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SEP 21 2017

PUBLIC SERVICE COMMISSION

September 21, 2017

VIA HAND-DELIVERY

John S. Lyons
Acting Executive Director
Public Service Commission
211 Sower Boulevard, P.O. Box 615
Frankfort, Kentucky 40602-0615

Re: *Big Rivers Electric Corporation's 2017 Integrated Resource Plan*

Dear Mr. Lyons:

Enclosed in connection with the 2017 Integrated Resource Plan ("IRP") of Big Rivers Electric Corporation are the following:

1. An original and ten (10) copies of petition for confidential treatment for portions of the 2017 IRP, along with one (1) sealed copy of the pages of the IRP that contain confidential information;

2. Ten (10) copies of the IRP with the confidential information redacted; and

3. One (1) additional, unbound copy of the IRP with the confidential information redacted.

Pursuant to 807 KAR 5:058 Section 2(2), by copy of this letter, Big Rivers hereby provides notice to the intervenors in its last IRP review proceeding, Case No. 2014-00166, that the 2017 IRP has been filed with the Public Service Commission and is available from Big Rivers upon request.

Big Rivers notes that, by order dated December 22, 2015, in Case No. 2014-00166, the Public Service Commission directed Big Rivers to file its 2017 IRP no later than September 21, 2017.

If you have any questions about this filing, please do not hesitate to contact me.

Sincerely,

Tyson Kamuf

TAK/abg
Enclosures

cc: Service List
Jeff Hohn
Marty Littrel
Dennis L. Cannon

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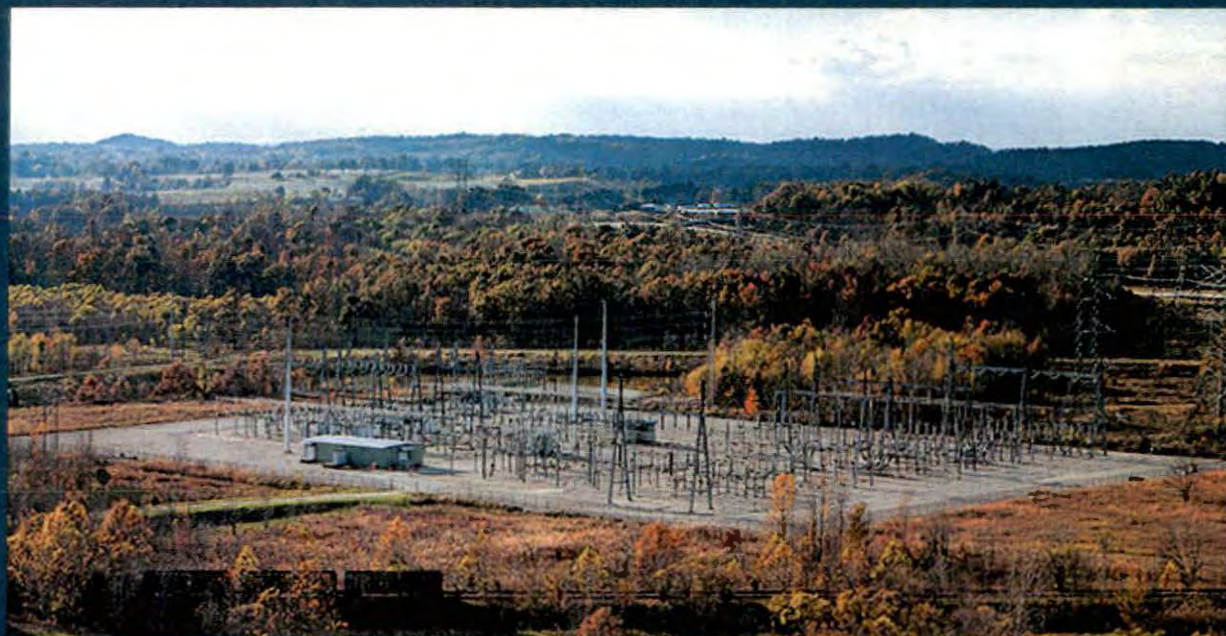


IRP Plan Summary

CHAPTER 1

1. IRP PLAN SUMMARY

1.1 Overview of 2017 IRP

This Integrated Resource Plan (IRP) is a road map for meeting Big Rivers Electric Corporation's (Big Rivers *or* the Company) mission to safely deliver competitive and reliable wholesale power to its Member-Owners.[1] It helps determine how Big Rivers will generate power in the future. Big Rivers utilizes a comprehensive, forward-looking decision support tool for evaluating resource options to meet company objectives at the lowest cost. The process considers supply and demand resource options, operating, fuel and purchased power costs, and technology costs associated with various resource plan outcomes. The electric utility industry is experiencing dynamic change at an accelerated pace, and one of the major drivers of change is the Clean Power Plan (CPP), a set of proposed Federal regulations limiting carbon emissions. Implementation of the CPP was expected in the coming years. However, the CPP is currently on hold, and because of the uncertainty of its disposition, as well as the changing energy marketplace, Big Rivers regularly reviews resource options. In addition to regular planning reviews, a triennial filing of an IRP is required by the Public Service Commission of Kentucky (Commission). This 2017 IRP is not to be considered a commitment to any specific course of action, but rather a plan that considers market conditions, load requirements, and legislation as of a certain point in time.

This 2017 IRP is provided to comply with Big Rivers' obligations under 807 KAR 5:058, to address the Commission Staff Report's recommendations on Big Rivers' previous IRP, and to give a comprehensive overview of Big Rivers' system and resource plans. It is grouped in logical sections to provide the reader with the information required by statute. A cross-reference table to the requirements of 807 KAR 5:058 is presented in Appendix C. A glossary of terms and acronyms used throughout this IRP are listed in Appendix I.

[1] Big Rivers' Mission Statement: "Big Rivers will safely deliver competitive and reliable wholesale power and cost effective shared services desired by our Member-Owners."

1.2 Introduction

Big Rivers filed its most recent IRP with the Commission on May 14, 2014, in Case No. 2014-00166[2] (2014 IRP). Commission Staff issued a report summarizing its review of Big Rivers' 2014 IRP on December 4, 2015, and recommended to the Commission a filing date of September 21, 2017, for Big Rivers' next IRP. The Commission, by order dated December 22, 2015, accepted the Commission Staff's recommendation for a September 21, 2017, file date, and closed Case No. 2014-00166.

This 2017 IRP was prepared by Big Rivers' staff, with the supporting inputs by GDS Associates, Inc. (GDS *or* GDS Associates) for load forecasting and Demand Side Management (DSM) analyses. The individuals responsible for preparation of this IRP and who will be available to respond to inquiries are listed in Table 1.1.

Table 1.1

2017 IRP Project Team

Company	***Name***	***Area of Expertise***
Big Rivers Electric Corporation	*Robert Berry*	*President and CEO*
	Mark Eacret	*V. P. Energy Services*
	Marlene Parsley	*Energy Services, Load Forecast*
	Russell Pogue	*Demand Side Management*
	Duane Braunecker	*Strategic Planning and Risk Management*
	Charles Jones	*Modeling*
	Jason Burden	*Power Production*
	Tom Shaw	*Environmental/Emissions*
	Chris Bradley	*Transmission*
	Chris Warren	*Finance*
	Roger Hickman	*Regulatory Affairs*
GDS Associates, Inc.	*Warren Hirons*	*Demand Side Management*
	John Hutts	*Load Forecast*

[2] *In the Matter of: The 2014 Integrated Resource Plan of Big Rivers Electric Corporation*, Case No. 2014-00166.

This 2017 IRP presents Big Rivers' resource plan for meeting projected power requirements through 2031. It presents the basis for the plan and the resulting actions Big Rivers will undertake with respect to meeting future load requirements through a portfolio of supply-side and demand-side resources. Supporting documents, figures, and tables are provided throughout this document and in the appendices, which are an integral part of the 2017 IRP.

The remainder of this chapter contains a description of Big Rivers and its planning goals and objectives, a load forecast summary of its generation and transmission assets, projected load growth, DSM[3] activities, and the resource plan developed to meet demand through 2031.

1.3 Description of the Utility

1.3.1 Overview

Big Rivers is a generation and transmission cooperative headquartered in Henderson, Kentucky. Big Rivers owns, operates and maintains electric generation and transmission facilities, and it purchases, transmits, and sells electricity at wholesale. It exists for the principal purpose of providing the wholesale electricity requirements of its three distribution cooperative Member-Owners; Jackson Purchase Energy Corporation (JPEC), Kenergy Corp. (Kenergy), and Meade County Rural Electric Cooperative Corporation (MCRECC) (collectively, the Members or Member-Owners). The Members, in turn, provide retail electric service to approximately 116,000 consumer-members located in all or parts of 22 western Kentucky counties: Ballard, Breckenridge, Caldwell, Carlisle, Crittenden, Daviess, Graves, Grayson, Hancock, Hardin, Henderson, Hopkins, Livingston, Lyon, Marshall, McCracken, McLean, Meade, Muhlenberg, Ohio, Union, and Webster. A map illustrating the Members' service territory is provided in Figure 1.1.

Big Rivers' wholesale rates applicable to its Members are shown in its current tariff, which is on file with the Commission. That tariff may be accessed from either the Commission's website (www.psc.ky.gov/tariffs/Electric/Big%20Rivers%20Electric%20Corporation/General%20Tariff.pdf) or

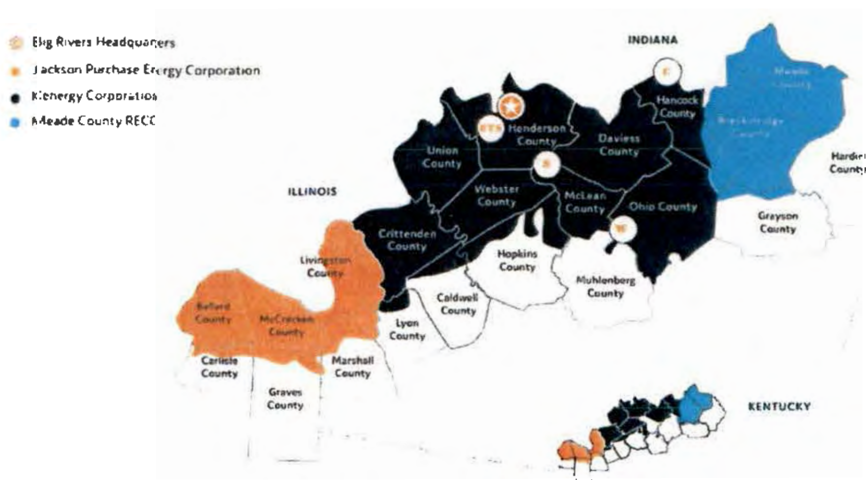
[3] In the context of Big Rivers' 2017 IRP, DSM is defined as all activities designed to impact electricity use, including demand response and energy efficiency programs.

from the Regulatory webpage of Big River's internet site (www.bigrivers.com/regulatory-affairs/). As shown in that tariff, these wholesale rates first became effective on February 1, 2014. There have been revisions to selected tariff sheets subsequent to that date. Specifically, Big Rivers modified its DSM tariff sheets effective September 11, 2015. Big Rivers also modified its Member Rate Stability Mechanism (MRSM) rider tariff sheets effective September 29, 2015, and it Fuel Adjustment Clause (FAC) rider tariff sheets effective October 30, 2016. On June 30, 2017, Big Rivers filed proposed changes to certain of its DSM tariff sheets, which are under review in Case No. 2017-00278.

Also on file with the Commission are Big Rivers' wholesale power contracts for select direct serve and non-system customers (www.psc.ky.gov/tariffs/Electric/Big%20Rivers%20Electric%20Corporation/General%20Tariff.pdf). Additionally, Big Rivers provides transmission and ancillary services to other entities under the Midcontinent Independent System Operator, Inc. (MISO) tariff.

Figure 1.1

Big Rivers' Members Service Area Map



1.3.2 Capacity Resources

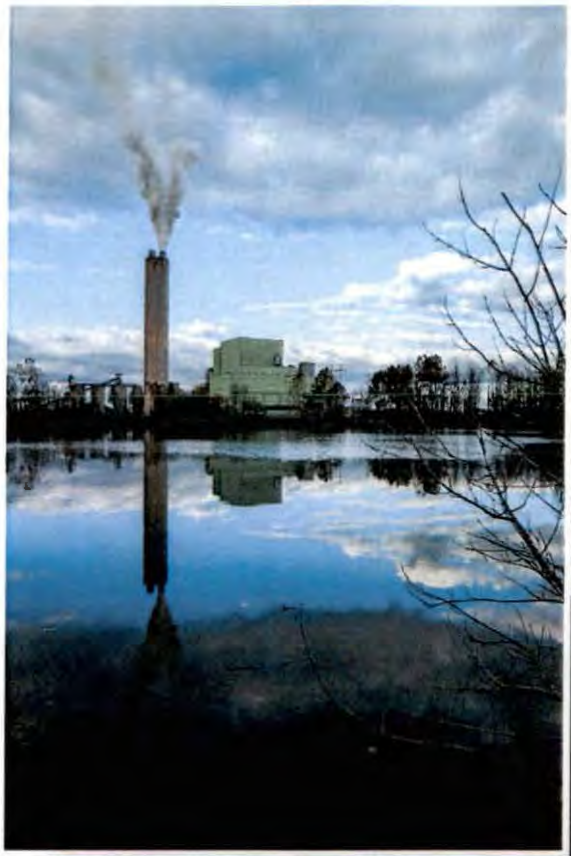
Big Rivers owns and operates the Robert A. Reid Plant (130 MW), the Kenneth C. Coleman Plant (443 MW), the Robert D. Green Plant (454 MW), and the D. B. Wilson Plant (417 MW), totaling 1,444 net MW of generating capacity. Total generation resources are 1,819 MW, including rights currently to 197 MW at Henderson Municipal Power and Light's (HMP&L) William L. Newman Station Two facility (HMP&L Station Two)[4] and 178 MW of contracted hydroelectric capacity from the Southeastern Power Administration (SEPA).[5] Force majeure conditions due to dam safety issues on SEPA's Cumberland River system have reduced Big Rivers' SEPA allotment to 154 MW, bringing Big Rivers' total generation capacity to 1,795 MW at the present time. Big Rivers expects the ongoing dam safety repairs to be completed and a return to full 178 MW capacity in 2019. Big Rivers began construction of seven small solar arrays totaling 120 kW direct current (dc), whose purpose is educational in nature, as described in Section 2.3. See Figures 1.2a through 1.2c for an overview of Big Rivers' generation facilities.

[4] HMP&L has the contractual right to increase or decrease its capacity reservation from HMP&L Station Two by up to 5 MW each year.

[5] In this analysis, both HMP&L load and generation are included. HMP&L has rights to 12 MW of SEPA capacity, which is assumed in this analysis to directly offset HMP&L load. Force majeure conditions on the SEPA system have reduced HMP&L's allocation to 10 MW.

Figure 1.2a

Generation Facility Overview



D.B. WILSON STATION

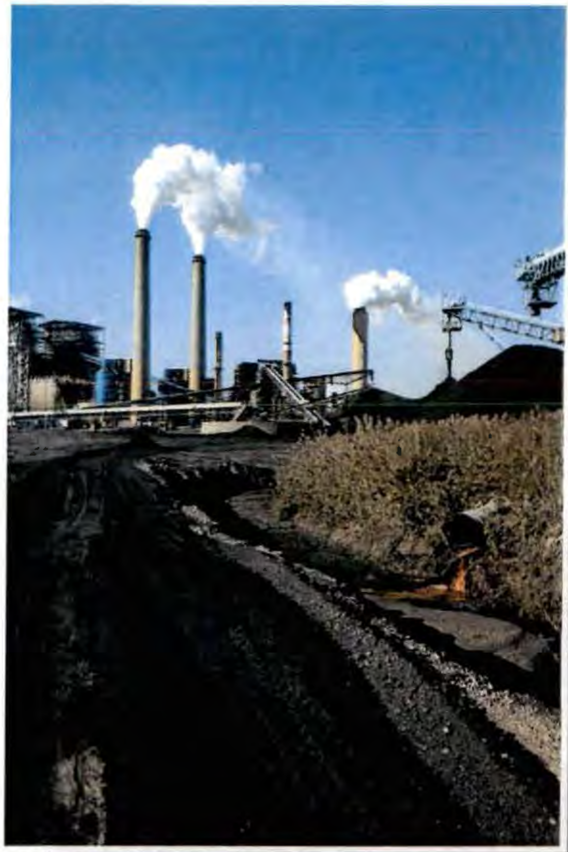
Wilson Station consists of a single, pulverized coal generating unit located near Centertown, Kentucky with a total rated generating capacity of 417 Net MW.

The Wilson Station includes:

- **Foster Wheeler boiler and Westinghouse turbine generator, commercialized in 1986.**
- **The flue gas desulphurization (FGD) system is a MW Kellogg horizontal flow wet limestone FGD. The FGD system consists of four horizontal limestone reagent absorbers with a designed sulphur dioxide (SO_2) removal rate of 90%.**
- **The electrostatic precipitator is designed to remove 99.87% of the particulate.**
- **The selective catalytic reduction (SCR) system is a Babcock Borsig delta wing design that uses catalyst and ammonia reagent to remove 90% of the unit's nitrous oxide (NOx) emissions.**
- **The Wilson plant has installed Dry Sorbent Injection equipment to control emissions in compliance with the U.S. Environmental Protection Agency's (EPA) Mercury and Air Toxics Standards (MATS) that went into effect on April 16, 2016.**

Figure 1.2b

Generation Facility Overview



SEBREE STATION

Sebree Station consists of three stations: the Robert D. Green Station, the Robert A. Reid Station, and HMP&L Station Two, with a combined net generating capacity of 896 MW. The facility consists of six units: four coal-fired and two with gas capabilities.

Robert D. Green Station:

- In 2015, Activated Carbon Injection (ACI) and Dry Sorbent Injection (DSI) systems were installed on the Green Units to control emissions in compliance with the EPA's MATS that went into effect on April 16, 2016.
- 231 MW Green Unit 1 has a B&W boiler and GE turbine/generator, commercialized in 1979.
- 223 MW Green Unit 2 has a B&W boiler and Westinghouse turbine/generator, commercialized in 1981.
- Pollution control includes an American Air Filter FGD system designed for 97% removal of SO_2. Precipitator removes 99.2% of particulate matter.

Robert A. Reid Station:

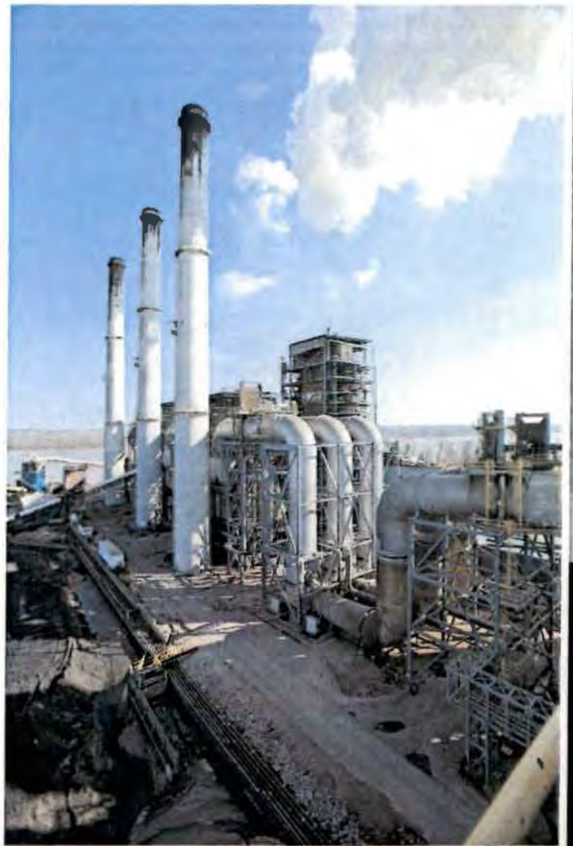
- As part of its 2012 Environmental Compliance Plan, Big Rivers planned to convert the coal-fired steam generating unit at Reid to burn natural gas, with construction expected to be completed during 2016. Due to economic reasons, Big Rivers has delayed plans to convert its Reid Unit 1 boiler to burn natural gas. Without the gas conversion, Reid Unit 1 is not compliant with MATS. Consequently, Big Rivers temporarily idled Reid Unit 1 in April 2016.
- 65 MW Reid Unit 1 has a Riley boiler and GE turbine/generator, commercialized in 1966. It has been retrofitted to partially burn gas for SO_2 and NOx control, and its precipitator removes 98.9% particulate matter.
- 65 MW Reid Combustion Turbine is a GE Frame 7C, commercialized in 1976. It was retrofitted in 2001 to burn natural gas in addition to fuel oil for SO_2 and NOx control.

HMP&L Station Two:

- The Station Two Units did not require additional control equipment to comply with MATS.
- 153 MW HMP&L Unit 1 has a Riley boiler and GE turbine/generator, commercialized in 1973. It was retrofitted with an FGD in 1995 for SO_2 control and an Alstom SCR in 2004 for NOx control.
- 159MW HMP&L Unit 2 has a Riley boiler and Westinghouse turbine/generator, commercialized in 1974. It was retrofitted with an FGD in 1995 for SO_2 control and an SCR in 2004 for NOx control.
- The SCR system is an Alstom design that uses catalyst and ammonia reagent to remove 90% of the unit's NOx emissions, the Wheelabrator FGD is designed to remove 92% SO_2, and the precipitator removes 99.4% particulate matter for both units.

Figure 1.2c

Generation Facility Overview



KENNETH C. COLEMAN STATION

Coleman Station consists of three pulverized coal generating units located near Hawesville, Kentucky and has a total generating capacity of 443 Net MW.

The Coleman Station includes:

- **150 MW Coleman Unit 1 has a Foster Wheeler boiler and Westinghouse turbine generator, commercialized in 1969.**
- **138 MW Coleman Unit 2 has a Foster Wheeler boiler and Westinghouse turbine generator, commercialized in 1970.**
- **155 MW Coleman Unit 3 has a Riley boiler and GE turbine generator, commercialized in 1972.**
- **The FGD system is a Wheelabrator Air Pollution Control design. This unique design combines the three generating units into a single FGD absorber that utilizes limestone as a reagent, and with forced oxidation, produces market grade gypsum. First operation occurred in February 2006, and it was commercialized in May 2007.**

1.3.3 Transmission System

Big Rivers owns, operates and maintains its 1,297 mile transmission system and provides for the transmission of power to its Members and third party entities served under the MISO tariff. A map of the transmission system is provided in Figure 1.3, and a more detailed map is provided in Appendix E. Discussion of Big Rivers' transmission planning is provided in Chapter 8.

Figure 1.3

Transmission System Map

Big Rivers Electric: System Map

Big Rivers ELECTRIC CORPORATION

[redacted]

1.3.4 Big Rivers' Load

Unless otherwise noted, references to total system energy and peak demand requirements in the 2017 Load Forecast are to Big Rivers' Members' native system, Big Rivers' Non-Member load, and HMP&L requirements.[6] Native system is the cumulative requirement of the Members' customer base load that Big

[6] See Appendix A, 2017 Load Forecast

Rivers is obligated to serve, and is the primary driver of load requirements. Non-Member load is defined as planned long-term load obligations that create value for Big Rivers' Members. Refer to Section 4.2.6 for more discussion of Non-Member load. Forecasts of HMP&L's aggregated peak demands and net energy for load were provided by HMP&L management in response to requests from Big Rivers for purposes of preparing the 2017 Load Forecast report.

Big Rivers categorizes native energy and peak demand into two classes: rural system and direct serve. The rural system is comprised of all retail residential, commercial, and industrial customers served by Big Rivers' Members, except for retail customers served under Big Rivers' Large Industrial Customer (LIC) tariff. Direct-serve customers are served under the Big Rivers' LIC tariff, which includes 20 large industrial customers in 2017. Approximately 90% of the accounts served by Big Rivers' Members are residential. A breakdown of actual energy sales for 2016 and projected sales for 2031 is presented in Figure 1.4.[7]

Figure 1.4

Class Energy Sales Proportions for Native Load

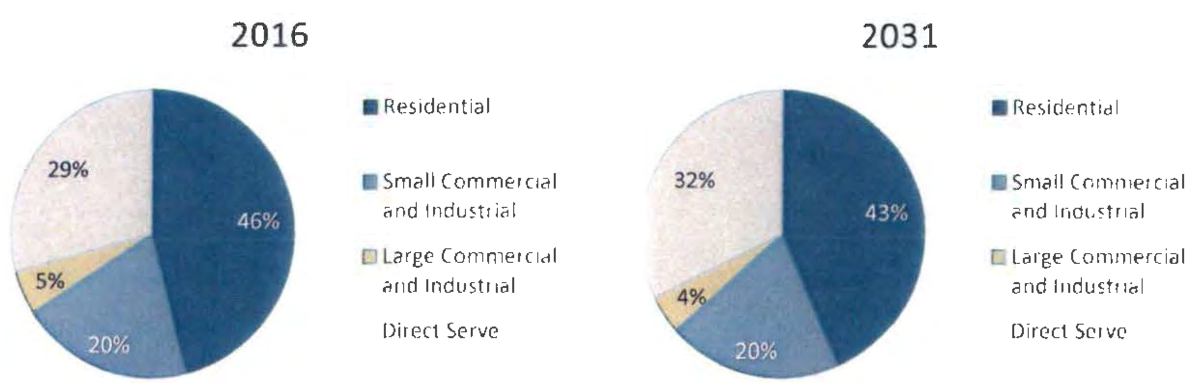


Figure 1.4 excludes Lighting and Irrigation classes which account for less than 1% total sales

[7] Requirements associated with HMP&L and Non-Member load are not reflected in Figure 1.4.

