-owners provide retail service to approximately 121,000 customers across 22 counties in western Kentucky.[7] BREC also sells electricity pursuant to three bilateral power contracts with entities in the state of Nebraska, Owensboro Municipal Utilities, and the Kentucky Municipal Energy

---

[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] 807 KAR 5:058, Section 7.

[3] 807 KAR 5:058, Section 8.

[4] Subject to the requirements that the utility provide adequate, efficient and reasonable service under KRS 278.030 and the rebuttable presumption against retirement of fossil fuel-fired electric generating units found in KRS 278.264.

[5] 2023 IRP, Section 2 at 15.

[6] 2023 IRP, Section 2 at 15.

[7] 2023 IRP, Section 2 at 16.

Agency.[8] BREC owns and operates 1,338 miles of transmission lines and 26 substations.[9] BREC has been a member of the Midcontinent Independent System Operator, Inc. (MISO) regional transmission organization (RTO) since 2010.[10]

BREC's stated present total power capacity is 1,114 megawatts (MW).[11] BREC owns and operates the following generating resources for a total power capacity of 936 MW:[12]

- Robert A. Reid Plant (Reid) (65 MW), converted from coal to natural gas-fired in 2022,
- Robert D. Green Plant (Green) (454 MW), converted from coal to natural gas-fired in 2022,
- D. B. Wilson Plant (Wilson) (417 MW), single coal unit station.

BREC also utilizes 178 MW of contracted hydroelectric capacity from the Southeastern Power Administration (SEPA).[13] BREC also maintains seven small-scale solar arrays (less than 1 MW) as a pilot program.[14] BREC has secured a contract to purchase an additional 160 MW of solar capacity beginning in 2025.[15]

BREC states that its strategic objectives set forth in its 2023 IRP include:[16]

- Reliably and efficiently providing for its members' electricity needs over the next 15 years through an appropriate mix of resources at the lowest reasonable cost by minimizing the net present value of the production and capital cost for serving the load;
- Maintaining a current and reliable load forecast;
- Providing competitively priced power to its members;
- Maximizing reliability while ensuring safety and minimizing costs, risks, and environmental impacts;
- Identifying potential new supply-side resources;
- Maintaining adequate planning reserve margins;

[8] 2023 IRP, Section 2 at 18.

[9] 2023 IRP, Section 2 at 23.

[10] 2023 IRP, Section 2 at 17.

[11] 2023 IRP, Section 2 at 18.

[12] 2023 IRP, Section 2 at 18–19.

[13] 2023 IRP, Section 2 at 18.

[14] 2023 IRP, Section 2 at 19.

[15] 2023 IRP, Section 2 at 19.

[16] 2023 IRP, Section 2 at 37.

- Developing and maintaining a diversified supply portfolio aligned with anticipated owner-member load; and
- Meeting North American Electric Reliability Corporation (NERC) guidelines and requirements.

BREC submitted its 2023 IRP to the Commission on September 29, 2023. On November 3, 2023, an Order was issued establishing a procedural schedule for this proceeding. The procedural schedule established a deadline for requesting intervention, two rounds of data requests to BREC, an opportunity for intervenors to file written comments, and an opportunity for BREC to file a response to any intervenor comments. A hearing was held on May 22, 2024. All parties were permitted to submit additional post-hearing data requests and comments prior to the filing of this report.

The following parties filed for, and were granted, intervention in this matter: Attorney General of the Commonwealth of Kentucky, by and through the Office of Rate Intervention (Attorney General), Kentucky Industrial Utility Customers (KIUC), Sierra Club, and Joint Intervenors Kentuckians for The Commonwealth and Kentucky Resources Council (Joint Intervenors). Intervenor comments to this Staff Report are due on September 6, 2024. Intervenors' and BREC's comments are summarized within this report's applicable sections.

The purpose of this report is to review and evaluate BREC's 2023 IRP in accordance with 807 KAR 5:058, Section 11(3), which requires Staff to issue a report summarizing its review of each IRP filing made with the Commission and make suggestions and recommendations to be considered by a utility in its next IRP filing. Staff recognizes that resource planning is a dynamic, ongoing process. Specifically, Staff's goals are to ensure, among other things, 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 BREC's most recent IRP filed in 2020.

The remainder of this report is organized as follows:

- Section 2: Load Forecasting—reviews BREC's projected load growth and load forecasting methodology.
- Section 3: Demand-Side Management and Energy Efficiency (DSM/EE)—summarizes BREC's evaluation of DSM opportunities.
- Section 4: Supply-Side Resource Assessment—focuses on supply-side resources available to meet BREC's load requirements and environmental compliance planning.
- Section 5: Integration—discusses BREC'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 for BREC's systems and BREC's load forecasting methodology. This section also reviews BREC's responses to Commission Staff's recommendations regarding load forecast in BREC's 2020 IRP and the parties' comments regarding BREC's load forecast. Commission Staff's discussion of and recommendations regarding BREC's load and demand forecasting are discussed in Section 6 of this report.

BREC's load forecast utilized a "bottom-up approach" which was the result of close cooperation between BREC, Jackson Purchase Energy Corporation, Kenergy Corporation, Meade County Rural Electric Cooperative Corporation, and Clearspring Energy Advisors, LLC (Clearspring).[17] Individual forecasts for each of the distribution cooperatives are integrated into BREC's load forecast.[18] BREC stated that the load forecast meets the requirements of the Rural Utilities Service (RUS) and will be used in part for RUS loan applications.[19] BREC also stated that the forecast may also be used to meet state and federal regulatory requirements and to participate in reliability council and independent transmission organization activities.[20]

Although 807 KAR 5:058, Section 7(3), only requires a 15-year load forecast, BREC provided a 20-year load forecast.[21]

Residential Class

The Residential sales forecast is a function of the number of customers forecast and the use per residential customer forecast. Woods & Poole Economics, Inc. provided household growth projections at the county level.[22] Using the current distribution of residential customers within each county, these projections were then weighted for each county within each distribution cooperative's service territory.[23] Growth estimates were then adjusted as necessary by BREC's cooperative staff.[24] The number of residential

[17] 2023 IRP, Appendix A at A-5.

[18] 2023 IRP, Appendix A at A-5.

[19]2023 IRP, Appendix A at A-6

[20] 2023 IRP, Appendix A at A-6.

[21] 2023 IRP at 28, Table 2.2.8(a).

[22] 2023 IRP, Appendix A at A-24.

[23] 2023 IRP, Appendix A at A-24.

[24] 2023 IRP, Appendix A at A-24.

customers is expected to increase from 102,118 in 2023 to 109,252 in 2042.[25] This growth represents an average annual rate of 0.37 percent over the 20-year period.[26]

The Residential use per customer forecast is obtained using econometric modeling techniques.[27] Residential use per customer is a function of electricity prices, alternate fuel prices, cooling and heating degree days, appliance saturation levels, and appliance efficiency levels and binary variables.[28] Appliances utilized in the modeling are air conditioning and heating equipment.[29] Cooling degree days (CDD), heating degree days (HDD), and peak day weather conditions are based on the prior 20-year average.[30] Residential use per customer is forecast to decrease slightly at an average annual rate of 0.07 percent over the forecast period from 14,093 kWh to 13,892 kWh.[31] Usage declines resulting from older, less efficient appliances being replaced are offset by forecast declines in the real price of electricity and growth in electric vehicle ownership.[32] BREC's Residential energy sales were forecast to increase at an average annual rate of 0.3 percent from 1,430,495 MWh to 1,517,731 MWh over the forecast period.[33]

General Commercial and Industrial (GCI) Class

The GCI class is defined as the total commercial and industrial loads minus the Direct Serve and the Large Commercial and Industrial (LCI) class.[34] The GCI forecast is a function of the number of GCI customers and GCI use, per customer.[35] Using econometric modeling, the number of GCI customers is a function of gross regional product, total retail sales, and total employment within the counties served, aligned with each distribution cooperative's 2022 GCI customers.[36] The number of GCI customers is

[25] 2023 IRP, Appendix A at A-23.

[26] 2023 IRP, Appendix A at A-23.

[27] 2023 IRP, Appendix A at A-25.

[28] 2023 IRP, Appendix A at A-25.

[29] 2023 IRP, Appendix A at A-25 and individual cooperative models at Appendix A, at A-96, A-100, and A-104.

[30] 2023 IRP, Appendix A at 65.

[31] 2023 IRP, Appendix A at A-23.

[32] 2023 IRP, Appendix A at A-25.

[33] 2023 IRP, Appendix A at A-23.

[34] 2023 IRP, Appendix A at A-27.

[35] 2023 IRP, Appendix A at A-27.

[36] 2023 IRP, Appendix A at A-29.

expected to increase at an average annual rate of 0.9 percent over the forecast period from 18,815 to 22,517.[37]

GCI use per customer was forecast using econometric techniques and was a function of binary variables, electricity prices, employment per customer, CDD, and HDD within the counties served.[38] Preliminary modeling results were reviewed by cooperative staff and modified if necessary based upon specific staff knowledge.[39] GCI use per customer is forecast to increase over the forecast period at an average annual rate of 0.04 percent from 30,798 kWh to 31,076 kWh.[40] Over the forecast period, BREC's GCI energy sales were expected to grow at an average annual rate of 0.95 percent from 579,464 MWh to 699,737 MWh.[41]

Large Commercial and Industrial Class

The LCI class is defined as the largest commercial and industrial customers that are not served under BREC's Large Industrial Class (LIC) tariff and do not qualify as Direct Serve customers.[42] In 2022, there were 29 LCI customers, increasing to 33 by 2028, then decreasing to 32 in 2030, and remaining at that level for the balance of the forecast period.[43] Energy sales forecasts were based upon staff knowledge and judgment with input from each cooperative.[44] Use per LCI customer was forecast to increase from 5,056 MWh in 2022 to 5,671 MWh in 2024 and then decline slightly to 5,618 MWh over the balance of the forecast period.[45] BREC's LCI class energy sales was forecast to grow from 146,626 MWh in 2022 to 187,146 MWh in 2027 and then decline to 179,788 through the balance of the forecast period.[46]

Direct Serve Class

The Direct Serve (DS) class includes customers served directly from the transmission system.[47] The number of DS customers was 16 in 2022, growing to 18 by 2024, and remaining at that level for the balance of the forecast period for load forecast

---

[37] 2023 IRP, Appendix A at A-28.

[38] 2023 IRP at 30; Appendix A at A-98, A-102, and A-106.

[39] 2023 IRP, Appendix A at A-30.

[40] 2023 IRP, Appendix A at A-28.

[41] 2023 IRP, Appendix A at A-39.

[42] 2023 IRP, Appendix A at A-27.

[43] 2023 IRP, Appendix A at A-32.

[44] 2023 IRP, Appendix A at A-31.

[45] 2023 IRP, Appendix A at A-32.

[46] 2023 IRP, Appendix A at A-32.

[47] 2023 IRP, Appendix A at A-33.

purposes.[48] DS use per customer was forecasted to grow from 56,001 MWh in 2022 to 123,618 in 2025, and fluctuate around that level for the balance of the forecast period.[49] BREC's DS energy sales were forecast to increase from 919,357 MWh in 2022 to 2,225,127 MWh in 2025 and fluctuate around that level for the balance of the review period.[50]

Street and Highway Class and Irrigation Class

The Street and Highway class forecast was created manually.[51] Over the forecast period, BREC anticipates 125 customers and 24,272 kWh use per customer annually.[52] BREC anticipates 3,034 MWh in energy sales annually over the forecast period.[53] BREC anticipates the five current irrigation customers will remain constant over the forecast period with an annual use per customer of 18,625 kWh and total irrigation energy sales of 93 MWh.[54]

Electric Vehicle and Distributed Generation Forecasts

BREC conducted separate forecasts for both electric vehicles (EV) and for distributed generation (DG), the results of which were incorporated into the load forecast.[55] The EV energy and peak load forecast for both residential and commercial and industrial customers is based the historical contribution to energy and peak load.[56] Historical values are derived from statewide vehicle registration data and regional projections from the U.S. Energy Information Agency (EIA) Annual Energy Outlook.[57] The annual energy values are fit to monthly and hourly contributions using estimated load shapes from the Department of Energy Alternative Fuels Data Center.[58] The total system energy and demand additions attributable to EV growth over the forecast period total 4,117 MWh increasing to 40,680 MWh and 557 kW to 5,500 kw respectively.[59] The DG

[48] 2023 IRP, Appendix A at A-33.

[49] 2023 IRP, Appendix A at A-34.

[50] IRP, Appendix A at A-34. Also, Kenergy has two DS smelter load customers that are not included in the load forecast because they do not contribute to BREC's energy or peak requirements. IRP, Appendix A, Footnote 2 at A-30.

