COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

2017 INTEGRATED RESOURCE PLAN OF BIG RIVERS ELECTRIC CORPORATION	))	CASE NO. 2017-00384

ORDER

The Commission initiated this proceeding for its Staff to conduct a review of the 2017 Integrated Resource Plan (IRP) filed by Big Rivers Electric Corporation (BREC) pursuant to 807 KAR 5:058. Attached in the Appendix to this Order is the report summarizing Commission Staff's review of the IRP. This report is being entered into the record of this case pursuant to 807 KAR 5:058, Section 11(3).

The Commission finds that the Staff Report represents final substantive action in this matter.[1] Final administrative action will be an Order closing the case, which will be issued after the period for comments on the Staff Report, has expired.

IT IS THEREFORE ORDERED that:

1. The Staff Report on BREC's 2017 IRP represents the final substantive action in this matter.

2. Any comments on the Staff Report shall be filed within ten days from the date of this Order.

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

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[1] The Staff Report can be accessed via the Commission's website at psc.ky.gov under "Utility Information—Industry Specific Info—Electric."

By the Commission

ENTERED

OCT 01 2019

KENTUCKY PUBLIC SERVICE COMMISSION

ATTEST:

Gwen R. Pinson

Executive Director

APPENDIX

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2017-00384 DATED OCT 0 1 2019

FIFTY-THREE PAGES TO FOLLOW

Kentucky Public Service Commission

Staff Report on the

2017 Integrated Resource Plan

of Big Rivers Electric Corporation

Case No. 2017-00384

August 2019

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 (Staff). The Commission's goal was to ensure that all reasonable options for the future supply of electricity were being examined in order to provide ratepayers a reliable supply of electricity at the lowest possible cost.

Big Rivers Electric Corporation (BREC) filed its 2017 Integrated Resource Plan (IRP) on September 21, 2017.[2] The IRP includes BREC's plan to meet its customers' electricity requirements for the period 2017-2031.[3] BREC is a generation and transmission (G&T) cooperative located in Henderson, Kentucky. It supplies electricity to three distribution cooperatives that, in turn, provides electric service to retail customers located in 22 western Kentucky counties. These member cooperatives, Kenergy Corp. (Kenergy), Meade County Rural Electric Cooperative Corporation (Meade RECC), and Jackson Purchase Energy Corporation (Jackson Purchase Energy), serve approximately 116,000 customers, of which nearly 90 percent are residential.[4] Over the four-year period from 2013-2016, BREC's load remained relatively flat, increasing only slightly from 724 MW to 726 MW.[5] Total energy requirements, however, declined over the same period from 4,027,402 MWH to 3,932,115 MWH.[6] Total system energy and peak demand requirements are projected to reach 4,372 GWH and 1,279 MW by 2036.[7] Beginning in 2017, Non-Member load was included in BREC's forecast, and while the forecast includes Non-Member peak demand, the forecast does not include any Non-Member energy since energy requirements, while significant, will occur via bilateral transactions and daily interactions with organized energy markets during each year.[8] Through 2036, Non-Member load adds between 450 MW to 501 MW to the Peak Demand forecast.[9]

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[2] BREC was assisted in the preparation of its IRP by GDS Associates, Inc. (GDS).

[3] While the planning period is 2017 through 2031, much of the information that was provided was through 2036, and Staff has included the information through 2036 where available.

[4] IRP at 7.

[5] *Id.* at 52, Table 4.2.

[6] *Id.* at 51, Table 4.1.

[7] *Id.* at 49.

[8] *Id.*

[9] *Id.* at 52, Table 4.2.

BREC owns 1,444 MW of net generating capacity at four generating stations: Reid, Coleman, Green, and Wilson.[10] Since May 2014, BREC's Coleman Generating Station has been idled. In April 2016, BREC idled its 65 MW Reid Unit 1.[11] At the time of the IRP filing, the total capacity available to BREC was approximately 1,819 MW including contractual rights to 197 MW of capacity available from Henderson Municipal Power & Light's (HMP&L) Station Two generating facility and 178 MW from the Southeastern Power Administration (SEPA). However, available capacity is currently reduced by 24 MW, to 1,795 MW, due to force majeure conditions on the SEPA system.[12] Subsequent to the IRP filing, in Case No. 2018-00146,[13] the Commission approved, among other things, BREC's request for a declaratory order confirming that the HMP&L Station Two units are no longer capable of normal, continuous, reliable operation for the economically competitive production of electricity. The Station Two units were retired effective February 1, 2019.[14]

BREC is a member of the Midcontinent Independent System Operator, Inc. (MISO). MISO directs BREC's generation dispatch and determines the reserves required to maintain resource adequacy within its multi-state footprint.

Due in large part to the loss of 850 MW of load resulting from the exit of two aluminum smelters from BREC's system in 2013 and 2014, the Commission ordered a focused management audit in an effort to mitigate the impact of the loss of the smelter loads.[15] The final report of the audit was issued in 2015 and included 23 findings and 5 recommendations, of which 3 of the recommendations are relevant to BREC's development of its IRP. The results of the audit and BREC's action plan to mitigate the impact of the loss of the smelter loads are discussed in more detail in Sections 2 and 4 of this report.

The Commission established a procedural schedule for this case, which allowed for two rounds of data requests to BREC, an opportunity for intervenors to file comments, and an opportunity for BREC to file reply comments. Intervenors include the Attorney General of the Commonwealth of Kentucky by and through the Office of Rate Intervention

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[10] *Id.* at 9.

[11] *Id.* at 44.

[12] *Id.* at 9. SEPA is expected to return to full capacity sometime in 2019. HMP&L has rights to 12 MW of SEPA capacity, which is assumed in BREC's IRP analysis to directly offset the HMP&L load. Force majeure conditions on the SEPA system have reduced HMP&L's allocation to 10 MW. During 2017, BREC began construction of seven small solar arrays totaling 120 kW direct current whose purpose is educational in nature.

[13] Case No. 2018-00146, *Application of Big Rivers Electric Corporation for Termination of Contracts and a Declaratory Order and for Authority to Establish a Regulatory Asset* (Ky. PSC Oct. 23, 2018).

[14] *See* BREC's October 29, 2018 letter in the Post Case Correspondence File for Case No. 2018-00146.

[15] Case No. 2013-00199, Application of BREC Electric Corporation for a General Adjustment in Rates, (Ky. PSC Apr. 25, 2014).

(Attorney General), Kentucky Industrial Utility Customers, Inc. (KIUC), and Ben Taylor and Sierra Club (Sierra Club). The Southern Renewable Energy Association (SREA) did not file for intervention in this proceeding but did submit comments.

BREC responded to two rounds of data requests from Staff and each of the intervenors. The Attorney General, Sierra Club, KIUC, and SREA submitted written comments to which BREC filed reply comments.

The purpose of this report is to review and evaluate BREC's 2017 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 and make suggestions and recommendations to be considered in future IRP filings. Staff recognizes resource planning is a dynamic and ongoing process. Specifically, the Staff's goals are to ensure that:

- All resource options are adequately and fairly evaluated;
- Critical data, assumptions, and methodologies for all aspects of the plan are adequately documented and are reasonable; and
- The report includes an incremental component, noting any significant changes from BREC's prior IRP filed in 2014.

In the current IRP, BREC states that its primary planning goal is to provide for its customers' electricity needs over the next 15 years through a mix of supply and demand-side options, at the lowest reasonable cost. To meet this goal, BREC identified the following planning objectives:[16]

- Maintain a current and reliable load forecast;
- Continue offering cost-effective Demand-Side Management (DSM) programs to its Members;
- Identify potential new supply-side resources and DSM programs;
- Provide competitively priced power to its Members;
- Maintain adequate planning reserve margins;
- Maximize reliability while ensuring safety, minimizing costs, risks and environmental impacts; and
- Meet North American Electric Reliability Corporation (NERC) guidelines and requirements.

Even though the Coleman and Reid stations are currently idled, BREC has no need for new capacity through 2031 in order to maintain an adequate reserve margin.[17] Its existing native load peak is expected to increase from 607 MW in 2016 to 684 MW in

[16] IRP at 15.

[17] *Id.* at 19–20.

2036, reflecting an average growth rate of 0.5 percent.[18] Including the projected load from HMP&L, Non-Member load, accounting for line loss and DSM program effects, the 2036 total system peak is forecasted to be 1,279 MW.[19] Energy requirements for BREC's native load are projected to increase from 3,244,594 MWh in 2016 to 3,593,196 MWh in 2036, also reflecting a 0.5 percent annual growth rate.[20] Incorporating HMP&L, line loss and DSM program effects, the projected 2036 total energy requirement is 4,372,403 MWh.[21]

MISO conducts an annual Loss of Load Expectation Study to determine a Planning Reserve Margin (PRM), Unforced Capacity (UCAP), zonal per unit Local Reliability Requirements, Capacity Import Limits and Capacity Export Limits. The reliability objective of the study is to determine a minimum PRM that would result in the MISO system experiencing a less than a one-day loss of load event every ten years. The 2017 study results indicated that the required reliability level is achieved when the amount of installed capacity is 1.158 times the MISO coincident Peak. Accordingly, for planning year 2017/2018, MISO has established a 15.8 percent reserve margin for installed capacity (ICAP). For planning purposes, BREC adopted MISO's 15.8 percent reserve margin. Based on DSM/Energy Efficiency (EE) programs established since 2011, BREC originally expected to reduce its energy requirements by 144,454 MWh by 2036 and to reduce its winter and summer peak demands by 23.93 MW and a 21.71 MW, respectively, by 2036.[22] However, due to changes in the composition of BREC's DSM portfolio since the filing of the IRP, the estimated future DSM program impacts will be significantly reduced. See Section 3 for more details. BREC's base case resource plan requires no capacity additions over the 15-year planning horizon to maintain a planning reserve margin of 15.8 percent.[23]

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, summarizes BREC's evaluation of DSM opportunities.

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[18] *Id.* at 49 and 52, Table 4.2. BREC defines Native System peak demand as the sum of Rural System coincident peak demand and Direct Serve customer coincident peak demands. Total peak demand is the sum of Native System, non-member load, HMP&L plus the effects of line losses and DSM programs.

[19] *Id.* at 52, Table 4.2.

[20] *Id.* at 51, Table 4.1. BREC's native load consists of 20 direct serve large commercial and industrial customers and the remaining rural system customers.

[21] *Id.* at 52, Table 4.2.

[22] *Id.* at 65, Table 4.12.

[23] *Id.* at 150–151.

- Section 4, Supply-Side Resources and Environmental Compliance, focuses on supply resources available to meet BREC's load requirements and environmental compliance planning.
- Section 5, Integration and Plan Optimization, discusses BREC's overall assessment of supply-side and demand-side options and their integration into an overall resource plan.

It is noted that departures from the filing schedule in 807 KAR 5:058 have caused overlaps of IRP filings. To help minimize future overlaps, Staff recommends to the Commission a filing date for BREC's next IRP on September 21, 2020.

SECTION 2

LOAD FORECASTING

INTRODUCTION

BREC provides power to three distribution cooperatives and those distribution cooperatives, in turn, provide retail service to customers in 22 counties located in the Western region of Kentucky. Within BREC's service area, approximately 90 percent of customer accounts are classified as residential. BREC's forecasts of energy consumption for major customer classes were developed using both short-term and long-term econometric models, statistically adjusted end-use (SAE) models, exponential smoothing and historical trending. BREC prepared its 2017 Load Forecast with the assistance of GDS Associates, Inc. (GDS). GDS developed the forecasting assumptions, which were then discussed with BREC's management.

Based on the requirements of the Rural Utility Service (RUS), BREC prepares a load forecast every two years but makes updates as needed for planning purposes. The 2017 load forecast was completed in July 2017 and adopted by BREC's Board of Directors in September 2017.[24] The 2017 forecast's economic outlook was based on data from the University of Louisville, Woods and Poole Economics, and Moody's Analytics. Additional data was collected from member residential customer surveys, the RUS Form 7 for each member distribution cooperative, the U.S. Census, the U.S. Department of Energy's Energy Information Administration (EIA), and the National Oceanic and Atmospheric Administration.[25] RUS accepts a 20-year historical period as the basis for normal weather, and BREC used this as the basis for its weather normalization adjustments.[26] Weather data was gathered from the Evansville, Indiana, Paducah, Kentucky, and Louisville, Kentucky weather stations.[27]

Over the 20-year forecast period (2017-2036), a select key assumption includes the number of households, which is projected to grow at an average rate of 0.1 percent annually. Employment is projected to increase at an average rate of 0.8 percent annually, and real average household income is projected to rise at an average rate of 1.7 percent annually. Gross regional product is projected to grow at an average annual rate of 1.6 percent, and real retail sales at an average annual rate of 1.0 percent. Heating and cooling degree days are based on 20-year historical averages ending with 2016.[28]

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[24] *Id.* at 49.

[25] *Id.* Appendix A, at 38–39.

[26] *Id.* at 42 and IRP at 72.

[27] IRP Appendix A, at 38 and 42.

[28] *Id.* at 9, 36, 42, and 41, Table 4.2.