1.4 Planning Goals and Objectives

Big Rivers' primary planning goal in its 2017 IRP is to reliably and efficiently provide for its Members' electricity needs over the next 15 years through an appropriate mix of supply and demand-side options, at the lowest reasonable cost. Big Rivers has established the following planning objectives to guide its 2017 IRP process:

- Maintain a current and reliable load forecast,
- Continue to offer cost-effective 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.

1.5 Load Forecast Summary

Big Rivers' total system energy and peak demand requirements are comprised of its native system load, Non-Member load, and HMP&L load. Total requirements include transmission losses. Native system energy and peak demand requirements are projected to reach 3,544 GWH and 675 MW, respectively, by 2031. Annual native load projections are presented in Table 1.2. Refer to Section 4.2.6 for details on additional Non-Member sales included in the 2017 Long Term Load Forecast Report. Section 7.2.1 describes Non-Member load used in the IRP analysis. Chapter 4 and Appendix A provide detailed descriptions of the load forecast.

Table 1.2

2017 Big Rivers Load Forecast – Weather- Normalized Native System Requirements

	Energy Requirements (MWH)	*Peak Demand (MW)*
2012	*3,337,591*	*607*
2013	*3,403,524*	*639*
2014	*3,377,106*	*604*
2015	*3,333,037*	*623*
2016	*3,272,279*	*620*
2017	*3,258,532*	*635*
2018	*3,343,114*	*645*
2019	*3,432,508*	*658*
2020	*3,473,299*	*661*
2021	*3,474,891*	*662*
2022	*3,478,946*	*663*
2023	*3,481,017*	*664*
2024	*3,490,159*	*665*
2025	*3,495,398*	*666*
2026	*3,501,719*	*667*
2027	*3,508,814*	*669*
2028	*3,520,620*	*670*
2029	*3,526,010*	*672*
2030	*3,535,190*	*674*
2031	*3,544,285*	*675*

Shaded year represents base year
Values in this table include DSM impacts and distribution losses

Native system energy and peak demand requirements are projected to increase at average compound rates of 0.5% and 0.6%, respectively, per year from 2016 through 2031. Continued increases in appliance efficiencies, consumer energy conservation awareness, and [redacted] in the price of retail electricity are expected to dampen growth in native energy sales over the near term; however, increased sales to existing direct serve customers will have positive impacts on native sales over the near term. Big Rivers established a record native peak of 748 MW during the winter of 2014. Under normal peaking weather conditions, Big Rivers estimates that peak would have been 706 MW. Native peak requirements are projected to increase from 648 MW in 2017 to 691 MW (including transmission losses) by the summer of 2031.

Key Economic and Demographic Influences: The key influences on the load forecast include economic activity, increases in heating and cooling equipment efficiencies, energy conservation, changes in retail electricity prices, and the continued stable base of large industrial load. With respect to the economic and demographic influences, number of households and total non-farm employment influence projections of the number of rural system customers. Average household income is one of the key inputs in the residential energy model. The number of households, employment, and average household income are projected to show low to moderate growth over the forecast period and are contributing factors to projected low growth in number of customers and average energy consumption per customer over the next 20 years. Refer to Chapter 4 for additional information regarding the economic outlook.

The forecast reflects an increase in the nominal price of retail electricity to rural system customers. Retail price projections were developed for each Member and are represented in the forecasting models as the quotient of annual revenue and annual kWh, by customer class. Projected retail prices reflect changes in Big Rivers' wholesale power cost to Members and changes in distribution-system related costs at the Member level. The "all-in" average retail price at the Member level was projected to increase approximately 13% in 2017,[8] followed by [redacted].[9] For residential customers, the elasticity of energy consumption with respect to price is -0.21 and was derived using the regression models for each Member.[10] The forecast reflects no direct decreases in energy sales and peak demand for the small and large commercial classes resulting from price increases expected over the near term.

---

[8] Increase is due to the expiration of credits associated with the operation of Big Rivers' MRSM which offset a base rate increase approved by the Commission in Case No. 2013-00199.

[9] [redacted] are described in nominal terms for discussion purposes. Price is expressed in real, or deflated, terms in the forecasting models described in Chapter 4 of this report.

[10] Average elasticity for Big Rivers' three Members.

The forecast reflects impacts associated with changes in heating and cooling appliance market shares and increases in their respective efficiencies. Over the course of the forecast horizon, the market shares for both heating and cooling are projected to increase minimally. A combination of increases in electric appliance market shares and increases in appliance efficiencies is expected to produce essentially flat average consumption in electric heating and air-conditioning per household over the long term.

The forecast includes the impacts of existing and future DSM and energy efficiency (EE) programs. Impacts of existing programs are captured indirectly through the historical energy consumption data used in developing the forecasting models. The impacts of future program offerings are computed and captured in the load forecast as post-modeling adjustments. DSM programs are projected to reduce peak demand and energy consumption by 17 MW and 113,951 MWH between 2017 and 2031.

The large commercial class, including both rural and direct serve customers, currently represents approximately 34% of total system energy consumption. Energy and peak projections for this class include only those customers that are currently being served. Following anticipated growth over the near term, energy and peak are held constant at 2021 levels through 2031 in the base case forecast. The optimistic economy forecast scenario reflects growth for new industrial load.[11]

The key economic and demographic assumptions upon which the load forecast that was prepared through 2036 is based are summarized below and discussed in greater detail in Chapter 4.

- The number of households will increase at an average rate of 0.1% per year from 2016-2036.
- Employment will increase at an average rate of 0.8% per year from 2016-2036.
- Real gross regional product will increase at an average rate of 1.6% per year from 2016-2036.

[11] Historically, due to the unpredictability of economic development successes and the significant increase in load resulting from the addition of new customers, Big Rivers' projections of energy and peak demand for the large industrial class reflect the base historical year values adjusted for known and measurable changes in consumption for existing customers, and new growth corresponding to potential customers that have a high likelihood of being served in future years.

- Real average income per household will increase at an average rate of 1.7% per year from 2016-2036.
- Real retail sales will increase at an average rate of 1.0% per year from 2016-2036.
- Inflation, as measured by the Gross Domestic Product Price Index, will increase at an average compound rate of 2.0% per year from 2016-2036.
- Nominal retail price (no adjustment for inflation) charged by Members to their retail member-consumers was projected to increase 13% by 2017.[12] From 2017 to 2029, the price of electricity to rural system customers is projected to [redacted] resulting in a [redacted] in real price.
- Heating and cooling degree days for the service area will be equal to averages based on the twenty years ending 2016.
- The market shares for electric heating, electric water heating, and air conditioning will continue to increase throughout the forecast period, but at a declining rate as maximum saturation levels are approached.
- The average operating efficiencies of major appliances will continue to increase throughout the forecast period, but at a declining rate as maximum efficiencies are approached.
- Impacts of existing energy efficiency programs will increase during the forecast horizon and will impact both energy and peak demand requirements.

1.6 No Planned Resource Acquisitions

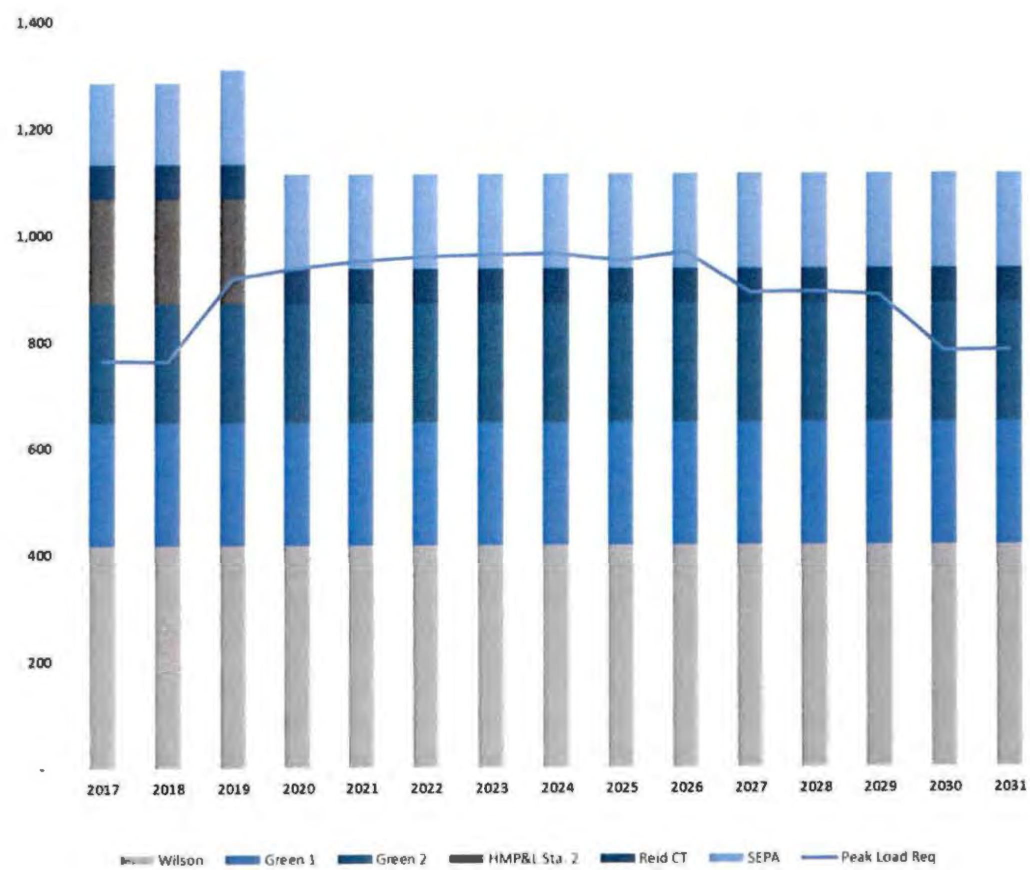
Big Rivers has no need for new capacity through 2031 to maintain an adequate reserve margin. In addition to existing capacity, Big Rivers has access to the wholesale power markets to buy and sell energy to maximize Member value and meet fluctuations in owned generation resource availability. Figure 1.5,

[12] Increase is due to the expiration of credits associated with the operation of Big Rivers' MRSM which offset a base rate increase approved by the Commission in Case No. 2013-00199.

below indicates projected capacity exceeding peak demand requirements through 2031, without the currently idled Coleman and Reid stations. This analysis includes native load and Non-Member sales that had been executed at the time of this IRP. See Section 7.2.2 Base Case Results and Chapter 11 Action Plan for details of changes in projected capacity.

Figure 1.5

Projected Capacity and Peak Demand Requirements (MW)



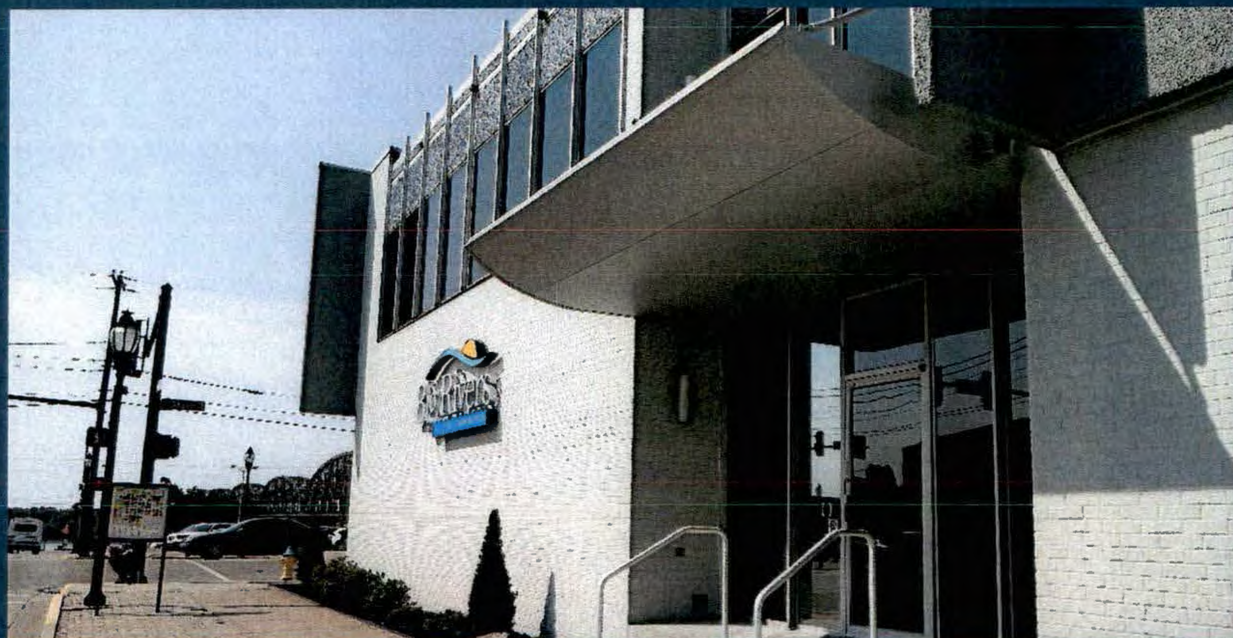
HMP&L Station Two capacity includes 197 MW Big Rivers contract capacity
SEPA Capacity includes up to 178 MW of Big Rivers capacity

1.7 Key Issues or Uncertainties

Big Rivers has completed an analysis of the newly finalized environmental regulations and has prepared a plan to achieve compliance within the time allowed by the regulations. One of the major drivers of change is the Clean Power Plan, a set of proposed Federal regulations limiting carbon emissions. The CPP is currently on hold, and because of the uncertainty of its disposition, as well as the changing energy marketplace, Big Rivers has suspended work on developing a strategy to comply with the CPP. In the event the CPP is restarted, Big Rivers will begin the task of developing a targeted compliance plan consistent with state and federal requirements.

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,
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.



Planning Process

CHAPTER 2

2. PLANNING PROCESS

Big Rivers has a robust strategic planning process which incorporates corporate strategic planning initiatives into all planning processes. To prepare the Resource Assessment required by this IRP, Big Rivers updated its load forecast, financial forecast, and DSM study. Additionally, Big Rivers incorporated the recommendations made by the Commission Staff in its report on Big Rivers' 2014 IRP. Appendix C of this IRP provides a cross-reference of those Commission Staff recommendations and this 2017 IRP, and Appendix D summarizes Big Rivers' responses to the recommendations. The results from these studies and Staff recommendations provided the inputs required to model the Big Rivers' system with respect to the integration of existing and future capacity resources.

2.1 Big Rivers' Strategic Plan

Big Rivers' mission is to safely deliver competitive and reliable wholesale power and cost-effective shared services desired by its Member-Owners. Big Rivers' strategic objectives are as follows:

- Continue Big Rivers' 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 Big Rivers 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 our Member-Owners;
- Work with our 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 (See Section 3.5); and
- Resolve the issues associated with the HMP&L contract [13]and the uneconomic operation of HMP&L Station Two generation units.

Figure 2.1

Big Rivers Values

[13] *In the Matter of: Application of Big Rivers Electric Corporation for a Declaratory Order*, Case No. 2016-00278.

Through a focused approach on maximizing Member value and maintaining long-term financial viability, Big Rivers continues to aggressively pursue its mission – providing the services to its Members for which it was created.

2.2 Load Forecast

The load forecast used in the 2017 Load Forecast analysis was completed in July 2017. Additional sensitivities to the 2017 Load Forecast were developed and included in this IRP process.

The 2017 forecast is developed using a "bottom-up" approach, as forecasts are developed individually for each of Big Rivers' three Members and aggregated to the Big Rivers level. Preliminary forecasts are presented to each of the Members for review and revision prior to development of the final Big Rivers forecast. Review meetings are held in person and via webinars.

The forecast is developed using both quantitative and qualitative methods. A series of econometric models are used to forecast energy consumption and peak demand for rural system customers.

Projections for large industrial customers are based on historical consumption and peak demand, combined with information received from the management of Big Rivers' Members regarding future plans and operations.

Big Rivers continuously reviews its load forecasting process and makes enhancements as new information and technologies become available. Big Rivers will continue to monitor industry advancements and best practices to enhance future forecast accuracy.

See Chapter 4 for further details of the 2017 load forecast methodologies.

2.3 Demand Side Management[14] Study and Renewable Energy

DSM measure lists were developed in an effort to address different customer classifications and end-use types. The measure list was restricted to DSM measures and practices that are currently commercially available. These are measures that are of most immediate interest to program planners.[15]

Significant detail is needed to estimate the average and total savings potential for individual measures or programs. Estimates of annual measure savings, costs, and useful lives were developed using various technical reference manuals (TRM), energy modeling software (BEopt), energy calculations, evaluation reports, and other secondary sources.[16] Program participation rates were developed using various data sources including building characteristic data from current Big Rivers' appliance saturation studies, U.S. Energy Information Administration (EIA) regional data,[17] and budgeting parameters, such as the level of incentives to be paid to retail member-consumers for installing energy efficiency measures through Big Rivers' DSM programs.

Big Rivers evaluates the cost-effectiveness of specific DSM measures when determining which DSM programs to implement. The net present value of costs vs. benefits is assessed, i.e., the costs to implement the measures are valued against the savings or avoided costs. The resultant benefit/cost ratios, or tests, provide a summary of the measure's cost-effectiveness relative to the benefits of its projected

[14] In the context of Big Rivers' 2017 IRP, DSM is defined as all activities designed to impact electricity use, including demand response and energy efficiency programs.

[15] About 100 individual measures were analyzed in the DSM portion of the IRP. After accounting for adjustments for different building types, housing characteristics and measures targeting space heating and cooling end-use, the number grew to exceed 200 measure permutations.

[16] TRMs: GDS relied primarily on the Illinois Technical Reference Manual. GDS also utilized the Mid-Atlantic Technical Reference Manual: http://www.neep.org/mid-atlantic-technical-reference-manual-v6.

BEopt: The BEopt™ (Building Energy Optimization) software provides capabilities to evaluate residential building designs and identify cost-optimal efficiency packages at various levels of whole-house energy savings along the path to zero net energy. BEopt can be used to analyze both new construction and existing home retrofits, as well as single-family detached and multi-family buildings, through evaluation of single building designs, parametric sweeps, and cost-based optimizations.

Energy Calculations: In some cases, GDS performed independent energy savings calculations using a variety of source data. GDS also relied on the various ENERGY STAR savings calculators that are provided on the ENERGY STAR Energy Efficient Products webpages: http://www.energystar.gov/certified-products/certified-products?c=products.pr_find_es_products. The DSM potential study provided in Appendix B provides a full listing of all energy savings assumptions and sources.

[17] https://www.eia.gov/consumption/commercial/data/2012/

load impacts. Measures were screened using the GDS Benefit/Cost Screening Model, which is an analysis tool designed to evaluate the costs, benefits, and risks of DSM programs and services.

The main criterion Big Rivers used to screen DSM measures was the Total Resource Cost (TRC) test. 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 (the "typical" California tests).[18] 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[19] are included in this test. Results are typically expressed as either net benefits or benefit-to-cost ratio.

The analysis performed to prepare this IRP represents the 2017-2031 timeframe, although the primary analytical focus for DSM programs is the first three years. This technique was used to concentrate on the near-term, while recognizing that course corrections due to evolving markets, technologies and regulations may be made along the way. A complete list of the DSM programs, their annual impacts and long-term savings potential are presented in greater detail in Section 5 of this IRP and in the DSM Potential Study provided in Appendix B.

Commission Staff included a comment on Big Rivers' 2014 IRP that Big Rivers should provide information from its Members on their customers' net metering statistics and activities in its next IRP. Big Rivers did provide detailed data through October 2016 to the Kentucky Energy and Environment Cabinet,[20] and Big Rivers' submission is summarized in Table 2.1.

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[18] http://www.epa.gov/cleanenergy/documents/suca/cost-effectiveness.pdf

[19] Administrative costs were included in the evaluation of the cost-effectiveness of the portfolio of programs. These costs were not included in the measure-level screening of specific technologies. This approach aligns with the EPA Guide for Conducting Energy Efficiency Potential Studies.
http://www.epa.gov/cleanenergy/documents/suca/potential_guide.pdf

[20] Full report is available at
http://energy.ky.gov/renewable/Documents/Kentucky%20Distributed%20Renewable%20Interconnections-2016.pdf

Table 2.1

Net Metering Statistics of Big Rivers' Members

Member-Owner	Renewable Resource (solar, wind, etc.)	Cumulative # of Net Metered Interconnections through October 2016	Cumulative Installed Net Metered Capacity through October 2016 (kW)
Total JPEC	Solar	12	141.2
Total Kenergy	Solar	14	127.3
Total MCRECC	Solar	12	45.0

Big Rivers' Members continue to see moderate growth in renewable energy production by net metered photovoltaic (PV) generation with a current generating capacity of about one third megawatt (dc). Provided federal subsidies are maintained, it is expected the growth will continue and even accelerate as the cost of PV construction falls.

Big Rivers is developing contract language for the first retail member-consumer owned PV generator larger than 30 kW, which will fall under Big Rivers' tariff sheet *Standard Rate-QFP-Cogeneration/Small Power Production Purchase Tariff-Over 100 KW* for renewable generation with capacity above 100 kW.

In late spring of 2017, Big Rivers began constructing seven small solar generation sites located in its Members' service areas. These arrays are solar demonstration projects and will provide education on PV generation to retail member-consumers and schools in the service areas. Two of the arrays are located on school grounds, one in a county park and the rest are located at Members' offices. The project will offer web access to cost and production data, and the public will be invited to visit the sites for a hands-on experience with the technology. As of the filing of this IRP, Big Rivers expects the arrays and web access to be operational before the close of 2017.

2.4 Resource Assessment

Big Rivers utilized Energy Exemplar's *Plexos*® production cost modeling software (See Section 7.1 for more information on *Plexos*®)

Changes since 2014 IRP

CHAPTER 3

3. CHANGES SINCE 2014 IRP

Since Big Rivers filed its 2014 Integrated Resource Plan (the 2014 IRP),[21,22] there have been some material events which impact the 2017 Integrated Resource Plan (the 2017 IRP). These material events include changes in Big Rivers'

- Load forecasts,
- Senior management and personnel development programs,
- Safety programs,
- Transmission system,
- Business plan development,
- Software,
- Strategic Planning and Risk Management Team,
- Resource plan, and
- Other regulatory events.

These changes, along with the results of a Commission-mandated Focused Management Audit[23] (Focused Audit) and other underlying assumptions impact the contents and analysis of this 2017 IRP.

3.1 Changes to Load Forecast

3.1.1 Load Forecasting Methodology

Since the 2014 IRP, Big Rivers has updated the load forecast methodology. In the load forecast supporting the 2014 IRP, energy use per customer for the rural system was projected by each Member using an econometric model. To enhance modeling, in the 2015 Load Forecast (the 2015 forecast),

[21] See *2014 Integrated Resource Plan of Big Rivers Electric Corporation*, Case No. 2014-00166. Filed May 15, 2014. Commission Staff Report dated December 4, 2014.

[22] See *Big Rivers Electric Corporation's Request for an Extension of Time to file its Next Integrated Resource Plan*, Case No. 2013-00034. Request filed by letter dated December 17, 2012. Commission Order dated January 29, 2013, granted extension from original due date of November 15, 2013, to May 15, 2014.

[23] See Section 3.5 for discussion of Focused Audit.

statistically adjusted end-use (SAE) models for each Member were developed to project Residential use per customer, and econometric models for each Member were developed to project Small Commercial use per customer. Additionally, in the 2015 Load Forecast, the methodology used to forecast rural system peak demand was changed from a load factor approach to econometric modeling. No significant changes were made between the 2015 and 2017 load forecasts with respect to methodology.

3.1.2 Updated Energy and Peak Demand Forecast

Since filing the 2014 IRP, Big Rivers commissioned GDS to prepare two formal load forecasts. Big Rivers updates its internal load forecast on a more frequent basis to meet MISO forecasting requirements and internal planning needs. Tables 3.1 through 3.3 present projected native system requirements from the 2014 IRP (which was prepared based on Big Rivers' 2013 Load Forecast), the 2015 Load Forecast, and the 2017 Load Forecast (the 2017 Forecast). Energy and peak demand requirements represent Big Rivers' native system load and exclude Non-Member and HMP&L requirements.

The growth rate in the number of customers has fallen slightly with each new forecast, due to the lower trend in historical growth and the lower outlooks in the number of projected households.

The forecast of total energy requirements was lowered in both the 2015 and 2017 forecasts. Total energy is a function of number of customers and energy use per customer, and both components were lowered in both forecasts. Average energy consumption has leveled in recent years due primarily to increases in appliance efficiencies and energy conservation. Consistent with the lowering of the energy forecasts in previous forecast studies, the projections of peak demand were also lowered.

Regarding Non-Member sales - due to Big Rivers' generating capacity in excess of native load needs, the 2017 Load Forecast report attached as Appendix A reflects plans for up to 501 MW of load and capacity for Non-Members in 2018. Non-Member load is comprised of Executed and Projected Sales of capacity and economic generation in excess of native load requirements. In addition to the Non-Member sales, economic energy will be sold in the MISO spot market with hedged prices where appropriate. Using a conservative approach, for 2017 IRP analysis purposes, only Executed Non-Member sales are included as described in Section 7.2.3.4.