[51] 2023 IRP, Appendix A at A-35.

[52] 2023 IRP, Appendix A at A-36.

[53] 2023 IRP, Appendix A at A-35–A-36.

[54] 2023 IRP, Appendix A at A-37-A-38.

[55] 2023 IRP, Appendix A at A-21.

[56] 2023 IRP, Appendix A at A-17.

[57] 2023 IRP, Appendix A at A-17.

[58] 2023 IRP, Appendix A at A-19.

[59] 2023 IRP, Appendix A at A-18.

forecast for both residential and commercial customers is based on historical DG capacity in each member system and forecast annual DG derived from the EIA Annual Energy Outlook.[60] The annual energy values are fit to monthly and hourly contributions using estimated load shapes from the National Renewable Energy Laboratory (NREL).[61] The total system energy and demand reduction (i.e. savings) attributable to DG growth over the forecast period is 612 MWh increasing to 1,680 MWh and negative 3,046 kW increasing to negative 8,357 kW.[62]

Total Rural System and Total System Energy

Total Rural system energy requirements equal the sum of the Residential, GCI, LCI, Street and Highway, and Irrigation customer classes plus distribution losses and BREC's own usage. Distribution losses are expected to grow from 105,760 MWh in 2023 to 114,353 MWh in 2042. BREC's own use is expected to range from 4,103 MWh in 2022 to 4,337 MWh in 2042. BREC's Total Rural System energy requirements were forecast to grow at an average annual rate of 0.52 percent from 2,269,586 MWh in 2022 to 2,519,073 MWh in 2042.[63]

BREC's Total System energy requirements are the sum of Total Rural System energy, plus Direct Serve, transmission losses, and Non-Member energy requirements. Transmission losses were forecast to grow from 74,851 MWh in 2022 to 113,674 MWh in 2042. BREC's Total System energy requirements were expected to increase at an average annual rate of 2 percent ranging from 3,269,978 MWh in 2022 to 4,857,874 MWh in 2042. These results are presented in the table below. Note that the Non-Member forecast energy amounts presented in the table below are not the same amounts used in the EnCompass model for determining resource additions and retirements. Owensboro Municipal Utilities (OMU) energy is the total value prior to any allocations of energy from OMU's share of the Southeast Electric Power Agency (SEPA) hydroelectric system and based on an hourly load profile curve. The Kentucky Municipal Electric Agency (KYMEA) was modeled as a call option in the model which results in a reduced obligation to KYMEA as fuel prices and market conditions vary over time.[64]

BREC's energy forecast is presented in the table below.[65]

---

[60] 2023 IRP, Appendix A at A-17.

[61] 2023 IRP, Appendix A at A-19.

[62] 2023 IRP, Appendix A at A-20.

[63] 2023 IRP, Appendix A at A-39.

[64] 2023 IRP, Footnote 70 at 69. Also see 2023 IRP at 133. BREC and 1898 & Company developed the EnCompass expansion planning model.

[65] 2023 IRP, Table 4.4(a) at 69; Appendix A at A-41 and A-91-93. Note that Aux load is historically negligible and not included in the forecast. *See also* Appendix A at A-45 and A-46. The Non-Member (OMU, KYMEA, Nebraska Entities) energy sales are net anticipated projections. Also, note that BREC makes bilateral short-term capacity sales with no associated energy. *See also* Appendix A at A-91-93. Direct Serve forecast included Domtar's contract sales amount only, not forecasted total sales.

Total Rural Direct Serve & Transmission Non-Member (MWh)

Year	Total Rural Requirements	Direct Serve & Aux Sales	Transmission Losses	Non-Member Requirements	Total System Energy Requirements
2018	2,366,988	953,822	86,858	359,615	3,767,283
2019	2,261,069	950,475	82,848	1,591,431	4,885,823
2020	2,164,868	841,639	77,120	1,565,152	4,648,780
2021	2,219,380	799,926	71,125	2,004,399	5,094,831
2022	2,269,586	925,541	74,851	2,210,824	5,480,803
2023	2,291,062	1,569,178	92,323	2,106,933	6,059,496
2024	2,343,506	2,172,620	108,209	2,106,933	6,731,268
2025	2,344,105	2,225,127	109,482	2,106,933	6,785,647
2026	2,354,461	2,225,127	109,730	2,106,933	6,796,252
2027	2,364,427	2,225,127	109.969	1,080,851	5,780,374
2028	2,373,176	2,227,894	110,245	784,825	5,496,140
2029	2,380,698	2,225,127	110,359	324,681	5,040,865
2030	2,394,861	2,225,127	110,698	0	4,730,686
2031	2,404,797	2,225,127	110,936	0	4,740,860
2032	2,425,591	2,227,894	111,501	0	4,764,986
2033	2,432,406	2,225,127	111,598	0	4,769,131
2034	2,441,782	2,225,127	111,822	0	4,778,731
2035	2,451,925	2,225,127	112,065	0	4,789,118
2036	2,466,634	2,227,894	112,484	0	4,807,012
2037	2,476,201	2,225,127	112,647	0	4,813,975
2038	2,485,134	2,225,127	112,861	0	4,823,122
2039	2,493,662	2,225,127	113,065	0	4,831,854
2040	2,501,574	2,227,894	113,321	0	4,842,789
2041	2,509,737	2,225,127	113,451	0	4,848,315
2042	2,519,073	2,225,127	113,674	0	4,857,874

Like the energy forecast, the Rural System coincident peak demand (Rural CP) is measured based on the demand coincident with the total BREC system. The Rural coincidence factor for each of the three distribution cooperatives is derived econometrically based on a monthly data set. The forecast factor is combined with the Rural energy forecast to predict the Rural coincident peak demand.[66] The forecast load

[66] 2023 IRP, Appendix A at A-48.

factor is a function of binary variables, monthly peak day temperature, CDD, HDD, appliance saturation, and appliance efficiencies.[67]

BREC's peak and non-coincident peak forecast is presented below.[68]

Total System NCP (kW)

Year	Rural Summer CP	Rural Winter CP	Rural Annual CP	Direct Serve and Aux CP	Transmission losses	Total Annual CP	Non-Member Sales	Total NCP
2018	502,549	556,742	556,742	95,530	16,382	668,654	64,608	733,262
2019	480,171	490,895	490,895	117,931	15,995	624,821	341,253	966,074
2020	460,173	440,685	460,173	107,748	14,562	582,483	346,820	929,303
2021	487,669	492,854	492,854	99,559	13,822	606,235	356,940	963,175
2022	510,098	590,652	590,652	99,928	16,185	706,765	365,780	1,072,545
2023	473,447	432,573	473,447	261,127	17,601	752,176	344,230	1,096,406
2024	481,988	484,213	481,988	338,288	19,654	839,930	345,700	1,185,630
2025	482,030	483,438	482,030	359,104	20,154	861,287	345,700	1,206,987
2026	483,992	485,070	483,992	359,104	20,201	863,296	345,700	1,208,996
2027	485,932	486,409	485,932	359,104	20,248	865,283	100,000	965,283
2028	488,179	488,028	488,179	359,104	20,301	867,584	100,000	967,584
2029	489,348	488,711	489,348	359,104	20,329	868,781	0	868,781
2030	492,199	490,944	492,199	359,104	20,398	871,701	0	871,701
2031	494,185	492,406	494,185	359,104	20,445	873,734	0	873,734
2032	498,436	496,027	498,436	359,104	20,547	878,087	0	878,087
2033	499,759	496,990	499,759	359,104	20,579	879,441	0	879,441
2034	501,606	498,509	501,606	359,104	20,623	881,332	0	881,332
2035	503,602	500,209	503,602	359,104	20,671	883,377	0	883,377
2036	506,528	502,945	506,528	359,104	20,741	886,373	0	886,373
2037	508,354	504,790	508,354	359,104	20,785	888,242	0	888,242
2038	510,032	506,532	510,032	359,104	20,825	889,961	0	889,961
2039	511,611	508,264	511,611	359,104	20,863	891,577	0	891,577
2040	513,047	509,905	513,047	359,104	20,897	893,048	0	893,048
2041	514,533	511,598	514,533	359,104	20,933	894,570	0	894,570

[67] 2023 IRP, Appendix A at A-99, A-103, and A-107 and BREC's Response to Staff's First Request, Items 64-69.

[68] 2023 IRP, Appendix A at A-49, A-51, A-91-93, and Table 4.3(a) at 67. *See also* BREC's Response to Staff's First Request, Item 3, and BREC's Response to Commission Staff's Second Request for Information (Staff's Second Request), Item 19. The Aux (or auxiliary power) category includes BREC's own energy and capacity use and any power required by certain BREC generators which have retired. Aux was expected to remain insignificant and was not included in the forecast. *See* IRP, Tables 2.2.8(a) and 2.2.8(b) at 28-29 and Appendix A at A-91 for historical usage levels. *See also* Appendix A at A-91-93. Non-member forecasts are included for the entire 2023-2042 forecast period and Direst Serve customer forecast includes Domtar's contract sales amount only.

2042	516,266	513,565	516,266	359,104	20,974	896,344	0	896,344

The large decrease in the seasonal and Rural CP figures from 2022 to 2023 was due primarily to the effects of the COVID-19 pandemic. For the Direct Serve & Aux CP, the addition of new customers accounted for the large increase from 2022 to 2025. Accounting for the pandemic, Rural Summer CP was forecast to grow at an average annual rate of 0.09 percent from 473,447 kW to 516,266 kW between 2023 and 2047. Similarly, the Rural Winter CP was forecast to grow at an average annual rate of 18.7 percent from 432,573 kW to 513,565 kW from 2023 to 2047. Using the Direct Serve customers and transmission losses, BREC's total annual CP is expected to increase significantly from 706,765 kW to 861,287 kW from 2022 to 2025 with the addition of the Direct Serve load. Thereafter, it is expected to increase slowly to 896,344 kW in 2042. Over the 20-year forecast period, CP is expected to grow at an average annual rate of 1.2 percent.

BREC's non-coincident peak (NCP) is calculated by adding Non-Member sales at their peak load values to Total Annual CP system sales.[69] Non-Member sales in this table are inclusive of Nebraska customers as well as sales to OMU, KYMEA, and via bilateral capacity contracts.[70] BREC's NCP was forecast to decrease from 1,072,545 kW to 896,344 kW over the 20-year forecast period. BREC did not forecast its required Non-Member energy or capacity sales beyond the expiration of the current contracts.[71] BREC explained that although it intends to seek renewal of the contracts, it did not know the probability of contract renewal or the potential contract terms.[72] Therefore, it did not attempt to forecast the potential future load.[73]

However, for the purposes of forecasting the optimal portfolio of future resources, Non-Member sales include BREC's required energy and capacity sales only, i.e., sales to OMU, KYMEA, and via bilateral capacity contracts.[74] BREC neither generates nor transmits power to the Non-Member customers in Nebraska.[75] These customers are served within the Southwest Power Pool (SPP) and BREC purchased the necessary capacity in the SPP.[76] In addition, the required Non-Member contract capacity represents

[69] 2023 IRP, Appendix A at A-50.

[70] 2023 IRP, Appendix A at A-45.

[71] 2023 IRP, Appendix A at A-51.

[72] BREC's Response to Staff's Second Request, Item 27.

[73] BREC's Response to Staff's First Request, Item 21 and BREC's Response to Staff's Second Request, Item 27. However, in Appendix A at A-91-93, includes a forecast of non-member load over the entire 20-year forecast period.

[74] 2023 IRP, Appendix A at A-45.

[75] 2023 IRP, Appendix A at A-45, note 6.

[76] BREC's Response to Staff's Second Request, Items 17-18.

an approximate 30 percent addition to BREC's total annual CP and 23 percent of its NCP in 2026.[77] As will be discussed below, the exclusion of forecast Non-Member sales when contract renewal is expected could skew the amount and timing of any forecast resource additions or retirements and is not appropriate in an IRP study.

Clearspring completed a DSM potential study in 2023.[78] An alternative energy and demand forecast was conducted based on a $1 million DSM spending scenario.[79] The DSM impacts are derived from each appliance end use.[80] The DSM-based forecast resulted in a 9,076 MWh decrease in energy use to 90,762 MWh over the forecast period.[81] Similarly, DSM expenditures resulted in a CP 1,714 kW decline to 17,142 kW over the forecast period.[82] BREC's EnCompass model base case forecast assumes no DSM spending in the future. Any additional DSM impacts are the result of prior DSM programs.[83]

For modeling purposes, the base case scenario used the load forecast discussed above. Four additional sensitivity scenarios were developed around the base case to account for possible load variances: Mild and extreme weather with normal economic growth and high and low economic growth with normal weather.[84] For the weather scenarios, only the Residential and GCI customer use per customer loads were sensitive to weather variations. For these customer classes, both HDD and CDD variables were altered to the 20-year maximum and minimum annual values.[85] These maximum and minimum values were then redistributed across each month based on an average monthly distribution of HDD and CDD values. For the two economic scenarios, the Residential, LCI, and Street and Highway classes were not modeled econometrically. Instead, they were directly modified by 1.0 percent relative to the base case forecast to create the high and low scenarios.[86]

---

[77] 2023 IRP, Appendix A at A-51.