FORECASTING APPROACH AND MODELS

A bottom-up approach is used in developing the load forecast, as projections are developed for each of the three distribution cooperatives and then aggregated to BREC's level.[29] Energy and Peak Demand are categorized into either rural system or direct serve customers. Rural system customers include all member system residential, commercial and industrial customers. The direct-serve class includes all large commercial, and industrial customers that are under the Large Industrial Customer (LIC) Tariff.

Short-term and long-run econometric and SAE models were developed to forecast the number of customers and average energy consumption per customer for the Residential and Small Commercial classes and Peak Demand for the Rural System. Informed judgment and historical trends were the basis for energy consumption and peak demand for each large commercial customer. Projections of the number of customers and energy sales for street lighting and irrigation were based on historical trends. Heating and cooling parameters are represented as a combination of degree days, equipment market share, and equipment efficiency. The three factors are then quantified into one variable.[30]

Weather Impacts

BREC collects weather data including heating and cooling degree days, and maximum and minimum monthly temperatures from weather stations in Evansville, Indiana, Paducah, Kentucky, and Louisville, Kentucky. Additional data is collected from MDA EarthSat Weather.[31] Both BREC's Rural System customers' peak demand and energy consumption are weather sensitive. While BREC is usually a summer peaking utility, under extreme weather conditions, the total system may peak in the winter. Winter peaks were set in 2008, 2009, 2014, and 2015.[32] In Staff's December 2015 Staff Report on BREC's 2014 IRP, Staff indicated that BREC's next IRP should include an analysis of the impacts of using time periods less than and greater than 20 years in the development of normal weather for use in its load forecasts. The results of the analysis have found an insignificant difference of 2 MW for the 30-year and -1 MW for the 10-year normalization from the average in Peak MW for the 20-year period.[33]

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[29] *Id.* at 9.

[30] *Id.* at 38 and 45–50.

[31] *Id.* at 38.

[32] *Id.* at 31, Table 3.14.

[33] IRP at 72 and Appendix D at D-3.

Economic Outlook

The number of households, non-farm employment, and household income are key factors driving the energy and demand projections. These factors are projected to grow in the low to moderate range.[34]

Prices and Price Elasticity

Retail energy prices are developed for each of the three distribution cooperatives by customer class and are expressed as the quotient of total class annual revenue and annual kWh.[35] Each distribution cooperative will see an increase in the nominal price of electricity over the forecast horizon. The real price of electricity is expressed in annual amounts to mitigate monthly variations in the average price. The elasticity of demand is developed using regression models for each distribution cooperative. Collectively, energy consumption is virtually inelastic with respect to price. For BREC, the residential class is estimated to have a -0.21 price elasticity. Thus, for a one percent increase in the energy price, consumption will drop 0.21 percent. Energy consumption for the small and large commercial classes is not expected to change with energy price changes over the near term.[36]

DSM/EE and Demand Response Impacts

BREC conducts periodic residential customer surveys to gather data including household characteristics and demographics, domicile characteristics, heating and cooling information, and appliance stock and usage information. The data serves as the basis for constructing forecast model inputs. Surveys are conducted for each of the distribution cooperatives in order to assist in the evaluation of potential EE and demand response programs.[37]

BREC conducted a 2017 DSM Potential Study (DSM Study) to evaluate opportunities for continuing or establishing new EE programs. Within the DSM Study, programs were evaluated for technical potential, economic potential, achievable potential over the 2017-2026 period for both residential and commercial/industrial customer classes. Based on its analysis, BREC incorporated the potential kW and kWh effects of 12 cost-effective programs into its forecasts. Over the forecast period, BREC projects savings of 9,654 MWh in 2017 growing to 144,454 MWh by 2036. Over the same period, the reduction in winter peak demand increases from 1.27 MW to 23.93 MW. The reduction in summer peak demand also rises from 1.45 MW in 2017 to 21.71 MW by

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[34] IRP at 8.

[35] *Id.*

[36] *Id.* at 8 and 48.

[37] IRP at 73 and BREC's Response to Commission Staff's First Request for Information (Staff's First Request), Item No. 15.

2036.[38] These results are subtracted from projected energy and peak demands to incorporate the effects of DSM and efficiency programs.[39]

FORECAST MODELS

BREC utilizes a combination of short-term and long-term econometric and SAE models to forecast the number of customers and customer energy usage at the Member system level. The results are then aggregated to the BREC system level. In addition, peak demand is forecasted at the Member system and BREC's level. The short-term models provide trend forecasts for up to three years. The long-term models allow for changes over time in the number of customers, in customer behavior, and the economy affecting energy usage patterns.

RESIDENTIAL ENERGY SALES

Short-term models are used to forecast up to three years using a time series trend analysis. In the long-term model, the residential customer forecast is a function of changes in the number of households served. Residential use per customer is forecasted using an SAE model. Using monthly data, Heating, Cooling, and Load indices are developed as dependent variables for the model. The Heating index is a function of heating degree days, home size, household income, number of households, real retail price of electricity, space heating market share, and average device efficiency. Increases in the real electricity prices and efficiency will have a negative effect on electricity use per customer. Increases in the other variables will increase electricity use per customer. Similarly, the Cooling index is a function of cooling degree days, household income, number of households, home size, real retail electricity price, market share of cooling devices, and device efficiency. The Base Load index is meant to capture the general trends in usage and characteristics of electricity using devices in the home including water heaters, refrigerators, standalone freezers, electric ranges and ovens, clothes washers and dryers, dishwashers, TVs and DVRs, computers, lighting, and other miscellaneous load. Also, the base Load index is developed such that the effects of changes in the real price of electricity, household size, and income are taken into account. As with the Heating and Cooling indices, increases in electricity prices will have a dampening effect on energy usage, and increases in the number of people in the household or income will lead to greater usage.[40] Total residential energy sales is the product of the number of residential customers and average energy use per customer.

The number of BREC's residential customers is projected to increase slowly at an average annual rate of 0.6 percent through 2036. Average use per customer is projected

[38] IRP at 65, Table 4.12.

[39] *Id.* IRP Appendix A at 44, Table 4.5.

[40] *Id.* at 46–48.

to slowly decline over the forecast period from 1,196 kWh per customer per month in 2017 to 1,177 kWh in 2036 as appliance efficiency and saturation increases. Growth in total residential energy sales, driven by increases in the number of customers is projected to grow at an average annual rate of 0.5 percent, increasing from 1,425,319 MWh in 2017 to 1,583,290 MWh in 2036.[41]

SMALL COMMERCIAL AND INDUSTRIAL ENERGY SALES

The number of small Commercial and Industrial (small C&I) customers is derived using a combination of short-run and long-run models. The small C&I class is made up of all small commercial and industrial customers with annual peak demand less than 1,000 kW. The short-run, small C&I customer forecast is based on the time trend of customer growth and is extended three years. For the long run, an econometric model is used to develop the forecast. The number of small C&I customers is a function of non-farm employment and the number of customers lagged one period.[42]

The average use per customer forecast is developed using an econometric model. Average use per customer is a function of weighted heating and cooling degree days and monthly variables. The weighted degree days are the product of degree days and appliance efficiency. Overall, average use per customer has been trending down as older equipment is replaced with newer, more efficient equipment. Small commercial total energy sales are the product of the number of customers and average energy use per customer.[43]

Growth in the number of small C&I customers is projected to increase an average rate of 1.1 percent per year over the forecast period. As with the residential class, average use per customer is projected to slowly decline by 0.3 percent annually from 2,985 kWh per customer per month in 2017 to 2,841 kWh in 2036. Total energy sales to the small C&I class are projected to increase at a rate of 0.9 percent per year from 623,101 MWh in 2017 to 731,169 MWh in 2036. Customer growth is the primary driver of growth in sales.[44]

LARGE COMMERCIAL AND INDUSTRIAL CLASS

There are two groups of large commercial and industrial (large C&I) customers, those in the Rural System and Direct Serve customers. Large C&I customers have annual peak demand greater to or equal to 1,000 kW. BREC expects its rural system large commercial customer class to grow from 28 in 2017 to 29 in 2018 and hold steady through the forecast period. Similarly, there are 20 Direct Serve customers in 2017 and

[41] *Id.* at 21, Table 3.5.

[42] *Id.* at 49–50.

[43] *Id.* at 50.

[44] *Id.* at 22, Table 3.6.

that number is projected to hold steady throughout the forecast period. Energy sales and peak demand are projected individually for each of the Rural System, and Direct Serve large C&I customers. For each Member system, the number of customers, energy sales, and peak demand are set at the most recent historical values and then projected forward based upon expected changes in operations for each customer.[45] Total energy sales to the large C&I customers are projected to climb from 1,106,507 MWh in 2017 to 1,299,566 MWh in 2021 and then hovering between 1,299,566 MWh and 1,303,001 MWh through 2036.[46]

STREET LIGHTING AND IRRIGATION CLASSES

Both of these customer classes each make up less than 0.1 percent of rural system sales. Projections for the number of customers and energy sales are based on historical trends. Energy sales to irrigation customer are projected to hold steady at 194 MWh over the forecast period. Sales to street lighting are projected to grow at 0.1 percent annually from 3,396 MWh in 2017 to 3,454 MWh by 2036.[47]

PEAK DEMAND

Regression models are developed for each Member cooperative to project a 1-hour coincident peak (CP) demand. The individual Member projections are then aggregated to Rural System CP demand. Rural System peak demand is strongly influenced by energy sales. Weather effects are included as separate variables as peak day heating and cooling degree days. Also, monthly peak day average daily temperatures are included to reflect peak day swings due to weather over the course of the year.[48] Under normal weather conditions, BREC is a summer peaking utility. Over the forecast period, Rural System summer weather adjusted CP peak demand increases from 502 MW to 527 MW. The winter weather adjusted CP demand rises from 495 MW to 517 MW.[49]

Native System peak demand is the sum of Rural System coincident peak demand, and Direct Serve customer peak demand. Direct Serve peak demand is developed by summing Direct Serve non-coincident peak demand and applying a projected coincidence factor. Rural System and Direct Serve customers are combined for the Native System peak load forecast. BREC projects the number of Native System customers to hold steady at 49 over the forecast period. Over the forecast period, distribution system losses

[45] *Id.* at 51.

[46] *Id.* at 23, Table 3.7.

[47] *Id.* at 24–25, Tables 3.8 and 3.9.

[48] *Id.* at 51–52.

[49] *Id.* at 28, Table 3.11.

are held steady at 3.2 percent.[50] Including the effects of DSM programs and distribution losses, Native System peak demand is projected to increase from 635 MW in 2017 to 684 MW by 2036.[51]

HMP&L provides its energy sales and peak demand to BREC.[52] HMP&L projects its energy sales to grow at 0.4 percent annually from 629,574 MWh in 2017 to 679,079 MWh in 2016. Its peak demand is projected to grow from 107 MW in 2017 to 116 MW in 2036.[53]

NON-MEMBER SALES

Beginning in 2017, BREC plans to sell both energy and capacity to Non-Members through either bilateral contracts or MISO. Non-member sales projections are based upon executed long-term transactions and projected potential sales. At the time of IRP publication, BREC had executed long-term capacity contracts with customers in Missouri beginning in 2017, Nebraska beginning in 2018, a multi-year MISO contract to a marketer beginning in 2018 and a 10-year sale to the Kentucky Municipal Energy Agency (KyMEA) beginning in 2019.[54] BREC forecasts Non-Member peak demand to hold steady at 500 MW through 2028 and decline to 450 MW by 2036. Only capacity sales are included in BREC's forecasts of peak demand.[55]

BREC will also make short-term energy sales via bilateral hedges, and participation in the MISO capacity auction and Day Ahead and Real Time energy markets. When appropriate, any available energy not otherwise dedicated will be sold in the MISO spot market via bilateral hedged prices.[56]

TOTAL SYSTEM

Neither HMP&L nor Non-Member peak demand is coincident with native load. Total system non-coincident peak demand is the summation of the weather adjusted Native System CP demand, HMP&L demand, and Non-Member demand. Transmission losses are held steady at 2.29 percent. Accounting for transmission losses, Total System non-coincident peak demand is greatest in the summer and increases from 1,254 MW in

[50] *Id.* at 17, Table 3.1.

[51] *Id.* at 18, Table 3.2 and at 29, Table 3.12.

[52] *Id.* at 52.

[53] *Id.* at 17–18, Tables 3.1 and 3.2.

[54] *Id.* at 26–27 and IRP at 41.

[55] IRP, Appendix A at 18, Table 3.2 and at 27, Table 3.10.

[56] *Id.* at 27.