In prior IRP analyses, Big Rivers' share of HMP&L Station Two was modeled as two units totaling 312 MW capacity, and HMP&L load was modeled as part of Big Rivers' load requirements. For this 2017 IRP, Big Rivers' share of HMP&L Station Two was modeled as a single 197 MW unit, excluding HMP&L's capacity reservation of 115MW, and HMP&L load is not included. This approach reflects HMP&L receiving the energy associated with the entire 115 MW reservation amount around the clock. See section 7.1.2 for more discussion of HMP&L Station Two generation resource treatment.

Table 3.1

Comparison of Projected Number of Customers

	Actual	*2014 IRP*	*2015 Load Forecast*	*2017 Load Forecast*
2005	*107,881*			
2006	*109,327*			
2007	*110,583*			
2008	*111,691*			
2009	*111,940*			
2010	*112,410*			
2011	*112,885*			
2012	*113,250*			
2013	*113,717*	*113,584*		
2014	*114,208*	*114,565*		
2015	*114,934*	*115,678*	*114,864*	
2016	*115,859*	*116,773*	*115,694*	
2017		*117,835*	*116,511*	*116,843*
2018		*118,838*	*117,529*	*117,809*
2019		*119,816*	*118,538*	*118,737*
2020		*120,804*	*119,523*	*119,781*
2021		*121,792*	*120,465*	*120,701*
2022		*122,754*	*121,386*	*121,568*
2023		*123,698*	*122,313*	*122,434*
2024		*124,602*	*123,206*	*123,299*
2025		*125,493*	*124,067*	*124,197*
2026		*126,386*	*124,910*	*125,044*
2027		*127,264*	*125,712*	*125,882*
2028		*128,156*	*126,511*	*126,786*
2029				*127,688*
2030				*128,589*
2031				*129,438*

Table 3.2

Comparison of Projected Native Energy Requirements (GWh)

	Actual	*Weather Adjusted*	*2014 IRP*	*2015 Load Forecast*	*2017 Load Forecast*
2005	*3,233*	*3,273*			
2006	*3,189*	*3,321*			
2007	*3,326*	*3,306*			
2008	*3,314*	*3,354*			
2009	*3,159*	*3,273*			
2010	*3,412*	*3,321*			
2011	*3,344*	*3,385*			
2012	*3,283*	*3,338*			
2013	*3,371*	*3,404*	*3,414*		
2014	*3,382*	*3,377*	*3,408*		
2015	*3,271*	*3,333*	*3,384*	*3,318*	
2016	*3,245*	*3,272*	*3,373*	*3,413*	
2017			*3,394*	*3,452*	*3,259*
2018			*3,416*	*3,469*	*3,343*
2019			*3,437*	*3,486*	*3,433*
2020			*3,460*	*3,496*	*3,473*
2021			*3,485*	*3,514*	*3,475*
2022			*3,511*	*3,536*	*3,479*
2023			*3,537*	*3,560*	*3,481*
2024			*3,562*	*3,581*	*3,490*
2025			*3,589*	*3,602*	*3,495*
2026			*3,616*	*3,624*	*3,502*
2027			*3,644*	*3,642*	*3,509*
2028				*3,669*	*3,521*
2029				*3,691*	*3,526*
2030				*3,714*	*3,535*
2031				*3,737*	*3,544*

Table 3.3

Comparison of Projected Native Peak Demand (MW)

	Actual	*Weather Adjusted*	*2014 IRP*	*2015 Load Forecast*	*2017 Load Forecast*
2005	*611*	*610*			
2006	*625*	*627*			
2007	*653*	*601*			
2008	*616*	*617*			
2009	*670*	*630*			
2010	*662*	*616*			
2011	*657*	*639*			
2012	*660*	*618*			
2013	*615*	*639*	*655*		
2014	*748*	*698*	*658*		
2015	*697*	*664*	*660*	*661*	
2016	*617*	*620*	*663*	*683*	
2017			*669*	*691*	*648*
2018			*673*	*693*	*660*
2019			*678*	*695*	*673*
2020			*683*	*697*	*676*
2021			*689*	*701*	*678*
2022			*695*	*704*	*679*
2023			*701*	*707*	*680*
2024			*707*	*711*	*681*
2025			*713*	*715*	*682*
2026			*719*	*720*	*683*
2027				*724*	*685*
2028				*729*	*686*
2029				*734*	*688*
2030				*740*	*689*
2031				*745*	*691*

3.2 Senior Management and Personnel Development

Big Rivers' workforce has long been the very cornerstone of its success. In order to ensure that continues, in 2015, Big Rivers implemented its first-ever long term People Strategy with a focus on Performance Management, Individual Development, Employee Wellness, Employee Engagement and the hiring, development and retention of top talent in the organization. Big Rivers has also implemented some top management changes since 2014, bringing added skills, knowledge, and experience to overcome challenges and exceed expectations. In July 2014, Robert W. (Bob) Berry became the 12th person elected as President and Chief Executive Officer (CEO) at Big Rivers, replacing Mark A. Bailey who served in those capacities from 2008 until retiring in 2014. Also in 2014, Lindsay N. Durbin (formerly Barron) replaced Billie J. Richert as Chief Financial Officer, and Michael W. (Mike) Chambliss replaced David G. Crockett as Vice President System Operations. In 2015, Mark J. Eacret joined Big Rivers as Vice President Energy Services, and Michael T. (Mike) Pullen became Vice President Production.

In addition, Big Rivers is making a substantial investment in its employee knowledge base. The Company is focused on helping its current leaders excel, while providing its future leaders with the industry experience and leadership training necessary to succeed. In 2016, Big Rivers, in partnership with Western Kentucky University, launched a number of new corporate education programs, including a Supervisor Development Program and a Management and Leadership Program. Big Rivers is also cultivating relationships with its Members, having created a Cooperative Leadership Program in 2016 to foster better communication, industry experience, and talent development across the system.

3.3 Safety Programs

Big Rivers' Board, management and union are committed to a safety-focused culture in which ALL employees are personally involved and responsible, for not only their own personal safety, but also the safety of others. Management places "SAFETY" above all other Big Rivers' core values; therefore, safety is the foundation for all decisions and expectations of Big Rivers' work force. Senior management, along with other Big Rivers employees, participate in a Monthly Safety Leadership Team meeting to discuss Big Rivers' safety performance, review incidents, and discuss needed changes/improvements in the Company's safety performance or policies.

Big Rivers continues to assist its Member-Owners regarding communication and education within their respective communities pertaining to electrical safety and responding to community requests for electrical safety information. Big Rivers hosts an annual Contractor Safety Kick-Off Meeting to promote the philosophy that everyone who works at Big Rivers' facilities is expected to maintain safety awareness and work safely. The ideal result of an involved, committed work force is ultimately, no personal injuries or death.

Following are safety achievements over the past years:

- Forty-three Governor's Safety and Health Awards from Kentucky Labor Cabinet, each award based on number of hours worked without experiencing a lost-time injury;
- One year or greater no lost-time incidents Company-wide in 2017:
  - Coleman Station: 11 years,
  - Transmission: 7 years,
  - Sebree Station: 6 years,
  - Headquarters: 6 years, and
  - Wilson Station: 1 year;
- Headquarters employees have worked one year without a recordable incident;
- Transmission employees have worked two years without a recordable incident;
- Wilson Station employees have worked one year without a recordable incident;
- Coleman Station employees have worked three years without a recordable incident; and
- 2016 Kentucky Employers' Mutual Insurance Destiny award for Big Rivers' commitment and success in maintaining a safe workplace.

3.4 Transmission

Big Rivers now maintains an extensive network of 1,297 miles of transmission lines and 24 substations. The Company has completed various upgrades that are expected to improve reliability for its Members. This includes the launch of innovative and automated technology in 2016 to further enhance Big Rivers' ability to respond to outages through the use of Automatic Restoration and Sectionalization (ARS) schemes. ARS will automatically shed any unneeded transmission line sections in an attempt to expedite the sectionalization of a 69 kV circuit that is experiencing an outage and quickly reenergize the rural or industrial delivery point substations. As an example, an ARS installation in Daviess County will automatically isolate three different transmission line sections totaling 23 miles of line in an attempt to quickly restore all substations. ARS will also automatically transfer a distribution substation that is experiencing an outage from a locked out transmission circuit to that substation's backup transmission circuit. These self-healing concepts are preprogrammed within the Big Rivers Energy Management System (EMS).

In 2016, the SERC Reliability Corporation (SERC) completed a comprehensive audit of Big Rivers' compliance with North American Electric Reliability Corporation (NERC) Planning Standards, Operating Standards, and Critical Infrastructure Protection (CIP) Cyber Security Standards. The audit was very successful with many positive observations noted by the SERC audit team.

Big Rivers, in partnership with LS Power and Hoosier Energy, secured MISO's first competitive transmission project in 2016. As part of this Duff-Coleman Extra High Voltage (EHV) 345 kV project, Big Rivers and its partners will implement, own, and operate a new transmission line extending approximately 31 miles from Big Rivers' Coleman EHV substation in Hancock County, Kentucky, to Dubois County, Indiana. The proposal designed by Big Rivers and its partners provided the best balance of high-quality construction, costs, operations, and maintenance. Big Rivers was honored by MISO's selection of this innovative project. Big Rivers will own and operate the Kentucky portion of the project. Engineering and design for this project began in 2017. Construction will commence once all relevant regulatory approvals are received, including any necessary approvals from the Commission. The project currently is scheduled to be in service sometime in 2021. MISO and the PJM Interconnection (PJM) have both approved a proposal by American Electric Power (AEP) to loop the circuit through the existing Rockport substation, potentially creating a Duff (Vectren/MISO) to Rockport (AEP/PJM) to Coleman EHV (Big Rivers/MISO) 345 kV circuit.

3.5 Focused Management Audit

In 2013, one of Big Rivers' two large smelter customers left Big Rivers' system. In 2014, the second smelter exited Big Rivers' system. The combined load of the two smelters was approximately 850 MW. Prior to the smelters' departures, Big Rivers developed and finalized a Load Concentration Analysis and Mitigation Plan (Mitigation Plan) as part of its risk management strategy. Big Rivers' Mitigation Plan outlined actions that Big Rivers might take to mitigate the rate impact of the lost smelter load on Big Rivers' Members. These actions included, among other things, seeking rate increases, marketing excess power on a short-term, mid-term, and long-term basis when market prices were favorable, evaluating bilateral sales agreements and wholesale power contracts, expanding existing load on Big Rivers' system, and attracting new industrial load to Big Rivers' service territory as well as reducing costs and optimizing existing assets.

The findings and final action plan of the Focused Audit[24] were issued in 2015, and generally confirm Big Rivers' past decisions and future plans as outlined in the Mitigation Plan. The Focused Audit was initiated by an order of the Commission,[25] and Big Rivers' leadership team and employees invested a great deal of time and effort in working with the auditors to ensure they had an accurate picture of the Company's past, present and future operations. The auditors noted twenty-three findings, many of which were positive or neutral toward Big Rivers' efforts, and only five recommendations. Of these recommendations, three are relevant to the development of this 2017 IRP:

- **Recommendation 2:** Based on finding 8, Big Rivers should continue to develop in-house expertise in terms of price forecasting and MISO market knowledge to develop more informed price forecasts, but only to the degree that it supports Big Rivers' mission and core business.
- **Recommendation 3:** Based on findings 20 and 21, Big Rivers should commence a study on the sale, retirement, or redevelopment of the Coleman facility, maintain the optionality around Wilson at this time, and revisit strategic options for the facility in the next two to three years.
- **Recommendation 4:** Based on Finding 22, Big Rivers should continue to pursue increased sales to existing and new load, including new members.

By fall 2014, Big Rivers was increasing the Company's in-house expertise regarding the MISO market, pursuing new energy sales, and analyzing the best use of the currently-idled Coleman Station. Most importantly, the Focused Audit's final report highlighted Big Rivers' mitigation successes. As of the filing of this 2017 IRP, Big Rivers has completed Recommendations 1 and 4, and continues to pursue

[24] Big Rivers Management Audit Report and Big Rivers Action Plan are available at http://psc.ky.gov/PSC_WebNet/Static_Presentations.aspx

[25] See *Application of Big Rivers Electric Corporation for a General Adjustment in Rates*, Case No. 2013-00199. Commission Order dated April 25, 2014

increased sales to existing and new load, as explained more fully in Section 4.2.6 "Non-Member Load." Recommendations 2, 3, and 5 are ongoing.

3.6 Big Rivers Business Plan Development

The Mitigation Plan, which was thoroughly analyzed and reviewed by the Commission, has evolved into a Business Plan, which is a dynamic process strategically leveraging Big Rivers' assets to achieve its mission to safely deliver competitive and reliable wholesale power and cost-effective shared services desired by its Member-Owners. Consistent with its Business Plan, and as Big Rivers has reported in response to Focused Audit Recommendation 4, Big Rivers continues to expand power marketing efforts across the Commonwealth and the country, securing short-term and long-term contracts for its excess energy. As a result of Big Rivers' Business Plan, the Company has been selling economic energy in the MISO day-ahead market at least partially hedging the price that the Company would realize using financial and physical instruments. In fact, the Wilson Unit has remained on line supported by economic sales, while market prices have not yet improved sufficiently to support returning Coleman to operational status since its idling in May 2014.

Also, Big Rivers has successfully negotiated and received Commission approval to execute wholesale full requirements purchased power contracts with entities in the State of Nebraska through 2026;[26] to provide a block of dispatchable power to nine communities which are members of the Kentucky Municipal Energy Agency (KyMEA) for ten years;[27] to sell capacity to the cities of California, Centralia, Hannibal, Kahoka, and Marceline in Missouri for three years;[28] and to sell a block of capacity to a national power marketer for six years.

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[26] See *Big Rivers Electric Corporation Filing of Wholesale Contracts Pursuant to KRS 278.180 and 807 KAR 5:011 §13*, Case No. 2014-00134.

[27] See *Filing of Agreement for the Purchase and Sale of Firm Capacity and Energy between Big Rivers Electric Corporation and the Kentucky Municipal Energy Agency*, Case No. 2016-00306. Commission Order dated December 12, 2016.

[28] See Big Rivers Electric Corporation Contracts at http://www.psc.ky.gov/Home/Library?type=Tariffs&folder=Electric.

The Company has also been successful in working with existing industrial customers to expand their respective loads. In April 2015, Big Rivers requested, and the Commission granted in August 2015, a Certificate of Public Convenience and Necessity (CPCN) to construct two 161-kV transmission lines in Hancock County, Kentucky.[29] These transmission lines, completed in July 2017, accommodate the expansion of a large industrial customer of one of Big Rivers' Members. Projects like these further stabilize Big Rivers' revenue and help ensure competitive rates for Big Rivers' Members.

3.7 Software

The 2014 IRP analysis was performed by GDS Associates, with oversight by Big Rivers' personnel. In this 2017 IRP, the recently re-organized Strategic Planning and Risk Management Department is leveraging Energy Exemplar's *Plexos®* production cost modeling software to capture all the costs of operating Big Rivers' fleet of generators, and to minimize costs by simulating the market on a forward basis. *Plexos®* is economic software that uses mathematically based optimization techniques for forecasting, and is used world-wide in the electric industry for planning. See Chapter 7 for more information on *Plexos®*.

3.8 Strategic Planning and Risk Management Team

In the fall of 2014, Big Rivers embarked on revamping and restructuring the Strategic Planning and Risk Management Department, which included an initiative to move production cost modeling in-house. This in-house team performed the analysis supporting this IRP. The restructuring of the department resulted in a four-person team listed below with the major duties of each position.

1. **Director Strategic Planning and Risk Management**

   Reports to Chief Financial Officer (CFO)

   Major Duties:

   - Directs and oversees the strategic planning function in support of Big Rivers' short- and long-term goals and business objectives.
   - Responsible for modeling team and in-house production modeling that will provide insights to improve operational efficiencies, drive corporate strategic decisions and provide understanding of scenario impacts on corporate financial metrics and Member-Owners' rates.

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[29] See *Application of Big Rivers Electric Corporation for a Certificate of Public Convenience and Necessity to Construct Two 161 kV Transmission Lines in Hancock County, Kentucky*, Case No. 2015-00051. Commission Order dated August 4, 2015.

- Responsible for further developing, maintaining and managing Big Rivers' organizational risk management program.

2. Manager Financial Planning and Analysis

Reports to Director Strategic Planning and Risk Management

Major Duties:

- Responsible for managing and overseeing all activities associated with financial forecasting and analysis.
- Oversees and is responsible for the reliability of the financial model data and outputs.
- Develops and maintains an understanding of current accounting rules and regulations, Rural Utilities Services (RUS) guidelines, Commission Orders, and utility best practices to ensure these are properly incorporated in the financial modeling of corporate operations.
- Works closely with Manager Generation Planning and Analysis to provide scenario analysis in support of management decision making needs of the Company.

3. Manager Generation Planning and Analysis

Reports to Director Strategic Planning and Risk Management

Major Duties:

- Responsible for managing and overseeing all activities associated with production cost model forecasting and analysis (both in-house models and models by third parties).
- Oversees and is responsible for the reliability of all activities associated with production cost modeling and analysis.
- Develops and maintains an understanding of current environmental regulations and utility best practices to ensure they are properly incorporated in the production cost model.
- Works closely with Manager Financial Planning and Analysis to provide scenario analysis in support of management decision making needs of the Company.

4. Risk Analyst

Reports to Director Strategic Planning and Risk Management

Major Duties:

- Assists the Director Strategic Planning and Risk Management with identification, planning and execution of Big Rivers' strategic planning activities.
- Assists in the continued development and maintaining Big Rivers' risk management program.
- Ensures the review, update and communication of Board policies, as well as assisting with policy compliance monitoring to ensure risk mitigation for the organization.
- Provides input and support to the strategic planning and analysis team.

3.9 Resource Plan

Big Rivers undertook a multimillion dollar renovation at two generating facilities to comply with MATS prior to its April 2016, compliance date. The Commission approved these projects as part of Big Rivers' 2012 Environmental Compliance Plan application.[30]

Since developing its 2014 IRP Base Case, Big Rivers idled its Kenneth C. Coleman Station Units 1, 2, and 3, representing total capacity of 443 MW, in May 2014.[31] Big Rivers idled its 65 MW Robert A. Reid Unit 1 in April 2016. Both stations were idled for economic reasons. On September 28, 2016, MISO notified Big Rivers that it was terminating the interconnection service for Coleman Station, effective September 1, 2016. On November 4, 2016, Big Rivers requested a waiver, or in the alternative, filing a complaint for the Federal Energy Regulatory Commission (FERC) to continue interconnection service.[32] At the time of Big Rivers' filing its 2014 IRP, MISO had temporarily disallowed the SEPA Cumberland River hydropower system as a qualifying capacity resource until the ability to schedule energy was reinstated. At the time of the 2014 IRP filing, Big Rivers anticipated return of full scheduling capability for SEPA's Cumberland River hydropower beginning in 2015. In a June 17, 2014, letter, SEPA issued Revised Interim Operation and Marketing Changes, effective July 1, 2014, for the Cumberland System of Projects. That letter described the issues that had restricted operations, including dam safety concerns at the Wolf Creek and Center Hill dams in the Cumberland System. As of this 2017 IRP, repairs to Wolf Creek had been completed. However, in light of the continued dam safety work at Center Hill, SEPA staff formulated a Revised Interim Operations Plan which reduced Big Rivers' allocation of dependable capacity from 178 MWs to 154 MWs, and annual firm contract year energy from 267,000 MWH to 222,500 MWH.

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[30] See *In the Matter of: 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*, Case No. 2012-00063. Commission Order dated October 1, 2012.

[31] Big Rivers filed its 2014 IRP on May 15, 2014. Big Rivers idled the last of the three Coleman Station units on May 8, 2014.

[32] Docket No. EL17-15-000 Request for Waiver, or in the alternative, complaint of Big Rivers Electric Corporation requesting continuation of Interconnection Service. On April 3, 2017, FERC granted rehearing for further consideration in that case, and on September 5, 2017, Big Rivers filed a motion to clarify the record on rehearing. That case is still pending at the time of filing this 2017 IRP.

Big Rivers' generation facilities have also garnered positive attention on the national level, with HMP&L Station Two winning Top Performer and Big Rivers' D.B. Wilson Station earning Runner-Up for their respective power plant categories in the Navigant Generation Knowledge Service (GKS®) Operational Excellence Awards. This accomplishment in 2015 highlights the high standard of operation and cost-efficiency of the Company's power-producing resources, and marks its fifth Navigant GKS® Operational Excellence Award company-wide in the last four years.

3.10 Other Regulatory Events

Prior to the filing of this 2017 IRP, Big Rivers filed two general rate applications, one in 2012 and the other in 2013. The Commission approved approximately 73% of Big Rivers' original request for increase in the 2012 case,[33] and granted about 51% of Big Rivers' request in the 2013 case, although consideration of a portion of Big Rivers' requests in both cases was deferred.[34] Moreover, in the 2013 case, the Commission approved with certain modifications Big Rivers' plan to utilize reserve funds that were established in 2009 to entirely offset the impact of the Commission-approved electric rate increase; these funds provided a full offset until the summer of 2016 for residential consumers, and until September 2015 for commercial consumers. Moving forward, margins from the long-term contracts with several Nebraska utilities may also be returned to Big Rivers' Members through its MRSM tariff currently on file with the Commission.

Since the filing of Big Rivers' 2014 IRP, the Commission has conducted semi-annual and biennial reviews of Big Rivers' FAC and Environmental Surcharge (ES) tariffs. Those reviews have resulted in no changes to the application of the FAC and ES with the exception of Commission-approved FAC agreements with

[33] See *Application of Big Rivers Electric Corporation for a General Adjustment in Rates*, Case No. 2012-00535. Commission Order dated October 29, 2013.

[34] See *Application of Big Rivers Electric Corporation for a General Adjustment in Rates*, Case No. 2013-00199. Commission Order dated April 25, 2014.

intervening parties.[35] The Commission has also approved Big Rivers' continued use of a base fuel cost of $.020932 per kWh.[36,37]

In November 2016, Big Rivers filed a request for a declaratory order with the Commission to construct seven solar power facilities.[38] These facilities will be located across Big Rivers' service territory at Big Rivers' Members' offices or at third parties served by a Big Rivers Member, including one middle school and one high school. As noted in testimony accompanying the application, these arrays are educational and demonstration projects to "demonstrate how the various components that make up the solar arrays operate to produce and deliver electricity to the Members' retail members. Both students in the Members' service areas at which arrays are located and the general public will be able to visit the sites and view related cost, weather and production data from the solar arrays. Big Rivers will provide this information on-line. As such, the arrays will also serve an educational purpose. These arrays will not replace, and are not a material supplement to, any of Big Rivers' existing generation."[39] On March 30, 2017, the Commission issued its Order approving Big Rivers' request and directing the Company submit certain post-case documentation. Big Rivers made its initial such post-case filing on June 30, 2017. As of the filing of this 2017 IRP, construction of these solar arrays continues with an expected completion before the end of 2017.

Finally, on June 30, 2017, Big Rivers made a tariff filing with the Commission. In this tariff filing, Big Rivers requested the Commission approve the withdrawal of its tariff sheets for two of its DSM and EE

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[35] See *An Examination of the Application of the Fuel Adjustment Clause of Big Rivers Electric Corporation from November 1, 2013 through April 30, 2014*, Case No. 2014-00230; *An Examination of the Application of the Fuel Adjustment Clause of Big Rivers Electric Corporation from November 1, 2012 through October 31, 2014*, Case No. 2014-00455; *Application of Big Rivers Electric Corporation for Approval of Amendment to Stipulation and Recommendation*, Case No. 2016-00286

[36] See *In the Matter of: An Examination of the Application of the Fuel Adjustment Clause of Big Rivers Electric Corporation from November 1, 2012 through October 31, 2014*, Case No. 2014-00455. Ordering Paragraph No. 2 of the Commission's Order, dated July 15, 2015.

[37] See *In the Matter of: An Examination of the Application of the Fuel Adjustment Clause of Big Rivers Electric Corporation from November 1, 2014 through October 31, 2016*, Case No. 2014-00455. Ordering Paragraph No. 2 of the Commission's Order, dated July 31, 2017.

[38] See *Application Of Big Rivers Electric Corporation For An Order Declaring The Construction Of Seven Solar Power Facilities To Be Ordinary Extensions Of Existing Systems In The Usual Course Of Business*, Case No. 2016-00409.

[39] *Ibid.* Direct Testimony of Russell L. Pogue, page 6, line 17 through page 7, line 4.

programs: DSM–05 – Residential Weatherization Program and DSM–10 – Residential Weatherization Program – Primary Heating Source Non-Electric. Big Rivers further requested the Commission approve changes to DSM–13 – Residential Weatherization A La Carte Program. On July 25, 2017, the Commission issued an Order suspending these tariff changes and opening an investigation of their reasonableness.[40]

The year 2016 brought a number of changes to the power landscape and our nation, with new faces in both the state and federal government, shifting energy sources, and undecided environmental regulations. Navigating that uncertainty will be one of the biggest challenges for Big Rivers, its Members, and the electric industry. However, Big Rivers remains confident that its leadership and skilled employees will continue guiding the Company to long-term stability.