[78] 2023 IRP, Appendix B.

[79] 2023 IRP, Appendix B at E-3.

[80] 2023 IRP, Appendix A at A-52.

[81] 2023 IRP at 126, Table 7.1.4(k).

[82] 2023 IRP, Appendix A at A-53.

[83] 2023 IRP, Appendix A at A-54-55.

[84] 2023 IRP, Appendix A at A-54.

[85] 2023 IRP, Appendix A at A-77.

[86] 2023 IRP Appendix A at A-58. *See* Appendix A, at 56 and 59 for Native System results for the four scenarios.

RESPONSES TO PREVIOUS COMMISSION STAFF'S RECOMMENDATIONS

Commission Staff issued a report on BREC's 2020 IRP (2020 IRP), which included recommendations for future load forecasts.[87] The following are BREC's 2023 IRP responses to 2020 IRP load forecast recommendations in Commission Staff's report:

1) BREC should provide a clear comparison of the efficacy of the econometric forecasting methodology that it began using with the 2020 IRP versus the previously used statistically adjusted end-use (SAE) modeling.

Response: BREC included an in-depth comparison of the two forecasting methodologies. BREC cited a research paper produced by the Lawrence Berkeley National Laboratory titled "Load Forecasting in Electric Utility Integrated Resource Planning" which examined the results of utilities that employed the econometric and SAE approaches.[88] The utilities using the econometric method to determine future demand growth resulted in a lower deviation from actual load growth.[89]

2) BREC should provide a comparison of forecasts using 15, 20, and 30-year weather normalization. If a different weather normalization benchmark is selected, BREC should provide a clear explanation why the change provides better forecasts.

Response: BREC provided ten, 15, and 20-year weather normalization data and used the 20-year period for its base case scenario. BREC asserted that the differences were minimal.[90] BREC stated that 20-year averages are commonly used in load forecasting.[91]

3) BREC should continue to provide comparisons of actual to forecasted results for the residential and small commercial and industrial classes along with reasons for any differences between forecasted and actual results.

Response: BREC provided this information in its 2023 IRP. The load forecasts in the 2020 IRP were all within 0.02 percent of the actual usage, an improvement over previous load forecasts dating back to 2013, which ranged from 0.05 to 1.86 percent error from actual usage.[92] BREC broke this information down by class for the 2020 IRP load forecast, showing a 0.06 to 0.16 percent overestimation of residential demand and a 0.41 to 0.92 percent underestimation of general commercial and industrial demand.[93]

---

[87] Case No. 2020-00299, *Electronic 2020 Integrated Resource Plan of Big Rivers Electric Corporation* (Ky. PSC Nov. 22, 2021), Order (Staff Report) at 17–18.

[88] 2023 IRP, Appendix A at A-66.

[89] 2023 IRP, Appendix A at A-67.

[90] 2023 IRP, Appendix A at A-77.

[91] BREC's Responses to Commission Staff's First Request for Information (Staff's First Request), Item 4 (filed Jan. 10, 2024).

[92] 2023 IRP, Appendix A at A-72.

[93] 2023 IRP, Appendix A at A-73.

4) BREC should continue to provide comparisons of actual and forecasted summer and winter peak demands using a variety of normalization periods along with reasons for any significant differences between actual and forecasted peak demand.

Response: In its 2023 IRP, BREC provided peak forecasts from the 2020 IRP compared to actual peaks without applying different weather normalization periods. For both summer and winter peak forecasts, the forecasts overestimated the peak for 2020, approximately accurately forecasted peak for 2021, and underestimated the peak for 2022.[94]

5) BREC should continue to explore new markets, including economic development efforts within its service territory, and provide an update on the status of non-member sales contracts.

Response: BREC stated that it receives numerous requests for information from potential economic development special contract partners, including 71 such requests in 2022.[95] Regarding its three non-member sales contracts, BREC stated that it may renew these contracts.[96] However, the IRP only uses non-member load in the forecasts for years that the existing contracts cover.[97]

INTERVENOR AND RESPONSE COMMENTS

KIUC argued that BREC changed how it forecast load and energy, ignoring the capacity value of behind-the-meter cogeneration set by MISO.[98] KIUC disagreed with this new methodology, stating that beginning in 2025, BREC plans to serve the full energy requirements of standby service customers, instead of its historic practice of planning to serve only the partial energy requirements of those customers.[99] BREC responded that its methodology change was intended to create a clear and accurate picture of actual system load obligations, which includes two co-generation partner customers. Service to these co-generators includes the risk that one of them will incur an outage outside the control of BREC that could result in a demand increase.[100]

---

[94] 2023 IRP, Appendix A at A-82–A-83.

[95] 2023 IRP at 24–25.

[96] BREC's Response to Intervenor Comments at 16.

[97] 2023 IRP at 69.

[98] The use of which is at issue in Case No. 2023-00312, *Electronic Tariff Filing of Big Rivers Electric Corporation and Kenergy Corp. to Revise the Large Industrial Customer Standby Service Tariff* (tariff filed Sept. 1, 2023).

[99] KIUC's Comments at 2.

[100] KIUC's Comments at 7–8.

In its post-hearing comments, KIUC reiterated its position that BREC's load forecast should reflect net load instead of gross load, and that the current methodology overstates BREC's capacity needs.[101]

Joint Intervenors' post-hearing comments questioned whether BREC's IRP strategy to build and hold significantly more capacity than necessary (assuming non-renewal of Non-Member contracts) should result in BREC evaluating a range of loads, especially as pertaining to Direct Serve Loads.[102] Joint Intervenors also commented that BREC should provide an analysis of the net benefit of Non-Member sales to BREC's members.[103]

[101] KIUC's Post-Hearing Comments at 1.

[102] Joint Intervenors' Post-Hearing Comments at 2.

[103] Joint Intervenors' Post-Hearing Comments at 2.

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.[104] This section briefly describes BREC's existing DSM and EE programs, summarizes how existing programs were reflected in the IRP, and discusses DSM/EE programs BREC reviewed to meet projected load. This section also reviews BREC's responses to Commission Staff's recommendations regarding DSM/EE in BREC's 2020 IRP and the parties' comments specifically regarding BREC's DSM/EE programs. Commission Staff's discussion of and recommendations regarding BREC's DSM/EE forecasting are located in Section 6 of this Report.

The Commission approved the discontinuation and phase-out of BREC's existing DSM programs in July 2018.[105] The same Order approved the only remaining DSM program that BREC currently offers, the Low-Income Weatherization Support Program (Low-Income Program), on a pilot basis.[106] The Low-Income Program launched in the early months of 2020, in coordination with the Community Action Agencies (CAA) in the region. However, BREC noted that the Low-Income Program has not had any activity since March 31, 2021 and should be re-evaluated.[107]

SUMMARY DISCUSSION OF DSM-EE

BREC engaged with Clearspring to conduct a DSM Market Potential Study (DSM MPS) that focuses on the economic evaluation of DSM potential within its service territory that includes energy efficiency measures, demand response, and dynamic pricing that would be appropriate for the member-owners of the BREC system.[108]

The DSM MPS objective was to identify potential cost-effective demand-side opportunities that could directly reduce demand and consumption of electricity over the 2024-2033 period, with the idea that cost-effective demand reduction for electricity may

---

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

[105] Case No. 2018-00236, *Demand-Side Management Filing of Big Rivers Electric Corporation on Behalf of Itself, Jackson Purchase Energy Corporation, and Meade County R.E.C.C. and Request to Establish a Regulatory Liability* (Ky. PSC Dec. 12, 2018), Order.

[106] Case No. 2018-00236, *Demand-Side Management Filing of Big Rivers Electric Corporation on Behalf of Itself, Jackson Purchase Energy Corporation, and Meade County R.E.C.C. and Request to Establish a Regulatory Liability* (Ky. PSC Dec. 12, 2018), Order.

[107] 2023 IRP at 88.

[108] 2023 IRP, Appendix B at E-1.

reduce future need for supply-side resources.[109] As part of the DSM MPS, Clearspring developed residential and non-residential segment end-use models of energy use, and then identify potential demand response (DR) and EE measures.[110] Clearspring evaluated those DR and EE measures with a qualitative screening tool that is designed to eliminate measures that do fit certain criteria.[111] Clearspring performed a quantitative economic analysis on the cost-effectiveness of these measures that included the Total Resource Cost (TRC), Participant Cost (PCT), Utility Cost (UCT), and Rate Impact Measure (RIM) tests.[112] Lastly, the four areas that the measures were evaluated for were estimates based on the technical, economic, achievable, and program potential for the 2024-2033 period.[113]

Clearspring compiled results for the residential segment for EE potential with 65 measures passing the technical potential screening.[114] Clearspring noted that only summer peak savings were illustrated as the analysis was conducted prior to MISO seasonal forecasts being available.[115] Of the 65 measures presented in the technical potential analysis, 34 measures passed the TRC test and yielded a benefit-cost ratio greater than one.[116] Clearspring explained that considering all 34 measures passed the TRC screening test and yielded a benefit-cost greater than one from the participant screening test, then all 34 measures would be considered for achievable energy efficiency potential.[117] A program scenario was developed based on an annual energy efficiency budget of $1 million annually, in which lighting, HVAC, and water-heated related measures produced extremely high TRC scores.[118] Overall, the residential program scenario achieved a TRC score of 2.4.[119]

Clearspring also compiled results for the non-residential segment for EE potential with 115 measures passing the technical potential screening.[120] Of the 115 measures presented in the technical potential analysis, 66 measures passed the TRC test and

[109] 2023 IRP, Appendix B at 1-2.

[110] 2023 IRP, Appendix B at E-1

[111] 2023 IRP, Appendix B at E-1-2

[112] 2023 IRP, Appendix B at E-1-2

[113] 2023 IRP, Appendix B at E-1.

[114] 2023 IRP, Appendix B at 3-11.

[115] 2023 IRP, Appendix B at 3-11.

[116] 2023 IRP, Appendix B at 3-3.

[117] 2023 IRP, Appendix B at 3-4.

[118] 2023 IRP, Appendix B at 3-6, Figure 3.1.

[119] 2023 IRP, Appendix B at 3-6.

[120] 2023 IRP, Appendix B at 4-1.

yielded a benefit-cost ratio greater than one.[121] Additionally, from the 66 measures that passed the TRC screening test, 65 measures yielded a benefit-cost greater than one from the participant perspective under the aggressive incremental cost assumption and would be considered for achievable EE potential.[122] A program scenario was developed based on an annual EE budget of $1 million annually, in which HVAC, lighting, and appliance related measures produced the highest TRC scores.[123]

Additionally, BREC modeled different load control and time-differentiated pricing options to observe any potential DR benefits.[124] Those programs included:

- Cycling of central air conditioning (25 percent)
- Cycling of central air conditioning (50 percent)
- Central air conditioning control
- Cycling of electric water heating (25 percent)
- Cycling of electric water heating (50 percent)
- Electric water heating control
- Peak-Time Rebate (Residential and Non-Residential)
- Direct Load Control (Residential and Non-Residential)
- Battery Storage (Residential and Non-Residential)
- Residential Level 2 Electric Vehicle Charging
- Commercial Fleet Charging
- Time-of-Use
- Critical-Peak-Pricing
- Real-Time-Pricing

The results of the TRC test for the DR programs are illustrated below.[125] BREC noted that the results included the most recent avoided energy and capacity cost projections but also that the benefits included operations and maintenance (O&M) savings and tax credits and costs include incremental measure costs, program costs, and any O&M costs.[126]

Program	Sector	Type	Direct Control	TRC	UCT	PCT
Air Conditioner Cycling (25%)	Residential	Load Management	Yes	1.6	0.7	2.2

[121] 2023 IRP, Appendix B at 4-2.

[122] 2023 IRP, Appendix B at 4-3.

[123] 2023 IRP, Appendix B at 4-5; Figure 4.1.

[124] 2023 IRP, Appendix B at 5-4

[125] 2023 IRP, Table 5.5(a) at 87.

[126] 2023 IRP at 75 and Appendix B at 1.6.