2017 to 1,279 MW in 2036 and winter peak demand over the forecast period increases from 1,245 MW to 1,272 MW.[57]

SENSITIVITY ANALYSIS

BREC conducted two types of sensitivity analyses modeling extreme and mild weather scenarios and optimistic and pessimistic economic growth scenarios. For the weather scenarios, only the residential and small commercial classes show any sensitivity to variations in weather. Under extreme weather conditions, Rural System energy use increases approximately seven percent and Native System by five percent over the base case normal weather assumption. In addition, by 2021, BREC moves from a summer to a winter peaking utility under extreme weather assumptions. Rural System winter peak demand increases 15-16 percent and Native System by 13.0 percent.[58] The impact on both Rural System and Native System winter peak demand is nearly twice the impact on summer peak demand. The Rural System winter extreme scenario impact increase over the base case scenario is 17.0 percent, while the analogous summer impact is 9.0 percent.[59]

The economic growth scenarios were modeled for each customer class. For the residential class, average household income growth was projected at 3.5 percent (optimistic) and 0.5 percent (pessimistic). Similarly, price elasticity was modeled at -0.11 (optimistic) and -0.31 (pessimistic). For the small commercial class, the optimistic and pessimistic forecasts are based on the number of customers growing 50.0 percent above and 75.0 percent below the base case. Similarly, average use per customer is modeled 10.0 percent above and below the base case. Both irrigation and Rural System large commercial energy sales are modeled 20.0 percent above and below the base case. Both street lighting and direct served large commercial customers are modeled 5.0 percent above and below the base case.[60] Under the economic growth scenarios, BREC remains a summer peaking utility. Under the optimistic scenario, Native System energy use fluctuates 9.0 percent above the base case scenario growing to 17.0 percent above the base over the forecast period. Similarly, the optimistic scenario for Native System summer peak demand begins at approximately 9.0 percent above the base case growing to 18.0 percent above the base case.[61]

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[57] *Id.* at 18 Table 3.2 and at 30, Table 3.13.

[58] *Id.* at 36, Table 3.17 and at 37, Table 3.18.

[59] *Id.*

[60] *Id.* at 35.

[61] *Id.* at 36, Tables 3.15 and 3.16.

CHANGES FROM PREVIOUS 2014 IRP

Since the 2014 IRP, BREC has enhanced its forecasting methodology. Previously, econometric models were developed for each Member system to forecast energy use per customer. Since then, BREC began using data obtained through its customer surveys and other data and developed SAE models[62] for each Member system to forecast residential and small C&I energy use per customer.[63] Since the 2014 IRP, both total energy requirements and peak demand forecasts are lower, driven by lower forecasts in the number of households and energy use per customer.

Projected Native System energy requirements have consistently declined from the 2013 forecast (reported in the 2014 IRP). Between the 2013 forecast and the current forecast, Native System annual sales projections decline between 0.3 percent to 4.0 percent.[64] BREC's Native peak demand projections are slightly higher in the current forecast as compared to the 2013 forecast.[65]

Another important change from the 2014 IRP concerns sales of energy and capacity to Non-Members. Non-Member load is made up of executed contracts and projected sales to load and capacity and economic generation in excess of native load requirements. Excess energy may also be sold in the MISO spot market. In response to the pending and subsequent loss of two aluminum smelters leaving the BREC system, BREC's risk management team developed a Mitigation Plan to begin the process of offsetting the loss of load. The Commission's 2014 Management Audit reviewed the Mitigation Plan and Action Plan Recommendations were issued in 2015. Action Plan Recommendation 4 called for BREC to continue pursuing increased sales to new and existing load and new members. The 2017 IRP projects sales to non-Members of up to 501 MW.[66]

INTERVENOR COMMENTS

There were no comments regarding BREC's load forecasting modeling, assumptions, or methodology.

BREC RESPONSES TO PREVIOUS STAFF RECOMMENDTIONS

The 2014 Staff Report made three recommendations regarding BREC's load forecast.

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[62] Id. at 45, Itron MetrixND software was used to develop the SAE models.

[63] IRP at 31–32.

[64] *Id.* Appendix A, at 13, Table 2.2.

[65] *Id.* at 14, Table 2.3.

[66] *Id.* at 11 and IRP at 32.

- BREC should develop a more diverse group of forecast scenarios, which includes a meaningful number of alternatives that are not part of its Mitigation Plan.
- BREC should include new or pending environmental regulations, which may impact its generation fleet in its sensitivity analyses in a manner that shows how it may respond to such regulations.
- BREC's next IRP should include an analysis of the impacts of using periods less than and greater than 20 years in the development of normal weather for use in its load forecasts.

BREC addressed these recommendations in its current IRP load forecast section. Staff is satisfied with and accepts BREC's responses to the forecasting related recommendations from the 2014 IRP.

DISCUSSION OF REASONABLENESS

Staff is satisfied with BREC's load forecasting overall. BREC's forecasting methodology incorporates a significant number of factors and assumptions. It is robust and well documented. Overall, the forecasting results appear to reflect the economic and demographic characteristics accurately in and changes affecting BREC's service territory. One area of remaining concern is the replacement of the aluminum smelter load. BREC's progress toward replacing that load was reasonably reflected in its load forecasts.

RECOMMENDATIONS FOR BREC's NEXT IRP

The following are Staff's recommendations regarding BREC's load forecast in its next IRP.

- Continue to explore ways to enhance residential and small C&I load forecasts and provide discussions of any refinements to forecasting methodology.
- Continue to provide comparisons of actual to forecasted results for the residential and small C&I classes along with discussions of reasons for any differences between forecasted and actual results.
- Continue to provide comparisons between actual and forecasted summer and winter peak demands using a variety of normalization periods. Provide a discussion of the reasons for any significant differences between actual and forecasted peak demands.
- Continue to explore new markets, including economic development efforts within its service territory, to replace the loss of the smelter loads and provide a discussion of BREC's efforts and how its efforts are reflected in the load forecast.

SECTION 3

DEMAND-SIDE MANAGEMENT AND ENERGY EFFICIENCY

INTRODUCTION

Demand-Side Management and Energy Efficiency (DSM/EE) programs are designed to make the production and delivery of energy more cost-effective with the goal to increase the efficient use of electricity. Each of BREC's three Member Cooperatives budgets, plans, administers and implements DSM/EE programs independently. Member Cooperatives invoice BREC monthly for costs incurred for promotion and incentives and BREC tracks retail member participation and calculates program impacts for reporting purposes. In terms of DSM and EE, BREC has made significant changes in its offerings since the 2017 IRP was filed. BREC offered 15 programs[67] at the filing date of this IRP. On June 30, 2017, BREC filed a separate case to propose certain DSM tariff revisions.[68] In that case, the Commission approved tariff changes that discontinued two residential weatherization DSM programs effective on December 21, 2017. On July 6, 2018, BREC filed an additional separate case with the goal of eliminating a majority of the DSM offerings.[69] The Commission subsequently approved tariff changes that decreased BREC's DSM portfolio to a total of four programs. These four programs were to be phased out through June 30, 2019, and BREC's request to create a Low-Income Weatherization Assistance DSM Program was approved.

DSM/EE PROGRAM SCREENING & EVALUATION PROCESS

BREC commissioned GDS to conduct a study (DSM Study) of potential demand response and EE programs in its service territory.[70] The study evaluates the cost-effectiveness of potential DSM measures when determining which to implement. Potential programs are screened for Technical Potential, Economic Potential, and Achievable Potential. Another screening criterion, Program Potential was evaluated as well, the results of which were based upon a specific program budget of either $1 million or $2 million.[71] The DSM Study covered the 10-year period of 2017–2026.[72] The DSM

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[67] IRP at 86.

[68] See Case No. 2017-00278, *Tariff Filing of Big Rivers Electric Corporation to Revise Certain Demand-Side Management Programs (Tariff Filing)*, (Ky. PSC June 30, 2017).

[69] See 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 (DSM Filing)*, (Ky. PSC July 6, 2018).

[70] IRP, Energy Efficiency and Demand Response Potential Report (Appendix B-DSM Potential Study).

[71] *Id.* at 2.

[72] The energy and demand impacts of the 15 energy efficiency programs already in place as of 2017 were included in BREC's load forecast.

Study results show that over the ten-year study period, maximum energy savings of 1,174,792 MWh is theoretically achievable under the Technical Potential scenario. In addition, under the Technical Potential scenario, maximum summer and winter demand savings of 224.3 MW and 128.0 MW, respectively, are theoretically possible. The Economic Potential analysis is a subset of the technical potential that is economically cost-effective as compared to conventional supply-side resources. Under the Economic Potential scenario, energy savings of 845,682 MWh, and summer and winter demand reductions of 41.6 MW and 36.1 MW, respectively, are possible. Applying the screening criteria yields for the Achievable Potential category generates a result of 228,863 MWh of energy savings, 41.6 MW of summer peak savings, and 36.1 MW of winter peak savings. Using the funding scenario with the budget criteria of $1 million shows results for the energy, summer and winter demand savings of 68,339 MWh, 10.5 MW, and 8.5 MW, respectively.[73]

The Total Resource Cost (TRC) test and the Utility Cost Test were used to evaluate the potential EE measures. In addition, the TRC test was used to determine economic potential savings.[74] The determination of the potential measure's cost-effectiveness relative to the benefits of its projected load impacts is measured by the Benefit to Cost ratios (net benefit). A TRC score of 1.0 or greater indicates that the net present value of benefits is greater than costs. At the Member system level, potential DSM measures were screened using the GDS Benefit/Cost Screening Model.[75]

The TRC test is the main criterion BREC used to screen DSM measures. The TRC test measures the net costs of an energy measure or program as a resource option based on the total costs of the program, including both the participant's and the utility's costs.[76] The benefits include the avoided electric supply costs, the reduction in transmission, distribution, generation, and capacity costs valued at the marginal cost for the period when there is an electric load reduction, and the savings of other resources such as fossil fuels and water. All equipment costs, installation, operation and maintenance, tax credits, cost of removal, and administration costs are included in this test.

ENERGY EFFICIENCY INITIATIVES

BREC has multiple EE programs whose results are not easily quantifiable such as member websites, energy use assessments, the recently installed solar arrays, and evaluation programs.[77] BREC does not track the energy impacts of such programs.

[73] IRP, Appendix B-DSM Potential Study, Table 1-1, Summary Results for Energy and Demand.

[74] *Id.* at 3.

[75] IRP at 26–27.

[76] *Id.* at 27.

[77] IRP at 65 and 66.

PROGRAM DESCRIPTIONS

For the development of this IRP, BREC premised its 2017 load forecast on the continuation of all of its existing DSM/EE programs. Following is a list of each of BREC's programs by customer class whose impacts are included in the load forecast.

Residential Programs

- DSM-01 High Efficiency Lighting Replacement
- DSM-02 Energy Star Clothes Washer Replacement
- DSM-03 Energy Star Refrigerator Replacement
- DSM-04 Residential High Efficiency Heating, Ventilation, and Air Conditioning (HVAC)
- DSM-05/DSM-10/DSM-13 Residential Weatherization
- DSM-06 Touchstone Energy New Home
- DSM-07 Residential HVAC Tune-Up

Commercial/Industrial (C/I) Programs

- DSM-08 C/I High Efficiency Lighting
- DSM-09 C/I General Energy Efficiency
- DSM-07 C/I HVAC Tune-Up
- DSM-11 C/I High Efficiency HVAC

Other

- DSM-12 High Efficiency Outdoor Lighting

Contemporaneously with BREC's IRP filing, the Commission was in the process of investigating the efficacy of electric utilities' continuing their DSM/EE programs. In Case Nos. 2017-00278[78] and Case No. 2018-00236, BREC filed revised tariff sheets proposing to withdraw nearly all of its existing DSM programs. Of the remaining programs, four were phased out by June 30, 2019,[79] as approved by the Commission including:

- DSM-04, Residential High Efficiency HVAC Program;
- DSM-08, C/I High Efficiency Lighting Program;
- DSM-11, C/I High Efficiency HVAC Program; and
- DSM-12, High Efficiency Outdoor Lighting Program.

The Commission also approved Jackson Purchase Energy and Meade County RECC's requests to modify and phase out their respective remaining DSM programs by June 30, 2019.[80] Kenergy Corporation filed a separate tariff withdrawing its DSM

[78] Case No. 2017-00278, *Tariff Filing of Big Rivers Electric Corporation to Revise Certain Demand-Side Management Programs.* (Ky. PSC Dec. 21, 2017).

[79] Case No. 2018-00236 at 10, (Ky. PSC Dec. 12, 2018).

[80] *Id.*

programs.[81] In Case No. 2018-00236, BREC petitioned the Commission to grant permission to implement two new DSM programs. The Commission approved the implementation of one, the Low-Income Weatherization Assistance Program.[82]

DSM PROGRAMS THAT ARE DISCONTINUED:

- DSM-01 - High Efficiency Lighting Replacement Program;
- DSM-02 - ENERGY STAR® Clothes Washer Replacement Incentive Program;
- DSM-03 - ENERGY STAR® Refrigerator Replacement Incentive Program;
- DSM-05 - Residential Weatherization Program;
- DSM-06 - Touchstone Energy® New Home Program;
- DSM-07 - Residential/Commercial HVAC & Refrigeration Tune-Up Program;
- DSM-09 - C/I General Energy Efficiency Program;
- DSM-10 - Residential Weatherization Program - Primary Heating Source Non-Electric; and
- DSM-13 - Residential Weatherization A La Carte Program.