Big Rivers remains focused on being viewed as one of the nation's top generation and transmission cooperatives, and providing services that the Member-Owners desire to meet future challenges. Big Rivers' efficient assets, knowledgeable employees, power marketing excellence, advanced engineering, and strong relationships align the organization with that vision.

[40] See *In the Matter of: Tariff Filing of Big Rivers Electric Corporation to Revise Certain Demand-Side Management Programs*, Case No. 2017-00278.

Load Forecast

CHAPTER 4

4. LOAD FORECAST

This 2017 IRP is based on Big Rivers' 2017 Load Forecast base case; however, a number of sensitivities were completed in the IRP planning process. The load forecast is generally updated every two years by GDS; however, Big Rivers makes updates as needed for planning purposes. The 2017 Load Forecast was completed in July 2017, and adopted by Big Rivers' Board of Directors in September 2017. The most recent historical year included in the 2017 Load Forecast is 2016, and the base forecast year for both that load forecast and this IRP is 2016. The forecast horizon covers years 2017 through 2036. This chapter will review the entire period through 2036, even though the IRP analysis covers 2016 through 2031. The Long-Term Load Forecast was prepared with estimates of Non-Member load (See Section 4.2.6), and the IRP analysis sections reflect more recent estimates of Non-Member load.

4.1 Total System Forecast

Total system energy and peak demand requirements are projected to reach 4,372 GWH and 1,279 MW by 2036. Total system requirements include native system, Non-Member, and HMP&L load. Non-Member load enters the forecast in 2017, 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 interaction with organized energy markets during each year. Refer to Section 4.2.4 below for a description and discussion of estimated Non-Member load. Refer to Section 7.2.1 for a description of Non-Member load used in the IRP analysis.

Native system energy and peak demand requirements are projected to increase at average compound rates of 0.5% and 0.5%, respectively, per year from 2016 through 2036 (See Section 1.5 for a description of the load forecast through the 15-year term of this IRP). Continued increases in appliance efficiencies, consumer energy conservation awareness, and [redacted] in the price of retail electricity are expected to dampen growth in native energy sales over the near term; however, increased sales to existing direct serve customers will have positive impacts on native sales over the near term. A record native peak of 748 MW was established during the winter of 2014. Under normal peaking weather conditions, that peak is estimated to have been 706 MW. Native peak requirements are projected to increase from 648 MW in

2017 to 700 MW by the summer of 2036. Tables 4.1 and 4.2 present projected total system energy and peak demand requirements. Tables 4.3 and 4.4 present monthly projections of energy requirements and peak demand for the first two years of the forecast.

A review of the 2015 Load Forecast, which included an analysis and comparison of energy and peak demand projections for 2016 to actual values for the year, was completed during February, 2017. Actual 2016 energy and peak demand values were weather adjusted to provide for a comparison of data on the same basis (projections reflect normal weather). The energy requirements forecast variance (actual v. forecast) for 2016 was -1.5 percent, the winter peak variance was -6.7 percent, and the summer peak variance was -6.0 percent.

Table 4.1

Historical and Projected Energy Requirements

	Member Coop Retail Sales (MWH)	*Distribution Losses (%)*	*Big Rivers Native Sales (MWH)*	*HMP&L (MWH)*	*Trans. Losses (MWH)*	*Total Energy Requirements (MWH)*
2012	3,163,984	3.6%	3,282,776	622,254	32,683	3,937,713
2013	3,268,608	3.0%	3,371,187	617,149	39,066	4,027,402
2014	3,266,158	3.4%	3,381,575	632,749	44,238	4,058,562
2015	3,162,679	3.3%	3,270,995	625,367	54,122	3,950,483
2016	3,133,967	3.4%	3,244,594	624,214	63,307	3,932,115
2017	3,148,864	3.4%	3,258,532	629,574	81,374	3,969,480
2018	3,232,699	3.3%	3,343,114	632,094	93,166	4,068,374
2019	3,321,653	3.2%	3,432,508	634,623	95,320	4,162,451
2020	3,362,261	3.2%	3,473,299	637,161	96,336	4,206,796
2021	3,363,840	3.2%	3,474,891	639,710	96,433	4,211,034
2022	3,367,701	3.2%	3,478,946	642,269	96,588	4,217,803
2023	3,369,689	3.2%	3,481,017	644,838	96,696	4,222,551
2024	3,378,562	3.2%	3,490,159	647,417	96,971	4,234,548
2025	3,383,383	3.2%	3,495,398	650,007	97,155	4,242,559
2026	3,389,404	3.2%	3,501,719	652,607	97,364	4,251,690
2027	3,396,162	3.2%	3,508,814	655,218	97,591	4,261,623
2028	3,407,566	3.2%	3,520,620	657,838	97,929	4,276,388
2029	3,412,531	3.2%	3,526,010	660,470	98,117	4,284,597
2030	3,421,270	3.2%	3,535,190	663,112	98,394	4,296,696
2031	3,429,928	3.2%	3,544,285	665,764	98,670	4,308,719
2032	3,442,021	3.2%	3,556,815	668,427	99,026	4,324,268
2033	3,447,245	3.2%	3,562,475	671,090	99,221	4,332,786
2034	3,455,903	3.2%	3,571,571	673,753	99,496	4,344,820
2035	3,464,561	3.2%	3,580,666	676,416	99,772	4,356,854
2036	3,476,655	3.2%	3,593,196	679,079	100,128	4,372,403

Shaded year represents base year

HMP&L based on HMP&L load forecast

Values include DSM impacts

Total energy requirements do not include Non-Member sales

Table 4.2

Historical and Projected Peak Demand

	Rural System (MW)	Direct Serve (MW)	Native System (MW)	Non-Member Load (MW)*	HMP&L (MW)	Trans. Losses (%)	Total Peak Demand (MW)
2012	534	120	654		115	0.83%	776
2013	480	129	609		108	0.97%	724
2014	612	128	740		102	1.09%	851
2015	568	120	688		100	1.37%	799
2016	487	120	607		107	1.61%	726
2017	502	133	635	487	107	2.05%	1,254
2018	502	143	645	501	108	2.29%	1,284
2019	503	155	658	500	108	2.29%	1,295
2020	504	157	661	500	108	2.29%	1,299
2021	505	157	662	500	109	2.29%	1,301
2022	506	157	663	500	109	2.29%	1,302
2023	507	157	664	500	110	2.29%	1,304
2024	508	157	665	500	110	2.29%	1,305
2025	509	157	666	500	111	2.29%	1,307
2026	510	157	667	500	111	2.29%	1,309
2027	512	157	669	500	112	2.29%	1,310
2028	513	157	670	500	112	2.29%	1,312
2029	515	157	672	490	112	2.29%	1,304
2030	516	157	674	480	113	2.29%	1,296
2031	518	157	675	480	113	2.29%	1,298
2032	520	157	677	470	114	2.29%	1,290
2033	522	157	679	470	114	2.29%	1,293
2034	523	157	680	460	115	2.29%	1,285
2035	525	157	682	460	115	2.29%	1,287
2036	527	157	684	450	116	2.29%	1,279

Shaded year represents base year

HMP&L based on HMP&L load forecast

Values include DSM impacts
****Non-Member Load Estimate including Executed and Projected Sales***
For IRP analysis, only Executed Non-Member load included

Table 4.3

Monthly Energy Sales by Sector and Total Generation

Year	***Month***	***Native Energy Requirements (MWH)***	***HMP&L (MWH)***	***Total System Energy Requirements (MWH)***
2018	*1*	*336,123*	*55,941*	*392,064*
2018	*2*	*294,226*	*54,321*	*348,547*
2018	*3*	*271,607*	*51,739*	*323,346*
2018	*4*	*235,032*	*49,334*	*284,365*
2018	*5*	*255,502*	*52,583*	*308,086*
2018	*6*	*297,663*	*58,483*	*356,146*
2018	*7*	*327,238*	*61,671*	*388,909*
2018	*8*	*313,905*	*59,386*	*373,291*
2018	*9*	*267,179*	*52,551*	*319,730*
2018	*10*	*247,310*	*48,709*	*296,019*
2018	*11*	*267,080*	*50,232*	*317,313*
2018	*12*	*308,601*	*51,957*	*360,558*
2019	*1*	*343,612*	*56,165*	*399,777*
2019	*2*	*300,884*	*54,538*	*355,422*
2019	*3*	*278,768*	*51,946*	*330,714*
2019	*4*	*242,819*	*49,531*	*292,350*
2019	*5*	*263,730*	*52,794*	*316,524*
2019	*6*	*305,625*	*58,717*	*364,342*
2019	*7*	*335,599*	*61,918*	*397,517*
2019	*8*	*320,828*	*59,623*	*380,452*
2019	*9*	*274,947*	*52,762*	*327,709*
2019	*10*	*255,426*	*48,904*	*304,330*
2019	*11*	*275,033*	*50,433*	*325,466*
2019	*12*	*315,684*	*52,166*	*367,849*

Values include DSM impacts and transmission losses
Total energy requirements do not include Non-Member Sales

Table 4.4

Monthly Peak Demand by Sector and Total System

Year	*Month*	*Native Peak Requirements (MW)*	*Non-Member Peak Requirements (MW)*	*HMP&L (MW)*	*Total System Demand Requirements (MW)*
2018	1	645	498	101	1,245
2018	2	595	498	98	1,191
2018	3	529	498	91	1,118
2018	4	441	498	84	1,023
2018	5	523	498	95	1,117
2018	6	622	513	105	1,240
2018	7	660	513	111	1,283
2018	8	654	513	111	1,277
2018	9	572	513	104	1,189
2018	10	458	513	93	1,064
2018	11	531	513	87	1,131
2018	12	584	513	96	1,192
2019	1	656	513	102	1,271
2019	2	605	513	98	1,216
2019	3	538	513	91	1,141
2019	4	448	513	85	1,046
2019	5	534	509	96	1,139
2019	6	634	512	105	1,251
2019	7	673	512	111	1,295
2019	8	667	512	111	1,290
2019	9	584	512	104	1,199
2019	10	467	512	93	1,071
2019	11	540	512	88	1,140
2019	12	594	512	96	1,201

Values include DSM impacts and transmission losses
Non-Member Peak Requirements in the Long-Term Load Forecast include both Executed and Projected Sales.

4.2 Customer Class Forecasts

This section presents historical and projected number of customers and energy sales by Member retail classifications. All values are net of DSM.

4.2.1 Residential

Residential sales MWH are projected to increase at an average rate of 0.5% per year from 2016 through 2036. Sales in 2017 are projected to decline due to continued increases in appliance efficiencies, energy conservation awareness, and an increase in the retail price of electricity. The number of customers is projected to increase at an average rate of 0.6% through 2036. Average use per customer is projected to decline in 2017 due to the reasons stated above and then decline in most years through 2027 due to increased lighting standards and continued increases in appliance efficiencies and energy conservation awareness. Beyond 2024, average use per customer is projected to remain relatively flat as average appliance efficiencies approach maximum levels and the market share of various electric end-uses continue a slight increasing trend.

Table 4.5

Residential

	Number of Customers	*Change per Year*	*% Change per Year*	*Energy Sales (MWH)*	*Normalized Energy Sales (MWH)*	*% Change per Year*	*Avg. kWh /Customer /Month*	*% Change per Year*
2012	*97,675*			*1,465,749*	*1,477,663*		*1,261*	
2013	*97,773*	*98*	*0.1%*	*1,509,915*	*1,491,767*	*1.0%*	*1,271*	*0.9%*
2014	*97,851*	*78*	*0.1%*	*1,531,776*	*1,481,737*	*-0.7%*	*1,262*	*-0.8%*
2015	*97,971*	*120*	*0.1%*	*1,448,343*	*1,455,382*	*-1.8%*	*1,238*	*-1.9%*
2016	*98,583*	*611*	*0.6%*	*1,441,268*	*1,437,332*	*-1.2%*	*1,215*	*-1.9%*
2017	*99,290*	*707*	*0.7%*		*1,425,319*	*-0.8%*	*1,196*	*-1.5%*
2018	*100,046*	*756*	*0.8%*		*1,440,401*	*1.1%*	*1,200*	*0.3%*
2019	*100,806*	*760*	*0.8%*		*1,451,613*	*0.8%*	*1,200*	*0.0%*
2020	*101,619*	*813*	*0.8%*		*1,458,290*	*0.5%*	*1,196*	*-0.3%*
2021	*102,311*	*692*	*0.7%*		*1,456,582*	*-0.1%*	*1,186*	*-0.8%*
2022	*102,952*	*641*	*0.6%*		*1,462,945*	*0.4%*	*1,184*	*-0.2%*
2023	*103,594*	*642*	*0.6%*		*1,467,217*	*0.3%*	*1,180*	*-0.3%*
2024	*104,236*	*642*	*0.6%*		*1,474,969*	*0.5%*	*1,179*	*-0.1%*
2025	*104,913*	*677*	*0.6%*		*1,484,613*	*0.7%*	*1,179*	*0.0%*
2026	*105,542*	*629*	*0.6%*		*1,492,013*	*0.5%*	*1,178*	*-0.1%*
2027	*106,162*	*621*	*0.6%*		*1,500,024*	*0.5%*	*1,177*	*-0.1%*
2028	*106,852*	*689*	*0.6%*		*1,509,328*	*0.6%*	*1,177*	*0.0%*
2029	*107,542*	*691*	*0.6%*		*1,518,488*	*0.6%*	*1,177*	*0.0%*
2030	*108,233*	*691*	*0.6%*		*1,527,802*	*0.6%*	*1,176*	*0.0%*
2031	*108,874*	*641*	*0.6%*		*1,537,050*	*0.6%*	*1,176*	*0.0%*
2032	*109,514*	*641*	*0.6%*		*1,546,298*	*0.6%*	*1,177*	*0.0%*
2033	*110,155*	*641*	*0.6%*		*1,555,546*	*0.6%*	*1,177*	*0.0%*
2034	*110,795*	*641*	*0.6%*		*1,564,794*	*0.6%*	*1,177*	*0.0%*
2035	*111,436*	*641*	*0.6%*		*1,574,042*	*0.6%*	*1,177*	*0.0%*
2036	*112,077*	*641*	*0.6%*		*1,583,290*	*0.6%*	*1,177*	*0.0%*

Shaded year represents base year

4.2.2 Small Commercial & Industrial (Small C&I)

Small commercial and industrial customers are defined as all commercial and industrial customers with annual peak demand less than 1,000 kW. Small commercial sales are projected to increase at an average rate of 0.9% per year from 2016 through 2036. Growth in the number of customers, projected at 1.1% per year, is the primary influence on growth in total class sales. Consumption per customer is projected to decline by 0.3% per year from 2016-2036 due to increases in appliance efficiencies.

Table 4.6

Small Commercial & Industrial

	Number of Customers	Change per Year	% Change per Year	Energy Sales (MWH)	Normalized Energy Sales (MWH)	% Change per Year	Avg. kWh /Customer /Month	% Change per Year
2012	15,435			595,342	594,981		3,212	
2013	15,797	362	2.3%	600,982	596,571	0.3%	3,147	-2.0%
2014	16,210	413	2.6%	609,780	597,097	0.1%	3,070	-2.5%
2015	16,806	596	3.7%	610,947	613,258	2.7%	3,041	-0.9%
2016	17,118	312	1.9%	620,471	617,093	0.6%	3,004	-1.2%
2017	17,398	280	1.6%		623,101	1.0%	2,985	-0.7%
2018	17,607	209	1.2%		629,211	1.0%	2,978	-0.2%
2019	17,774	167	1.0%		633,508	0.7%	2,970	-0.3%
2020	18,005	231	1.3%		639,695	1.0%	2,961	-0.3%
2021	18,234	228	1.3%		645,779	1.0%	2,951	-0.3%
2022	18,460	226	1.2%		651,797	0.9%	2,942	-0.3%
2023	18,684	224	1.2%		657,776	0.9%	2,934	-0.3%
2024	18,907	223	1.2%		663,726	0.9%	2,925	-0.3%
2025	19,128	221	1.2%		669,630	0.9%	2,917	-0.3%
2026	19,346	219	1.1%		675,453	0.9%	2,909	-0.3%
2027	19,563	217	1.1%		681,217	0.9%	2,902	-0.3%
2028	19,777	215	1.1%		686,926	0.8%	2,894	-0.3%
2029	19,990	212	1.1%		692,558	0.8%	2,887	-0.2%
2030	20,199	210	1.0%		698,122	0.8%	2,880	-0.2%
2031	20,407	208	1.0%		703,630	0.8%	2,873	-0.2%
2032	20,615	208	1.0%		709,138	0.8%	2,867	-0.2%
2033	20,823	208	1.0%		714,646	0.8%	2,860	-0.2%
2034	21,031	208	1.0%		720,154	0.8%	2,854	-0.2%
2035	21,239	208	1.0%		725,661	0.8%	2,847	-0.2%
2036	21,447	208	1.0%		731,169	0.8%	2,841	-0.2%

Shaded year represents base year

4.2.3 Large Commercial & Industrial (Large C&I)

The large commercial & industrial class is defined as all commercial and industrial customers that have annual peak demand greater than or equal to 1,000 kW. The class includes rural system customers and direct serve customers. Large C&I sales for Big Rivers' three Members are projected to be essentially flat after 2020, as the Long-Term Load Forecast only added known, anticipated changes.

Table 4.7

Large Commercial & Industrial

	Number of Customers	***Change per Year***	***% Change per Year***	***Energy Sales (MWH)***	***% Change per Year***	***Avg. kWh /Customer /Month***	***% Change per Year***
2012	*44*			*1,098,999*		*2,105,362*	
2013	*52*	*8*	*19.0%*	*1,153,723*	*5.0%*	*1,857,847*	*-11.8%*
2014	*51*	*(1)*	*-1.3%*	*1,121,005*	*-2.8%*	*1,828,719*	*-1.6%*
2015	*52*	*1*	*1.8%*	*1,099,899*	*-1.9%*	*1,762,658*	*-3.6%*
2016	*51*	*(1)*	*-1.8%*	*1,068,889*	*-2.8%*	*1,743,702*	*-1.1%*
2017	*48*	*(3)*	*-5.7%*	*1,106,507*	*3.5%*	*1,914,373*	*9.8%*
2018	*49*	*1*	*2.1%*	*1,179,003*	*6.6%*	*1,998,311*	*4.4%*
2019	*49*	*0*	*0.0%*	*1,261,771*	*7.0%*	*2,138,595*	*7.0%*
2020	*49*	*0*	*0.0%*	*1,298,788*	*2.9%*	*2,201,335*	*2.9%*
2021	*49*	*0*	*0.0%*	*1,299,566*	*0.1%*	*2,202,655*	*0.1%*
2022	*49*	*0*	*0.0%*	*1,299,566*	*0.0%*	*2,202,655*	*0.0%*
2023	*49*	*0*	*0.0%*	*1,299,566*	*0.0%*	*2,202,655*	*0.0%*
2024	*49*	*0*	*0.0%*	*1,303,001*	*0.3%*	*2,208,477*	*0.3%*
2025	*49*	*0*	*0.0%*	*1,299,566*	*-0.3%*	*2,202,655*	*-0.3%*
2026	*49*	*0*	*0.0%*	*1,299,566*	*0.0%*	*2,202,655*	*0.0%*
2027	*49*	*0*	*0.0%*	*1,299,566*	*0.0%*	*2,202,655*	*0.0%*
2028	*49*	*0*	*0.0%*	*1,303,001*	*0.3%*	*2,208,477*	*0.3%*
2029	*49*	*0*	*0.0%*	*1,299,566*	*-0.3%*	*2,202,655*	*-0.3%*
2030	*49*	*0*	*0.0%*	*1,299,566*	*0.0%*	*2,202,655*	*0.0%*
2031	*49*	*0*	*0.0%*	*1,299,566*	*0.0%*	*2,202,655*	*0.0%*
2032	*49*	*0*	*0.0%*	*1,303,001*	*0.3%*	*2,208,477*	*0.3%*
2033	*49*	*0*	*0.0%*	*1,299,566*	*-0.3%*	*2,202,655*	*-0.3%*
2034	*49*	*0*	*0.0%*	*1,299,566*	*0.0%*	*2,202,655*	*0.0%*
2035	*49*	*0*	*0.0%*	*1,299,566*	*0.0%*	*2,202,655*	*0.0%*
2036	*49*	*0*	*0.0%*	*1,303,001*	*0.3%*	*2,208,477*	*0.3%*

Shaded year represents base year

4.2.4 Irrigation

Only one of Big Rivers' Members provides service to irrigation customers. Energy sales for the class account for less than 1% of total system sales. Energy sales are influenced by weather during growing seasons. No new customers are expected during the forecast period, and sales projections for the class are based on average sales for the most recent seven years.

Table 4.8

Irrigation

	Number of Customers	*Change per Year*	*% Change per Year*	*Energy Sales (MWH)*	*% Change per Year*	*Avg. kWh /Customer /Month*	*% Change per Year*
2012	5			440		7,338	
2013	4	(1)	-15.0%	48	-89.2%	933	-87.3%
2014	4	(0)	-5.9%	136	186.9%	2,843	204.8%
2015	4	0	0.0%	62	-54.8%	1,286	-54.8%
2016	4	0	0.0%	47	-24.0%	977	-24.0%
2017	4	0	0.0%	194	313.8%	4,041	313.8%
2018	4	0	0.0%	194	0.0%	4,041	0.0%
2019	4	0	0.0%	194	0.0%	4,041	0.0%
2020	4	0	0.0%	194	0.0%	4,041	0.0%
2021	4	0	0.0%	194	0.0%	4,041	0.0%
2022	4	0	0.0%	194	0.0%	4,041	0.0%
2023	4	0	0.0%	194	0.0%	4,041	0.0%
2024	4	0	0.0%	194	0.0%	4,041	0.0%
2025	4	0	0.0%	194	0.0%	4,041	0.0%
2026	4	0	0.0%	194	0.0%	4,041	0.0%
2027	4	0	0.0%	194	0.0%	4,041	0.0%
2028	4	0	0.0%	194	0.0%	4,041	0.0%
2029	4	0	0.0%	194	0.0%	4,041	0.0%
2030	4	0	0.0%	194	0.0%	4,041	0.0%
2031	4	0	0.0%	194	0.0%	4,041	0.0%
2032	4	0	0.0%	194	0.0%	4,041	0.0%
2033	4	0	0.0%	194	0.0%	4,041	0.0%
2034	4	0	0.0%	194	0.0%	4,041	0.0%
2035	4	0	0.0%	194	0.0%	4,041	0.0%
2036	4	0	0.0%	194	0.0%	4,041	0.0%

Shaded year represents base year

4.2.5 Street Lighting

Energy sales for the class account for less than 1% of total system sales. Projections of number of customers is based on a historical trend, and energy sales are assumed to increase at a rate equal to the residential class.

Table 4.9

Street Lighting

	Number of Customers	*Change per Year*	*% Change per Year*	*Energy Sales (MWH)*	*% Change per Year*	*Avg. kWh /Customer /Month*	*% Change per Year*
2012	*92*			*3,454*		*3,146*	
2013	*91*	*(0)*	*-0.1%*	*3,486*	*0.9%*	*3,178*	*1.0%*
2014	*91*	*(0)*	*-0.5%*	*3,461*	*-0.7%*	*3,169*	*-0.3%*
2015	*100*	*9*	*10.1%*	*3,429*	*-0.9%*	*2,853*	*-10.0%*
2016	*103*	*3*	*3.2%*	*3,291*	*-4.0%*	*2,654*	*-7.0%*
2017	*103*	*0*	*0.0%*	*3,396*	*3.2%*	*2,739*	*3.2%*
2018	*103*	*0*	*0.0%*	*3,399*	*0.1%*	*2,741*	*0.1%*
2019	*103*	*0*	*0.0%*	*3,402*	*0.1%*	*2,744*	*0.1%*
2020	*103*	*0*	*0.0%*	*3,405*	*0.1%*	*2,746*	*0.1%*
2021	*103*	*0*	*0.0%*	*3,408*	*0.1%*	*2,749*	*0.1%*
2022	*103*	*0*	*0.0%*	*3,411*	*0.1%*	*2,751*	*0.1%*
2023	*103*	*0*	*0.0%*	*3,414*	*0.1%*	*2,753*	*0.1%*
2024	*103*	*0*	*0.0%*	*3,417*	*0.1%*	*2,756*	*0.1%*
2025	*103*	*0*	*0.0%*	*3,420*	*0.1%*	*2,758*	*0.1%*
2026	*103*	*0*	*0.0%*	*3,423*	*0.1%*	*2,761*	*0.1%*
2027	*103*	*0*	*0.0%*	*3,426*	*0.1%*	*2,763*	*0.1%*
2028	*103*	*0*	*0.0%*	*3,429*	*0.1%*	*2,766*	*0.1%*
2029	*103*	*0*	*0.0%*	*3,432*	*0.1%*	*2,768*	*0.1%*
2030	*103*	*0*	*0.0%*	*3,435*	*0.1%*	*2,771*	*0.1%*
2031	*103*	*0*	*0.0%*	*3,438*	*0.1%*	*2,773*	*0.1%*
2032	*103*	*0*	*0.0%*	*3,441*	*0.1%*	*2,775*	*0.1%*
2033	*103*	*0*	*0.0%*	*3,445*	*0.1%*	*2,778*	*0.1%*
2034	*103*	*0*	*0.0%*	*3,448*	*0.1%*	*2,780*	*0.1%*
2035	*103*	*0*	*0.0%*	*3,451*	*0.1%*	*2,783*	*0.1%*
2036	*103*	*0*	*0.0%*	*3,454*	*0.1%*	*2,785*	*0.1%*

Shaded year represents base year

4.2.6 Non-Member

Big Rivers optimizes available resources to bring value to its Members by selling economic resources to Non-Members when those resources are not needed to serve Member load.