Air Conditioner Cycling (50%)	Residential	Load Management	Yes	3.3	1.5	2.2
Air Conditioner Control (100%)	Residential	Load Management	Yes	6.5	2.9	2.2
Water Heater Cycling (25%)	Residential	Load Management	Yes	0.3	0.1	2.2
Water Heater Cycling (50%)	Residential	Load Management	Yes	0.5	0.2	2.2
Water Heater Control (100%)	Residential	Load Management	Yes	0.9	0.4	2.2
Level 2 EV Charger	Residential	Load Management	Yes	1.2	1.1	1.3
Battery Storage	Residential	Load Management	Yes	0.4	1.0	2.8
Residential Load Control	Residential	Load Management	Yes	5.5	3.4	1.6
DLC (Customer Ownership)	Non-Residential	Load Management	Yes	2.1	1.2	1.2
DLC (Utility Ownership)	Non-Residential	Load Management	Yes	2.1	1.8	1.5
Battery Storage	Non-Residential	Load Management	Yes	0.9	2.4	5.9
Fleet Charging (Off-Peak)	Non-Residential	Load Management	Yes	2366.0	3.4	600.0
Peak Time Rebate	All	Load Management	No	49.5	2.3	121.9
Residential TOU	Residential	Dynamic Pricing	No	18.7	30.8	13.7
Residential CPP	Residential	Dynamic Pricing	No	41.1	67.9	68.6
Non-Residential TOU	Non-Residential	Dynamic Pricing	No	10.5	53.1	30.4
Non-Residential CPP	Non-Residential	Dynamic Pricing	No	37.8	191.7	199.3
Plug-In EV TOU	All	Dynamic Pricing	No	0.1	10	0.1

BREC explained that forward capacity prices in MISO have seen a significant rise as compared to the past decade, and that consequently, the benefit-cost ratio of DR programs has risen.[127] As illustrated above, the following programs passed the TRC test:

- Air conditioning Cycling and Control
- Level 2 Charger Control
- Residential Load Control
- Non-Residential DLC
- Fleet Charging Off-Peak
- Peak-Time Rebate

[127] 2024 IRP at 88.

- Time-of-Use (Residential and Non-Residential)
- Critical Peak Pricing (Residential and Non-Residential)

However, BREC explained that it should continue evaluating EE/DR programs that were deemed cost-effective.[128] BREC also explained that it does not know how MISO's seasonal capacity construct and implementation will impact future avoided cost assumptions, but that, based on Clearspring's recommendations, it will:

- Work with Member-Owners to evaluate EE measures in both the residential and non-residential sectors;
- Maintain residential and non-residential education for the Member-Owners' staffs;
- Provide onsite efficiency evaluations for commercial and industrial members;
- Continue to monitor opportunities for DR programs, looking for reductions in costs or increases in the value of avoided cost; and
- Monitor the opportunity of new technologies that may provide peak demand reduction benefits at a lower cost than current programs evaluated.[129]

<u>RESPONSES TO PREVIOUS COMMISSION STAFF'S RECOMMENDATIONS</u>

Commission Staff's report on BREC's 2020 IRP included recommendations for DSM evaluation.[130] The following are BREC's 2023 IRP responses to DSM recommendations:

1) BREC should continue to support Member Systems with educational opportunities and work with Kentucky Community Action Agencies to enhance the low-income weatherization program.

Response: BREC stated that the existing "Low-Income Weatherization Support Program Pilot has seen no activity since March 31, 2021 and should be re-evaluated."[131]

2) BREC should continue to look for and provide updates of future opportunities to support Member-Owners with new DSM/EE programs.

Response: BREC stated that it planned to "[a]long with Members, continue to evaluate opportunities for energy efficiency and demand response programs looking for reductions in cost or increases in the value of avoided cost.[132]

---

[128] 2023 IRP at 88.

[129] 2023 IRP at 88-89.

[130] Case No. 2020-00299, 2020 Staff Report (filed Nov. 22, 2021) at 23.

[131] 2023 IRP at 88.

[132] 2023 IRP at 181.

INTERVENOR AND RESPONSE COMMENTS

The Attorney General commented that due to the increasing capacity prices in MISO, the corresponding increase in value of DSM programs necessitates BREC's continued evaluation of these programs.[133]

Joint Intervenors collectively filed comments including a report prepared by Energy Futures Group.[134] Joint Intervenors' comments regarding DSM alleged that (1) some DSM programs were eliminated subjectively under qualitative screening; (2) the review methodology underestimated savings and overestimated costs; and (3) the IRP assumes no DSM programs during the planning period.[135] BREC's responses to intervenor comments did not address this assumption. The modeling outputs indicated that a DSM suite of programs was only chosen by the model in some portfolios,[136] despite its net positive savings based on a TRC score of 3.1.[137] BREC responded that Joint Intervenors unreasonably favor DSM.[138]

Joint Intervenors' post-hearing comments reiterated its perceived flaws in BREC's evaluation of DSM programs and also questioned "the arbitrarily selected $1 million program scenario" budget.[139]

---

[133] Attorney General's Comments at 17.

[134] Joint Intervenors' Comments, Exhibit 1.

[135] Joint Intervenors' Comments at 11.

[136] 2023 IRP at 146–147.

[137] 2023 IRP at 80.

[138] BREC's Response to Intervenor Comments at 9.

[139] Joint Intervenors' Post-Hearing Comments at 1–2.

SECTION 4

SUPPLY-SIDE RESOURCE ASSESSMENT

INTRODUCTION

In this Section, Commission Staff reviews, summarizes, and comments on BREC's evaluation of existing and future supply-side resources. Commission Staff's discussion of and recommendations regarding BREC's supply-side resource assessment forecasting are in Section 6 of this Report.

SUMMARY OF EXISTING AND PLANNED CAPACITY AND RESOURCES

BREC currently has access to 1,114 MW of capacity. This capacity is derived from the following sources:[140]

- Sebree Station, which accounts for 519 MW of capacity and includes two plants;
- Robert D. Green plant (Green) includes two natural gas-fired turbines, converted from coal-fired in 2022, and providing 231 MW and 223 MW of capacity;
- Robert A. Reid plant (Reid) contains a combustion turbine (CT) with 65 MW capacity;
- Coal-fired generation production from D.B. Wilson Station (Wilson Station) near Centertown, Kentucky, consisting of a single unit with a total rated net capacity of 417 MW; and
- A contract with the Southeastern Power Administration (SEPA) for 178 MW of hydroelectric capacity.

BREC has also executed a solar power purchase agreement which will add 160 MW of capacity in 2025. BREC also maintains seven small-scale solar power arrays totaling 165 MWh in energy production.

As a MISO member, BREC is required to satisfy its planning reserve margin requirement (PRMR), which can be accomplished through its own generation resources, or by purchasing capacity through MISO or through bilateral contracts.

TRANSMISSION SYSTEM PLANNING

BREC owns, operates, and maintains 1,338 miles of conductor and 26 substations as part of its transmission system.[141] BREC noted that it has implemented Automatic Restoration and Sectionalization (ARS) technology to enhance its ability to respond to outages. ARS automatically sheds any unneeded transmission line sections in an attempt to expedite the sectionalization of a 69 kV circuit that is experiencing an outage, and quickly reenergizes the rural or industrial delivery point substation. ARS also

[140] 2023 IRP at 18–19.

[141] 2023 IRP at 41.

automatically transfers a distribution substation that is experiencing an outage from a locked–out transmission circuit to that substation's backup transmission circuit.[142] These self–healing concepts are preprogrammed within the Big Rivers Energy Management System.[143] BREC stated it has also enhanced system reliability by utilizing steel and ductile iron poles for all new construction projects, adding Remote Control Switches to strategic locations to improve switching response, upgrading many relays to new microprocessor relays, and utilizing fiber-optic communication.[144]

BREC stated that in 2022, SERC Reliability Corporation (SERC), which is responsible for ensuring the reliability and security of the electric grid across 16 states, completed a Critical Infrastructure Protection (CIP) Audit, including review of CIP Standards relating to Cyber Security and protection of the Bulk Electric System. The SERC CIP audit team noted in its closing statements that BREC had no Potential Non-Compliance items.[145] BREC was granted a Certificate of Public Convenience and Necessity (CPCN) to construct a new Transmission Control Center.[146] BREC was also granted CPCNs for two new 161 kV transmission lines.[147]

BREC's transmission planning was reliant in part on MISO's transmission planning process. BREC summarized this planning process, including:[148]

- Ensuring a reliable and resilient transmission system that can respond to the operational needs of the MISO region;
- Identifying solutions to transmission issues that are informed by near-term and long-range needs and provide reliable access to electricity at the lowest total electric system cost;
- Supporting federal, state, and local energy policy and member goals by planning for access to a changing resource mix;

---

[142] 2023 IRP at 41.

[143] 2023 IRP at 41.

[144] 2023 IRP at 41.

[145] 2023 IRP at 41–42.

[146] Case No. 2022-00433, *Electronic Application of Big Rivers Electric Corporation for a Certificate of Public Convenience and Necessity Authorizing Construction of a New Transmission Operations Center and an Order Authorizing Big Rivers to Dispose of Property* (Ky. PSC June 1, 2023), Order.

[147] Case No. 2021-00275, *Electronic Application of Big Rivers Electric Corporation for a Certificate of Public Convenience and Necessity to Construct a 161 KV Transmission line in McCracken County, Kentucky* (Ky. PSC Jan. 14, 2022), Order; Case No. 2022-00012, *Electronic Application of Big Rivers Electric Corporation for a Certificate of Public Convenience and Necessity to Construct a 161 KV Transmission line in Henderson County, Kentucky* (Ky. PSC June 6, 2022), Order.

[148] 2023 IRP at 167.

- Providing an appropriate cost allocation mechanism that ensures that the costs of transmission projects are allocated in a manner roughly commensurate with the projected benefits of those projects; and
- Coordinating planning processes with neighbors and working to eliminate barriers to reliable and efficient operations.

BREC provided planned transmission system additions confidentially.[149] BREC's member cooperatives own and manage the distribution systems for retail customers in BREC's service territory.

MAINTENANCE AND OPTIMIZATION

BREC stated that its maintenance activities are focused on improving generation efficiency, and that during forced outages, it washes air heaters, cleans condenser tubes, replaces leaking valves and traps, and repairs air or gas leaks.[150]

BREC touted the following optimization measures undertaken within the last ten years:[151]

- BREC installed High Performance Human Machine Interfaces at Wilson Station in 2019, giving Control Room Operators (CROs) greater awareness, leading to faster response times and better decisions when issues occur;
- Operations Training Simulators were implemented for training its Wilson and Green CROs, providing a realistic reproduction of the generating unit operation which can simulate unit start-ups, shutdowns, and malfunctions;
- Controllable loss monitoring allows operating variables such as condenser back pressure, excess oxygen, and boiler exit gas temperature to be managed in real-time;
- BREC contracts with third parties to optimize instrument tuning with outside contractors to optimize the operational controls of the generation units to minimize any upsets while generation output is lower during coal pulverizer cycling; and BREC maintains boiler efficiency via tuning its coal pulverizer. BREC routinely checks coal fineness on the pulverizers and the amount of loss on ignition in the boiler ash. Pulverizer inspections are performed every 3,000 hours of operation. Also, Big Rivers periodically hires contractors to test pulverizer performance and balance coal flow through pulverizer coal pipes.

[149] 2023 IRP at 171.

[150] 2023 IRP at 32.

[151] 2023 IRP at 32–33.

SUMMARY OF NEW GENERATION CONSIDERED

MISO received FERC approval in August 2022 to move from a summer/winter resource adequacy construct to a seasonal (summer, fall, winter, spring) construct.[152] For MISO Local Load Zone 6, to which BREC belongs, the seasonal MISO PRMR is 7.4 percent for summer 2023, 14.9 percent for fall 2023, 25.5 percent for winter 2023-2024, and 24.5 percent for spring 2024 in the IRP analysis.[153] The MISO PRMR was determined by the MISO Loss of Load Expectation (LOLE) study. These seasonal PRMRs are the minimum capacity requirements needed for BREC to meet is MISO tariff obligations and form the basis of BREC's target capacity levels in its resource selection and portfolio analyses.

For the existing or approved generation resources, BREC assumed the following for the EnCompass model:[154]

- Wilson remains coal fired and in operation throughout the 20-year forecast period;
- The Green units have the option to either retire in June 2029 or continue operations over the forecast period;
- The Reid Combustion Turbine (CT) remains operational throughout the forecast period;
- BREC continues the existing SEPA contract; and
- The Unbridled Solar Facility is modeled as a Power Purchase Agreement (PPA) beginning in 2025.[155]

The resources made available to the EnCompass model include:[156]

- 635 MW Natural Gas Combined Cycle (NGCC);[157]
- 21 MW blocks of Wartsilla reciprocating engines;
- 237 MW Simple Cycle Combustion Turbine (CT);
- 105 MW aeroderivatives;
- 100 MW utility scale solar;
- 100 MW utility scale onshore wind;
- 50 MW x 200 MWh utility scale standalone/paired Li-Ion storage.