While BREC's rates contain a DSM component based on forecasted annual DSM spending of approximately $1 million, it anticipates much less spending on DSM in future years than the amount recovered through rates, which would result in annual savings of approximately $750,000 once the remaining DSM programs are phased out in 2019, and the Low-Income Weatherization Assistance program is established.[83] The Commission found it reasonable for BREC to create a regulatory liability for the unspent portion of the $1 million of DSM revenues. The regulatory liability would be offset in BREC's next rate case against the regulatory asset associated with the annual depreciation expense for the Wilson Generating Station.[84]

DSM DEMAND RESPONSE PROGRAMS

The DSM Study prepared by GDS evaluated a total of 15 potential demand response programs for the Residential, Commercial and Industrial customer classes. The programs included air conditioner cycling, water heater controls, time-of-use rates, critical peak pricing, smart thermostats, lighting applications, distributed generation, energy management systems, and interruptible rates.[85] Because the MISO region as a whole and BREC, in particular, are long on generation capacity, the value of demand response programs is low. Even though two programs passed the TRC test, Commercial Distributed Generation and Interruptible Rate, BREC has chosen to forego pursuing a

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[81] Tariff Filing System 2018-00293, (filed June 13, 2018).

[82] Case No. 2018-00236 at 10, (Ky. PSC Dec. 12, 2018).

[83] *Id.* at 9.

[84] *Id.* at 8–9.

[85] IRP at 86, Table 5.6 and Appendix B at 39, Table 5.5.

formal demand response program at this time. BREC will continue to monitor opportunities for demand response and to monitor technology changes that may allow for effective demand response programs at lower costs. [86]

RESPONSE TO RECOMMENDATIONS ON 2014 IRP

The 2014 Staff Report made six recommendations regarding BREC's DSM and EE programs.

- Include estimates of costs associated with proposed and potential environmental rules in future DSM/EE benefit/cost analyses.
- Research and report on best practices for DSM/EE program promotion, educational programs, and innovative marketing opportunities.
- Research and report on possible partnering with its member cooperatives in order to enhance marketing and reduce advertising costs.
- Report on the work undertaken to enhance the evaluation, measurement, and verification procedures to ensure DSM/EE programs are achieving expected goals.
- Continue to monitor opportunities for demand response.
- Consider developing a DSM education program similar to that offered by Duke Energy Kentucky, Inc. (Duke Kentucky). Duke Kentucky provides the Energy Education for Schools Program, which educates students about EE in homes and in schools through an EE curriculum. The program is operated under contract by National Energy Education Development (NEED).

BREC addressed these recommendations in its current IRP, DSM Section 5 and in Supply-Side Analysis and Environmental, Section 6.

Regarding the recommendation that BREC is to consider developing a DSM education program similar to that offered by Duke Kentucky and operated under contract by NEED, BREC and its Member Systems, considered this type of education program, but determined that designing an educational program built around BRECs' solar education and demonstration project would be more beneficial.[87]

Commission Staff also recommended that BREC include estimates of costs associated with proposed and potential environmental rules in future DSM/EE benefit/cost analyses. There has been no new carbon emission legislation passed at either the federal or state level since 2014, so BREC estimates the cost of complying with environmental regulations at $0/ton for carbon emissions. BREC will continue to monitor state and federal policies in order to determine if future analysis should include environmental costs offset by DSM/EE programs.[88]

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[86] *Id.* at 87–88.

[87] IRP at 96.

[88] *Id.*

In response to Commission Staff's recommendation to continue researching and reporting on the best practices for DSM/EE program promotion, educational programs, and innovative marketing opportunities, BREC will continue to study and evaluate other regional EE programs. They will also study promotional efforts as well as monitor other utility innovation in DSM through the website, Cooperative.com and the most recent State EE Scorecard published by the ACEEE.[89]

BREC's response to Commission Staff's recommendation to enhance marketing and reduce advertising costs by possibly collaborating with its member cooperatives is ongoing. BREC continues to work with its Members to track the participation in each individual program and the impact of those enacted measures on the load. BREC believes the current evaluation, measurement and verification procedures are appropriate for tracking its current EE program impacts.[90]

PUBLIC / INTERVENOR COMMENTS:

Neither the Attorney General nor SREA had any comments pertaining to DSM. However, the Sierra Club argues that BREC is disregarding the results of its own DSM study, which showed that six of its existing DSM programs had positive net benefits. Furthermore, by withdrawing its DSM programs, BREC is depriving its customers of additional savings that could come from pursuing cost-effective DSM programs.[91] Sierra Club cites the DMS Study commissioned by BREC to note that the Program option of spending $2 million rather than $1 million nets more than double the benefits.[92] Sierra Club further argues that BREC used outdated information to dismiss the option of diversifying its energy portfolio into renewable energy resources.[93]

BREC RESPONSE TO SIERRA CLUB COMMENTS:

In response to Sierra Club comments, BREC argues that, in Case No. 2018-00236, the Commission approved the ultimate removal of all of the existing DSM and EE programs due to those programs not being cost-effective.[94] BREC explains that it plans to provide funds to community action agencies in order to accommodate a need for low-income weatherization initiatives. BREC states that it and its Members will also continue to provide EE education to all retail members and customers so they may make informed energy use decisions. In addition, BREC will provide assistance to its Member staffs and

[89] American Council for an Energy-Efficient Economy (http://aceee.org/state-policy/scorecard).

[90] IRP at 94–97.

[91] Ben Taylor and Sierra Club's Comments on the 2017 Integrated Resource Plan of Big Rivers Electric Corporation at 14 (filed Oct. 12, 2018).

[92] *Id.*

[93] *Id.* at 12.

[94] BREC's Response to Comments at 23.

customers in the following ways: Energy Use Assessments, Power Quality Assessments, Energy Savings Analysis, Power Factor Correction, Technology Evaluation, and EE Education.[95] In response to the Sierra Club criticism about outdated information, BREC states that the sources Sierra Club mentions were not available at the time the IRP was developed and that it continues to evaluate and identify energy resources in order to use the best available sources for concrete analytical assessment.[96]

DISCUSSION OF REASONABLENESS:

For the purposes of the current IRP, Staff is satisfied with BREC's treatment of its DSM programs. BREC should keep in mind that the elimination of most of its DSM programs may have an impact on future IRP load forecasts and resource assessments and model accordingly. Staff is encouraged that BREC will be providing assistance to low-income customers and continuing with its Member System and retail customer education and assessment programs.

RECOMMENDATIONS FOR BREC's NEXT IRP

The following are Staff's recommendations regarding BREC's DSM programs in its next IRP.

- Continue to work with the Member Systems and community action agencies to look for ways to enhance the low-income weatherization program.
- Continue to monitor new technologies and best practices that may lower BREC's DSM program costs and or enhance program benefits. Provide updates on consideration of existing and potential DSM programs in BREC's service territory.

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[95] *Id.* at 24–26.

[96] *Id.* at 19.

SECTION 4

SUPPLY-SIDE RESOURCE ASSESSMENT

EXISTING CAPACITY

BREC currently has access to 1,819 MW of total generating capacity. It owns 1,444 MW of predominately coal-fired generation. As mentioned in Section 1, it has an additional 197 MW available from coal-fired units, which are owned by HMP&L, which will be operated by BREC until February 1, 2019, when the units will be retired due to uneconomic operations. Another 178 MW is available from two hydroelectric power plants operated by SEPA. Force majeure conditions on the SEPA capacity have limited its contribution, yet these limitations are expected to be lifted sometime in 2019.[97] At the time of the IRP filing, BREC's total generation capacity is 1,795 MW, but this will be reduced to 1,622 MW in 2019 due to the retirement of the HMP&L units and assumption of the end of the force majeure conditions with SEPA. Reid Unit 1 and the Coleman Station are currently idled due to the loss of load resulting from the exit of the aluminum smelters.

BREC's predominately coal-fired generating facilities reside at three locations: the Sebree Station located in Sebree, D.B. Wilson Station located near Centertown, and the Kenneth C. Coleman Station near Hawesville.

Since the filing of its last IRP, the compliance date for the Mercury and Air Toxic Standards rule (MATS) became effective on April 16, 2015. BREC requested a one-year delay, as allowed by rule, from the Kentucky Division of Air Quality (KYDAQ) for the Green Station, Reid/HMP&L Station II, and Wilson Station.[98] The KYDAQ approved these requests,[99] and the new compliance date was April 16, 2016. BREC undertook a multi-million dollar renovation at Green Units 1 and 2 to comply with the MATS requirements and installed Activated Carbon Injection (ACI) with Dry Sorbent Injection (DSI) on Green Units 1 and 2. The system was placed into operation in April 2016 meeting the MATS requirement.[100]

The Sebree Station consists of six generating units with a combined capacity of 896 MW. Included are Green Unit 1, a 231 MW coal-fired generator commissioned in 1979 and Green Unit 2, a 223 MW coal-fired generator brought online in 1981. For

[97] IRP at 9.

[98] *Id.* at 99.

[99] MATS Extension Approval Dates: Reid – June 9, 2014; Wilson – June 23, 2014; Green – September 23, 2014; HMP&L Station Two – January 6, 2015.

[100] *See* Case No. 2012-00063, *Application of Big Rivers Electric Corporation for Approval of its 2012 Environmental Compliance Plan, for Approval of its Amended Environmental Cost Recovery Surcharge Tariff, for Certificates of Public Convenience and Necessity, and for Authority to Establish a Regulatory Account* (Ky. PSC Oct. 1, 2012).

pollution control, the Green units are fitted with a Flue Gas Desulfurization Unit ("FGD") for SO_2 removal, over-fired air (coal re-burn) for NO_X control and a precipitator for reducing emission particulate matter. For MATS compliance, the units are equipped with DSI/Carbon with FGD. Also, at the station are Reid Unit 1, a 65 MW coal/gas-fired generator commissioned in 1966[101] and the Reid Combustion Turbine, a 65 MW natural gas/fuel oil-fired generator brought online in 1976. Reid Unit 1 Title V permit is under review by the KYDAQ to utilize the four existing natural gas burners in place of the coal burners to comply with MATS. For pollution control, Reid Unit 1 is able to burn natural gas for SO_2 and NO_X control and MATS compliance. It is also fitted with a precipitator to reduce particulate matter emissions. HMP&L Unit 1, a 153 MW coal-fired generator commissioned in 1973 and HMP&L Unit 2, a coal-fired 159 MW generator brought online in 1974 are retrofitted with an FGD for SO_2 control and a Selective Catalytic Reduction ("SCR") system to reduce NO_X, and SCR with FGD for MATS compliance.[102]

The Wilson Station has a single 417 MW coal-fired generating unit commissioned in 1986. It is fitted with an FGD to reduce SO_2, an SCR for NO_X limitation, an electrostatic precipitator for particulate matter control and SCR with FGD for MATS compliance.[103]

The Coleman station is currently idled. It contains three units with a combined generating capacity of 443 MW. Coleman 1 is a 150 MW coal-fired unit commissioned in 1969. Coleman 2 is a 138 MW coal-fired generator commissioned in 1970. Coleman 3 is a 155 MW coal-fired generator that came online in 1972. Emissions from the three generating units pass through a single FGD absorber.[104] None of the units at Coleman Station are MATS compliant at this time. BREC states that, since the Coleman Station units have been idled since 2014 and have not operated since the compliance date for MATS, controls will not be required until the units are restarted.[105]

Table 4.1 shows BREC's generation fleet, year of operation, capacity, fuel supply, and emission control equipment. The two HMP&L units are included at their maximum capacity values.

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[101] Reid Unit 1 was retrofitted in 2001 to burn natural gas. See the Staff Report in *Case No. 2014-00166, Big Rivers Electric Corporation's 2014 IRP* (December 2015) at 33.

[102] IRP at 98, Table 6.4.

[103] *Id.* and IRP at 10.

[104] *Id.* at 12.

[105] *Id.* at 100.

Table 4.1[106]

Unit	Operation	Capacity (MW)	Fuel	SO_2 Control	NO_x Control	Particulate Control	MATS Control
Coleman 1	1969	150	Pulverized Coal	FGD	Low Nox Burners Overfire Air	Precipitator	None
Coleman 2	1970	138	Pulverized Coal	FGD	Low Nox Burners Overfire Air	Precipitator	None
Coleman 3	1972	155	Pulverized Coal	FGD	Low Nox Burners fire	Precipitator	None
Green 1	1979	231	Pulverized Coal	FGD	Overfire Air Low Nox Burners	Precipitator	DSI/Carbon with FGD
Green 2	1981	223	Pulverized Coal	FGD	Low Nox Burners	Precipitator	DSI/Carbon with FGD
HMP&L 1	1973	153	Pulverized Coal	FGD	SCR	Precipitator	SCR with FGD
HMP&L 2	1974	159	Pulverized Coal	FGD	SCR	Precipitator	SCR with FGD
Reid 1	1996	65	Coal Natural gas	Burn Medium Sulfur Coal	Burn Natural Gas	Precipitator	Natural Gas
Reid CT	1976	65	#2 Oil Natural Gas	NA	SCR	NA	Natural Gas
Wilson 1	1986	417	Pulverized Coal	FGD	SCR	Precipitator	SCR with FGD

BREC states that it has no need for new capacity through 2031 to maintain an adequate reserve margin.[107] BREC also states that in addition to existing capacity, it has

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[106] *Id.* at 10–12 and 98, Table 6.4.