Non-Member sales will be served from capacity of Big Rivers' Members, and are adjusted from time-to-time as resources and economics dictate. For Non-Member load, capacity and/or energy may be purchased when economic and when it benefits our Members. Capacity and energy will be sold when economic either bilaterally or via participation in the MISO Day-Ahead and Real-Time energy markets. Non-Member capacity sales included in the Long-Term Load Forecast report are made up of Executed Sales of capacity and Projected Sales. Projected Sales are the difference between the Forecasted Sales target and Executed Sales. The Forecasted Sales target is frequently evaluated over time to fully optimize available Big Rivers resources. Optimization includes evaluation of costs to deliver Big Rivers' generation versus buying from the market, and when all-in costs of purchasing capacity and/or energy are more economical than transmission and associated generation costs, those purchases are made to bring the most value to our Members. In the Long Term Load Forecast report, both Executed and Projected Sales were included, however for purposes of the IRP analysis, only Executed Sales were included (See Section 7.2 Modeling Results for treatment of Non-Member load in IRP analysis). Projected Sales could be comprised of long-term sales, short-term optimization sales, and possibly new Member additions, despite the 'Non-Member' moniker.

- **Executed Long-Term Transactions** include capacity sales to several Missouri municipals beginning in 2017, contracts with Nebraska customers set to begin in 2018, a multi-year MISO [redacted] capacity sale beginning in 2018, and a ten-year sale to KyMEA to begin in 2019. Combined with approximately 50 MW of internal native load growth beginning in 2017 and extending through 2036 (See Table 4.2 Native System MW), these projects further stabilize Big Rivers' revenue and help ensure competitive rates for its Members.
- **Short-Term Optimization Transactions** are sales of available economic energy via bilateral hedging transactions and participation in the MISO capacity auction and Day-Ahead and Real - Time energy markets. These transactions bring value to Big Rivers' Members during the lead

time required for execution and delivery of long-term contracts. All available economic energy not dedicated to Non-Member sales will be sold in the MISO spot market with hedged prices where appropriate.

4.2.7 Interruptible or Curtailable Load

Big Rivers provides wholesale electric service to its three Members-Owners: Kenergy, JPEC, and MCRECC. The current tariff under which Big Rivers provides service is on file with the Commission;[41] that tariff has an effective date of February 1, 2014. Big Rivers does not currently operate any direct control programs and does not provide electric service to any retail or wholesale customers under an interruptible or curtailable contract or tariff.

Although no Member-consumers are currently taking this service, Big Rivers offers a Voluntary Curtailment Rider, which provides a means for potentially reducing system peak demand during peak periods. On March 10, 2000, Big Rivers, in conjunction with JPEC, Kenergy, and MCRECC, filed the Voluntary Curtailment Rider with the Commission. The Commission approved the Voluntary Curtailment Rider as filed in its Order dated April 6, 2000, in Case No. 2000-00116.[42] Since the rider is voluntary, it is not considered as a means for reducing load in this IRP. As presented in Table 4.10, there have been four voluntary curtailments, one in 2008 and three in 2009, affecting two customers, and reducing load by an estimated 1 to 25 MW.

Table 4.10

2000-2016 Voluntary Industrial Curtailment Results

Year	*Number of Curtailments*	*Load Reduction (MW)*
2000-2007	*0*	*n/a*
2008	*1*	*20*
2009	*3*	*1 to 25*
2010-2016	*0*	*n/a*

[41] That tariff is also accessible from Big Rivers' corporate internet site at www.bigrivers.com/regulatory.

[42] *In the Matter of: Joint Tariff Filing of Big Rivers Electric Corporation, Jackson Purchase Energy Corporation, Kenergy Corp., and Meade County rural Electric Cooperative Corporation*, Case No. 2000-00116.

4.3 Weather Adjusted Energy and Peak Demand Requirements

Rural system energy consumption and peak demand are impacted by prevailing weather. Energy sales and peak demand for direct serve customers are not weather sensitive, as they are primarily industrial customers whose energy use is driven by their industrial processes and not by the weather. Both extreme and mild weather conditions have been experienced over the most recent four years. As measured by degree days, 2010 was the hottest year in over 20 years, and 2010 was the coldest year since 1997. More recently, January 2014 represented one of the most extreme winter months Big Rivers has experienced in the last 20 years, resulting in a new all-time native system peak of 740 MW. Table 4.11 presents actual and weather adjusted energy and peak demand requirements for recent years.

Table 4.11

Weather Normalized Native System Energy and Peak Demand

	Energy (MWH)		*Winter Peak (MW)*		*Summer Peak (MW)*	
	Actual	*Normal*	*Actual*	*Normal*	*Actual*	*Normal*
2007	*3,325,859*	*3,306,150*	*597*	*601*	*648*	*594*
2008	*3,313,571*	*3,354,190*	*611*	*617*	*604*	*606*
2009	*3,159,286*	*3,272,941*	*665*	*630*	*594*	*608*
2010	*3,411,558*	*3,321,276*	*647*	*616*	*657*	*614*
2011	*3,344,199*	*3,385,423*	*624*	*580*	*652*	*639*
2012	*3,282,776*	*3,337,591*	*569*	*618*	*654*	*607*
2013	*3,371,187*	*3,403,524*	*597*	*618*	*609*	*639*
2014	*3,381,575*	*3,377,106*	*740*	*698*	*602*	*604*
2015	*3,270,995*	*3,333,037*	*688*	*664*	*617*	*623*
2016	*3,244,594*	*3,272,279*	*600*	*605*	*607*	*620*

Values represent energy and peak demand without transformer losses

Under normal peaking weather conditions, Big Rivers' annual peak demand is projected to occur during the summer season. Historical data shows, however, that Big Rivers' actual annual peak demand was set during January in 2008, 2009, 2014, and February of 2015. The impact of severe weather is greater during winter months than summer months due primarily to supplemental electric strip heating within Big

Rivers' Members' service territories; therefore, while the base case forecast shows Big Rivers to be summer peaking, under the most extreme weather conditions, the system is most likely to be winter peaking.

4.4 Impact of Existing and Future Energy Efficiency and Demand Side Management Programs

Big Rivers assisted its Members with the implementation of ten (10) energy efficiency programs in 2010, and added two (2) additional programs in 2013 for a total of twelve (12) programs. The projected impact of these programs beginning in 2017 is presented in Table 4.12. Across the 2011-2016 timeframe, the programs continued to grow and yield increasing levels of deemed savings. Deemed savings were developed using customized residential and C&I sector-level potential assessment Excel models and Company-specific cost effectiveness criteria including the most recent Big Rivers avoided energy and capacity cost projections. The results of modeling provide detailed information on energy efficiency measures that are cost-effective and have potential kWh and kW savings. The data referenced in this report were the best available at the time this analysis was developed. As building and appliance codes and energy efficiency standards change, and as energy prices fluctuate, additional opportunities for energy efficiency may occur while current practices may become outdated.

The impacts of existing programs are quantified indirectly in the 2017 Load Forecast through historical sales and peak demand. The estimated impacts of new programs and increased participation in existing programs are captured in the 2017 Load Forecast through post-modeling adjustments.

As noted earlier, on June 30, 2017, Big Rivers made a DSM tariff filing with the Commission. In that filing, Big Rivers requested approval to withdraw two of its existing DSM Programs and to modify a third DSM Program. The Commission suspended those tariff revisions; its review and investigation of them is still open as of the filing of this 2017 IRP.

Table 4.12

Estimated Future DSM Program Impacts

Year	*Impact on Energy Requirements (MWh)*	*Impact on Winter Peak Demand (MW)*	*Impact on Summer Peak Demand (MW)*
2017	9,654	1.27	1.45
2018	19,509	2.58	2.92
2019	28,836	3.78	4.26
2020	38,111	5.32	5.67
2021	41,690	6.22	6.24
2022	50,212	7.63	7.51
2023	58,478	9.01	8.76
2024	66,745	10.39	10.01
2025	74,040	11.69	11.11
2026	81,245	13.15	12.22
2027	88,266	14.51	13.26
2028	95,313	15.87	14.31
2029	101,708	16.97	15.24
2030	107,851	17.97	16.17
2031	113,951	18.97	17.09
2032	120,052	19.96	18.01
2033	126,152	20.95	18.94
2034	132,253	21.95	19.86
2035	138,353	22.94	20.78
2036	144,454	23.93	21.71

Below are programs that are not tracked for impact because they are educational in nature and/or not readily quantifiable.

- **Member Websites:** Each of Big Rivers' Members' websites provides easy-to-use Home Energy education tools. The web-based modules provide education and calculation methods to improve efficiency and save energy in the home. Adjustable inputs specific to a home allow customers to compare their current energy use to estimated energy use resulting from various improvements in efficiency.

- **Energy Use Assessments:** These assessments are provided to commercial and industrial customers upon request. Walk-through energy audits help identify simple and low cost efficiency measures that customers can install or implement themselves. Third-party service providers such as the Kentucky Pollution Prevention Center and the Kentucky Department for Energy Development and Independence[43] assist customers in achieving energy reduction goals.[44] Educational programs are also available for employees of commercial and industrial retail member-consumers.

- **Renewable Energy:** Big Rivers offers renewable energy to its Members. Big Rivers is installing seven solar arrays totaling 120 kW dc capacity in 2017. These arrays are for educational and demonstration purposes.

- **Energy Savings Analysis:** Big Rivers provides energy saving analyses to industrial and large commercial customers by combining efforts with the Members, the Department of Energy (DOE),[45] and the University of Louisville's Kentucky Pollution Prevention Center.[46]

- **Power Factor Correction:** Members' staffs provide assistance to correct lagging power factor at a Commercial or Industrial (C&I) facility. These corrections save money for the customer and improve the efficiency of both transmission and distribution facilities.

- **Technology Evaluation:** Members' staffs assist in the evaluation and implementation of technologies that benefit the productivity, profitability and energy efficiency of a C&I facility.

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[43] http://energy.ky.gov/Pages/default.aspx

[44] Kentucky Pollution Prevention Center, https://louisville.edu/kppc/es/technical_services.html
Kentucky's Department for Energy Development and Independence, http://energy.ky.gov/Pages/default.aspx

[45] http://energy.gov/

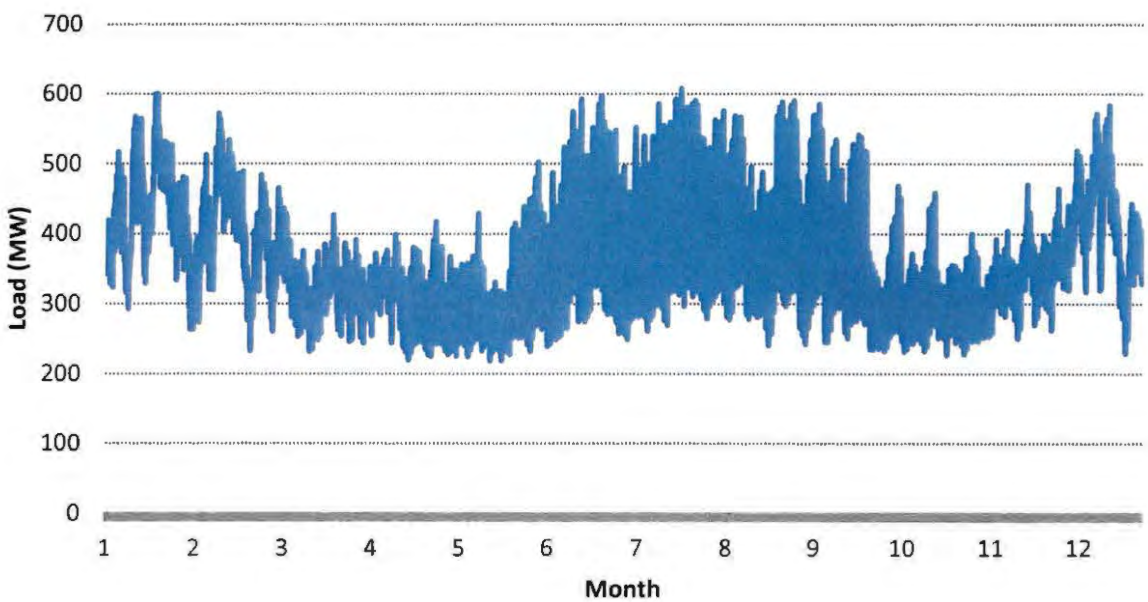
[46] https://louisville.edu/kppc/

4.5 Anticipated Changes in Load Characteristics

Big Rivers' hourly native system load shape for 2016 is presented in Figure 4.13. Big Rivers' system can be summer or winter peaking depending on the severity of seasonal temperatures; however, the system is projected to be summer peaking over the next 20 years.

Figure 4.13

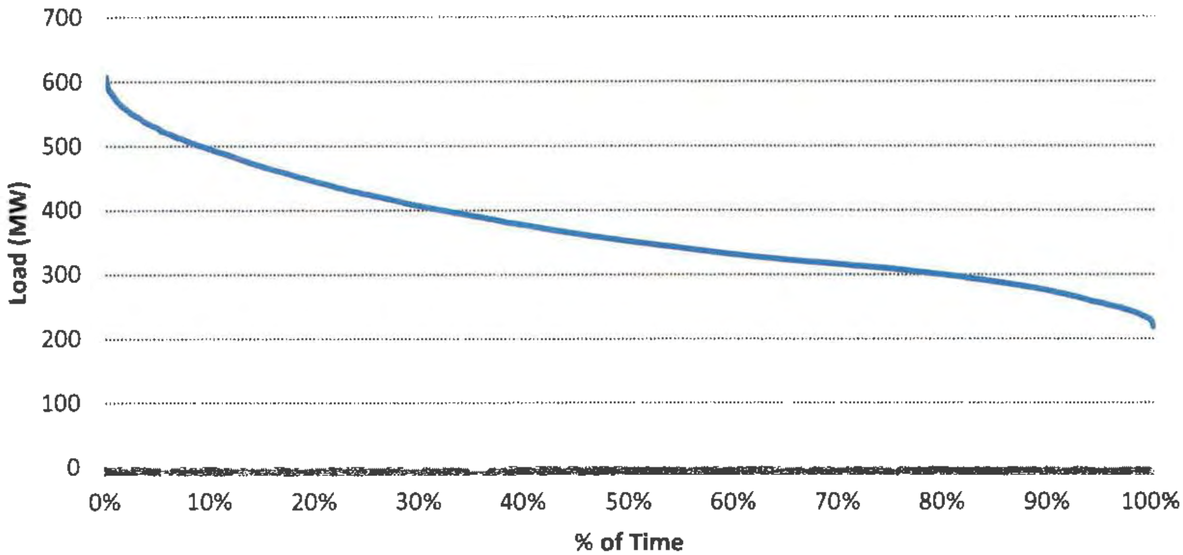
2016 Annual Native Load Shape



An annual load duration curve for 2016 native load is presented in Figure 4.14. The native system load factor for 2016 was 60.8%.

Figure 4.14

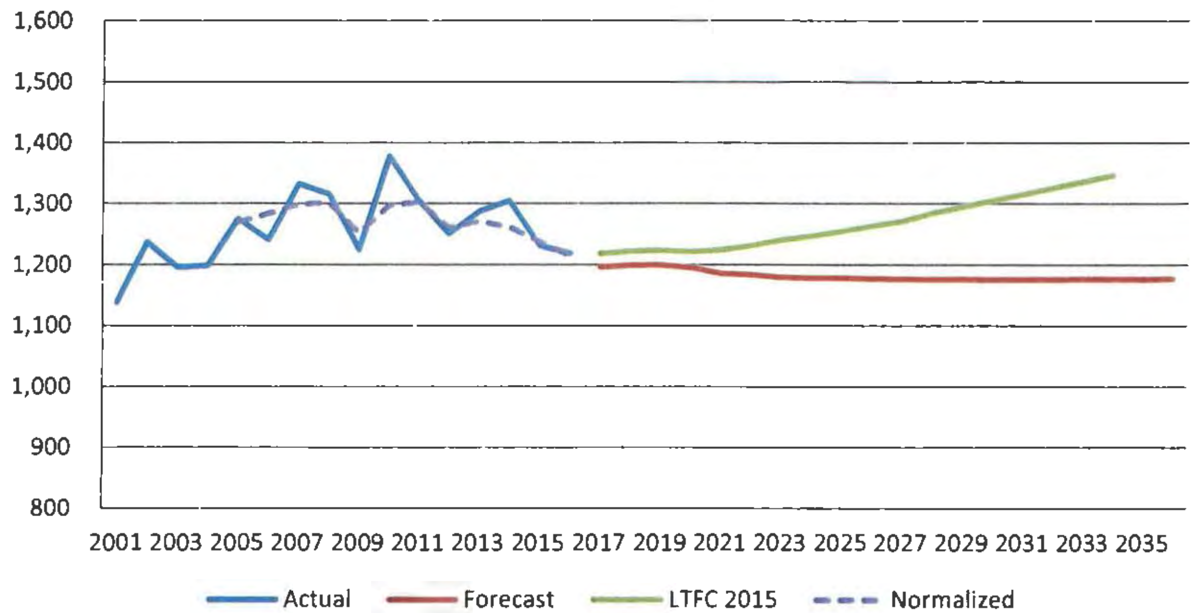
2016 Annual Native Load Duration Curve



- **Residential Consumption**: Average kWh use per customer has leveled in recent years due primarily to energy conservation, price increases, and increases in appliance efficiencies. Consumption is projected to decline over the next 20 years primarily as a result of continued increases in appliance efficiencies and minimal increases in electric heating, cooling, and water heating market shares. Figure 4.3 presents average monthly kWh per customer for historical and projected periods.

Figure 4.15

Average Monthly Residential kWh Consumption per Customer by Year



4.6 Load Forecast Methodology

The forecast was developed using quantitative and qualitative methods. Econometrics was used to develop forecasting models to project the number of customers and average energy consumption per customer for the Residential and Small Commercial classifications, and peak demand for the rural system. Informed judgment, combined with historical trends, was used to project energy consumption and peak demand for each large commercial customer. The number of customers and energy sales for the street lighting and irrigation classes were projected based on historical trends and judgment.

Big Rivers contracted with GDS to assist in developing the load forecast. The preliminary forecasts were reviewed with Member management. The Members' forecasts were finalized and aggregated to the Big Rivers level. Refer to Appendix A, 2017 Load Forecast, Section 4, for a complete description of the forecast methodology and model outputs.

4.7 Alternative Load Forecast Scenarios

Big Rivers' base case forecast reflects expected economic growth and normal weather conditions. To address the inherent uncertainty related to these factors, long-term high- and low-range projections are developed. The range forecasts reflect the energy and demand requirements corresponding to more optimistic or pessimistic economic growth, potential EPA and other environmental regulations, and mild or extreme weather conditions. Tables 4.16 through 4.19 present the alternative forecast scenarios at the control area level, including generation and transmission losses.

- **Economy Scenarios**: The two economic drivers in the forecasting models, number of households and average household income, are adjusted from base case values to produce the optimistic and pessimistic forecast scenarios. Refer to Appendix A, 2017 Load Forecast, Section 3.6, for details regarding the economic forecast scenarios.

Table 4.16

Optimistic/Pessimistic Economy

Native System

	Energy (MWH)			*Winter Peak Demand*			*Summer Peak Demand*		
	Pessimistic	*Base*	*Optimistic*	*Pessimistic*	*Base*	*Optimistic*	*Pessimistic*	*Base*	*Optimistic*
2016	*3,272,279*	*3,272,279*	*3,272,279*	*605*	*605*	*605*	*620*	*620*	*620*
2021	*3,209,069*	*3,474,891*	*3,772,649*	*604*	*657*	*716*	*609*	*662*	*722*
2026	*3,155,483*	*3,501,719*	*3,894,838*	*592*	*661*	*741*	*597*	*667*	*748*
2031	*3,116,750*	*3,544,285*	*4,045,005*	*581*	*668*	*770*	*587*	*675*	*779*
2036	*3,087,352*	*3,593,196*	*4,204,585*	*573*	*676*	*801*	*579*	*684*	*811*

Table 4.17

Optimistic/Pessimistic Economy

Rural System

	Energy (MWH)			*Winter Peak Demand*			*Summer Peak Demand*		
	Pessimistic	***Base***	***Optimistic***	***Pessimistic***	***Base***	***Optimistic***	***Pessimistic***	***Base***	***Optimistic***
2016	*2,304,554*	*2,304,554*	*2,304,554*	*492*	*492*	*492*	*499*	*499*	*499*
2021	*2,120,358*	*2,328,879*	*2,569,336*	*454*	*498*	*550*	*460*	*505*	*557*
2026	*2,066,772*	*2,355,707*	*2,691,525*	*441*	*502*	*574*	*448*	*510*	*583*
2031	*2,028,039*	*2,398,273*	*2,841,693*	*430*	*509*	*603*	*438*	*518*	*614*
2036	*1,995,377*	*2,443,749*	*2,997,666*	*422*	*517*	*634*	*430*	*527*	*646*

- **Weather Scenarios**: Rural system energy and peak demand is weather sensitive. The impact of weather on industrial customers is insignificant. Under extreme weather conditions, rural system energy is projected to be 7% higher than normal, and peak demand is projected to be approximately 16% higher than normal. The impact of extreme weather conditions on winter peak demands is approximately twice that on summer peak demand.

Table 4.18

Mild/Extreme Weather

Native System

	Energy (MWH)			*Winter Peak Demand*			*Summer Peak Demand*		
	Mild	***Base***	***Extreme***	***Mild***	***Base***	***Extreme***	***Mild***	***Base***	***Extreme***
2016	*3,272,279*	*3,272,279*	*3,272,279*	*605*	*605*	*605*	*620*	*620*	*620*
2021	*3,347,168*	*3,474,891*	*3,629,644*	*582*	*657*	*743*	*620*	*662*	*706*
2026	*3,372,151*	*3,501,719*	*3,659,113*	*586*	*661*	*749*	*625*	*667*	*712*
2031	*3,413,284*	*3,544,285*	*3,704,569*	*592*	*668*	*757*	*632*	*675*	*721*
2036	*3,460,837*	*3,593,196*	*3,756,284*	*599*	*676*	*766*	*640*	*684*	*731*

Table 4.19

Mild/Extreme Weather

Rural System

	Energy (MWH)			*Winter Peak Demand*			*Summer Peak Demand*		
	Mild	*Base*	*Extreme*	*Mild*	*Base*	*Extreme*	*Mild*	*Base*	*Extreme*
2016	*2,304,554*	*2,304,554*	*2,304,554*	*492*	*492*	*492*	*499*	*499*	*499*
2021	*2,201,156*	*2,328,879*	*2,483,632*	*423*	*498*	*585*	*463*	*505*	*549*
2026	*2,226,139*	*2,355,707*	*2,513,101*	*427*	*502*	*590*	*468*	*510*	*555*
2031	*2,267,272*	*2,398,273*	*2,558,556*	*433*	*509*	*598*	*475*	*518*	*564*
2036	*2,311,390*	*2,443,749*	*2,606,837*	*440*	*517*	*607*	*483*	*527*	*574*

4.8 Normal Weather Periods Analysis

Staff Recommendation No. 3 in Section 2 – Load Forecasting of the Commission Staff's December 2015 report on Big Rivers' 2014 IRP indicated that Big Rivers' 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. As a result of that request, Big Rivers contracted with GDS to perform weather normalization analysis using 10-year and 30-year historical periods. Results of that analysis showed less than 1% average difference in Peak MW compared to 20-year normal periods when using either the 10-year or 30-year normalization. In fact, the variance from the base forecast resulted in less than 2 MW maximum difference for the 30-year average and -1 MW maximum difference from base for the 10-year normalization period. These small variances are well within expected margins for error, and scenarios studied for this IRP evaluated greater variations in load (See Section 7.2.3.4 for Load Forecast Scenarios studied), so no further analysis was conducted.

4.9 Research and Development

Big Rivers conducts residential surveys periodically to monitor changes in household major appliances and various end-uses. This schedule is expected to continue in future years. Results from the surveys are used to develop key inputs for the load forecasting models.

Big Rivers will continue to utilize end-use data and information obtained from its Appliance Saturation Surveys, along with data available from the United States Department of Energy's Energy Information Administration and any other sources that may become available in the future.

Big Rivers assists its three Members in evaluating the potential impacts of new energy efficiency and demand response programs. The Company continues to monitor potential load management and other demand response type programs.

As discussed in Sections 3.7 and 3.8, Big Rivers has implemented *Plexos®* modeling tool and has restructured its Strategic Planning and Risk Management Department, and the Company continues to improve on these enhanced resources.

Demand Side Management

CHAPTER 5

5. DEMAND SIDE MANAGEMENT

5.1 Demand Side Management

The 2017 DSM Potential Study (the DSM Study *or* the 2017 DSM Study) study presents results from the evaluation of opportunities for energy efficiency programs in Big Rivers' Members' service territories. Estimates of technical potential, economic potential, and achievable potential are provided for the ten-year period spanning 2017-2026 for the residential and commercial/industrial (C&I), or nonresidential sectors. Results from two program potential scenarios are also presented to estimate the portion of the achievable potential that could be realized given specific funding levels for existing Big Rivers DSM programs.