---

[152] 2023 IRP at 132–133.

[153] 2023 IRP at 133.

[154] 2023 IRP at 106.

[155] 2023 IRP at 105.

[156] 2023 IRP at 107.

[157] Dr. Talina Matthews testified that because BREC would plan to self-build any planned NGCC, BREC could choose any capacity. Hearing Testimony of Dr. Talina Matthews (Matthews Testimony), Hearing Video Transcript (HVT) at 13:27:16 (May 22, 2024).

- Economic market capacity purchases at forward cost of new entry as a least cost option for small capacity purchases to meet seasonal reserve margins without having to potentially overbuild.[158]

BREC omitted multiple resources from the NREL and EIA reports from consideration as potential resources for the EnCompass model. For example, advanced nuclear, biomass, and advanced storage options were dismissed due to high costs and technology maturity risk.[159] Wind resources were included in the present IRP using production assumptions consistent with rural Kentucky generation profile data in order to retest assumptions that led to the exclusion of wind resources from BREC's previous IRP.[160] BREC reported that it modeled the generic wind resources as residing in its load zone, MISO Local Load Zone 6.[161] BREC is not aware of any utility scale wind facilities in its service territory, though there are several MISO approved wind projects in Local Load Zone 6.[162]

At hearing, BREC's Chief Financial Officer (CFO), Dr. Talina Matthews, testified that BREC was in the process of developing a new strategic plan, looking at all available generation resource options, and that BREC would not be applying for a CPCN for the 635 MW NGCC absent a co-generation partner.[163]

<u>SUMMARY OF COMPLIANCE PLANNING</u>

BREC identified the following environmental rulemaking that factored into cost considerations for new and existing generation:[164]

- Proposed Environmental Protection Agency (EPA) Greenhouse Gas rule;
- Coal Combustion Residuals (CCR) "Legacy Pond" rule;
- Cross-State Air Pollution Rule (including the Good Neighbor provisions); and
- Revised Effluent Limitations Guideline.

---

[158] 2023 IRP at 107-108. The reciprocating engine, CTs, and aeroderivatives are all fuel by natural gas. *See also* 2023 IRP at 109-134 for assumptions regarding potential resources and costs.

[159] 2023 IRP at 125.

[160] 2023 IRP at 125.

[161] BREC's Response to Staff's First Request, Item 29(a)

[162] BREC's Response to Staff's First Request, Item 29 and BREC's Response to Staff's Second Request, Item 32.

[163] Matthews Testimony, HVT at 11:38:00.

[164] 2023 IRP at 57.

However, BREC stated that it did not assess the costs of these individual compliance requirements.[165] Instead BREC stated that due to the constantly changing nature of pending and challenged environmental regulation, it has chosen to use an aggressive carbon-reduction scenario in its IRP modeling as a proxy for increased environmental regulation cost as opposed to attempting to predict the cost effect of each potential regulatory change individually.[166] The exception is that BREC's 2020 Environmental Compliance Plan (ECP) already includes the implementation of CCR Legacy Pond requirements to its ash pond closures.[167]

BREC also noted the passage of KRS 278.264 in 2023, which replaced the general requirement that CPCNs only be granted for the least-cost reasonable alternative for meeting a need[168] with a rebuttable presumption against the retirement of fossil fuel-fired electric generation.[169]

[165] BREC's Response to Intervenor Comments at 4.

[166] BREC's Response to Intervenor Comments at 4.

[167] 2023 IRP at 100.

[168] *Kentucky Utilities Co. v. Pub. Serv. Comm 'n*, 252 S.W.2d 885 (Ky. 1952).

[169] 2023 IRP at 57.

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 BREC plan. This section also reviews BREC's responses to Commission Staff's recommendations regarding integration in BREC's 2020 IRP and also reviews the parties' comments regarding integration. Commission Staff's discussion of and recommendations regarding BREC's integration are in Section 6 of this Report.

In addition to the base case, BREC ran nine portfolio sensitivities—six single variable sensitivities for expansion planning, and three in-production cost modeling sensitivities designed to evaluate the impact of changing a single variable without introducing additional uncertainty. The six portfolio sensitivities included Low Load growth, High Load growth, Low Gas prices, High Gas prices, 20 percent higher capital costs for all new resources, and 10 percent higher MISO PRMR.[170] For the base case, all fossil-fueled generation was economically committed into the market according to startup costs, minimum up-time, minimum down-time, and ramp rates.[171] All fossil-fueled generation was economically dispatched into the market according to each unit's specific operating parameters including maximum and minimum capacity, heat rates, unit outage rates, and planned outages. The solar and wind units were modeled with a fixed hourly generation profile from the National Database by Horizon Energy for renewable alternatives based in Kentucky. The SEPA volumes were modeled according to contract terms. All new resource alternatives were evaluated based on project feasibility based on expectations for permitting and transmission interconnection.[172]

The optimal plan under the Base Case conditions included both Green units retiring in 2029 and a 635 MW NGCC being added that same year. The results of the sensitivity analysis in the table below show how the optimal plan changes with the different scenario assumptions.[173]

Year	Base Case Conditions	Low Load	High Load	Low Gas	High Gas	High CapEx +20%	High PRMR +10%
2024			DSM Program	DSM Program			DSM Program
2028			PACE Solar (100 MW) PACE				

[170] 2024 IRP at 138–140.

[171] 2024 IRP at 133.

[172] 2024 IRP at 134.

[173] 2024 IRP at 140-141 and Table 7.2.3(a) at 141.

			Storage 4-hr (50 MW)				
2029 Retirements	Green 1 & 2	Green 1 & 2	Green 1 & 2	Green 1 & 2	Green 1 & 2	Green 1 & 2	Green 1 & 2
2029	BREC CC (635 MW)	BREC CC (635 MW)	BREC CC (635 MW) Wind (100 MW)	1x 7FA CT (237 MW)	BREC CC (635 MW) Wind (200 MW)	BREC CC (635 MW)	BREC CC (635 MW) Wind (100 MW)
2030				1x 7FA CT (237 MW)	Wind (200 MW)		
2031					Wind (200 MW)		
2032					Wind (200 MW)		
2033					Wind (200 MW)		
2034					Wind (200 MW)		

The PACE Solar (100 MW) and PACE Battery Storage 4-hr (50 MW) projects are the result of BREC's evaluation of these projects under the Inflation Reduction Act's (IRA's) Powering Affordable Clean Energy (PACE) program.[174] In November 2023, BREC was invited by RUS to submit a completed application, which was submitted in January 2024.[175] These two separate projects were modeled as a paired resource but could also be operated separately.[176] Due to the timing and nature of the two PACE programs, they were neither listed as an existing resource nor as a potential resource.[177] However, it is not clear why this subsidized government project was not selected by the EnCompass model more often.

Based on the results of the scenario sensitivity analysis and using the EnCompass model, BREC developed three portfolios shown in the table below.[178] These portfolio selections involve review of the quantitative outputs from the modeling runs by BREC's management to qualitatively select a preferred portfolio, which BREC refers to as the Base Case Portfolio, alongside an Alternative Portfolio and an Aggressive Carbon Reduction Scenario. The Base Case Portfolio is considered the portfolio that BREC would follow as its preferred plan under expected levels of load, fuel cost, and regulation. Note that the Wilson and Reid units continue to operate over the forecast period. The Base Portfolio is the same as the output selected by Encompass in the Base Case scenario with the addition of the PACE Solar and Storage facility. The Alternative Portfolio

[174] 2024 IRP at 120.

[175] BREC's Response to Staff's Second Request, Item 33(b).

[176] 2024 IRP at 120, 143, and BREC's Response to Staff's Second Response, Item 33(a).

[177] BREC's Response to Staff's Second Request, Item 24(a).

[178] 2024 IRP Table 7.3.1(a) at 143. *See also* 2024 IRP at 149, 156, and 159 for additional explanations of portfolio development.

replaced the 635 MW NGCC with two 237 MW CTs. The CTs satisfied the MISO PRMR but could not provide sufficient base load energy. The model added 700 MW of wind to supply the necessary energy.[179] For the Aggressive Carbon Reduction Portfolio, the buildout of the resources is the same as the Base Portfolio with the addition of a 90 percent carbon capture equipment added to both the Wilson and NGCC units after 2032. However, the capacity reduction caused by the carbon capture equipment resulted in a capacity shortfall in the winter season. The model added 200 MW of wind resources to satisfy the MISO PRMR.[180]

Year	Base Portfolio	Alternative Portfolio	Aggressive Carbon Reduction (ACR) Portfolio
2028	PACE Solar (100 MW) PACE Storage 4-hr (50 MW)	PACE Solar (100 MW) PACE Storage 4-hr (50 MW)	PACE Solar (100 MW) PACE Storage 4-hr (50 MW)
2029 Retirements	Green 1 & 2	Green 1 & 2	Green 1 & 2
2029 June	BREC CC (635 MW)	2x 7FA CT (450 MW)	BREC CC (635 MW)
2030		Wind (200 MW)	
2031		Wind (200 MW)	
2032		Wind (200 MW)	Wilson Carbon Capture BREC CC Carbon Capture Wind (200 MW)
2033		Wind (100 MW)	
2036			Wind (100 MW)
2040			Wind (100 MW)

BREC subjected these three portfolios to the same previous scenario sensitivity analyses plus three carbon emission adder scenarios.[181] The carbon emission adders totaled $5, $15, and $25 per ton starting in 2032.[182] Across the nine sensitivity scenarios, the Base Portfolio had the lowest 15-year net present value (NPV) in all but the Mid and High carbon price scenarios. In a 27-year NPV analysis, the Base Portfolio had the lowest NPV in every sensitivity scenario.[183] Based on the analyses, the Base Portfolio

[179] 2024 IRP at 156.

[180] 2024 IRP at 159.

[181] 2024 IRP Figure 7.4(a) at 148.

[182] 2024 IRP at 148.

[183] 2024 IRP discussion and Confidential Tables 7.4.4(a) and 7.4.4(b) at 162–163.

represents BREC's preferred portfolio. BREC stated that this plan is not a commitment for certain actions currently or at any time in the future.[184] However, 807 KAR 5:058 intends the IRP to serve as BREC's preferred plan that represents a foundational reference point and BREC's most likely course of action based upon its extensive modeling and analysis.

RESPONSES TO PREVIOUS COMMISSION STAFF'S RECOMMENDATIONS

Commission Staff's report on BREC's 2020 IRP included recommendations for demand and supply integration.[185] The following are BREC's 2023 IRP responses to integration recommendations:

1) BREC should continue to rigorously test its base case least cost plan and provide appropriate supporting tables and documentation. In addition, it would also be helpful to be able to visualize (in tabular form) when various levels of capacity are added over the forecast period.

Response: BREC provided graphs, as opposed to tables, showing forecasted load and base case capacity positions for summer and winter for each year of the 15-year period.[186]

2) As long as BREC has the excess capacity to provide service to Non-Member customers or that BREC intends to purchase any energy or capacity shortfalls, then, everything else being equal, there is no need to include them in its forecast modeling. However, if that is not the case, then BREC should include Non-Member obligations in its modeling to provide a more complete analysis of potential LT Plans. For the next IRP, BREC should include Non-Member obligations in its forecasts and modeling or provide a detailed explanation as to why it is not included.

Response: BREC included existing Non-Member obligations in its load forecasts.[187]

3) BREC should carefully weigh the reasonableness and timing of various technology implementation.

Response: None.

4) The potential role of DSM/EE and cogeneration could be more important in the future. For the next IRP, BREC should include these options as potential resources in its modeling.

---

[184] 2024 IRP at 178.

[185] Case No. 2020-00299, 2020 Staff Report at 42–43.

[186] 2024 IRP at 150–151, Figures 7.4.1(a-b).

[187] 2024 IRP at 150, note 88.

Response: The selected DSM/EE suite of programs was used as an available resource for modeling, selected under some but not all scenarios.[188] Cogeneration was not considered as a resource option.[189]

5) BREC should ensure that information provided in tables is described completely and is consistent across tables.

Response: None.

<u>INTERVENOR AND RESPONSE COMMENTS</u>

The Attorney General emphasized the need for grid reliability, cautioning against reducing dispatchable thermal generation via coal, natural gas, and nuclear fuels in favor of non-dispatchable renewable resources.[190] However the Attorney General also noted that the unpredictability of fuel costs can cause affordability issues.[191] The Attorney General was also skeptical about the current federal environmental regulatory framework regarding carbon capture, including uncertainty around the presumption that such technology will be available on the predicted timeline, and the cost of such requirements.[192] BREC agreed with the Attorney General's assessment regarding continued use of thermal generation as a primary resource to maintain reliability.[193] The Attorney General further stated that "[t]he OAG agrees with BREC's decisions in this IRP to keep the Wilson plant operating as a coal-fired unit for the foreseeable future"[194] but without any explanation of why this assumption results in greater reliability or cost-savings for consumers.