[107] *Id.* at 19.

access to the wholesale power markets to buy and sell energy to maximize Member value and meet fluctuations in owned generation resource availability.[108]

BREC considers energy and peak demand in two classes, rural and large industrial. The rural class primarily consists of residential, commercial, and industrial customers served by BREC's members. This class comprises up to 90.0 percent of the accounts served and sales to this class, as a percent of total sales, are projected to decrease from 46 percent in 2016 to 43 percent by 2031.[109] The large industrial class includes 49 large commercial and industrial customers,[110] and this segment is projected to be essentially flat over the planning period.[111]

BREC's number of consumers, total energy requirements, and peak demand for selected years from 2015 to 2031 are shown below in table 4.2.[112]

Table 4.2

Year	Consumers	Total system energy (GWh)	Total system peak (MW)
2015	114,934	3,950	799
2022	121,568	4,218	1,302
2027	125,882	4,262	1,310
2031	129,438	4,309	1,298

Reliability Criteria

As a MISO member, BREC is required to follow MISO's tariff requirements. Among its MISO obligations is that of maintaining system reliability in operating and planning while offering service at the lowest cost. The resource adequacy principals developed by MISO contain three primary points: a footprint-wide resource planning reserve margin, standardized capacity resource qualifications, and member entities complying with Load Serving Entity (LSE) compliance requirements.[113]

Module E-1 (Resource Adequacy) of MISO's tariff provides forward transparent capacity signals, recognizes congestion that limits aggregated deliverability and

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108 *Id.*

109 *Id.* at 14.

110 The number of customers presented in BREC's 2014 IRP, page 36, Table 4.7, represents direct serve customers that were served under BREC's Large Industrial Customer tariff. The number of customers presented in the 2017 IRP, Chapter 4, Section 4.2.3, page 58, Table 4.7, represents all rural system and direct serve customers whose load exceeds 1 MW.

111 IRP, Appendix A, at 23.

112 *Id.* at 12, 17, and 18.

113 IRP at 149.

complements state resource planning processes.[114] MISO annually performs studies, based on information provided by Market Participants, to evaluate current market conditions to forecast future planning environments. These studies are used to develop the Loss of Load Expectation (LOLE), which is utilized in setting the PRM for the upcoming planning year and a 9-year PRM forecast. In addition, the LOLE is utilized to determine UCAP, zonal per-unit Local Reliability Requirements, Capacity Import Limits and Capacity Export Limits.[115] The results of the MISO study and its deliverables supply, including the PRM Requirement, are inputted to the MISO Planning Reserve Auction (PRA).

BREC is located in MISO's regional Zone 6 along with entities in Indiana. MISO's location-specific approach in its PRA is intended to provide efficient price signals to encourage the appropriate resources to participate in the locations where they provide the most benefit. This methodology creates a variety of options for LSEs to obtain the resources required to meet their PRM requirements, including Fixed Resource Requirements, bilateral transactions, self-scheduling, capacity deficiency payments, and auction purchases.[116] Market Participants participate in the PRA using the Module E Capacity Tracking Tool.

MISO utilizes a program developed by General Electric called Multi-Area Reliability Simulation (GEMARS) to calculate the LOLE for the applicable planning year. GEMARS uses a sequential Monte Carlo simulation to model a generation system and assess the system's reliability based on any number of interconnected areas. GEMARS calculates the annual LOLE for the MISO system and each Local Resource Zone by stepping through the year chronologically and taking into account generation, load, load modifying and EE resources, equipment-forced outages, planned and maintenance outages, load forecasting uncertainty and external support.[117] Beyond the planning year 2017-2018 LOLE study analysis, a LOLE analysis was performed for the five-year-out planning period of 2020-2021 and the ten-year-out planning year of 2026-2027.[118]

To determine the required annual reserve margin, MISO completes a system-wide resource adequacy study and determines a reserve requirement based on its currently projected overall system peak. The procedures used to calculate its reserve requirements are in the MISO Business Practices Manual (BPM). The BPM-calculated ICAP planning reserve margin for members in the planning year 2017–2018 is 15.8 percent.[119] This same percentage was utilized throughout the IRP planning period. The

[114] *Id.* at 150.

[115] *Id.* at 150–151.

[116] *Id.* at 150.

[117] *Id.* at 152.

[118] *Id.* at 157

[119] *Id.* at 155.

calculated Unforced Capacity planning reserve margin is 7.8 percent for the 2017-2018 planning year.[120]

BREC stated the evaluation of its own reserve margins showed reserves in excess of MISO's requirement (15.8 percent ICAP) over the planning period.[121] Prospectively, it will continue to comply with MISO's tariff requirements, which include the possibility of varying amount of planning reserves. In addition, BREC will continue to evaluate the proper reserve target by continuing participation in MISO stakeholder groups such as the Resource Adequacy Subcommittee, Loss of Load Expectation Working Group, and other groups, to ensure that its participation in the MISO market provides optimum value to its Members.[122]

BREC did not produce a formal reserve margin study in the current IRP as recommended in the Staff Report on its 2014 IRP. Instead, BREC utilized the MISO reserve margin study for this IRP. In its discussion of why it did not conduct a utility-specific reserve margin study, BREC maintains that its tariff requires MISO to perform a study to determine a minimum amount of planning reserve requirements, and that the uncertainty and cost of conducting a utility-specific reserve margin study outweighs the value of such a study.[123]

See Table 4.3 below for MISO's PRM from 2017 through 2026.

Table 4.3[124]

Metric	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
PRM_{ICAP}	15.8%	15.6%	15.3%	15.4%	15.5%	15.5%	15.6%	15.6%	15.7%	15.7%
PRM_{UCAP}	7.8%	7.5%	7.3%	7.3%	7.4%	7.5%	7.6%	7.6%	7.7%	7.8%

Supply-Side Resources

During 2015, BREC transitioned its production cost modeling for its resource assessment and acquisition planning from a third-party vendor to an in-house operation administered by the Strategic Planning and Risk Management department. BREC purchased Energy Exemplar's production cost modeling software *Plexos®* in February of

[120] *Id.*

[121] *Id.* at 157.

[122] *Id.*, at 157–158.

[123] *Id.*, Appendix D at 6.

[124] IRP at 157.

2015. Since that time, utilization of the *Plexos*® ST Plan®, which emulates a market-clearing engine for detailed analysis, has been significant.[125]

For IRP modeling, the *Plexos*® LT Plan® (long-term capacity expansion planning optimization model) was utilized to develop BREC's optimal portfolio of energy resources and any future capacity.[126] The LT Plan® model uses advanced algorithms that analyze all the possible portfolio options based on the inputs and constraints entered and provides the certainty of what and when to optimally invest or retire capacity resources.[127] The LT Plan® objective is to minimize the net present value of the capital and production costs formulated as a mixed-integer problem.[128]

In the modeling process, BREC developed its Base Case using inputs, constraints and assumptions based on the best information available at the time the IRP was prepared. The Base case and the scenarios utilized the BREC 2016-2030 Long-Term Financial plan with the following updates:

- Market power prices for energy and capacity
- Spot fuel prices for coal, natural gas and fuel oil
- SEPA costs and power projections
- Load utilizing the 2017 Load Forecast[129]

BREC completed an analysis of the newly finalized environmental regulations and prepared a plan to achieve compliance within the time allowed by the regulations.[130] One of the major drivers of change is the Clean Power Plan (CPP), a set of proposed regulations limiting carbon emissions from fossil fuel power plants. BREC stated that since the CPP is currently on hold, and because of the uncertainty of its disposition, as well as the changing energy marketplace, BREC has suspended work on developing a strategy to comply with the CPP until such time it is restarted.[131]

Other uncertainties were addressed in this analysis using a sensitivity case approach. In addition to the Base Case, cases were developed that considered changes in:

1. Energy Locational Marginal Price (LMP) Market Price,

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[125] *Id.* at 106.

[126] *Id.*

[127] *Id.*

[128] *Id.*

[129] *Id.* at 107.

[130] *Id.* at 21.

[131] *Id.*

2. Spot Coal Price,
3. Natural Gas Price,
4. Load Forecast,
5. Renewable Portfolio Standards,
6. Demand-Side Management Incentive Increase, and
7. HMP&L Station Two Contract Sensitivity.[132]

Specific generation resource options utilized by BREC in its analysis are as follows:

- Wilson remains coal-fired through 2019 and beginning in 2020 can either remain coal-fired or retire.[133]
- Green units remain coal-fired through 2019 and beginning in 2020 can remain coal-fired, convert to natural gas, or retire.
- HMP&L Station Two units are modeled as one 197 MW unit (the current BREC contractual allocation of Station Two capacity) and remain coal-fired through 2019. Beginning in 2020, HMP&L Station Two can remain coal-fired, convert to natural gas or BREC can exit the contract with the City of Henderson.
- Reid CT remains a resource as a natural gas fired unit.
- SEPA is modeled assuming BREC must continue the contract through 2019 and beginning in 2020 can either continue or exit the contract.
- New 100 MW natural gas combustion turbine can be built beginning in 2020.
- New 702 MW natural gas combined cycle unit can be built beginning in 2020.
- New 20 MW fixed solar units can be built beginning in 2020.[134]

The last three-generation resources listed above were included as viable options in the LT Plan®. They were modeled using cost estimates provided in the EIA's Capital Cost Estimates for Utility Scale Electricity Plants report (EIA report) dated November 2016. BREC did not include every option in the EIA report in the 2017 IRP modeling process due to either their high cost, lack of viable options, or BREC had already developed high-level projections that are closer to actual cost that the EIA projections.[135]

BREC stated that the LT Plan® model results included in the IRP do not constitute a commitment by it for a specific course of action especially with the current uncertainty regarding environmental compliance and commodity price forecasts (coal, natural gas

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[132] *Id.*

[133] Note: Wilson conversion to natural gas was not modeled because of the high capital costs to get natural gas supply to Wilson and the relative low capital cost to make the Wilson coal-fired unit compliant with CCR and ELG regulations, IRP at 108.

[134] *Id.* at 108.

[135] *Id.* at 114.

and market power prices).[136] Rather, the 2017 IRP is a plan that considers market conditions, load requirements, and legislation as of a certain point in time.

Assessment of Non-Utility Generation – Cogeneration, Renewables, and Other Sources

Cogeneration

BREC's IRP includes capacity and energy from SEPA and from its seven solar arrays, which have been in operation since mid-December 2017.[137] The solar arrays are meant primarily to provide demonstration and education of PV generation to retail member–consumers and schools in the areas. In addition, BREC Members continue to see moderate growth in renewable energy production by net-metered PV generation.[138] BREC has signed a contract with a retail customer who recently installed a 210 kW solar generator and has received one other inquiry regarding the QFP/QFS Cogeneration/Small Power Production tariffs.[139] On file with the Commission, BREC has a renewable energy tariff and makes Energy Star certified renewable power available to its three-member cooperatives, which in turn offer the power to their members.

BREC modeled its least cost Renewable Portfolio Standard (RPS) in its LT Plan®. Only fixed solar capacity was modeled in the plan, and BREC stated that it would most likely pursue purchase power agreements to meet the requirements for the RPS. BREC modeled a scenario assuming Kentucky adopted an RPS where 15.0 percent of peak native load capacity is sourced from renewable resources by 2020, 20 percent by 2025, and 25 percent by 2030.[140] To supply this solar, BREC would build 100 MW of solar in 2020, 40 MW of solar in 2025, and 40 MW of solar (total of 180 MW) in this scenario.[141]

Regarding SEPA, the dam repairs have returned Lake Cumberland to normal levels, and the full capacity is expected in 2019. See Table 4.4.[142]

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[136] *Id.* at 109.

[137] Response to Staff's First Request, Item 10.

[138] IRP Appendix D at 7.

[139] BREC's response to the Attorney General's Initial Request for Information (Attorney General's First Request), Item 4.

[140] *Id.* at 133.

[141] *Id.*

[142] *Id.* at 99.

Table 4.4[143]

	SEPA Capacity (MW)	SEPA Energy (GWh)
2017	154	222
2018	154	222
2019	178	267
2020	178	267
2021	178	267
2022	178	267
2023	178	267
2024	178	267
2025	178	267
2026	178	267
2027	178	267
2028	178	267
2029	178	267
2030	178	267
2031	178	267

<u>Compliance Planning</u>

BREC completed an analysis of the newly finalized regulations and prepared a plan to achieve compliance within the time allowed by the regulations. The major projects in the plan are the Wilson and Sebree Stations' CCR/ELG projects. BREC also provided an estimate of the fully projected cost of returning the Coleman Station to service,[144] but stated that it had evaluated various considerations for Coleman Station independent of its 2017 IRP.[145] BREC notes that its environmental compliance plan may be modified by the outcome of litigation against nearly every newly proposed regulation and that it will continue to monitor the outcome of the litigation and will make any necessary adjustments to meet modified compliance limits or schedules.[146]

The EPA's Cross State Air Pollution Rule (CSAPR) replaced the Clean Air Interstate Rule (CAIR) that was vacated by federal courts on July 11, 2008.[147] CSAPR requires 23 states to reduce annual SO_2 and NO_X emissions to assist downwind regions in attaining 24-hour and/or Annual Particulate Matter 2.5 (PM 2.5) National Ambient Air Quality Standards (NAAQS). CSAPR utilizes allowances issued by the EPA to track

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[143] These SEPA levels include only BREC's share.