All results were developed using customized residential and C&I sector-level potential assessment Excel models and Company-specific cost effectiveness criteria including the most recent Big Rivers avoided energy and capacity cost projections for electricity. The results of this study provide detailed information on energy efficiency measures that are cost-effective and have potential kWh and kW savings. The data referenced in this report were the best available at the time this analysis was developed. Appendix B of this IRP provides the entire 2017 DSM Study.

5.2 Market Potential Study – Energy Efficiency

This study examines the potential to reduce electric consumption and peak demand through the implementation of DSM technologies and practices in residential, commercial, and industrial facilities. The study assessed energy efficiency potential and demand response throughout Big Rivers' Members' service territories over ten years, from 2017 through 2026. The study had five primary objectives:

- Develop databases of energy efficiency and demand response measures in the residential and nonresidential sectors - the measure database reflects current industry knowledge of energy efficiency and demand response measures, accounts for known codes and standards, and aligns with the market and demographics of Big Rivers' Members' consumers;
- Evaluate the electric DSM technical potential savings in Big Rivers' Members' territories;

- Calculate the Total Resource Cost (TRC) test and Utility Cost Test (UCT) benefit-cost ratios for potential electric energy efficiency measures, and determine the electric energy efficiency economic potential savings (using the TRC test) for Big Rivers' Members;
- Evaluate the potential for achievable savings through DSM programs over a ten-year horizon (2017-2026);
- Estimate the potential savings over a ten-year period from the delivery of a portfolio of energy efficiency programs based on a specific funding level - the portfolio of energy efficiency programs has been analyzed based on two funding scenarios: the current $1.0 million incentive budget and a $2 million incentive budget.

Figure 5.1 provides the technical, economic, achievable and program potential (two funding scenarios) across all sectors in the Big Rivers service territory. The economic potential is approximately 25% of forecasted sales by 2026. Economic potential refers to the subset of the technical potential that is economically cost-effective as compared to conventional supply-side energy resources. Economic potential follows the same adoption rates as technical potential. Like technical potential, the economic scenario ignores market barriers to ensure actual implementation of efficiency. Finally, economic potential only considers the costs of efficiency measures themselves, ignoring any programmatic costs (e.g., marketing, analysis, administration) that would be necessary to capture them. The program potential at the $1.0 million incentive scenario is approximately 2% of forecasted sales by 2026. Chapters 3 and 4 of the 2017 DSM Study in Appendix B provide sector level details. Chapter 6 of that study provides program potential details.

Figure 5.1

Electric Efficiency Potential Savings Summary

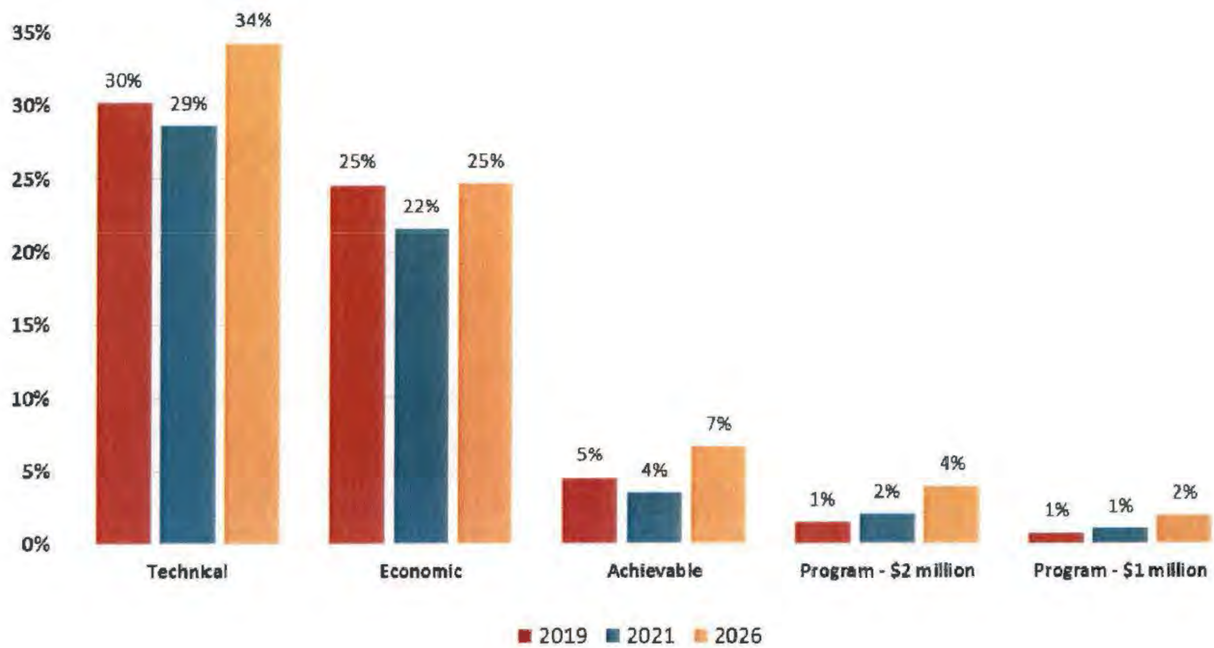


Table 5.1 provides the 10-yr energy, summer demand, and winter demand potential.

Table 5.1

Summary Results for Energy and Demand

Potential	MWh	Summer MW	Winter MW
Technical	1,174,792	224.3	128.0
Economic	845,682	164.4	110.5
Achievable	228,863	41.6	36.1
Program - $2 million	136,582	20.6	16.2
Program - $1 million	68,339	10.5	8.5

5.3 Program Potential Study

Table 5.2 shows the net present value benefits, costs and benefit-cost ratios for the two program potential scenarios examined in the DSM Study. The overall cost-effectiveness ratios have decreased since the last study, but still indicate that the program potential scenarios are cost-effective overall. There are several reasons for decreased cost-effectiveness including reduced opportunity for low cost lighting savings due to changing market conditions and the effect of minimum efficiency standards required of the manufacturer established by DOE and Energy Independence and Security Act of 2007 (EISA). The avoided capacity costs used to value demand savings also decreased since the last study.

Table 5.2

Program Potential Cost-Effectiveness (TRC Test)

Potential	NPV Benefits	NPV Costs	NPV Savings (Benefits - Costs)	TRC Test Ratio
Program - $2 million	$126.3	$83.0	$43.3	1.5
Program - $1 million	$62.6	$43.8	$18.8	1.4

Based on the results of the achievable potential analysis, and based on a review of energy efficiency programs currently offered, Big Rivers plans to continue funding for the following energy efficiency programs as part of its DSM portfolio and will evaluate new opportunities. The cost effectiveness of many of the residential programs are lower than the 2014 DSM Study, primarily as a result of the change in avoided cost and therefore the programs and budgets will be reevaluated in the next year:

Table 5.3

List of Programs Evaluated in the Study

Sector	Program Name
Residential	Residential Lighting Program
Residential	Residential Efficient Appliances Program
Residential	Residential HVAC Program
Residential	Residential HVAC Tune-Up Program
Residential	Residential New Construction Program
Residential	A La Carte Individual Prescriptive Program
Commercial/Industrial	C&I Prescriptive Lighting Program
Commercial/Industrial	C&I Prescriptive HVAC Program
Commercial/Industrial	C&I General Program
Commercial/Industrial	Outdoor Lighting LED

These programs represent the end-uses and equipment that continue to hold significant opportunity for cost-effective savings in the residential and commercial/industrial sector[47] and align with Big Rivers' current DSM offerings. It is important to note that the potential savings, benefits, and costs presented in this section are a subset of the achievable potential. The objective of the calculation of program potential is to estimate what could be achieved given specific funding levels, specifically the results shown in Table 5.1. This summary is not intended to represent specific future program designs, and is not based on actual or approved budgets in future years. Big Rivers will continue to evaluate current programs for cost effectiveness and innovative technologies entering the market.

The analysis considered program potential at two different funding scenarios: a \$2.0 million annual incentive scenario and a \$1.0 million annual incentive scenario. In each case, the residential sector was allocated 50% of the incentive budget, and the nonresidential sector was also allocated 50% of the incentive budget.

Figure 5.2 provides the program potential for the 3-year, 5-year, and 10-year program potential for each funding scenario. The \$2.0 million funding scenario program potential is 1.5% of forecast sales over the 3-

[47] Commercial and industrial customers served under Big Rivers' Standard Rate Schedule RDS – Rural Delivery Service (Big Rivers' Rural Delivery Service Tariff).

year timeframe, and rises to 4.0% across the 10-year timeframe. The $1.0 million funding scenario program potential is 0.8% of forecast sales over the 3-year timeframe, and rises to 2.0% across the 10-year timeframe.

Figure 5.2

Electric Energy (MWh) Cumulative Annual Program Potential (as a % of System Sales)

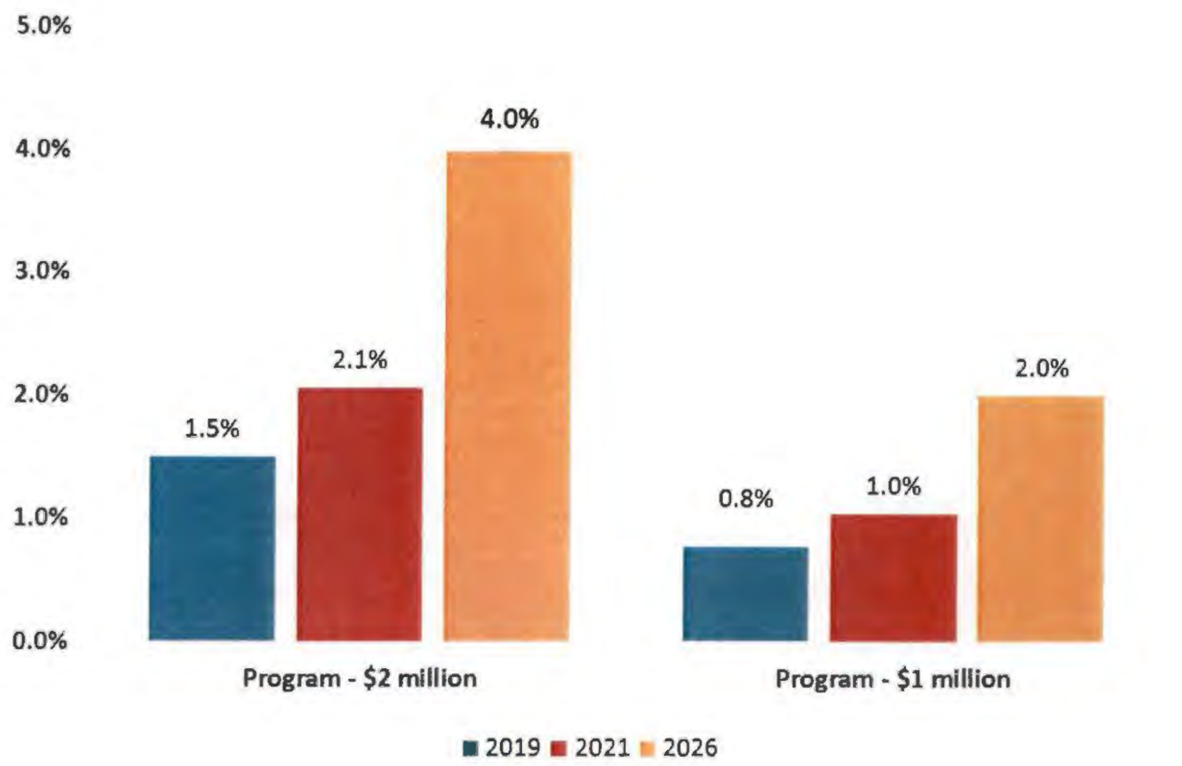


Table 5.4 provides 1-, 2-, 3-, 5-, and 10-year estimates of cumulative annual program potential for energy, summer peak demand, and winter peak demand. The $2.0 million program potential is nearly 50,000 MWh by 2019, and the $1.0 million program potential is approximately half that amount at just over 25,000 MWh. Summer peak demand program potential is 7.4 MW and 3.8 MW, respectively, for the $2.0 million and $1.0 million program potential scenarios.

Table 5.4

Program Potential Summary

	2017	2018	2019	2021	2026
Annual Energy (MWh)					
Program - $2 million	16,286	32,996	49,434	69,138	136,582
Program - $1 million	8,443	17,102	25,262	34,964	68,339
Summer Peak Demand (MW)					
Program - $2 million	2.5	5.0	7.4	10.5	20.6
Program - $1 million	1.3	2.6	3.8	5.4	10.5
Winter Peak Demand (MW)					
Program - $2 million	1.8	3.7	5.5	8.0	16.2
Program - $1 million	1.0	1.9	2.8	4.2	8.5

Table 5.5 provides a summary of the program potential for the $1 million incentive scenario. The C&I Prescriptive Lighting program provides the most potential energy savings over the next three years, followed by the Outdoor Lighting LED program and the Residential Lighting Program.

Table 5.5

$1 Million Scenario – Savings by Program

Program Name	2017	2018	2019	2021	2026
Residential Lighting Program	531	1,248	2,183	0	0
Residential Efficient Appliances Program	279	536	769	1,210	1,973
Residential HVAC Program	299	657	1,068	1,929	4,100
Residential HVAC Tune-Up Program	738	1,476	1,475	1,473	1,467
Residential New Construction Program	169	339	508	847	1,695
A La Carte Individual Prescriptive Program	460	918	1,370	3,160	7,426
C&I Prescriptive Lighting Program	4,055	8,111	12,166	16,818	32,710
C&I Prescriptive HVAC Program	561	1,122	1,684	2,806	5,612
C&I General Program	199	395	589	968	1,851
Outdoor Lighting LED	1,151	2,301	3,452	5,753	11,505
Total MWH	**8,443**	**17,102**	**25,262**	**34,964**	**68,339**

Big Rivers and its Members will continue to seek and evaluate new technologies and opportunities to benefit the Members' retail consumers and reduce the cost of energy. As the benefits of some programs wane, the falling costs and efficiency gains of new technologies will result in the need to shift spending to more effective programs and sectors.

5.4 Residential Energy Efficiency Program Potential Scenarios

The program potential assessment involved six residential programs and four C/I programs. Each of these programs was assigned an annual budget. This discussion focuses on the $1.0 million incentive scenario, and the incentives and savings estimated for each program. More detailed discussions of the programs which focus on the measures included in the programs and the estimated administrative costs are located in Appendix B, DSM Potential Study.

- **Residential Lighting Program:** Big Rivers offers a residential lighting replacement program to its Members. This program promotes use of LED bulbs by providing free bulbs at annual meetings and during Cooperative Month in October. LED bulbs are increasing in cost-effectiveness due to rapidly dropping retail prices and are expected to gain a dominant market share in the next few years.
- **Residential Efficient Appliance Programs:** Big Rivers offers two residential efficient appliance programs to its Members. The programs promote installation of efficient clothes washers and refrigerators and the removal and recycling of older inefficient refrigerators. For this 2017 DSM Study, GDS combined efficient clothes washers, efficient refrigerators and refrigerator recycling measures into a consolidated Residential Efficient Appliances program.
- **Residential HVAC Program:** Big Rivers offers a residential HVAC replacement program to its Members. This program promotes increased consideration and use of high-efficiency HVAC systems among the retail member-consumers of the Members by providing financial incentives to a Members' retail member-consumers to upgrade their HVAC systems.
- **Residential Weatherization Programs:** Big Rivers currently offers three residential weatherization programs[48] to its Members. These programs promote the implementation of weatherization measures among the retail member-consumers.
- **Residential New Construction Program:** Big Rivers offers a residential new construction program to its Members. This program provides incentives to homeowners and builders to use energy efficient building standards.
- **Residential HVAC Tune-Up Program:** Big Rivers offers a residential HVAC tune-up program to its Members. This program promotes the initiation of annual maintenance on heating and air conditioning equipment among the retail member-consumers of the Members by providing

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[48] On June 30, 2017, Big Rivers made a tariff filing with the Commission and thereby requested the Commission's approval to discontinue two of its current residential weatherization programs, and to amend the third such program. The Commission has suspended the tariffs pending its investigation and review of Big Rivers' request.

reimbursement to retail consumer-members that have their heating and cooling systems professionally cleaned and serviced.

5.5 Commercial and Industrial Energy Efficiency Program Potential Scenarios

Three program potential scenarios for the commercial and industrial sector[49] are discussed below. The discussions focus on the $1.0 million incentive scenario, and the incentives and savings estimated for each program. More detailed discussions of the programs which focus on the measures included in the programs and the estimated administrative costs are located in Appendix B, DSM Potential Study.

- **Commercial and Industrial Prescriptive Lighting Program:** Big Rivers offers a prescriptive lighting replacement program to its Members' commercial and industrial members. This program provides an incentive to commercial and industrial retail member-consumers for whom service is taken under Big Rivers' Rural Delivery Service Tariff to upgrade poorly designed and low efficiency lighting systems.
- **Commercial and Industrial Prescriptive HVAC Program:** Big Rivers offers a prescriptive HVAC program to its Members' commercial and industrial member-consumers. This program provides an incentive to commercial and industrial retail member-consumers to upgrade inefficient HVAC equipment and to maintain and tune-up their existing equipment.
- **Commercial and Industrial Prescriptive General Program:** Big Rivers offers a general program to its Members' commercial and industrial member-consumers. This program provides an incentive to retail commercial and industrial retail member-consumers served under the Big Rivers Rural Delivery Service Tariff to upgrade all aspects of cost-effective energy efficiency achievable in individual facilities.
- **Commercial and Industrial Outdoor Lighting Program:** Big Rivers offers an incentive to their Members who install high efficiency LED outdoor lighting. Outdoor lighting technology is in the process of a major technological upgrade with the use of LED lamps capable of surviving the harsh environment of an outdoor fixture. Products are being introduced continuously into the

[49] Commercial and industrial customers served under Big Rivers' Rural Delivery Service Tariff.

market for evaluation and Big Rivers' Members are in the process of converting to the longer life technologies. Successful deployment of this technology will eventually mean a substantial reduction in the cost of outdoor lighting through lower energy use, lower maintenance cost, and longer life.

5.6 Market Potential Study – Demand Response

The DSM Potential Study discusses the overall objectives and results of the market potential study. The DSM Study focused on energy efficiency programs, but also included an evaluation of possible demand response programs in Big Rivers' service territory. This Chapter 5 of the 2017 IRP provides a brief overview of the results of the demand response analysis. Section 5.4 of the DSM Potential Study provides a more complete discussion of the demand response analysis. The full study can be found in Appendix B, DSM Potential Study.

5.7 Current Demand Response Programs

Big Rivers does not currently operate any direct control programs and does not provide electric service to any retail or wholesale customers under an interruptible or curtailable contract or tariff. Big Rivers offers a Voluntary Curtailment Rider, which provides a means for potentially reducing system peak demand during peak periods. In the last fourteen years, there have been four curtailments affecting two commercial customers. The maximum estimated load reduction due to the two voluntary curtailment customers is 20-25 MW. There have been no curtailments from 2010 through 2016. See subsection 4.2.7 for more information.

5.8 Demand Response Programs Evaluated

A list of potential Demand Response (DR) programs representing the most common and most likely to be cost-effective were evaluated in this screening analysis. Big Rivers focused the analysis on the most common types of programs that a utility might use in starting a demand response initiative. If more of these programs passed the screening, the list of potential programs for screening would have been expanded. Programs not included initially, but that could have been considered if further analysis was warranted, include but are not limited to: dual fuel heat pumps, electric thermal storage (ETS) heating units for residences, ETS cooling units for commercial buildings, direct control of swimming pool pumps, and direct control of agricultural applications such as irrigators and grain dryers.

A total of fifteen programs were evaluated, with a mix of both residential and commercial incentive-based and price-based programs. Consistent with the energy efficiency evaluation, DR programs are primarily evaluated based on the TRC test, but UCT and Participant Cost Test (PCT) were also calculated. Table 5.6 provides the results of the evaluations.

Table 5.6

Demand Response Programs Evaluated Results

Sector	Program	Basis	Peak Effect	Direct Control	Summer kW Savings per Unit	Winter kW Savings per Unit
Residential	Air Conditioner - 33% Cycling	Incentive	Peak Shift	Yes	0.8	0.0
	Air Conditioner - 50% Cycling	Incentive	Peak Shift	Yes	1.1	0.0
	Water Heater - 40/50 Gallon	Incentive	Peak Shift	Yes	0.4	0.6
	Time-of-Use (TOU) Rate	Price	Peak Shift	No	0.2	0.1
	Critical Peak Pricing (CPP) Rate	Price	Peak Shift	No	1.0	0.5
	Smart Thermostat w/ CPP Rate	Incentive / Price	Peak Shift	Yes	1.4	0.5
Commercial	Distributed Generation	Incentive	Peak Clip	Yes	350.0	350.0
	Lighting - Small Application	Incentive	Peak Clip	Yes	2.1	2.1
	Lighting - Large Application	Incentive	Peak Clip	Yes	20.6	20.5
	Energy Management System (EMS)	Incentive	Peak Shift	No	11.9	11.9
	Time-of-Use (TOU) Rate	Price	Peak Shift	No	0.1	0.1
	Critical Peak Pricing (CPP) Rate	Price	Peak Shift	No	0.6	0.6
Industrial	Distributed Generation	Incentive	Peak Clip	Yes	1,000.0	1,000.0
	Energy Management System (EMS)	Incentive	Peak Shift	No	149.6	149.6
	Interruptible Rate	Price	Peak Clip	No	1,000.0	1,000.0

5.9 Conclusions for Demand Response

With Big Rivers and the region in and around MISO being long on capacity,[50] the value of demand response programs is presently low, even lower than in the 2014 DSM Potential Study. Furthermore, there are no benefits associated with avoided transmission facilities (an assumption consistent with the 2014 DSM Potential Study). Therefore, it is not surprising that most of the DR programs analyzed do not pass the TRC test. The following programs did pass the TRC test.

- **Commercial Distributed Generation:** This program passes the TRC test, but only by a small margin. The benefit cost ratio is 1.17. If there are any C&I accounts that already have distributed generation for back-up or other purposes, then Big Rivers' Members could conceivably consider approaching such customers about use of the generators for peak shaving. However, EPA rules may prohibit or limit such programs. Furthermore, many customers that own generation for emergency purposes may be hesitant to participate in a demand response program or allow a utility to have control of their resource.
- **Interruptible Rate:** This program is highly beneficial with very little cost, because the assumption is that the industrial customer is able to curtail 1 MW without additional equipment. An interruptible rate program looks highly beneficial in many DR studies even with low avoided cost benefits. Obviously, the challenge to the utility is finding candidates that meet these stringent criteria that would be willing to either change shifts or operations in order to reduce their power bills.

5.10 Recommendation

At this time, based on the 2017 DSM Potential Study's conclusions, Big Rivers has elected to not pursue a formal demand response program. Most of the typical DR programs analyzed in this screening are not cost-effective at this time, and those that are cost effective are either complicated to implement or are only marginally cost effective. Big Rivers would be better served by using its DSM budgets pursuing higher

[50] 2017 OMS MISO Survey Results showed projected sufficient resources to manage resource adequacy risk https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/Workshops%20and%20Special%20Meetings/2017/20170616%20OMS-MISO%20Survey%20Results%20Conference%20Call/2017%20OMS-MISO%20Survey%20Results.pdf

value energy efficiency programs, which do also provide peak demand reductions although overall energy reductions are the target objective. When and if capacity tightens in the region, the value of capacity should increase, approaching the avoided cost of a peaking unit. At that time, demand response programs could become cost effective. Big Rivers will, therefore, continue to monitor the cost effectiveness of DR. Based on GDS' recommendations in this study, Big Rivers will:

- Not pursue a full-scale demand response program at this time.
- Continue to monitor opportunities for demand response, looking for reduction in costs or increases in the value of avoided peaking generation.
- Monitor the opportunity of new technologies that may provide peak demand reduction benefits at a lower cost than current programs evaluated.[51]
- Encourage the Members to consider whether any existing large commercial or industrial accounts would be benefitted by an interruptible rate arrangement. If so, determine whether there is a desire on the part of the Members to offer an interruptible rate arrangement.

[51] For example, several utilities have begun to investigate pilot battery storage programs tied to residential customers that own solar generation. Such programs, however, would be cost prohibitive in Big Rivers' case given very low avoided cost benefits as batteries are currently costly pieces of equipment. Therefore, this new DR approach has not been formally evaluated as part of the 2017 DSM Potential Study.