The Attorney General's post-hearing comments reiterated the need for reliability via dispatchable generation resources.[195] The Attorney General noted that President and CEO Robert Berry, COO Nathan Berry, and Vice-President for Federal and RTO Regulatory Affairs Erin Murphy were no longer employed by BREC at the time of the hearing and that as a result BREC's new management was not necessarily committed to the IRP as filed.[196] However, the Attorney General supported the plan to retire the Green Units despite their capacity value because they are rarely operated due to high heat rates

---

188 2024 IRP at 146–147.

189 2024 IRP at 114.

190 Attorney General's Comments at 15–16.

191 Attorney General's Comments at 16.

192 Attorney General's Comments at 6, 17.

193 BREC's Response to Intervenor Comments at 2–3.

194 Attorney General's Comments at 16–17.

195 Attorney General's Post-Hearing Comments at 2–3.

196 Attorney General's Post-Hearing Comments at 1–2.

and resulting cost.[197] The Attorney General noted that this would result in the need for replacement generation and favored an NGCC due to its relative efficiency and cost.[198] The Attorney General also noted the requirements of KRS 278.264 enacted in 2023 and Senate Bill 349 enacted in 2024, which impose additional hurdles on utilities seeking to retire fossil fuel-powered generation resources.[199]

Intervenor KIUC's comments included an endorsement of BREC's plan to construct a 635 MW NGCC plant by 2029.[200] KIUC supported this position by asserting that (1) once the Green Station is retired, additional capacity and energy will be required, and NGCCs provide baseload energy in an efficient manner; (2) NGCCs have low heat rates and low forced outage rates, resulting in reliable, low-cost generation compared to natural gas peaking units, which have high capacity but low heat rates per cost, or renewables, which have low capacity; and (3) an NGCC built near the current Green Station site would require minimal additional electric transmission infrastructure and gas pipeline infrastructure.[201] However, based on hearing testimony casting doubt on BREC's intentions to construct a 635 MW NGCC absent a co-generation partner and the decision to review all available generation options, KIUC commented that the IRP "may already be stale" with regards to generation selections.[202]

Intervenor Sierra Club commented that BREC failed to meet IRP requirements by disallowing the modeling construct to consider retiring and replacing Wilson Station within the next 15 years, despite reliability questions arising from the Winter Storm Elliott outage and the cost of environmental regulations.[203] BREC disputes the reliability questions raised by Sierra Club, noting that the 2.5-hour outage (Sierra Club claims it was a six-hour outage) was minimal, especially compared with other utilities affected by Winter Storm Elliott.[204]

Sierra Club questioned BREC's response to planned and potential environmental regulation. Sierra Club points out that

> [N]ew Clean Air Act Section 111(d) proposed rules do not require CCS for coal-fired units. Rather, they provide a variety of paths for existing coal-fired units based on retirement in

---

[197] Attorney General's Post-Hearing Comments at 2.

[198] Attorney General's Post-Hearing Comments at 3.

[199] Attorney General's Post-Hearing Comments at 4.

[200] KIUC's Comments at 1.

[201] KIUC's Comments at 1.

[202] KIUC's Post-hearing Comments at 1.

[203] Sierra Club's Comments at 5.

[204] BREC's Response to Intervenor Comments at 3–4.

> 2032, 2035, 2040, or beyond. If a utility commits to retiring a unit by 2035, for example, it can either commit to a 20% capacity factor limitation or meet an emissions rate consistent with 40% gas co-firing. Big Rivers has not evaluated this array of options to determine costs and benefits of the different paths, including the economics and ultimate cost to customers of each of the different options.[205]

Sierra Club also stated that BREC failed to account for the cost of all aspects of planned environmental regulation.[206] BREC responded that due to the constantly changing nature of pending and challenged environmental regulation, it has chosen to use an aggressive carbon-reduction scenario in its IRP modeling as a proxy for increased environmental regulation cost as opposed to attempting to predict the cost effect of each potential regulatory change individually.[207] BREC stated that it did not include Wilson Station retirement as a variable for modeling purposes because it is a reliable and significant part of its dispatchable generating fleet and because of new legislative hurdles for retirement of fossil fuel-fired units under KRS 278.264.[208]

Lastly, Sierra Club asserted that BREC did not include benefits of the Inflation Reduction Act (IRA) in its modeling.[209]

Sierra Club's Post-Hearing Comments requested that the Commission "commence an investigatory docket into Big Rivers failure to provide an adequate IRP and through which Big Rivers may complete a statutorily compliant IRP" for failing to comply with 807 KAR 5:058.[210] Sierra Club asserted that the IRP failed to sufficiently address the furnishing reliable service at the lowest possible cost.[211] Sierra Club suggested BREC evaluate:

> a. environmental compliance costs associated with the GHG rule, MATs rule, Good Neighbor Rule, ELG Rule, and CCR Rule (including evaluation of actual CCS costs),
> b. earlier retirement and alternative resource scenarios for Wilson (with a requirement to run an optimization model that picks the optimal retirement date and replacement portfolio for

---

205 Sierra Club's Comments at 12.

206 Sierra Club's Comments at 14–15.

207 BREC's Response to Intervenor Comments at 4.

208 BREC's Response to Intervenor Comments at 17.

209 Sierra Club's Comments at 20.

210 Sierra Club's Post-Hearing Comments at 1.

211 Sierra Club's Post-Hearing Comments at 3.

> Wilson based on expected compliance costs and alternative compliance pathways),
> c. alternative resource scenarios for the NGCC plant,
> d. uncapped demand response scenarios,
> e. maximizing savings from utility-scale investments incentivized by the IRA, and
> f. maximizing savings from clean energy financing programs such as the Energy Infrastructure Reinvestment Program, New Era Program, and Rural America Energy Program.[212]

Joint Intervenors provided extensive comments as well. Like Sierra Club, Joint Intervenors questioned BREC's decision not to use retirement of Wilson Station as a variable, asserted that BREC underestimated future environmental compliance costs, and alleged that BREC did not fully pursue IRA cost-savings opportunities.[213] Joint intervenors also questioned why BREC did not evaluate distributed energy resources (DERs), particularly in the form of behind-the-meter battery storage.[214] BREC responded that its modeling did include battery storage, but subject to the current technological and cost limitations and MISO capacity accreditation.[215] Joint intervenors also disagreed with BREC's use of 326 MW build constraints placed on renewable resources.[216] BREC stated that Joint Intervenors' proposed approach unreasonably favored renewables and anticipated advances in storage capabilities over reliability and cost-effectiveness.[217]

Joint intervenors argued that BREC's plan projects more generation and capacity than are necessary.[218] BREC responded that unanticipated demand spikes from its non-member sales cannot be projected with the same level of accuracy as other customer classes, requiring additional capacity.[219] However, joint intervenors claimed that BREC should revaluate whether these on-member contracts should be renewed.[220]

In post-hearing comments, Joint Intervenors reiterated their positions that BREC do more to pursue cost-saving opportunities under the IRA and the 2021 Bipartisan

[212] Sierra Club's Post-Hearing Comments at 26.

[213] Joint Interveners' Comments at 2, 16, 25.

[214] Joint Intervenor's Comments at 14–16.

[215] BREC's Response to Intervenor Comments at 15.

[216] Joint Intervenor's Comments, Exhibit 1 at 9.

[217] BREC's Response to Intervenor Comments at 9.

[218] Joint Intervenor's Comments at 34.

[219] BREC's Response to Intervenor Comments at 15.

[220] Joint Intervenor's Comments at 38.

Infrastructure Law, and that BREC should have allowed retirement of Wilson Station in the model.[221]

BREC's response comments characterized Sierra Club and Joint Intervenors' post-hearing comments as focusing too much on eliminating fossil fuel resources regardless of impact on reliability or cost and Wilson Station's derates and outages despite its overall reliability.[222] BREC also justified its use of carbon-pricing proxies in lieu of estimating environmental compliance costs due to the uncertainty of the applicability of environmental regulations in the future.[223]

---

[221] Joint Intervenors' Post-Hearing Comments at 1–2.

[222] BREC's Post-Hearing Response Comments at 4.

[223] BREC's Post-Hearing Response Comments at 5.

SECTION 6

REASONABLENESS AND RECOMMENDATIONS

INTRODUCTION

Commission Staff concludes that BREC's 2023 IRP is unreasonable and inconsistent with 807 KAR 5:058. The overall methodology behind BREC's load forecast is reasonable and consistent with 807 KAR 5:058, Section 7, with the exception of how Non-Member sales were handled. However, the resource acquisition plan does not comply with 807 KAR 5:058, Section 8. Hearing testimony provided by BREC made it clear that the selected generation portfolio in no way reflected a plan that BREC intends on following even in the short term.[224] The acquisition plan as filed is not a useful resource for the Commission, BREC, or its ratepayers for evaluating the need for and cost-effectiveness of potential generation options. BREC CFO Talina Matthews testified that BREC is developing a new strategic initiative in which all appropriate resources would be considered.[225] This section discusses the reasonableness of BREC's 2023 IRP and the issues and areas for improvement and makes recommendations for BREC's next IRP.

LOAD FORECASTING

BREC's IRP includes an insufficient level of explanation accompanying presentation of the differences in energy, coincident peak (CP), and non-coincident peak (NCP) forecast results. Energy sales including transmission losses are consistently reported.[226] However for peak demand, transmission losses and non-member sales are not consistently reported. Transmission losses are appropriately reported and included in CP totals across all tables except for Table 7.1.6(a), which presents energy, CP and NCP totals used in the EnCompass model. Total annual CP matches in Table 2.2.8(a) and Table 4.3(a), but not in Table 7.1.6(a).[227]

The base case load forecast used in the EnCompass modeling is provided below.[228]

---

[224] Matthews Testimony, HVT at 11:39:31.

[225] Matthews Testimony, HVT at 11:38:00.

[226] IRP, Table 2.2.8(b) at 29, Table 4.4(a), at 69, Table 7.1.6(a) and Appendix A at A-91-93. Note that Transmission losses are consistently reported across the various tables.

[227] IRP, Table 2.2.8(a) at 28, Table 4.3(a) 67, Table 7.1.6(a) at 132, and Appendix A at A 91-93.

[228] IRP, Table 7.1.6(a) at 132.

Year	Member Energy GWh	Non-Member Energy GWh	Total Energy GWh	Member Peak MW	Non-Member Peak MW	Total Peak MW
2023	3,953	1,621	5,574	714	250	964
2024	4,624	1,658	6,282	798	250	1,048
2025	4,679	1,378	6,056	818	250	1,068
2026	4,689	1,174	5,863	820	250	1,070
2027	4,700	199	4,898	822	100	922
2028	4,711	171	4,882	824	100	924
2029	4,716	194	4,910	825	100	925
2030	4,731	0	4,731	828	0	828
2031	4,741	0	4,741	830	0	830
2032	4,765	0	4,765	834	0	834
2033	4,769	0	4,769	835	0	835
2034	4,779	0	4,779	837	0	837
2035	4,789	0	4,789	839	0	839
2036	4,807	0	4,807	842	0	842
2037	4,814	0	4,814	844	0	844
2038	4,823	0	4,823	845	0	845
2039	4,832	0	4,832	847	0	847
2040	4,843	0	4,843	848	0	848
2041	4,848	0	4,848	850	0	850
2042	4,858	0	4,858	851	0	851

Table 7.1.6(a) (the table above) contains energy, CP, and NCP data, utilized in the EnCompass model. A footnote explains differences in Non-Member energy sales between Table 7.1.6(a) and Table 4.4(a), which contains values greater than Table 7.1.6(a). The footnote reads, "total non-member energy utilized in EnCompass differs from the load forecast due to the following factors: (1) OMU energy is the total value prior to any allocations of energy from OMU's share of the SEPA Hydro system and based off an hourly profile curve, and (2) KYMEA is modeled as a call option in the model which results in a reduced obligation to KYMEA as fuel prices and market conditions vary over time."[229] The reasoning for making these modeling decisions versus the actual forecast as it impacts the modeling results is unclear. From a logical planning perspective, BREC should forecast and model the energy and demand that BREC is responsible for providing. Commission Staff does not find BREC's explanation as to the reasoning of why KYMEA was modeled as a call option and not a full contract obligation compelling, when BREC is planning to renew said contracts. Likewise, BREC did not explain whether OMU is modelled as a call option.