[144] BREC's response to the Attorney General's First Request, Item 7.

[145] BREC's response to Staff's First Request, Item 6.

[146] IRP at 104.

[147] *Id.* at 98.

emissions. As was the case in CAIR, the EPA provides serialized allowances that are surrendered to track emissions and those that are not utilized in the year provided by the EPA are "banked" in the account for future use.[148] BREC will not receive additional allowances due to the retirement of HMP&L Station 2 on February 1, 2019; however, CSAPR allowances allocated by the EPA will continue for a period of 5 years after the first year the units do not operate.[149] With both Coleman Station and Reid Station idled, BREC has sufficient allocation of allowances to cover both the annual and season emissions.[150] BREC stated that the SO_2 allowances issued to it under CSAPR are sufficient to meet the emissions of its operating facilities, and, in addition, it maintains a bank of approximately 28,000 SO_2 allowances as projected through 2017.[151]

With the exception of the Coleman and Reid Stations, BREC currently utilizes and included the estimated costs associated with the operation of compliance systems on all of its coal-fired units.[152] In order to comply with the MATS requirements, BREC installed ACI with DSI on Green Units 1 and 2. Wilson Station has SCR and FGD in place to control mercury. HMP&L Station Two Units 1 and 2 also have an SCR and an FGD scrubber to control mercury. Reid Station Unit 1 has a Title V permit under review by the KYDAQ to utilize four existing natural gas burners in place of the coal burners, which, if approved, will allow the units to comply with MATS.[153]

At the time of the filing of the IRP, the MATS rule was under litigation, and the EPA had asked the United States Court of Appeals for the D.C. Circuit to hold in abeyance its ruling until the current EPA files its decision on the Supplemental Finding for costs the prior EPA developed.[154] BREC stated that depending upon the outcome of the litigation, it could continue to operate the control equipment as designed, reduce the operation of the control equipment if the limits are lowered, or suspend the operation of the control equipment.[155] On December 27, 2018, the EPA issued a proposed revised Supplemental Cost Finding for the Mercury and Air Toxics Standards, as well as the Clean Air Act required risk and technology review.[156] After taking account of both the cost to coal- and

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[148] *Id.* For a detailed explanation of the CSAPR, see pages 98–99 of the IRP and BREC's Response to Staff's First Request, Item 18.

[149] BREC's response to KIUC's First Request for Information, Item 6.

[150] IRP at 99.

[151] *Id.*

[152] The Coleman Station Units were idled in May 2014 and have not operated past the April 2015 compliance date; therefore, controls will not be required until the units are restarted.

[153] IRP at 100.

[154] *Id.* In the final decision, no emission requirements were proposed to be changed.

[155] *Id.*

[156] https://www.epa.gov/mats/regulatory-actions-final-mercury-and-air-toxics-standards-mats-power-plants.

oil-fired power plants of complying with the MATS rule (costs that range from $7.4 to $9.6 billion annually) and the benefits attributable to regulating hazardous air pollutant (HAP) emissions from power plants (quantifiable benefits that range from $4 to $6 million annually), as EPA was directed to do by the United States Supreme Court, the agency proposes to determine that it is not appropriate and necessary to regulate HAP emissions from power plants under Section 112 of the Clean Air Act.[157] However, the emission standards and other requirements of the MATS rule, first promulgated in 2012, would remain in place since EPA is not proposing to remove coal- and oil-fired power plants from the list of sources that are regulated under Section 112 of the Clean Air Act.[158]

Coal combustion residuals (CCR) are the waste products remaining from the combustion of coal in an electric generating facility. These residuals include fly ash, bottom ash, and scrubber waste. The EPA published the final rule regarding the disposal of CCR waste in the Federal Register on April 17, 2015 (CCR Rule).[159] The CCR Rule establishes technical requirements for CCR landfills and surface impoundments under Subtitle D of the Resource Conservation and Recovery Act of 1976. The CCR Rule requires that minimum design criteria are met for new and existing sites as well as recordkeeping and design reviews to be maintained on a publicly accessible web site.

To dispose of CCRs, BREC operates three facilities that utilize ash pond (surface impoundments) – Coleman Station, Green Station, and the Reid/HMP&L Station. It has installed groundwater monitoring as required by the CCR Rule around the Green and Reid /HMP&L ash ponds.[160] The idled Coleman Station was not generating at the time the rule was established and therefore is not required to install groundwater monitoring until the units are returned to service.

BREC operates two special waste landfills at the Green and Wilson Stations. Both had existing groundwater monitoring wells that are used to comply with the CCR Rule. BREC has established a publicly accessible web site and has populated the site with the reports and studies required to date under the CCR Rule.[161]

On November 3, 2015, the EPA published in the Federal Register the Effluent Limitations Guideline rule (ELG Rule), which imposed compliance dates and best available technology economically achievable (BAT) effluent limitations and pretreatment standards for steam electric power generation.[162] The new standards and compliance

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[157] *Id.*

[158] *Id.*

[159] IRP at 100.

[160] *Id.*

[161] *Id.* at 101.

[162] *Id.*

dates apply to the following waste streams: fly ash transport water, bottom ash transport water, FGD wastewater, flue gas mercury control wastewater, and gasification water. In order to comply with the ELG Rule, BREC engaged Burns & McDonnell to perform a compliance report on the Green Station CCR/ELG. The final report was issued on July 11, 2017, and contained several recommendations, which will allow BREC to comply with the CCR/ELG Rules.[163] BREC stated that the compliance date with the CCR/ELG rules may change due to pending litigation of the rule. On June 6, 2017, the EPA made notice that the compliance dates would be postponed until it completes reconsideration of the 2015 rule and conducts a rulemaking to potentially revise the new, more stringent BAT effluent limitations and pretreatment standards for existing sources.[164] To date, the EPA has not finalized its decision on the rulemaking, but BREC will continue to monitor the actions taken by the courts and the EPA and adjust compliance requirements and construction dates as appropriate.[165]

The Clean Water Act, Section 316(b), requires that existing electric generation facilities that are designed to withdraw at least 2.0 million gallons per day of cooling water ensure that the cooling water intake structure location, design, construction, and capacity reflect the best technology available to minimize harmful impacts on the environment.[166] BREC pointed out the two main components of the final rule that affects its operations. First, facilities that withdraw at least 2.0 million gallons but less than 125.0 million gallons of cooling water per day must reduce fish impingement under one of the seven options available for meeting the best control technology for this requirement.[167] Second, facilities that withdraw 125.0 million gallons or more of cooling water per day are required to conduct studies to help the permitting agency determine whether and what site-specific controls, if any, would be required to reduce the number of aquatic organisms affected by cooling water systems.[168]

BREC stated that Section 316(b) of the Clean Water Act affects the Wilson Station, in that it must comply with the requirements for facilities that withdraw at least 2.0 million gallons per day of cooling water and the Green and Coleman Stations will be required to comply with the requirements for facilities that withdraw at least 125.0 million gallons of cooling water per day.[169] In 2017, BREC completed the study of the Wilson Station and submitted it to the Kentucky Division of Water (DOW) for its review. BREC stated that the Wilson Station already utilizes the Best Available Control Technology (BACT) with a

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[163] *Id.*

[164] *Id.* at 101 and 102.

[165] *Id.* at 102.

[166] *Id.*

[167] *Id.*

[168] *Id.*

[169] *Id.* at 102–103.

closed cooling water system; therefore, it does not anticipate additional technology to comply with Section 316(b) of the Clean Water Act. Also in 2017, BREC submitted a request to the DOW with the Sebree Station 2017 Kentucky Pollution Discharge Elimination System (KPDES) permit renewal to collect the required information for Sebree Station during the next five-year cycle of the issued permit. BREC stated that the Sebree Station units utilize closed cooling technology on four of the five units that comply with the BACT; Reid Station Unit 1 is a once-through cooling that BREC anticipates may need to be modified by installing a new fine screen with a fish return system at the intake.[170] With respect to the Coleman Station, it withdraws more than 125.0 million gallons of water per day when operational for its once-through cooling system. Since the Coleman Station is currently idled, BREC submitted a request to the DOW with the Coleman Station KPDES to begin the required studies within six months after the station returns to operational status.[171]

The CPP was designed to reduce carbon dioxide emissions from fossil fuel power plants. The United States Supreme Court stayed the implementation of the CPP on February 9, 2016. As mentioned earlier in this report, BREC has suspended work on developing a strategy to comply with the CPP until such time it is restarted.

On August 21, 2018, the U.S. Environmental Protection Agency proposed the Affordable Clean Energy (ACE) rule, which would establish emission guidelines for states to develop plans to address greenhouse gas emissions from existing coal-fired power plants. The ACE rule would replace the 2015 Clean Power Plan, which EPA has proposed to repeal because it exceeded EPA's authority. The Clean Power Plan was stayed by the U.S. Supreme Court and has never gone into effect. The ACE rule has several components: a determination of the best system of emission reduction for greenhouse gas emissions from coal-fired power plants: a list of candidate technologies states can use when developing their plans: a new preliminary applicability test for determining whether a physical or operational change made to a power plant may be a major modification triggering New Source Review: and new implementing regulations for emission guidelines under Clean Air Act section 111(d).[172]

<u>Generator Efficiency Improvements</u>

For BREC's base load units, the heat rate has improved by 560 BTU/kWh, or 5.0 percent, in the 8-year period from 2009 to 2016."[173] Recent generation improvement activities include operations training simulation for control room operators, reducing

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[170] *Id.* at 103.

[171] *Id.*

[172] https://www.epa.gov/stationary-sources-air-pollution/proposal-affordable-clean-energy-ace-rule.

[173] IRP at 90.

controllable losses, maintenance activities that focus on improving generation efficiency, control instrument tuning and optimization, and coal pulverizer tuning.[174]

BREC utilizes the GKS® benchmarking service provided by Navigant Consulting to compare its unit performance against its peers. BREC's units have compared favorably as the Coleman Station, Wilson Station, and HMP&L Station Two have won awards based upon detailed analysis of cost, performance and safety data from Navigant's industry-leading database.[175]

Transmission

BREC owns and operates a transmission system containing 1,297 miles of transmission line and 24 substations.[176] Its transmission system consists of the physical facilities necessary to transmit power from its generation plants and interconnection points to all substations from which customers of its three Member cooperatives are served. Since its last IRP, BREC has completed various upgrades that are expected to improve reliability for its Members and enhance its ability to respond to outages. Among the upgrades is the launch of the use of the Automatic Restoration and Sectionalization (ARS) schemes.[177] ARS will allow for the automatic transfer of a distribution substation that is experiencing an outage from a locked transmission circuit to that substation's backup transmission circuit, a self-healing concept preprogrammed within BREC's Energy Management System.[178]

BREC notes that it is consistently looking for ways to improve and upgrade its transmission system facilities, which are designed to meet all industry standards including those set forth by NERC and the Southeast Electric Reliability Corporation (SERC). In 2016, SERC completed a comprehensive audit of BREC's compliance with NERC Planning Standards, Operating Standards, and Critical Infrastructure Cyber Security Standards, which resulted in many positive observations by the SERC audit team.[179]

Also in 2016, BREC, in partnership with LS Power and Hoosier Energy, secured MISO's first competitive transmission project.[180] This project, the Duff-Coleman Extra High Voltage (EHV) 345 kV project, which the Kentucky portion will be owned and

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[174] *Id.* at 92.

[175] *Id.*

[176] *Id.* at 38.

[177] *Id.*

[178] *Id.* at 38–39.

[179] *Id.* at 39.

[180] *Id.*

operated by BREC, will allow the partners to implement, own, and operate a new transmission line extending approximately 31 miles from the Coleman EHV Station in Hancock County, Kentucky to Dubois County, Indiana.[181] Both MISO and PJM Interconnection LLC have approved a proposal by American Electric Power to loop the circuit through the existing Rockport substation, potentially creating a Duff to Rockport to Coleman EHV 345 kV circuit.[182] The project is scheduled to be in service in 2021.

BREC continually assesses its transmission system's ability to transfer power into and out of its local balancing area as well as performing transfer capability studies as a participant in MISO and SERC seasonal assessments. BREC stated that while transfer capability values can vary significantly due a number of factors, study results demonstrate that it can import sufficient generation to satisfy all of its firm demand requirements as well as support the export of its generation power greater than the amount required to serve native load.

BREC's system optimization and more efficient utilization of its existing transmission facilities from 2012 through August 2017 involved BREC constructing, and placing in-service, approximately six miles of new transmission line to serve five new delivery point substations.[183] An additional 17 miles of 69 kV and two miles of 161 kV lines were constructed to strengthen the transmission network and improve system reliability.[184] To increase transmission line current ratings, approximately seven miles of 69 kV and eight miles of 161 kV lines were reconductored with higher current capacity conductors.[185] In 2016, Kentucky Utilities Company (KU) and BREC completed the construction necessary to loop an existing BREC-owned 165 kV circuit through the new KU Mantanzas substation in Ohio County, Kentucky to improve system reliability and efficiency.