Supply-Side Analysis and Environmental

CHAPTER 6

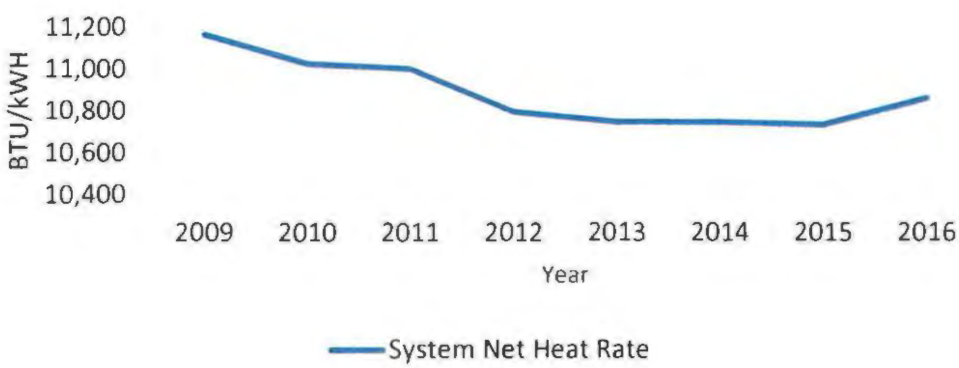
6. SUPPLY-SIDE ANALYSIS AND ENVIRONMENTAL

6.1 Generation Operations Update

Big Rivers' senior management places an emphasis on generation efficiency, and Big Rivers continues to make strides in generation efficiency improvements. For the Big Rivers base load units, the heat rate has improved 560 BTU/kWh or 5.0% in the 8-year period from 2009 to 2016. Refer to Figure 6.1.

Figure 6.1

System Net Heat Rate



System Net Heat Rate	
Year	**BTU/kWH**
2009	11,167
2010	11,025
2011	11,001
2012	10,795
2013	10,747
2014	10,745
2015	10,733
2016	10,861

2009 to 2016 Improvement	
BTU/kWH	**%**
560	5.0%

Specific generation improvement activities include:

- **Operations Training Simulators:** Big Rivers purchased Operations Training Simulators for Wilson, Green, HMP&L and Coleman Stations in 2011 and 2012 for training Control Room Operators (CROs). Well trained CROs have a significant impact on improving the generation efficiency of the units they are operating.
- **Controllable Losses:** Controllable losses are operating variables (*i.e.*, condenser back pressure, excess oxygen, boiler exit gas temperature, etc.) that the CRO can influence (control) and that have an impact on generation efficiency. Monitors are available on a real time basis for the CROs and management to visually monitor controllable losses.
- **Maintenance:** Maintenance activities remain focused on improving generation efficiency. During forced outages, the washing of air heaters, cleaning condenser tubes, replacing leaking valves and traps, and repairing air/gas leaks are some examples of tasks that are completed.
- **Instrument Tuning:** Excellent control instrument tuning is vital for improving generation efficiency when the generation units are dispatched at different loads. Big Rivers' instrument department, along with outside contractors (Asea Brown Boveri (ABB) Distributed Control System (DCS)) tuners, have continued to optimize the operation controls of the generation units to minimize any upsets while generation output is cycling.
- **Coal Pulverizer Tuning:** Good combustion is important in maintaining good boiler efficiency, and a properly tuned coal pulverizer (mill) is vital to good combustion. Big Rivers routinely checks coal fineness on the pulverizers and the amount of loss on ignition (LOI) in the boiler ash. Mill inspections are performed every 3,000 hours of operation. Also, Big Rivers periodically hires contractors to test pulverizer performance and balance coal flow through pulverizer coal pipes.

Big Rivers' generation performance continues to be very good. Table 6.1 presents the five year averages (2012-2016) of key performance indicators of the Big Rivers generating units.

Table 6.1

Key Performance Indicators per IEEE Standards

Unit	*Net Generation (MWHrs)*	*Net Heat Rate (BTU/kWH)*	*Gross Capacity Factor (%)*	*Gross Capacity Output (%)*	*Equivalent Availability Factor (%)*	*Equivalent Forced Outage Rate (%)*
Green 1	*1,536,666*	*10,970*	*77.9*	*87.3*	*91.1*	*4.0*
Green 2	*1,478,194*	*11,065*	*77.1*	*87.2*	*94.2*	*2.1*
Henderson 1	*1,007,610*	*10,657*	*76.5*	*87.8*	*85.9*	*6.8*
Henderson 2	*919,080*	*11,001*	*67.1*	*84.0*	*79.3*	*13.6*
Wilson 1	*3,156,228*	*10,546*	*86.2*	*93.9*	*91.2*	*4.3*
SYSTEM	*8,097,777*	*10,787*	*79.0*	*89.3*	*89.5*	*5.4*

Big Rivers continues to utilize the GKS® benchmarking service provided by Navigant Consulting to compare unit performance against its peers. Big Rivers' units have compared favorably, and Coleman Station won Navigant's Operation Excellence Award Top Performer in the Small Plant Category three consecutive times (five year period from 2007-2011, five year period from 2008-2012, and five year period 2009-2013). Wilson Station was awarded Runner-Up in the Medium Plant Category for the Operation Excellence Award in 2015 (five year period from 2010-2014). Also in 2015, HMP&L Station Two was awarded the Top Performer in the Small Plant Category (five year period from 2010-2014). The awards are based on detailed analysis of cost, performance and safety data from Navigant's industry-leading GKS® database, which contains data for more than seventy percent of the U.S. electric utility generation coal fleet -- representing more than 216,000 MWs of generation and more than 640 coal-fired units. The analysis of cost and performance includes a weighted comparison of non-fuel operation and maintenance costs and availability/reliability measures during the five year evaluation period. Award winners must also demonstrate safety performance in the top half of their respective comparison groups.

6.2 Resource Addition Options

See Table 6.2, below for the operating characteristics of existing Big Rivers resources.

Table 6.2

Operating Characteristics of Existing Big Rivers Resources

Plant	Unit	Location (Kentucky County)	Status	Commercial Operation Date	Type of Facility	Net Dependable Capability		Fuel Type		Typical Fuel Storage Capability	Expected Retirement Date
						Summer	Winter	Primary	Secondary		
K.C. Coleman	1	Hancock	Existing	November-1969	Steam Turbine	146	146	Coal	Natural Gas	30 days	2035
K.C. Coleman	2	Hancock	Existing	September-1970	Steam Turbine	146	146	Coal	Natural Gas	30 days	2035
K.C. Coleman	3	Hancock	Existing	January-1972	Steam Turbine	151	151	Coal	Natural Gas	30 days	2035
R.D. Green	1	Webster	Existing	December-1979	Steam Turbine	231	231	Coal	Oil	60 days	2041
R.D. Green	2	Webster	Existing	January-1981	Steam Turbine	223	223	Coal	Oil	60 days	2041
HMP&L Station Two	1	Henderson	Existing	June-1973	Steam Turbine	153	153	Coal	Oil	60 days	2035
HMP&L Station Two	2	Henderson	Existing	April-1974	Steam Turbine	159	159	Coal	Oil	60 days	2035
R.A. Reid	1	Henderson	Existing	January-1966	Steam Turbine	45	45	Coal	Oil	60 days	2025
R.A. Reid CT		Henderson	Existing	March-1978	Combustion Turbine	65	65	Gas			*
D.B. Wilson	1	Ohio	Existing	November-1986	Steam Turbine	417	417	Coal	Oil	60 days	2045

* The expected Retirement Date of the Reid CT will depend greatly on the number of operating hours experienced over the next several years.
With relatively low operating hours and continued maintenance, it should provide reasonably available capacity for a number of years into the future.

6.3 Big Rivers' SEPA Allocation

As of July 1, 2014, a Revised Interim Operations Plan from the U. S. Army Corps of Engineers reduced Big Rivers' allocation of Cumberland River system hydropower dependable capacity from 178 MW to 154 MW, and annual firm contract year energy from 267,000 MWH to 222,500 MWH. This 2017 IRP anticipates a return to Big Rivers' full contract amounts for capacity and energy in 2019. This valuable renewable resource provides diversity to Big Rivers' generation portfolio.

6.4 Purchased Power

In the preparing this IRP, interaction with the MISO Day-Ahead and Real-Time energy markets was assumed for Big Rivers' native load and generating resources. This means that all native load is purchased from MISO, and all available generation is sold to MISO, or to outside parties bilaterally, per the MISO tariff.

Generation optimization is a significant consideration in the continual development of Big Rivers' Business Plan. Optimization includes evaluation of costs to deliver Big Rivers' generation versus buying from the market. When all-in costs of purchasing capacity and/or energy are more economical than transmission and associated generation costs, those purchases are made to bring the most value to Big Rivers' Members.

6.5 Overview of Existing and New DSM Programs Included in the Plan

Big Rivers initiated its current DSM programs in 2011 through a series of pilot programs to determine the effectiveness of, and demand for, a set of programs that provided incentives for retail member-consumers served under Big Rivers' Rural Delivery Service tariff. Retail member-consumers responded to the programs positively and the programs were moved to tariffed programs in 2012. Since their inception, the DSM programs have remained consistent with some minor changes to adapt to shifting market conditions and innovations in efficiency.

One major change occurred in 2017 with the withdrawal of Sherlock Homes from the weatherization contractor market. Sherlock Homes was the third-party weatherization contractor selected by Big Rivers to perform whole-house weatherization and duct sealing for the Members on a turnkey basis. By providing fully integrated weatherization services, Sherlock Homes was able to reliably and quickly put in place an effective and high quality weatherization process. Unfortunately, as utilities in other states moved away from weatherization programs, Big Rivers was not a large enough market to maintain Sherlock Homes' revenue requirements and, consequently, Sherlock Homes notified Big Rivers that it could no longer service Big Rivers. Consequently, on June 30, 2017, Big Rivers made a DSM tariff filing with the Commission to withdraw its two residential weatherization tariffs and to modify the remaining weatherization A La Carte program to allow the retail member-consumer to select the contractor for duct sealing. Table 6.3 lists the DSM programs offered throughout 2016 and into 2017 by residential and commercial measures.

Table 6.3

DSM Programs Offered

Residential Programs	Units	Unit Quantity	Spend 2016
DSM-01 High Efficiency Lighting Replacement	bulbs	40483	$65,514
DSM-02 Energy Star Clothes Washer Replacement	unit	497	$40,260
DSM-03 Energy Star Refrigerator Replacement	unit	301	$23,350
DSM-04 Residential High Efficiency HVAC	unit	257	$58,850
DSM-05/DSM-10/DSM-13 Residential Weatherization	homes	231	$337,106
DSM-06 Touchstone Energy New Home	homes	3	$5,000
DSM-07 Residential HVAC Tune-Up	unit	585	$14,625
Commercial/Industrial (C/I) Programs			
DSM-08 C/I High Efficiency Lighting	kW saved	315	$110,114
DSM-09 C/I General Energy Efficiency	kW saved	127	$44,289
DSM-07 C/I HVAC Tune-Up	Units	589	$22,150
DSM-11 C/I High Efficiency HVAC	ton	75	$5,612
Other			
DSM-12 High Efficiency Outdoor Lighting	fixture	1,748	$122,360
Total			$849,230

Big Rivers budgets $1.0 million annually for DSM programs, and in 2016, the incentive spend was $849,230 for incentives with an additional $54,800 in promotional expenses, for a total 2016 spend of $904,030. The balance of the 2016 budget was rolled over to the 2017 DSM budget. The Members have increased promotional efforts in 2017 in an effort to increase retail member program participation. Big Rivers is working with its Members to provide design and production work of promotional material such as bill inserts and billboard design. Big Rivers is also providing funding to the Members to update websites to more effectively communicate the benefits of energy efficiency to the retail member-consumers. Details of each of Big Rivers' DSM programs are located within Big Rivers' Rural Delivery Service tariff which is on file at the Commission.[52]

Based on the analysis and recommendations in the DSM Potential Study of this 2017 IRP, and the loss of a qualified weatherization contractor, Big Rivers and its Members will evaluate the current programs and modify those programs to maintain cost effectiveness and technological relevance. Big Rivers and its Members will continue to study and evaluate other regional energy efficiency programs and promotional efforts as well as monitor other utility innovation in DSM through such publications as Best Practices Knowledgebase articles published on Cooperative.com and The 2016 State Energy Efficiency Scorecard published by the American Council for an Energy-Efficient Economy.[53]

In response to Commission Staff's recommendation from the 2014 IRP, Big Rivers considered Duke's education program and determined, in consultation with its Members, designing an educational program built around Big Rivers' solar education and demonstration project would be beneficial at this time.

Also in response to Commission Staff's recommendation from the 2014 IRP, Big Rivers considered environmental costs in the DSM evaluation conducted for this IRP. No federal or state carbon emission legislation has been passed since 2014. For this reason, the DSM evaluation assumes a cost of $0/ton of

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[52] See Tariff Sheet Nos. 3 through 23.04 of Big Rivers' current tariff on file at the Commission: http://psc.ky.gov/tariffs/Electric/Big%20Rivers%20Electric%20Corporation/General%20Tariff.pdf

[53] See http://aceee.org/state-policy/scorecard

carbon emissions in the avoided energy and capacity costs. This assumption properly estimates the cost of complying with environmental regulations at the present time. Big Rivers will continue to monitor state and federal policies to determine if it becomes appropriate in the future to include in its analysis any benefits related to environmental costs offset by DSM/EE programs.

Big Rivers has been offering a menu of residential and commercial energy efficiency programs since October 2011, in addition to energy efficiency consumer education, with an annual budget of $1,000,000 collected in base rates through its Rural Delivery Service (RDS) tariff. Big Rivers initially added these programs to its tariff in early 2012; two additional programs were added in June 2013.

Big Rivers continues to work with its Members to track the participation in each individual program and the impact of those enacted measures on the load of Big Rivers. Big Rivers' Members submit monthly reports to Big Rivers for reimbursement and tracking the estimated effect on future load. All demand and energy impact measurement is based on modeling from the current DSM potential study and program participation requirements administered and documented by each Member. Big Rivers believes the current evaluation, measurement and verification procedures are appropriate for tracking its current energy efficiency program impacts. No additional procedures are warranted at this time.

Big Rivers is in the process of constructing seven small solar generation sites located in the Members' service areas. These solar arrays are meant to provide demonstration of and education on photovoltaic generation to retail member-consumers and schools in the areas. Two of the arrays are located on school grounds, one in a county park and the rest are located at Members' offices. This project will include offering web access to cost and production data, and the public will be invited to visit the sites for a hands-on experience with the technology.

Future DSM program development will be influenced by the benefit/cost results of the analysis in the DSM Potential Study. The programs will continue to be as comprehensive in nature as possible for both residential and commercial retail member-consumers. Incentives will be used to influence buying decisions and promote education in the area of energy efficiency.

6.6 Environmental

Big Rivers' generation system consists of six coal-fired units of various sizes and vintages, one natural gas boiler, and one combustion turbine (CT). Big Rivers also operates and has the contractual right to certain amounts of the capacity and energy from two coal fired units owned by HMP&L. Table 6.4 identifies the environmental controls by operating unit:

Table 6.4

Environmental Controls on Existing Units

Unit	Net Capacity	Commercialized	SO2 Control	NOx Control	MATs
R.A. Reid 1	65 MW	1966	Natural Gas	Natural Gas	Natural Gas
K.C. Coleman 1	150 MW	1969	FGD Retrofit in 2006	Over-fired Air	None
K.C. Coleman 2	138 MW	1970	FGD Retrofit in 2006	Over-fired Air	None
K.C. Coleman 3	155 MW	1972	FGD Retrofit in 2006	Over-fired Air	None
Henderson 1	153 MW	1973	FGD Retrofit in 1995	SCR Retrofit in 2004	SCR with FGD
Henderson 2	159 MW	1974	FGD Retrofit in 1995	SCR Retrofit in 2004	SCR with FGD
R.D. Green 1	231 MW	1979	FGD	Coal re-burn	DSI/Carbon with FGD
R.D. Green 2	233 MW	1981	FGD	Coal re-burn	DSI/Carbon with FGD
D.B. Wilson	417 MW	1986	FGD	SCR Retrofit in 2004	SCR with FGD
R.A. Reid CT	65 MW	1976	Natural Gas	Natural Gas	Natural Gas

6.6.1 Clean Air Regulations – Cross State Air Pollution Rule

EPA implemented the Cross State Air Pollution Rule (CSAPR) on January 1, 2015, to replace the Clean Air Interstate Rule (CAIR) that was previously vacated by federal courts on July 11, 2008. CSAPR requires twenty-three states to reduce annual SO_2 and NO_x emissions to help downwind areas attain the 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 emissions. As was the case in CAIR, the EPA provides serialized allowances that are surrendered to track emissions. Allowances that are not utilized in the year provided by EPA are "banked" in the account for future use.

Phase I allowances issued by the EPA under CSAPR ran from January 1, 2016, through December 31, 2016, and Phase 2 allowances began January 1, 2017. Accounts for Phase 2 allowances have been populated through 2018. Phase 2 allowance allocations were reduced by approximately 55 percent for SO_2, 10 percent for NO_x annual, and 50 percent for NO_x seasonal as compared to Phase 1 allocations. The EPA has indicated that seasonal Phase 1 NO_x allowances not utilized for compliance in previous years, also known as banked Phase 1 NO_x seasonal allowances may be reduced in value depending upon an analysis by the EPA on actual emissions in 2015 and 2016 as compared to the allocations that were available. EPA has not, as of August 24, 2017, issued any final directive on the possible reduction in value of banked seasonal Phase I allowances.

Phase 2 NO_x allowances issued under CSAPR are surrendered at a rate of one allowance for each ton of NO_x emitted for both the annual program and the seasonal program which runs from May 1 to September 30 each calendar year. With both Coleman Station and Reid Station idled, Big Rivers has sufficient allocations of allowances to cover both the annual and seasonal emissions.

SO_2 allowances issued to Big Rivers under CSAPR are sufficient to meet the emissions of the operating facilities. Additionally, Big Rivers maintains a bank of approximately 28,000 SO_2 allowances as projected through 2017.

6.6.2 Mercury and Air Toxics Standards

The date for compliance with MATS was April 16, 2015. Big Rivers requested a one year delay, as allowed by the rule, from the Kentucky Division for Air Quality (KYDAQ)[54] for the Green Station, Reid/HMP&L Station II and Wilson Station. KYDAQ approved these requests,[55] and the new compliance date was April 16, 2016.

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[54] Commonwealth of Kentucky, Energy and Environment Cabinet, Department of Environmental Protection, Division for Air Quality.

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

To meet the MATS requirements, Big Rivers 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. Wilson Station has SCR and FGD systems already in service which control mercury. Big Rivers updated Wilson's existing DSI system in 2016 to make it more reliable. HMP&L Station Two Units 1 and 2 also have an SCR and FGD scrubber in service which control mercury. Coleman Station units were idled in May 2014, and therefore, have not operated past the April 2015 compliance date for MATS; controls will not be required until the units are restarted. Reid Station Unit 1 Title V permit is under review by the KYDAQ to utilize four (4) existing natural gas burners in place of the coal burners. Approval by KYDAQ will allow the Reid Station Unit 1 to operate on natural gas without additional controls for MATS.

The MATS rule is currently under litigation; however, the EPA asked the United States Court of Appeals for the D.C. Circuit court to hold in abeyance its ruling until the current EPA files its decision on the Supplemental Finding for costs the prior EPA developed. Depending upon the outcome, Big Rivers 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.

6.6.3 Coal Combustion Residuals

Coal Combustion Residuals (CCR) are residues from the combustion of coal and include fly ash, bottom ash, and scrubber waste. The EPA published the final rule regulating the disposal of CCR waste in the Federal Register on April 17, 2015 (CCR Rule). The 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.

Big Rivers operates three facilities that utilize ash pond (surface impoundments) - Coleman Station, Green Station, and Reid/HMP&L Station. Big Rivers installed groundwater monitoring as required by the rule around the Green and Reid/HMP&L ash pond. Coleman Station, which Big Rivers idled in May, 2014, 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.

Big Rivers operates two special waste landfills, one located at the Green Station and one located at Wilson Station. Both landfills had existing groundwater monitoring wells that are used to comply with the CCR requirement.

Finally, Big Rivers has established a publicly-accessible web site and has populated the site with the reports and studies required to date.

6.6.4 Effluent Limitations Guidelines

The EPA published in the Federal Register on November 3, 2015, the Effluent Limitations Guideline (ELG) rule, that imposed compliance dates and best available technology economically achievable (BAT) effluent limitations and pretreatment standards for steam electric power generation. The new standards and compliance dates apply to the following waste streams: fly ash transport water, bottom ash transport water, FGD wastewater, flue gas mercury control wastewater, and gasification wastewater. Big Rivers, in response to this rule, contracted with Burns and McDonnell to evaluate technology for compliance with the rule.

Burns and McDonnell issued a final Green Station CCR/ELG Compliance report on July 11, 2017. The report recommended [redacted]

The compliance dates listed above may be changed due to pending litigation of the rule and the EPA's notice that they have announced plans to conduct a rulemaking to potentially revise the new, more stringent BAT effluent limitations and pretreatment standards for existing sources. The EPA published in the Federal Register on June 6, 2017, a notice that compliance dates would be postponed until EPA completes reconsideration of the 2015 rule. To date, the EPA has not finalized its decision on the rulemaking. Big Rivers will continue to monitor the actions taken by the courts and the EPA and adjust compliance requirements and construction dates as appropriate.

6.6.5 Clean Water Act, Section 316(b)

Section 316(b) of the Clean Water Act (CWA § 316(b)) requires existing 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. There are two main components to the final rule, pursuant to CWA § 316(b), that affect Big Rivers.

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. There are seven options for meeting the best control technology available for reducing impingement. Second, facilities that withdraw 125.0 million gallons or more of cooling water 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 by cooling water systems.

Big Rivers' D.B Wilson Station 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. Big Rivers completed the study for Wilson Station in 2017 and submitted it to the Kentucky Division of Water (DOW)[56] for its review. Wilson Station already utilizes the 'Best Available Control

[56] Commonwealth of Kentucky, Energy and Environment Cabinet, Department of Environmental Protection, Division of Water.

Technology (BACT)' with a closed cooling water system; therefore, Big Rivers does not anticipate additional technology will be required at Wilson Station.

Big Rivers 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 5-year cycle of the issued permit. The Sebree Station units utilize closed cooling technology on four of the five units that comply with the BACT; the Reid Station Unit 1 is a once-through cooling system. Big Rivers anticipates the intake structure may need to be modified by installing a new fine screen with a fish return system at the intake as a result of the once-through cooling system utilized at Reid Station Unit 1.

When operational, Coleman Station withdraws more than 125.0 million gallons of water per day for the once-through cooling system. Since the Coleman Station is currently idled, Big Rivers submitted a request to the DOW with the Coleman Station 2017 KPDES permit renewal to begin the required studies within six months after the station returns to operational status.

6.6.6 Clean Power Plan

The Clean Power Plan (CPP) was designed to reduce carbon dioxide from fossil fuel power plants. On February 9, 2016, the United States Supreme Court stayed the implementation of the CPP. President Donald Trump signed an Executive Order on March 3, 2017, that in addition to other directives, directed the EPA Administrator to review, and if necessary, revise or rescind regulations that may place unnecessary burdens on coal-fired utilities. On April 4, 2017, in response to the Executive Order, the EPA published notice in the Federal Register that the EPA is reviewing and, if appropriate, will initiate proceedings to suspend, revise or rescind the CPP. Additionally, the EPA sent a letter dated March 30, 2017, to Matt Bevin, Governor of the Commonwealth of Kentucky, stating that "… States and other interested parties have neither been required nor expected to work towards meeting the compliance dates set in the CPP."

Collectively, these actions have stopped the implementation of the CPP to date. Based upon these aforementioned actions, Big Rivers has suspended further development of any specific strategy to comply with the CPP. Big Rivers will continue to monitor judicial, executive, and legislative action. In the event the CPP is restarted, Big Rivers will resume the task of developing a compliance plan commensurate with the rules included in the regulation at that time.

6.7 Environmental Summary

Big Rivers has completed an analysis of the newly finalized regulations and has prepared a plan to achieve compliance within the time allowed by the regulations. See Table 6.5 for the Wilson and Sebree Stations' CCR/ELG Compliance cost data. This plan may be modified by the outcome of litigation against nearly every newly proposed regulation. Big Rivers will continue to monitor the outcome of the litigation and any necessary adjustments to meet modified compliance limits or schedules.

Table 6.5

CCR/ELG Compliance Cost

Cost Data ($ millions)

Plant	Regulations	Project	2020	2021	2022	Total
Green Station (Coal)	ELG/CCR	[redacted]				
Green Station (Coal) Total						
HMP&L Station Two (Coal)	ELG/CCR					
HMP&L Station Two (Coal) Total						
Wilson Station (Coal)	**ELG/CCR**					

Electric Integration Analysis

CHAPTER 7

7. ELECTRIC INTEGRATION ANALYSIS

Big Rivers' resource assessment and acquisition plan provides an adequate and reliable supply of electricity to meet forecasted electricity requirements at the lowest possible cost. Big Rivers considered the potential impacts of selected, key uncertainties as described in this chapter and developed potentially cost-effective resource options.