[229] 2024 IRP at 132, footnote 83. *See also* BREC's Response to Staff's First Request, Item 2. BREC neither generates nor transmits energy to serve non-member customers in the SPP.

Arguably, for modeling and planning purposes, the intentional exclusion of approximately 25 percent of system load (Non-Member sales) when BREC intends to seek contract renewals, coupled with the 21 MW to 24 MW attributable to BREC CP to MISO CP coincidence factor exclusion is contrary to the purpose of the IRP process. BREC is planning its system at capacity levels that are less than what could occur.[230]

RECOMMENDATION: In the future, BREC should provide more detailed explanations regarding the manipulation of the data and the calculations ultimately used in forecast calculations within the IRP as well as clear explanations for any inconsistencies between tables. For example, the IRP would have benefited from having the table provided to Commission Staff in BREC's response to Staff's First Request, Item 9, as well as an explanation as to the BREC CP to MISO CP. Furthermore, BREC should define all terms, such as BREC CP to MISO CP, that are not common to the industry.

BREC should strive for consistency throughout its IRP when possible, including across all tables. For example, transmission losses are not consistently reported across tables within the IRP.

Treatment of the BREC CP to MISO CP Coincidence Factor in Resource Planning

BREC provided a reconciliation of multiple presentations of Member Peak Load.[231] BREC stated "[t]he BREC to MISO Coincidence factor represents the approximate percentage of Big Rivers' coincident peak measured at the time of the MISO system peak"[232] and that the CP to MISO CP coincidence factor "reduces Big Rivers' capacity requirement as BREC's peak does not always occur at the same time as the MISO peak."[233] The reconciliation table provided in BREC's Response to Staff's First Request, Item 9, shows that the BREC CP to MISO CP coincidence factor accounts for the timing difference between BREC's forecast peak demand, which satisfies BREC's MISO PRMR, and the forecast MISO peak. The coincidence factor amounts to a forecast difference of 21 MW (2023) growing to 24 MW (2042). From a planning and modeling perspective, Staff understands the purpose of modeling and analyzing the resources necessary to satisfy BREC's MISO PRMR. However, that is only one scenario that explores the minimum necessary to fulfill that obligation. By the same token, it does not make sense to purposefully not model what the least reasonable cost portfolio of resources would be if BREC were to satisfy its actual forecast peak demands. This issue is discussed further below.

Treatment of Non-Member Sales

---

[230] *See* BREC's Response to Staff's First Request, Item 9. BREC adequately explained the apparent confusion regarding the treatment of transmission losses. However, in doing so, it identified an additional variable that had not been explained previously.

[231] *See* BREC's Response to Staff's First Request, Item 9.

[232] BREC's Response to Staff's Second Request, Item 21.

[233] BREC's Response to Staff's Post Hearing Request For Information, Item 4.

From a planning and modeling perspective, the rationale for including Nebraska Non-Member energy and capacity requirements in the forecasts when it is not required is confusing and misleading and is contrary to BREC's statements that it neither generates nor transmits energy to its Nebraska customers and that both capacity and energy for those customers is procured within the SPP.[234] Tables 4.3(a) and 4.4(a)[235] have Non-Member sales forecasts which include sales to contracted Nebraska non-members. Table 7.1.6(a) excludes the Non-Member sales to Nebraska. BREC stated that Table 7.1.6(a) includes the load required to serve non-members. Satisfying these customers' contracts has no real physical impact on BREC's generation or transmission system or MISO's system. Including these customers in BREC's energy load forecast inflates the forecast in an artificial manner for no apparent purpose other than to technically document what is forecasted to satisfy the contracts. The rationale for this is not adequately explained in the IRP.

Neither Non-Member energy nor demand were forecast beyond the current contract expiration dates, which is illogical when BREC intends to seek contract renewals.[236] BREC's reasoning was that the probability of renewal was unknown, as were the potential contract terms.[237] As a long-term planning study, the IRP is replete with and based upon myriad assumptions about the future, none of which are known with certainty. To purposefully exclude 250 MW, or about 25 percent of BREC's current load, because the exact details of a future contract are unknown, appears to be arbitrary and contrary to the purpose of the IRP process. The exclusion of such a large load calls into question the validity and usefulness of any modeling results beyond the current contract expiration dates, beginning in 2027.

An additional observation concerns BREC's seasonal capacity position relative to its MISO PRMR through the 2029-2030 planning year.[238] The figures in the confidential table indicate that BREC's capacity position changes in multiple seasons across multiple planning years if it were to add back the 21 MW to 24 MW attributable to the BREC CP to MISO CP coincidence factor to its actual forecasted system peak. If BREC were then to assume that the total 250 MW of Non-Member contract obligations are renewed beginning in 2027, then its forecast capacity position changes drastically. The end result is that BREC's long-range plan and preferred portfolio of resources are not credible.

RECOMMENDATION: For the next IRP, BREC should ensure that its load forecasts are based on realistic assumptions that reflect its intentions. In addition, given BREC's

---

[234] BREC's Response to Staff's First Request, Item 2 and Item 8 and BREC's Response to Staff's Second Request, Item 17.

[235] 2024 IRP at 69.

[236] BREC's Response to Staff's First Request, Item 21 and Tables 4.3(a), 4.4(a), and 7.1.6(a) respectively.

[237] BREC's Response to Staff's Second Request, Item 27.

[238] *See* 2024 IRP at 150, Confidential Table 7.4.1(a) and BREC's Confidential Response to Staff's Second Request, Item 16.

preferred portfolio in the present case, additional scenarios should have been run exploring what combination of resources would be necessary to satisfy its Non-Member contract customers, as well as its actual peak demand.

DEMAND-SIDE MANAGEMENT

The TRC score of 3.1 for the full suite of DSM programs selected in its DSM study indicates that implementation of the selected programs would result in savings of more than three times the cost of the suite of programs.[239] However, BREC has stated that it does not plan on implementing any DSM programs at this time. In addition, the DSM study only covered a ten-year period as opposed to full program lives, which misrepresents the long-term value of these programs, as many of the programs have front-loaded costs.

RECOMMENDATION: Moving forward, Commission Staff expects BREC to fully utilize the DSM MPS and carefully review and evaluate the study findings. Staff recommends that BREC develop a plan to implement DSM and EE programs that BREC has identified as being cost-effective and meet targets for BREC's energy savings and demand reductions goals in the future. BREC has not shown any amount of effort into creating DSM/EE programs that were found cost-effective and result in energy-savings in the DSM MPS. Commission Staff notes that should a minimal capacity deficit arise, DSM programs are a unique and cost-effective way to reduce energy consumption for its customers so that BREC would have the opportunity to meet its native load with its own generation, rather having to purchase additional energy from the MISO market and incurring unnecessary costs.

Commission Staff also notes that BREC has incurred the cost of paying for the development of the DSM MPS without fully realizing and utilizing the results of the study, and Commission Staff wants to caution BREC to make sure that it is incurring costs that are beneficial and prudent for its customers.

INTEGRATION

Record Keeping

Throughout the hearing, BREC's witnesses were unable to explain why certain decisions were made by BREC executives who were no longer employed by BREC. The Commission cannot evaluate the reasonableness of the IRP if BREC cannot establish why key decisions were made during the decision-making process.

RECOMMENDATION: For the next IRP, BREC should ensure that its witnesses are familiar with and able to discuss in detail the reasoning supporting all assumptions and recommendations.

Discovery

BREC should be prepared to re-run its modeling simulations during discovery if requested. Commission Staff asked BREC to re-run its modeling simulations to address its concerns, but BREC argued that it could not run the simulation because it "does not have projections developed for ongoing O&M costs related to Green Units 1 and 2, assuming the unit could retire in any year, and developing those projections is a laborious and time-consuming undertaking."[240] The result is a selected base scenario plan that cannot be adopted because of selected wind power that is simply not available. BREC stated that it used estimated Green Station fixed and variable O&M expense through 2029 and 2043 in its modeling, leading to selection of retiring those units.[241] Therefore, it can project for other years as well. Even if BREC were unable to make such projections, that inability does not obviate the need to re-run the simulation to account for other, unrelated problems, such as the inclusion of unavailable wind power in the selected portfolio.

RECOMMENDATION: Be prepared to re-run modeling simulations as required by Commission Staff.

Construction and Compliance Timelines

The Base Case Portfolio selected retirement of Green Station in 2028 and the construction of a 635 MW NGCC in 2029.[242] This plan would require BREC to complete several tasks, including those mandated by newly passed legislation, that would extend construction timelines:

- Filing notice to the Kentucky Energy Planning and Inventory Commission (EPIC) at least 180 days prior to applying to the Public Service Commission to retire a fossil fuel-powered unit;[243]
- Waiting up to 135 days for EPIC to submit its report;[244]
- BREC filing with the Public Service Commission applications to retire Green Station,[245] for a site compatibility certificate, and a CPCN for the proposed NGCC.[246]

---

[240] BREC's Response to Commission Staff's First Request for Information (Staff's First Request), Item 53 (filed Jan. 5, 2024).

[241] BREC's Response to Staff's Second Request, Item 41.

[242] 2024 IRP at 143.

[243] Senate Bill 349, Section 1(7)(b).

[244] Senate Bill 349 Section 1(7)(i).

[245] The Public Service Commission must rule on retirement applications within 180 days of receiving an administratively complete application under KRS 278.164(1).

[246] Site compatibility and CPCN matters must be ruled upon by the Public Service Commission within eight months of application filing per Senate Bill 349, Section 2(1).

- Finalizing any financing, construction contracts, and construction time; and
- Awaiting interconnection with MISO.

RECOMMENDATION: Future modeling should include an assumption that retirements and new generation construction not be permitted to be selected by the model in years that BREC cannot feasibly comply with retirement statutes and still add interconnected replacement generation. Senate Bill 349 (which was not enacted until after the IRP was filed) adds time to the retirement timeline. Since the regulatory approval timeline for a retirement and site compatibility and CPCN approval for capacity replacement construction has increased, BREC would be unlikely to complete the retirement, construction of replacement generation, and interconnection process within the time frame included in its Base Case Portfolio. BREC should state in its IRP the estimated timeline for construction and the bases for the time frames used.

Modeling and Assumptions – Base Case and Six Scenarios

The IRP is a long-range planning tool. As such, it is the vehicle that should be used to include and test the impact of various assumptions, none of which are known with certainty, that have a direct impact on the load forecast. By not including significant amounts of load in BREC's load forecast, it is planning for resources that may not be sufficient to actually serve its required future demand as well as skewing both the need for and the timing of any possible generation retirements and additions. Relying on incidental capacity and energy purchases from the MISO markets is not a sufficient backstop. The omission of required future demand casts significant doubt on the veracity of the Base Portfolio.

All available and near market ready (such as small nuclear reactors) resources and options should be treated as input options. Although economic retirement of Wilson Station may seem an unlikely output result, retirement could conceivably be selected under high regulatory cost scenarios. The possibility of the model selecting Wilson for retirement should have been included for maximum transparency. BREC has not introduced any facts making this potential selection prohibitive. Economic retirement of Wilson Station should have been an input option for resource selection. Nuclear power was also rejected, in part due to the high cost.[247] Cost should not necessarily prevent an available resource from being utilized as a resource input option in the resource portfolio selection analysis. The model will determine cost-effectiveness. A potential resource addition or retirement option should not be excluded unless a reason is provided for why inclusion is prohibitive. For the Green units 1 and 2, the EnCompass model only had two choices, retire in 2029 or run until 2040. To get a better picture of when the most cost-effective time to retire the units would be, the model should have been allowed to dynamically decide when or if retirement was the best option.

[247] BREC's Response to Attorney General's First Request for Information (Attorney General's First Request), Item 31 (filed Jan. 5, 2024).

On the other hand, BREC does not consider wind to be economically feasible since there were no wind resources proposed in its recent all-source RFP. In addition, the intermittent operation of wind remote to BREC's load brings the risk of congestion costs that are not easily quantified or hedged.[248] However, BREC stated that it wanted to ensure a robust analysis and quantitative support for its position and that the IRP demonstrates that generic wind do not provide enough value for inclusion in the Base Portfolio.[249] Given BREC's concerns and considerations of wind's economic viability vis-à-vis no wind resource proposals in RFP responses, it remains unclear why BREC would still model wind resources when no actual ongoing wind facility or potential wind facility developer responded to the all-source RFP.[250] Conversely, there are and have been many solar projects proposed and approved in Kentucky with several in the western part of the state, which would seem to indicate solar is an economically viable resource. In addition, BREC has some experience with solar projects with the Unbridled Solar project and two others that were canceled. These projects should have given BREC some inkling of future costs to help fine tune cost projections. The fact that the EnCompass model consistently chose a resource for which BREC believed was not economically viable over a resource that appears to be economically viable in Kentucky, detracts from the usefulness of the Base Portfolio as a reasonable least-cost resource plan.