BREC also completed the replacement of the two-way radio system for it and its three Members. Each of the four companies now operates its own two-way radio system sharing a common backbone infrastructure. The new system accommodates two-way radio communication among the companies during emergencies.

A list of BREC's completed transmission system additions for the 2012-2017 time period is below.

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[181] *Id.*

[182] *Id.*

[183] *Id.* at 144.

[184] *Id.*

[185] *Id.* at 144–145.

Table 4.5[186]

Completed Transmission System Additions (2012 – 2017)	**Year**
Wilson 161/69 kV transformer addition	2012
Wilson – Centertown 69 kV line	2012
Meade – Garrett 69 kV line reconductor	2012
Garrett – Flaherty 69 kV line project	2013
Riveredge 69 kV Transmission Service	2013
Maxon 69 kV service	2013
Wilson – KU Matanzas 161 kV line	2014
Paradise 161 kV reconductor from new tap point	2014
Buttermilk 69 kV Service	2014
Cumberland – Caldwell Springs 69 kV line	2014
Hancock County 69 kV mobile capacitor bank	2014
White Oak 161/69 kV substation addition	2015
Irvington Substation switching and metering	2015
Meade County 161/69 kV transformer replacements (2)	2015
KU Matanzus – New Hardinsburg/Paradise 161 kV tap line	2016
West Owensboro 69 kV reconductor	2016
KU Matanzas – New Hardinsburg/Paradise 161 kV tap line	2016
LAM2 Substation addition for 13.8 kV Service	2016
Hancock County-LAM-2 161 kV line addition	2017
Coleman EHV – Aleris 161 kV line additions (2 circuits)	2017
Centerview 69 kV service	2017

BREC's planned system additions for 2017 through 2031, exclusive of those for which it has requested confidentiality, are the Coleman-Coleman EHV 161 kV lines 1 and

[186] *Id.*, at 146.

2 upgrade, and the Coleman EHV – Duff (Vectren) 345 kV line addition, both of which are scheduled to be completed in 2020.[187]

Distribution System

BREC, a generation and transmission cooperative, provides energy to three distribution cooperatives. It does not own any distribution facilities.

INTERVENOR COMMENTS AND BREC'S RESPONSES

The Attorney General's Comments

The Attorney General recognized and commended the progress BREC has made since its last IRP in light of the loss of the 850 MW smelter loads and its adherence and achievements related to the recommendations made in the focused management audit and ordered in its last base rate case. The Attorney General suggested that BREC should continue following the recommendations. The recommendations, as they relate to the IRP, are the development of in-house expertise regarding price forecasting and MISO market knowledge to the extent that it supports BREC's core business; that it should keep the Wilson plant in operation while revisiting options for it in the next two to three years: study whether the sale, retirement, or redevelopment of the Coleman Station would be the best way forward; and that it should continue its pursuit of increased sales of existing and new load.[188]

The Attorney General recognizes the uncertainty surrounding the electric industry in general and particularly with respect to operations and environmental requirements. He agrees with BREC in taking a proactive approach in addressing these uncertainties by devoting resources to the planning group to focus on forecasting and modeling trends in the broader market. He understands that any environmental compliance plans cannot be finalized until there is more clarity with respect to existing and proposed environmental regulations. He maintains that BREC must ensure that any costs related to the Coleman Station, including depreciation expense, should be treated in such a way as to ensure that ratepayers are not burdened with paying exorbitant and unnecessary costs.[189]

The Attorney General would like to continue to see evidence that BREC is at least seriously evaluating the current market for different, diverse renewable resources and consider a long-term buildout of new renewable generation as an option, if and when it may be cost-effective to build.[190] Most importantly, the Attorney General urges BREC to continue to give due consideration to the overall state of its current generation fleet, and

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[187] *Id.* at 147.

[188] Attorney General's Comments at 2.

[189] *Id.* at 4.

[190] *Id.* at 7.

in moving forward, BREC should formulate a transparent plan to timely address findings and course of action with respect to its power plants that are currently idled.[191]

KIUC Comments

KIUC stated that when it moved to intervene in this proceeding, it had a number of concerns regarding the detail surrounding BREC's 2017 IRP. These included: 1) the status of the idled Coleman generating facility and environmental upgrades needed to restart that facility; 2) the impact of environmental and other costs surrounding BREC's long-term sales to the Nebraska utilities, Missouri municipal utilities, and to the Kentucky Municipal Energy Agency; 3) the financial implications of the retirement of the Coleman Station; and, 4) projected rate changes on native load customers, including assumptions about the disposition of the depreciation deferral.[192] BREC addressed these concerns in its June 21, 2018 response to KIUC's discovery request. On September 26, 2018, BREC submitted a Settlement Agreement, Stipulation, and Recommendation in Case No. 2018-00146 (Settlement) signed by BREC, KIUC and the Attorney General, which generally resolved the concerns raised by KIUC in this proceeding. Given the discovery responses and, more importantly, the pending Settlement, KIUC did not object to approval of BREC's 2017 IRP.[193]

Sierra Club Comments

The Sierra Club contends that BREC's IRP suffers from shortcomings similar to those that plagued its 2014 IRP in that it failed to openly and transparently evaluate the range of risks facing BREC or the variety of resource options for minimizing and responding to such risks.[194] In support of its claims, the Sierra Club states that the IRP is a flawed document that fails to satisfy the standards of Kentucky law for a number of reasons including:

- BREC's strategy of maintaining all the generation that it owns while attempting to acquire new non-member customers is costly for its captive customers;
- BREC continues to keep the Coleman Station and Reid Unit 1 idled, rather than retiring those plants, thus forcing its customers to cover the cost of maintaining capacity even though the significant cost of bringing that capacity back online makes it highly unlikely that BREC would ever do so;
- BREC's purported evaluation of whether to retire the Wilson and Green Plants was fatally flawed and biased in favor of continued operation of those plants;

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191 *Id.*

192 Comments of KIUC at 1.

193 *Id.*, at 1–2.

194 Sierra Club's Comments at 1.

- BREC failed to make a real effort to diversify its energy portfolio by dismissing renewable energy resources in its IRP after only a cursory consideration that relied on outdated information; and
- BREC has chosen to eliminate all of its EE and DR programs even though its own studies show that the programs provide additional savings for customers.[195]

The Sierra Club stated that until the shortcomings in BREC's IRP are remedied, the reasonableness of BREC's future actions relying on this resource planning is suspect, and the Commission Staff should find the IRP to be inadequate and require BREC to address these future shortcomings in all future resource planning and decision-making.[196]

The Sierra Club engaged Synapse Energy Economics, Inc. (Synapse) to review the reasonableness of the alternative resource assumptions used in BREC's modeling and the profitability of non-member contracts for short and long-term sales. Synapse found that BREC relied on unreasonably conservative cost assumptions for renewable resources and omitted battery storage and wind from the model altogether.[197] In addition, Synapse found that the revenue from some of the long-term contracts is not sufficient to cover the contract's share of system average fixed costs, and that continued reliance on short-term optimized sales will subject the utility to volatile and uncertain revenue streams that could fall short of covering the associated production costs.[198]

Southern Renewable Energy Association (SREA) Comments

SREA stated that BREC's IRP does not accurately evaluate wind or solar energy resources.[199] It maintains that BREC excluded all wind energy, tracking solar, battery storage, and power purchase agreement resources. SREA further maintains that BREC did not include an analysis with current federal incentives. As a result, SREA avers that BREC cannot definitively prove that its IRP results in the lowest possible cost. SREA requested that BREC incorporate its data regarding renewable energy metrics and re-run its analyses and that BREC issue a Request for Proposal for renewable energy to collect real world, directly relevant information for its planning purposes and potentially identify projects for procurement.[200]

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[195] *Id.* at 1–2.

[196] *Id.* at 2.

[197] Synapse Memorandum at 1.

[198] *Id.*

[199] SREA Comments at 16.

[200] *Id.* at 16–17.

Response to Recommendations in the 2014 IRP Staff Report

In its Staff Report on BREC's prior IRP in Case No. 2014-00166, Staff made the following recommendations concerning supply-side resources.

- BREC's next IRP should include scenarios where one or more existing coal-fired units are retired, converted to use alternate fuels, or sold.
- BREC should perform a utility-specific reserve margin study, as has been requested previously.
- BREC should continue to include consideration of renewable generation in its modeling and provide a discussion of its assessment of renewable power in its next IRP, especially when considering the future impact of GHG/carbon regulation and related costs per ton of CO_2.
- BREC should include a discussion of its consideration of distributed generation in its next IRP.
- BREC should provide information from its member-owner cooperatives on their customers' net metering statistics and activities in its next IRP.
- In its next IRP, BREC should continue to provide a detailed discussion of specific generation efficiency improvements and activities undertaken.
- The discussion in the next IRP of endeavors to increase generation and transmission efficiency should include the impact of the efforts instituted to comply with environmental regulations.
- A full and detailed discussion of compliance actions relating to current and pending environmental regulations should be included in BREC's next IRP.

In responding to the 2014 Staff Report recommendations, BREC provided the information summarized below, which is also noted and discussed in other portions of this report.

BREC's resource options in the 2017 IRP analysis included retirement, and/or natural gas conversion for several units as well as additional options that are listed in Table 7.1 of the IRP.[201] It has focused its efforts to enhance its replacement load as was recommended in the focused management audit as well as attracting new load within its service territory. As mentioned earlier in this report, BREC's Mitigation Plan is expected to replace much of the lost load as evidenced by the addition of a cumulative 500 MW of replacement load through 2019.

BREC did not perform a utility specific reserve margin as recommended in the 2011 and 2014 Staff Reports. Instead, BREC utilized the MISO reserve margin study for this IRP. BREC maintains that its tariff requires MISO to perform a study to determine a minimum amount of planning reserve requirements and that the uncertainty and cost of conducting a utility-specific reserve margin study outweighs the value of such a study.

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[201] *Id.* Appendix D, at 5.

As BREC has no additional generation needs through the 2031 planning period, the IRP includes no new generation sources, including renewable, cogeneration, non-utility, or distributed generation other than the seven solar arrays, which have been operating since mid-December 2017. BREC will continue to monitor judicial, executive, and legislative action. In the event the CPP is restarted, BREC will resume the task of developing a compliance plan commensurate with the rules included in in the regulation at that time.[202] BREC also modeled a scenario assuming Kentucky adopted a renewable portfolio standard.

With respect to distributed generation, BREC stated that its Members continue to see moderate growth in renewable energy production by net-metered PV generation.

Recent generation improvement activities include: operations training simulation for control room operators, reducing controllable losses, maintenance activities that focus on improving generation efficiency, control instrument tuning and optimization, and coal pulverizer tuning. BREC continues to monitor opportunities for transmission improvements and more efficient utilization of its existing facilities for power transmission. BREC completed an analysis of newly finalized environmental regulations and prepared an environmental compliance plan to achieve compliance within the time allowed by the regulation, which will bring all units, with the exception of the Coleman Station Units and Reid Unit 1, into compliance.

BREC addressed its options, plans and costs for environmental compliance in its Base Case and Sensitivities and Cost analysis. It will continue to monitor existing and proposed environmental regulation for compliance. In addition, it provided a discussion of compliance actions related to current and pending environmental regulations.[203]

Staff is generally satisfied with BREC's responses to its previous recommendations and the information provided in support thereof and believes BREC's responses adequately address those recommendations.

DISCUSSION OF REASONABLENESS

The 2014 Staff Report's discussion of reasonableness related to BREC's supply-side resource assessment pointed out that it would only be reasonable if its load replacement goals materialize. As previously mentioned, BREC has made significant progress to replace the load from the loss of the smelters and has made progress in enhancing its native load. During the 15-year period covered by this IRP, BREC will continue to have excess generation and can maintain an adequate reserve margin.

With respect to BREC's response to Staff's prior recommendation for a utility specific reserve margin, including BREC's position that a BREC utility-specific study

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[202] *Id.* at 6.

[203] *Id.* at 9.

would be expected to return results comparable with a MISO analysis, Staff agrees that such a study would be duplicative and, therefore, the cost of conducting a utility-specific reserve margin study outweighs the value of such a study.

Staff acknowledges the Sierra Club's concerns with respect to the idled Coleman and Reid Unit 1 cost assumptions and the SREC's comments regarding the lack of renewables utilized in the modeling of supply-side resources and the profitability of its short-term and long-term contracts.

RECOMMENDATIONS

Supply-Side Resource Assessment

An IRP should emphasize the strongest resource and business plan determined from a wide range of possible expectations from future scenarios. It seems reasonable that there might be scenarios presented by BREC where one or more existing coal-fired units are retired, converted to use alternate fuels, or sold.

- BREC's next IRP should continue to include scenarios where one or more existing coal-fired units are retired, converted to use alternate fuels, or sold.

Renewable Generation and Distributed Generation

BREC does not currently need additional generation; however, they may have customers such as industrial and commercial customers that desire access to renewable or low carbon generation in the future. BREC should provide information on any requests for renewable generation and distributed generation in the future. It should also include the following:

- Consideration of renewable generation to meet its customers' goals in its modeling and provide a discussion of its assessment of renewable power in its next IRP, especially when considering the future impact of GHG/carbon regulation and related costs per ton of CO_2.
- A discussion of its consideration of and costs associated with distributed generation in its next IRP.
- Information from its member-owner cooperatives on their customers' net metering statistics and activities in its next IRP.
- Current and accurate cost assumptions in its modeling for renewable resources.

Generation Efficiency

807 KAR 5:058, Section 8(2), requires that utilities describe and discuss all options considered for inclusion in an IRP, including improvements to and more efficient utilization of existing utility generation and transmission facilities.[204] In addition, the Commission in

[204] 807 KAR 5:058, Section 8(2)(a).

an earlier Administrative Case[205] specifically noted this requirement and directed the "jurisdictional generators to focus greater research into cost-effective generation efficiency initiatives and to include a full, detailed discussion of such efforts in subsequent IRPs in accordance with Section 8(2)(a)."

In its next IRP, BREC should continue to provide a detailed discussion of the following:

- Specific generation efficiency improvements and activities undertaken.
- Endeavors to increase generation and transmission efficiency should include the impact of the efforts instituted to comply with environmental regulations.

Compliance Planning

807 KAR 5:058, Section 8(5)(f), requires that utilities include a description and discussion of actions to be undertaken during the 15 years covered by the plan to meet the requirements of the Clean Air Act and amendments, and how these actions affect the utility's resource assessment. EPA had proposed a CPP, which BREC did not address in its IRP due to the court action that stayed the plan. The 2014 Staff Report recommended that BREC should develop a comprehensive list of options, plans, and costs to achieve compliance with existing, proposed, and anticipated environmental regulations in its next IRP.

As part of this IRP, BREC provided an explanation of new and pending environmental regulations and options for compliance as discussed earlier in this Section. Staff recognizes the uncertainty regarding the current and proposed environmental regulations. Staff notes that BREC is approaching compliance planning cautiously because some regulations are in litigation, some are not yet final, and the financial impact of any actions BREC may take could ultimately impact its planning for environmental regulation compliance. Staff takes this opportunity to reinforce the Commission's expectation that environmental planning is to be performed on a comprehensive basis, taking into account not only existing and pending regulations, but also modeling different environmental assumptions and evaluating the impact of such assumptions.

In its next IRP, BREC should continue to include a detailed discussion of the following:

- Compliance actions relating to current and pending environmental regulations.
- Address more fully the Sierra Club's comments regarding the Coleman Station and Reid Unit 1 regarding the cost assumptions and the SWEA's comments regarding renewables in the modeling for supply-side resources.

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[205] Case No. 2007-00300, *Consideration of the Requirements of the Federal Energy Policy Act of 2005 Regarding Fuel Sources and Fossil Fuel Generation Efficiency* (Ky. PSC Aug. 25, 2009) at 23.

SECTION 5

INTEGRATION AND PLAN OPTIMIZATION

PLANNING GOALS AND OBJECTIVES

BREC stated that it has a robust strategic planning process, which incorporates corporate strategic planning initiatives into all planning processes.[206] In preparing its Resource Assessment requirements for this IRP, BREC updated its load forecast, financial forecast, and DSM study as well as incorporating the recommendations made in the 2014 Staff Report. BREC's states that its mission is to safely deliver competitive and reliable wholesale power and cost-effective shared services desired by its Members-Owners.[207] Its strategic objectives are as follows:

- Continue BREC's emphasis on safety for employees, Member-Owners, retail member-consumers, contractors and the public;
- Focus on sales of available power and develop long-term, stable revenue streams;
- Maintain a strong balance sheet and appropriate debt service ratios;
- Continuously improve internal capability to perform integrated, complex financial and operational analytics in order to support good decision-making in a dynamic environment and oversee risk management activities;
- Continue emphasis on safe, reliable, and low-cost operations, maximize the economic value of existing assets, and evaluate cost-effective opportunities to increase portfolio diversity;
- Develop and execute plans to comply with existing and proposed environmental regulations while minimizing the associated costs;
- Safely and reliably operate the BREC system and enhance performance through adoption of leading practices, use of tiered metrics, and consistent benchmarking that allows gap-based business planning;
- Hire and retain top talent, develop employees and leaders for the future, manage performance, and plan for future retirements through training and succession planning;
- Provide cost-effective shared services desired by its Member-Owners;
- Work with its Member-Owners and key stakeholders to build relationships and manage expectations through open communications and engagement strategies;
- Complete the action items from the Commission-mandated focused management audit recommendations; and
- Resolve the issues associated with the HMP&L contract and the uneconomic operation of HMP&L Station Two generation units.[208]

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[206] IRP at 23.

[207] *Id.*

[208] *Id.* at 23–24.

THE INTEGRATION PROCESS

A resource assessment and acquisition plan was developed by BREC based on providing an adequate supply of electricity to meet forecasted energy requirements at the lowest possible cost over the 15-year planning horizon. As previously mentioned, in February 2015, BREC purchased Energy Exemplar's production cost modeling software *Plexos®* due to its vast production cost modeling capability. For the IRP modeling, the *Plexos®* LT Plan® develops BREC's optimal portfolio of energy resources and any future capacity.[209] The LT Plan® model uses advanced algorithms that analyze all possible portfolio options based on the inputs and constraints entered and provides the certainty of what and when to optimally invest or retire capacity resources.[210] The LT Plan® objective is to minimize the net present value of the production costs formulated as a mixed-integer problem. As discussed in Section 4 of this report, BREC developed its Base Case scenario using inputs, constraints and assumptions based on the best information available at the time the IRP was prepared and the analysis utilized the generation resource options also discussed in Section 4.

The LT Plan® model determines the least-cost option by utilizing the generation resources listed in Section 4. The 2016-2030 Long-Term Financial Plan includes environmental compliance with CCR and ELG assuming Green Station units and HMP&L Station 2 remain coal-fired. In the LT Plan® modeling for the Base Case and scenarios, costs have been entered for the generator resource options that include the existing generators and new generation resources and the LT Plan® in determining the least cost options inclusive of environmental strategy, as converting to gas, and/or retiring early and/or staying on coal.[211]

Base Case and Sensitivity Cases

The Base Case included: updated market power prices for energy and capacity; updated spot fuel prices for coal, natural gas and fuel oil; updated SEPA costs and power projections; and, updated load utilizing the 2017 load forecast. BREC's sensitivities included market energy prices, coal prices, natural gas prices, load forecasts, renewable portfolio standards, and a DSM scenario.[212] In addition, a scenario with the option to exit HMP&L Station Two contract beginning in 2018 was completed.

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[209] *Id.* at 106.

[210] *Id.*

[211] *Id.* at 108.

[212] *Id.* at 109–110.

BREC ran seven model scenarios with the descriptions and results that follow:

1. Market Energy Price Scenarios

In this scenario, market energy price LMP forecasts were modified by percentages higher and lower from the Base Case to see the impact those changes had on the results for determining the least-cost plan.[213] In the higher price scenarios, there were no changes to the least–cost option from the Base Case at 10 percent higher prices and HMP&L Station Two remained in operation using coal at 20 percent higher prices. In the lower price scenarios, both Green units were converted to natural gas at 10 percent and 20 percent lower prices.

2. Coal Price Scenarios

In this scenario, coal prices were modeled at higher and lower percent differences from the Base Case.[214] At 10 percent lower coal prices, there were no changes to the least-cost option. At 20 percent lower coal prices, BREC remains in the HMP&L Station Two contracts and those units would remain coal-fired. At 10 percent to 20 percent higher coal prices, both Green units would be converted to natural gas.

3. Natural Gas Price Scenarios

In this scenario, the delivered natural gas price forecast was modeled as a change from the Base Case scenario.[215] There were no changes to the least-cost option at 20 percent higher natural gas prices. At 10 percent lower natural gas prices, both Green Units would be converted to natural gas in 2020. In the additional scenarios where natural gas prices were 20 percent to 30 percent lower, there were no changes from the 10 percent lower natural gas prices in the least-cost option.

4. Load Forecast Scenarios

In developing its modeling for the load forecast scenarios, rather than modeling every load forecast scenario that was included in developing the load forecast, BREC modeled the extremes (the maximum and minimum) in the load forecasts.[216] There were four sensitivities provided from the Base Load Forecast: Optimistic Economy, Pessimistic Economy, Extreme Weather and Mild Weather, including the load impacts of its Non-Member load. In the minimum load forecast, BREC's native load was modeled at the pessimistic economy peaks and its Non--Member contracts are terminated at the end of the contracts. In the maximum load forecast, the contracts are forecasted to continue through 2031 although no new Member or Non-Member load beyond native load

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[213] *Id.* at 126.

[214] *Id.* at 128.

[215] *Id.* at 129.

[216] *Id.* at 131.

growth included in the optimistic economy load forecast was included for energy and peak demand.[217] Both the low load and the high load scenario results are the same as the Base Case.

5. Renewable Portfolio Standards Scenario

In this scenario, BREC's modeling assumed that Kentucky adopted a renewable portfolio standard where 15 percent of peak native load capacity is sourced from renewable resources by 2020, 20 percent by 2025 and 25 percent by 2030.[218] Only fixed solar capacity was modeled in the LT Plan®, which BREC stated that it was highly likely it would pursue under purchase power agreements.[219] In this scenario, BREC would build 100 MW of solar in 2020, 40 MW of solar in 2025 and 40 MW of solar in 2030.

6. Demand-Side Management Scenario

In this scenario, additional DSM programs were modeled as an economic resource in the Base Case, and then evaluated if additional DSM spending would provide a least-cost resource.[220] The DSM impacts were determined to be 14 years in length and forecasted EE savings were provided for an additional $1 million annual spend. Fourteen possible DSM projects were modeled in the LT Plan® that could be selected to provide a least-cost solution. The results of the modeling determined that additional DSM spending for any of the projects did not provide a least-cost solution with the base case inputs.

7. HMP&L Station Two Contract Scenario

In the Base Case scenario, the least-cost plan had BREC exiting the HMP&L Stations Two contract beginning in 2020, the earliest date BREC can contractually exit. When that constraint was removed from the model, the least-cost option resulted in exiting the contracts in 2018. As mentioned earlier in this report, the HMP&L Station Two units were retired at the end of February 2019.

In all scenarios, BREC modeled its worst-case estimated compliance cost for current environmental regulations including CSAPR, MATS, CCR, ELG and CWA Section 316(b) regulations.[221] By doing so, the LT Plan® modeled the least-cost option for compliance with the applicable regulations by evaluating whether existing generation resources should remain coal-fired, convert to natural gas or retire, or whether new generation resources should be constructed.

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[217] Id. at 132.

[218] *Id.* at 133.

[219] *Id.*

[220] *Id.* at 134.

[221] *Id.* at 139.

Overall Integration

BREC's optimal (least-cost) plan for the Base Case resulted in exiting the HMP&L Station Two contracts in 2020 with no changes to the other units' operation and with no new generation resources being built. The Reid CT was modeled as a generation resource with no other options, and the idled generators (Coleman Station and Reid Unit 1) were not included in the analysis. Throughout the planning period, BREC is long on generation capacity, even though it has had success in selling some of its excess capacity and will continue to look for additional opportunities for other Non-Member sales. For years beyond 2020, BREC's lowest reserve margin occurs in 2026 at 33.6 percent, and in 2031 the reserve margin is 65.0 percent.[222]

RESPONSE TO STAFF RECOMMENDATIONS FROM THE 2014 IRP

Staff made the following recommendations in the 2014 Staff Report for BREC's 2017 IRP:

- BREC's optimization and integration analysis should be broadened to include alternatives containing levels of replacement load other than the full amount of its planned replacement load.

In BREC's Long Term Load Forecast Report, both Executed and Projected Sales were included in the analysis. However, for purposes of the IRP, only Executed Sales are included in the analysis. The 2017 IRP Base Case includes Non-Member load for Nebraska Customers and KyMEA, which are contracts that had been executed at the time the 2017 IRP was filed. BREC also ran a sensitivity analysis on high load including internal load growth as anticipated in the Mitigation Plan, and Nebraska Customer and KyMEA load extended through the end of the analysis.[223]

BREC had a Market Potential Study performed for EE and estimated the potential savings over a 10-year period from the delivery of a portfolio of energy efficiency programs based on two funding scenarios: $1 million and $2 million incentive budget. In addition, its integration analysis included a DSM scenario where additional DSM programs were modeled as an economic resource to see if an additional $1 million in DSM spending would provide the least cost resource.[224]

DISCUSSION OF REASONABLENESS AND RECOMMENDATION

In summary, Staff is generally satisfied with the information contained in BREC's IRP integration and optimization plan. Staff is well aware of BREC's unique situation and commends its efforts to comply with the Mitigation Plan, its progress in developing in-

[222] *Id.* at 122.

[223] *Id.* Appendix D at 10.

[224] *Id.* at 11.

house expertise to address future planning and compliance issues, and its improvement in financial performance. Staff acknowledges the concerns of the intervenors and commentators in this case regarding the costs related to the idled units, renewable energy opportunities, and the cost of electricity to its customers. All other recommendations for BREC's next IRP filing, the timing of which will be determined by the Commission, are contained in Sections 2, 3, and 4 of this report.

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