BREC should not include as an assumption for planned co-generation for which it has found no potential partner. If a "generation co-owner" assumption is made, then an additional "all else being equal" modeling run should be made where there would be no "co-owner" assumption. That particular sized generation unit could be available as a resource option, but even though it may be more efficient, it would not necessarily be chosen due to its size and cost relative to BREC's need. The Green units have a combined 454 MW capacity. BREC's IRP did not clearly explain why a 635 MW NGCC unit was selected in six out of seven scenarios. In the Low Gas scenario, two 237 MW CTs are selected. BREC did not make clear why it needed the additional capacity, especially since BREC appears to be only satisfying its MISO PRMR (based on MISO peak), not its own forecast peak, and it has excluded up to 274 MW of capacity from its load forecasts. At hearing, BREC revealed that the reason for the excess capacity was that it planned for the 635 MW NGCC unit to be a co-generation project with another utility, but that no co-generation agreement was obtained.[251]

RECOMMENDATION: For long range planning purposes, if BREC knows that no co-generation partner has been obtained when conducting its IRP analyses, BREC should (a) include a discussion of what it intends to do with the excess capacity as a part of a

---

[248] 2024 IRP at 156.

[249] BREC's Response to Staff's First Request, Item 53.

[250] *See also* BREC's Response to the Joint Intervenors' First Request for Information, Item 44. BREC noted that it has not carried out any studies as to the viability of wind resources in Kentucky. The closest pocket of wind generation is in MISO is north-central Indiana and the LMPs of wind injection are often quite volatile compared to the LMPs in western Kentucky. BREC prefers predictable stable resources.

[251] Hearing Testimony of Jason Burden, HVT at 09:41:40.

scenario run that assumes a co-generation partner is obtained and (b) conduct another scenario run that assumes no co-generation partner is obtained and there is no need for a relatively larger generation unit. *A priori* assumptions regarding the selection of and timing of generation technologies being added or retired should be avoided unless mandated by pending or recent enforceable regulations or for which the utility has committed for retirement in a given year. For modeling purposes, regulations being challenged in court should be modeled in scenario analyses, but not ignored as if they did not exist. If such assumptions are made, the model should be permitted to select addition or retirement of any generation technologies in any year. The model should consider the useful lives of generation resources, fuel costs, and any other costs or benefits beyond the 15-year planning horizon. If capacity limits are placed on a resource, BREC should explain the basis for those limits.

Explanation of contingencies

BREC's IRP indicates that under the Base Portfolio, it will have a seasonal capacity surplus in some years and seasons and seasonal capacity shortfall in others.[252] BREC stated that it will address seasonal capacity shortfalls by purchasing capacity.[253] The purpose of the IRP is to determine necessary capacity and meet capacity needs in the most cost-effective manner. Other than for hedging purposes or to meet capacity needs resulting from underestimation of load, BREC should avoid reliance on the capacity market to meet capacity needs.[254] Commission Staff recognizes that meeting one seasonal capacity reserve margin may result in surplus capacity in another season. However, all plan portfolios should at least meet the lowest seasonal capacity requirements relative to reserve margins, unless BREC forecasts an economic benefit to buying or selling capacity.

Under the Base Portfolio, assuming Non-Member contracts are not renewed and as illustrated in its results, BREC will have excess capacity beyond its MISO PRMR starting in 2030 upon expiration of those contracts.[255] BREC did not explain how it planned to treat its excess capacity.

RECOMMENDATION: Unless the model predicts an economic benefit to purchasing capacity, its BREC's modeled portfolios should attempt to meet net reserve margin requirements via owned generation. The net cost of any expected purchases or sales of capacity based on seasonal capacity shortfalls or surplus should be represented in the IRP. If a contingency, such as renewal of Non-Member sales, has a significant impact on

[252] 2024 IRP at 152, Table 7.4.1(a).

[253] *See* BREC's Response to Staff's First Request, Item 50.

[254] The Commission recognizes that under some circumstances, short term incidental market or bilateral capacity purchase may be necessary to fulfill MISO PRMR.

[255] 2024 IRP at 150–151, Figures 7.4.1(a-b).

load forecast, BREC should indicate how it will respond if the plan may result in a capacity shortfall or surplus.

Explanation of Model Selections

From confidential Table 7.1.4(i) page 122, solar generation appears to be more cost advantageous versus either wind or the 4-hour Li-Ion BESS. It is unclear why the model did not choose solar and consistently chose wind as an intermittent resource.

The PACE Solar (100 MW) and PACE (50 MW) 4-hour storage projects were only selected in the High Load Growth scenario.[256] The PACE projects are government subsidized projects and BREC should have explained why subsidized projects would not have been selected under every scenario.

Based on a completed DSM/EE potential study, BREC ran a separate $1 million DSM spending program scenario that, all else being equal, saved up to approximately 90,762 MWh energy and 17 MW capacity.[257] Only the DSM demand response program was included in the scenario modeling.[258] However, the evaluated DSM/EE program had a TRC score of 3.1,[259] indicating that implementation of the selected programs would result in savings of more than three times the cost of the suite of programs.

RECOMMENDATION: When the portfolio selection and scenario evaluation analyses produce results that seem counterintuitive or unexpected, BREC should provide an explanation of those results. In addition, BREC should strive to be more precise in describing and explaining assumptions pertaining to individual potential resources. The IRP should include the terms of loan forgiveness for the PACE Solar and Storage projects to explain why a federally subsidized program was not selected under most scenarios.

Environmental Compliance

BREC stated that it has not conducted any formal analysis for the cost of compliance with potential EPA regulations.[260] At hearing, BREC indicated that it did not plan on implementing carbon capture technology at Wilson Station due to the estimated

[256] 2024 IRP at 141, Table 7.2.3(a).

[257] 2024 IRP at 126, Table 7.1.4(k).

[258] Table 7.1.4(k) and the accompanying explanation are not entirely clear. Demand response and interruptible programs, not energy efficiency, are usually thought of as dispatchable, hence inclusion in portfolio/resource selection analyses in Table 7.2.3(a). Conservation and energy efficiency programs are usually included in the modeling as load reducing programs.

[259] 2024 IRP at 80.

[260] BREC's Response to Staff's Second Request, Item 14.

cost of approximately $4 billion,[261] but had not evaluated the cost in the IRP, nor had it allowed the model to retire Wilson Station due to pending carbon capture requirements.

RECOMMENDATION: BREC should either complete such an analysis or provide more detailed information about how it selected the carbon dispatch adder costs sensitivities. Whether using adder cost sensitivities or carbon capture and other compliance cost estimates, retirement of Wilson Station should be permitted by the model. If BREC is making decisions based on an estimated cost of $4 billion, the IRP should include the basis for this estimate in future IRPs.

BREC's use of estimated environmental compliance costs was not included in the base scenario modeling run except for regulations that have already been implemented. BREC then ran additional scenarios for low, medium, and high carbon adder sensitivities. BREC also included an Aggressive Carbon Reduction Portfolio alongside its Base Portfolio.

RECOMMENDATION: Since BREC included the PACE Solar and Storage projects for its Base Portfolio even though it was not selected under most scenarios, Commission Staff does not necessarily take issue with the methodology for including compliance costs. However, BREC should include more information on how environmental compliance informed its decision-making at the portfolio selection stage. BREC should also clarify the purpose of the Aggressive Carbon Reduction Portfolio.

REASONABLENESS

Optimally, a utility should plan to file a CPCN application shortly after its IRP is filed, if the IRP plans for construction of new generation within the first five years of the planning horizon, with minimal changes in the justification for the planned project from the IRP. A variety of conditions can result in the need for changes to the plan or its justification, and the utility bears the burden to establish the need and lack of wasteful duplication if material changes are made from the IRP or if change in conditions negates previous justifications for the proposed plan.

BREC's IRP is nearly useless to inform any future CPCN application evaluation. Although the overall methodology of the load forecast conforms to 807 KAR 5:058, Section 7, the omission of an expected 25 percent of its expected load from Non-Member sales results in an underestimation of needed capacity and the illusion of excess capacity. BREC's poor planning with regard to its assumptions entirely negates the usefulness of the resource modeling process. BREC's selection of a 635 MW NGCC unit was based on a co-generation plan that never came to fruition yet was included as the sole NGCC resource option with no mention of the contingent co-generation plan in the IRP. This means that BREC will likely not retire Green Units 1 and 2, so nothing from the Base Portfolio can be relied upon except perhaps the PACE Solar and Storage projects.

[261] Matthews Testimony, HVT at 12:04:07.

BREC apparently has no plans to apply for a CPCN for generation in the near future.[262] If BREC files for a CPCN requesting additional generation, it should consider including an updated load forecast and resource portfolio analysis demonstrating that the requested generation asset is the most reasonable cost-effective solution to the identified need. In the short-term, BREC will be capacity short in relation to its seasonal reserve margins. If BREC fails to plan accordingly between now and its next IRP, filling the gap by relying on market purchases may result in increased cost to its ratepayers.

While Commission Staff acknowledges Sierra Club's post-hearing comments regarding ways BREC could improve its IRP, Staff does not recommend that the Commission require BREC to file a new IRP. Commission Staff has incorporated several of Sierra Club's comments into its recommendations.

Commission Staff has determined that BREC's 2023 IRP is unreasonable, due to its minimal usefulness to the Commission, BREC, and its ratepayers in evaluating available resource options and determine the least-cost reasonable alternatives for meeting its capacity needs during the planning horizon.

[262] Matthews Testimony, HVT at 13:24:30.

*Angela M Goad
Assistant Attorney General
Office of the Attorney General Office of Rate
700 Capitol Avenue
Suite 20
Frankfort, KENTUCKY 40601-8204

*Jody M Kyler Cohn
Boehm, Kurtz & Lowry
36 East Seventh Street
Suite 1510
Cincinnati, OHIO 45202

*Honorable Michael L Kurtz
Attorney at Law
Boehm, Kurtz & Lowry
36 East Seventh Street
Suite 1510
Cincinnati, OHIO 45202

*Ashley Wilmes
Kentucky Resources Council, Inc.
Post Office Box 1070
Frankfort, KENTUCKY 40602

*Joe F. Childers
Childers & Baxter PLLC
300 Lexington Building, 201 West Sho
Lexington, KENTUCKY 40507

*Nihal Shrinath
Sierra Club
2101
Webster St. , Suite 1300
Oakland, CALIFORNIA 94612

*Byron Gary
Kentucky Resources Council, Inc.
Post Office Box 1070
Frankfort, KENTUCKY 40602

*John Horne
Office of the Attorney General Office of Rate
700 Capitol Avenue
Suite 20
Frankfort, KENTUCKY 40601-8204

*Patrick Woolsey
Sierra Club
2101
Webster St. , Suite 1300
Oakland, CALIFORNIA 94612

*Evan Buckley
Dinsmore & Shohl, LLP
101 South Fifth Street
Suite 2500
Louisville, KENTUCKY 40202

*John Lavanga
Dinsmore & Shohl, LLP
City Center, 100 W. Main Street
Suite 900
Lexington, KENTUCKY 40507

*Big Rivers Electric Corporation
710 West 2nd Street
P. O. Box 20015
Owensboro, KY 42304

*Tom Fitzgerald
Kentucky Resources Council, Inc.
Post Office Box 1070
Frankfort, KENTUCKY 40602

*Honorable Kerry E Ingle
Attorney at Law
Dinsmore & Shohl, LLP
1400 PNC Plaza
500 West Jefferson Street
Louisville, KENTUCKY 40202

*Senthia Santana
Big Rivers Electric Corporation
710 West 2nd Street
P. O. Box 20015
Owensboro, KY 42304

*Gregory B Ladd
Office of the Attorney General Office of Rate
700 Capitol Avenue
Suite 20
Frankfort, KENTUCKY 40601-8204

*Larry Cook
Assistant Attorney General
Office of the Attorney General Office of Rate
700 Capitol Avenue
Suite 20
Frankfort, KENTUCKY 40601-8204

*Edward T Depp
Dinsmore & Shohl, LLP
101 South Fifth Street
Suite 2500
Louisville, KENTUCKY 40202

*Jody Kyler Cohn
Boehm, Kurtz & Lowry
36 East Seventh Street
Suite 1510
Cincinnati, OHIO 45202

*J. Michael West
Office of the Attorney General Office of Rate
700 Capitol Avenue
Suite 20
Frankfort, KENTUCKY 40601-8204

*Tyson Kamuf
Corporate Attorney
Big Rivers Electric Corporation
710 West 2nd Street
P. O. Box 20015
Owensboro, KY 42304