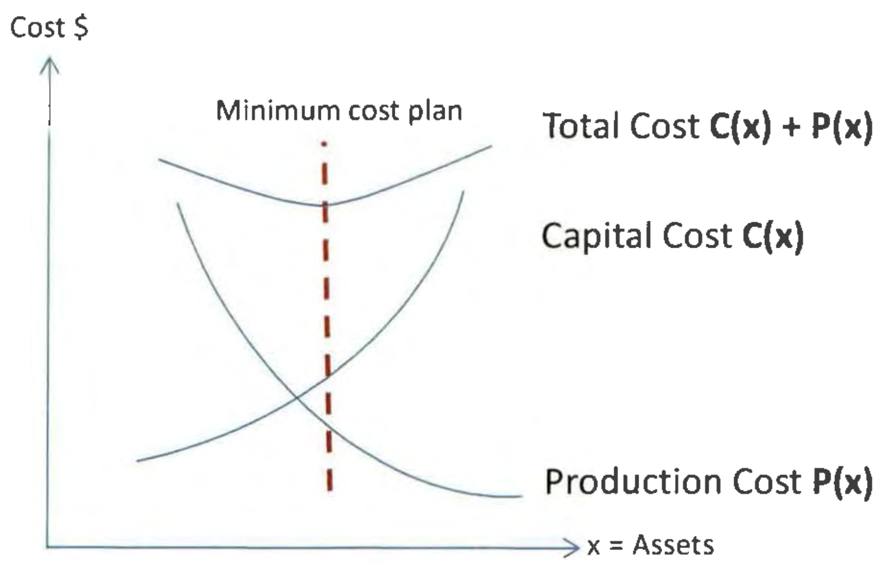
7.1 In-House Production Cost Model (Plexos®)

Prior to 2015, Big Rivers utilized a third party to perform production cost modeling. However, in February 2015, Big Rivers purchased Energy Exemplar's production cost modeling software *Plexos®*. *Plexos®* was chosen due to its vast production cost modeling capabilities. By May 2015, *Plexos®* had been installed on the newly purchased servers and training webinars on *Plexos®* had been completed by the Strategic Planning and Risk Management department. Since May 2015, the Strategic Planning and Risk Management group have been familiarizing themselves with the capabilities of this robust software. Utilization of the *Plexos®* ST Plan® model, which emulates a market clearing engine for detailed analysis, has been significant over the last two years.

For the IRP modeling, the *Plexos®* LT Plan® (long-term capacity expansion planning optimization model) develops Big Rivers' optimal portfolio of energy resources and any future capacity. The LT Plan® model uses advanced algorithms that analyze all the possible portfolio options based on the inputs and the constraints entered and provides the certainty of what and when to optimally invest or retire capacity resources. The LT Plan® objective is to minimize the net present value (NPV) of the capital and production costs formulated as a mixed-integer problem. The capital costs include cost of new generation builds or environmental compliance and cost of generation retirements. The production costs include the cost of operating the system and the notional cost of unserved energy (calculates the market interaction). This optimum option selected is the least cost option for that unique input and constraint parameter.

Figure 7.1

PLEXOS® LT Plan Optimization



7.1.1 Modeling Overview

Big Rivers developed its Base Case using inputs, constraints and assumptions based on the best information available at the time this IRP was prepared. Multiple scenarios with changes in input variables were analyzed. The Base Case and the scenarios utilized the Big Rivers' 2016-2030 Long-Term Financial Plan with the following updates:

- 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
- Updated load utilizing the 2017 Load Forecast

The LT Plan® model determines the least-cost option by utilizing the generating resource options listed below. The 2016-2030 Long-Term Financial Plan includes environmental compliance with CCR and ELG assuming Green Station units and HMP&L Station Two units remain coal-fired. In the LT Plan® modeling for the Base Case and the scenarios, costs have been entered for the generator resource options that include the existing generators and new generating resources and the LT Plan® is determining the least cost option inclusive of environmental strategy, as converting to gas, and/or retiring early, and/or staying on coal are some of the possibilities to help Big Rivers achieve compliance with environmental regulations. Big Rivers' analysis utilized the following generation resource options:

- Wilson remain coal-fired through 2019 and beginning in 2020 can either remain coal-fired or retire. 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.
- Green units must 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 197MW unit (the current Big Rivers contractual allocation of Station Two capacity) and must remain coal-fired through 2019. Beginning in 2020, HMP&L Station Two can remain coal-fired, convert to natural gas or Big Rivers can exit the contract with the City of Henderson.
- Reid CT remains a resource as a natural gas fired unit
- SEPA is modeled assuming Big Rivers 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.

The LT Plan® model constraints are set up to meet capacity reserve margin requirements but there are no constraints on the volume (kWh) being produced from the generation resources. The model works exactly the way MISO works. All the load is purchased at the market price and the generation resources are economically dispatched at the market price. Therefore if the market price is higher than the cost to generate, the generator will be dispatched and vice-versa. The least-cost option may conclude that it is cheaper to buy the load from the market rather than generate from the available resources. In this example, the associated risk of purchasing from the market needs to be taken into consideration.

It should be understood that the LT Plan® model results included in this IRP do not constitute a commitment by Big Rivers for a specific course of action especially with the current uncertainty regarding environmental compliance and commodity price forecasts (coal, natural gas and market power prices). It should be understood that changes to the inputs, constraints and assumptions that impact this IRP result can, and do, occur without notice. With that said, Big Rivers has run sensitivities to the Base Case to show the impact that changing the inputs can have on the modeling results for the least cost option. Big Rivers understands that there are relationships between the inputs, i.e. natural gas prices have a relationship to energy prices, but has opted to only change one input variable at a time. Big Rivers believes there is value in this sensitivity analysis as the impact of that variable can be evaluated without scrutinizing the relationship between the other inputs. Relationships between the inputs can vary depending on the forecasts/assumptions included in the scenario. For example, natural gas prices and energy prices have a relationship but in a low natural gas forecast scenario, the relationship will vary depending on the forecast for other generation types (coal, renewables, etc.) and what generator is providing the incremental energy or setting the energy price. Therefore, when evaluating the scenario results, it is very important to know that the modeling only involved modifying one input and did not assume how modifying that input would change the other inputs. Big Rivers' sensitivities included market energy prices, coal prices, natural gas prices, load forecasts, renewable portfolio standards and an increased DSM scenario. Also, a scenario with the option to exit the HMP&L Station Two contract beginning in 2018 was completed.

7.1.2 Model Generation Resource Options

Table 7.1 shows the generation resources that are currently operating and the options that were made available for those resources in the model. The LT Plan® used these generation resources as options for determining the optimal or least-cost plan for the Base Case and each scenario.

Table 7.1

Generation Resources

Generation Resources				
Existing (Currently Operating) Big Rivers Assets				
Generation Resource	**Capacity, MW**	**Option**	**2017-2019**	**2020-2031**
Wilson Unit 1	417	Coal-Fired	X	X
		Retired		X
Green Unit 1	231	Coal-Fired	X	X
		NG Conversion		X
		Retired		X
Green Unit 2	223	Coal-Fired	X	X
		NG Conversion		X
		Retired		X
HMP&L Station 2*	197	Coal-Fired	X	X
		NG Conversion		X
		Exit Contracts		X
Reid CT	65	NG Fired	X	X
SEPA	178	Continue	X	X
		Exit Contract		X
Total	**1,311**			

*** Modeled as one unit at the net capacity for Big Rivers**

Wilson Unit 1 was modeled with two options: either remaining coal-fired or retiring in 2020 or any subsequent year thereafter. Both Green Units were modeled with three options: remaining coal-fired; converting to natural gas firing in 2020 or any subsequent year thereafter; or retiring in 2020 or any subsequent year thereafter. HMP&L Station Two was modeled: remaining coal-fired; converting to natural gas firing in 2020 or any subsequent year thereafter; or exiting the HMPL Station Two contract in 2020 or any subsequent year thereafter. However, both units were modeled as a single unit because HMP&L Station Two is owned by the City of Henderson. The City of Henderson is currently allocated 115 MW from HMP&L Station Two (Big Rivers is allocated 197 MW) and that energy can be supplied from either unit. The Reid CT is natural gas fired and was modeled as a capacity resource. Big Rivers 2016-2030 Long-term Financial Plan was the source for the fixed operating and maintenance (O&M) production costs which had anticipated compliance costs for CCR and ELG with the units remaining coal-fired. Estimates for the natural gas conversion, including natural gas supply lines, were based on budgetary information provided by multiple external sources. Equipment conversion cost information came from equipment manufacturers and pipeline cost information came from pipeline companies that build, maintain and operate natural gas pipelines. Because expected operational impacts varied, depending on the information source, Big Rivers opted to model most of the generator operation parameters for the natural gas conversion as unchanged to the coal unit. Two generator operation parameters were changed. The maximum capacity was lowered by 10% and the heat rate was increased by 6%. Also a firm gas supply charge was added for the natural gas conversion. A detailed engineering study would be required for each generating unit to determine an accurate predicted change to operation parameters resulting from conversion to burn natural gas. Retirement costs were estimated using the Coleman Station brownfield net salvage value costs provided in the formal decommissioning study performed by Burns and McDonnell for Big Rivers. The estimate for the Coleman Station was the basis for the retirement costs for the other stations; however, the retirement costs for the other stations were adjusted based on a comparison of the station sizes, the number of pieces of equipment, etc. In the 2014 IRP report, Commission Staff recommended Big Rivers include new or pending environmental regulations which may impact its generation fleet in its sensitivity analyses. The Base Case includes options for CCR, ELG and CWA § 316(b) compliance. Section 6.6.6 discusses Big Rivers' consideration of the CPP. See Table 7.2 for the Fixed O&M costs that were used in the LT Plan® models.

Table 7.2

Fixed O&M Costs

Fixed O&M Costs - $M (Source 2016-2030 Long Term Forecast)																	
Unit	Option	Fixed Costs	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Wilson	Coal Fired	Fixed O&M Cost	[redacted]														
		ECP (CCR, ELG & 316b) Capital Costs															
		Total Fixed Costs															
Unit	Option	Fixed Costs	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Green Station	Coal Fired	Fixed O&M Cost	[redacted]														
		ECP (CCR, ELG & 316b) Capital Costs															
		Total Fixed Costs															
	Natural Gas Conversion (earliest 2020)	Fixed O&M Cost															
		ECP (CCR, ELG & 316b) Capital Costs															
		Firm Gas Demand Charge															
		Total Fixed Costs															
Unit	Option	Fixed Costs	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
HMP&L Station Two (Net)	Coal Fired	Fixed O&M Cost	[redacted]														
		ECP (CCR, ELG & 316b) Capital Costs															
		Total Fixed Costs															
	Natural Gas Conversion (earliest 2020)	Fixed O&M Cost															
		ECP (CCR, ELG & 316b) Capital Costs															
		Firm Gas Demand Charge															
		Total Fixed Costs															

Retirement/Exit Contracts Costs by Year - $M																
Unit	Option	Fixed Costs	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Wilson	Retirement Earliest 2020	Net Salvage Value - Brownfield	[redacted]													
		Net Book Value														
		Total Retirement Cost														
Unit	Option	Fixed Costs	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Green Station	Retirement Earliest 2020	Net Salvage Value - Brownfield	[redacted]													
		Net Book Value														
		ECP (CCR, ELG & 316b) Capital Costs														
		Total Retirement Cost														
Unit	Option	Fixed Costs	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
HMP&L Station Two (Net)	Exit Contracts Earliest 2020	Net Salvage Value - Brownfield	[redacted]													
		Net Book Value														
		ECP (CCR, ELG & 316b) Capital Costs														
		Total Exit Contract Cost														
	Exit Contracts Earliest 2018 in Scenario	Net Salvage Value - Brownfield														
		Net Book Value														
		ECP (CCR, ELG & 316b) Capital Costs														
		Total Exit Contract Cost														

SEPA, Big Rivers' allotment of Cumberland River system hydroelectric power, was modeled with two options: either continuing the contract or exiting the contract with 2020 being the earliest date to exit. There is no penalty for exiting the SEPA contract but there is a minimum 37 month termination notice that must be given by Big Rivers to SEPA. See Table 7.3 for the SEPA volume and cost projections that were included in the LT Plan® models.

Table 7.3

SEPA Volume and Cost

SEPA			
Year	**Price (Includes Transmission) $/MWh**	**Capacity MW**	**Volume MWh**
2013	$ 24.30	Run of River	434,426
2014	$ 29.29	Run of River	311,031
2015	$ 32.99	Run of River / Weekly Sch.	274,066
2016	$ 47.95	Weekly Sch.	161,945
2017	$ 42.44	154	222,480
2018	[redacted]	154	222,000
2019	[redacted]	178	267,000
2020	[redacted]	178	267,000
2021	[redacted]	178	267,000
2022	[redacted]	178	267,000
2023	[redacted]	178	267,000
2024	[redacted]	178	267,000
2025	[redacted]	178	267,000
2026	[redacted]	178	267,000
2027	[redacted]	178	267,000
2028	[redacted]	178	267,000
2029	[redacted]	178	267,000
2030	[redacted]	178	267,000
2031	[redacted]	178	267,000

Also, see Table 7.4 for new generation resources considered in the LT Plan®. New units were modeled using cost estimates provided in the U.S. Energy Information Administration's (EIA) Capital Cost Estimates for Utility Scale Electricity Generating Plants report dated November 2016.[57]

Table 7.4

2016 EIA Capital Cost Estimates

2016 EIA Capital Cost Estimates

U.S. Energy Information Administration (EIA) Capital Cost Estimates for Utility Scale Electricity Generating Plants (November 2016)

Plant Type		Plant Characteristics		Plant Costs (2016$)					
		Capacity	Heat Rate	Overnight Capital Cost - Base Project	Location Variation (Kentucky)	Delta Cost Difference	Total Location Project Cost	Fixed O&M	Non-Fuel Variable Cost
		MW	BTU/kWh	$/kW	%	$/kW	$/kW	$/kW-yr	$/MWh
Coal	Ultra Supercritical Coal	650	8,800	$ 3,636	-7%	$ (271)	$ 3,365	$ 42.10	$ 4.60
	Ultra Supercritical Coal with CCS	650	9,750	$ 5,084	-7%	$ (345)	$ 4,739	$ 70.00	$ 7.10
	Pulverized Coal Conversion to Natural Gas (CTNG)	300	10,300	$ 226	-9%	$ (21)	$ 205	$ 22.00	$ 1.30
	Pulverized Coal Greenfield with 10-15 percent	300	8,960	$ 4,620	-10%	$ (449)	$ 4,171	$ 50.90	$ 5.00
	Pulverized Coal Conversion to 10% Biomass	300	10,360	$ 537	-10%	$ (53)	$ 483	$ 50.90	$ 5.00
Natural Gas	Natural Gas Combined Cycle (NGCC)	702	6,600	$ 978	-7%	$ (67)	$ 911	$ 11.00	$ 3.50
	Advanced Natural Gas Combined Cycle (ANGCC)	429	6,300	$ 1,104	2%	$ 26	$ 1,130	$ 10.00	$ 2.00
	Combustion Turbine (CT)	100	10,000	$ 1,101	-5%	$ (53)	$ 1,048	$ 17.50	$ 3.50
	Advanced Combustio Turbine	237	9,800	$ 678	-4%	$ (26)	$ 652	$ 6.80	$ 10.70
	Reciprocating Internal Combustion Engine	85	8,500	$ 1,342	-6%	$ (85)	$ 1,257	$ 6.90	$ 5.85
Uranium	Advanced Nuclear (AN)	2,234	N/A	$ 5,945	-3%	$ (149)	$ 5,796	$ 100.28	$ 2.30
Biomass	Biomass (BBFB)	50	13,500	$ 4,985	-10%	$ (876)	$ 4,109	$ 110.00	$ 4.20
Wind	Onshore Wind (WN)	100	N/A	$ 1,877	-4%	$ (68)	$ 1,809	$ 39.70	$ -
Solar	Solar - Photovoltaic - Fixed (PV)	20	N/A	$ 2,671	-10%	$ (272)	$ 2,399	$ 23.40	$ -
	Solar - Photovoltaic - Tracking (PV)	20	N/A	$ 2,644	-11%	$ (280)	$ 2,364	$ 23.90	$ -
	Solar - Photovoltaic - Tracking	150	N/A	$ 2,534	-9%	$ (236)	$ 2,298	$ 21.80	$ -
Storage	Battery Storage (BES)	4	N/A	$ 2,813	-3%	$ (89)	$ 2,724	$ 40.00	$ 8.00

Big Rivers did not include every option listed in the EIA report in the 2017 IRP modeling process. Many of the new generation options could be dismissed without analysis for varying reasons. Advanced Nuclear, Biomass, and Battery Storage options were dismissed due to their high costs. Onshore Wind was not considered due to the lack of viable locations for wind energy to be built in northwestern Kentucky. The Pulverized Coal Conversion to Natural Gas price projections were not used as Big Rivers had developed high level cost projections for converting its coal-fired units that will be closer to actual costs than the EIA projections. The three new generation resources that were included in the LT Plan® models are represented in Table 7.5.

[57] https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capcost_assumption.pdf

Table 7.5

New Assets (Source 2016 EIA Capital Cost Estimates)

New Assets (Source 2016 EIA Capital Cost Estimates)				
Resource Type	**Capacity, MW**	**Fuel**	**2017-2019**	**2020-2031**
Combustion Turbine	100	NG	[redacted]	X
Combined Cycle	702	NG	[redacted]	X
Solar (Fixed)	20	N/A	[redacted]	X

7.2 Modeling Results

7.2.1 Base Case Inputs/Constraints

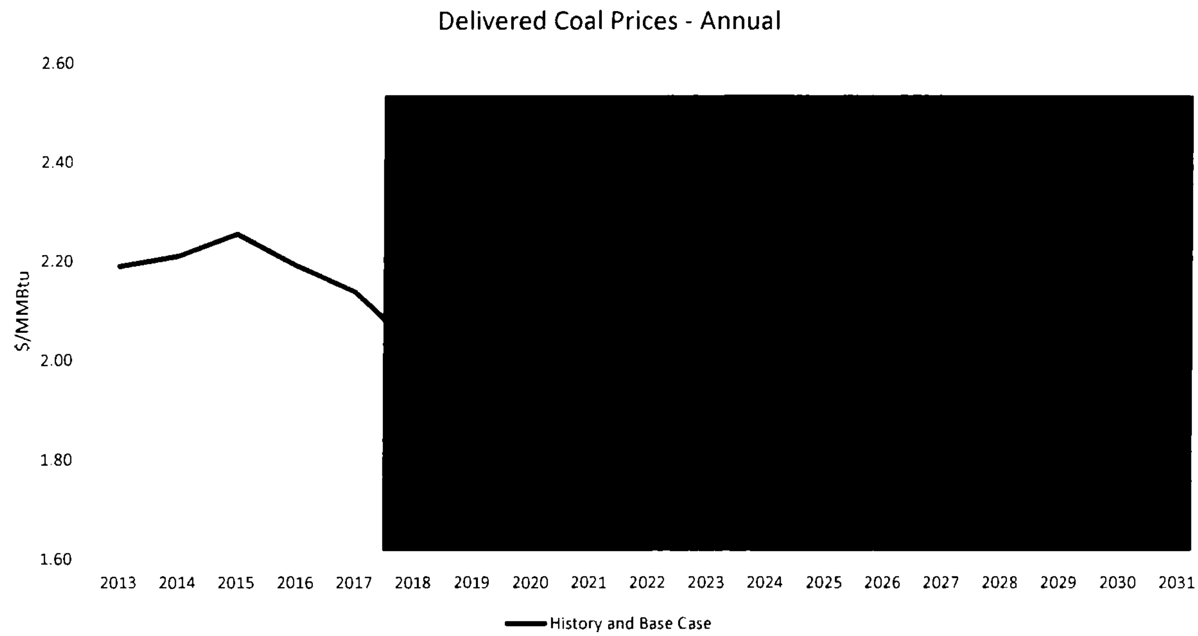
Big Rivers developed the Base Case where inputs and constraints were entered in the LT Plan® model as the best information available at the time the IRP was prepared. The inputs and constraints for the Base Case are explained in greater detail below.

- **Generation Commit:** All generators are modeled as economic commit with a minimum time of one day off and one day on with a seven day look-ahead. Therefore, the model would evaluate whether to operate the generator based on a seven day rolling economic evaluation but with the constraint that if the generator were removed from service (not operated), it would be off a minimum of one day and if the generator were put into service (operated), it would be on (operating) a minimum of one day.

- **Generation Dispatch:** All generators are modeled as economic dispatch with the operating parameters provided for that particular unit (max and min capacity, heat rate, unit outage rate, planned outages, etc.) that were utilized in the 2016-2030 long term financial plan.
- **Production Fixed Costs:** The production fixed costs utilized were sourced from the 2016-2030 long term financial plan. The 2016-2030 long term financial plan includes compliance with existing environmental regulations (CSAPR, MATS, etc.) and future compliance with new environmental regulations (CCR, ELG and CWA § 316(b)) assuming the units continue operating as coal-fired units. Also, Big Rivers has consulted with various outside vendors to develop a cost estimate for natural gas conversion for the Green Units and HMP&L Station Two. Additionally, Big Rivers utilized the Coleman Station brownfield cost forecast to estimate the retirement cost for its coal-fired units. In Table 7.2, estimates are provided for compliance with environmental regulations as natural-gas fired units and retirement.
- **Production Non-Fuel Variable Costs and Generator Operating Parameters:** The production non-fuel variable cost and the generator operating parameters (i.e. heat rate, outage rate, etc.) were modeled consistent with the 2016-2030 long-term financial plan, and are available in Technical Appendix F.
- **Coal Prices:** Current contract prices and spot prices were utilized through 2020 and prices thereafter were inflated using JD Energy long term fuel forecast from May 2017 (see Appendix G). Figure 7.2 below displays annual spot coal prices with historical prices from 2013 and forecasted prices through 2031. It can be seen that prices peaked in 2015 and have dropped the last two years. The forecast shows the prices to [redacted].

Figure 7.2

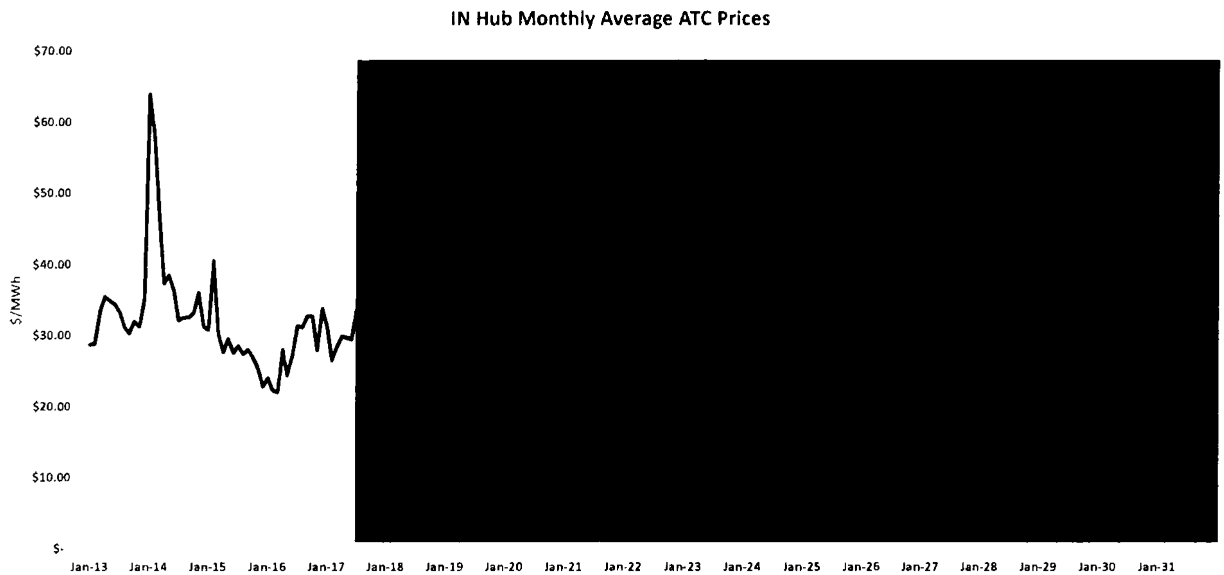
Delivered Coal Prices



- **Energy Market Prices:** Energy market price forecasts were received from a third party, ACES (ACES methodology for energy market price forecasts can be seen in Appendix G). Average monthly energy market prices are shown in Figure 7.3 for the day-ahead IN Hub LMP price. Historical prices from January 2013 to May 2017 and forecasted prices through December 2031 were included in the graph below. The historical prices have not been adjusted to normalized weather (forecasted prices are predicting normalized weather). The impact that the 2014 Polar Vortex had on energy prices is easily seen. Also, forecasted energy prices are currently [redacted].

Figure 7.3

IN Hub Monthly Average Around the Clock (ATC) Prices



- **<u>Capacity Prices:</u>** Capacity price forecasts were based upon internal evaluations of the market and are shown in the table below. Historical MISO capacity auction prices are shown beginning with the 2014/2015 planning year through the 2017/2018 planning year with forecasted prices beginning in the 2018/2019 planning year. Also, Big Rivers has hedged or presold capacity and those prices have been included in the table. The LT Plan® did not use the hedged capacity prices and only used the forecasted capacity prices in the modeling. See Table 7.6 Capacity Price Forecast, below.

Table 7.6

Capacity Price Forecast

MISO Capacity Auction Price		
Planning Year	$/MW-Day	
14/15	$ 16.75	
15/16	$ 3.48	Hedged Capacity
16/17	$ 72.00	$/MW-Day
17/18	$ 1.50	[redacted]
18/19	[redacted]	
19/20		
20/21		
21/22		
22/23		
23/24		
24/25		
25/26		
26/27		
27/28		
28/29		
29/30		
30/31		
31/32		

- **Natural Gas Prices:** Price forecasts were provided from a third party, ACES. A firm gas supply is expected to be required for generation resources to receive capacity payments from MISO in the future, therefore, a firm gas supply demand charge was added to the fixed O&M costs on the firm gas capacity required for the natural gas conversion models. The forecasted firm gas demand charge can be seen below in Table 7.7

Table 7.7

Firm Gas Demand Charge Forecast

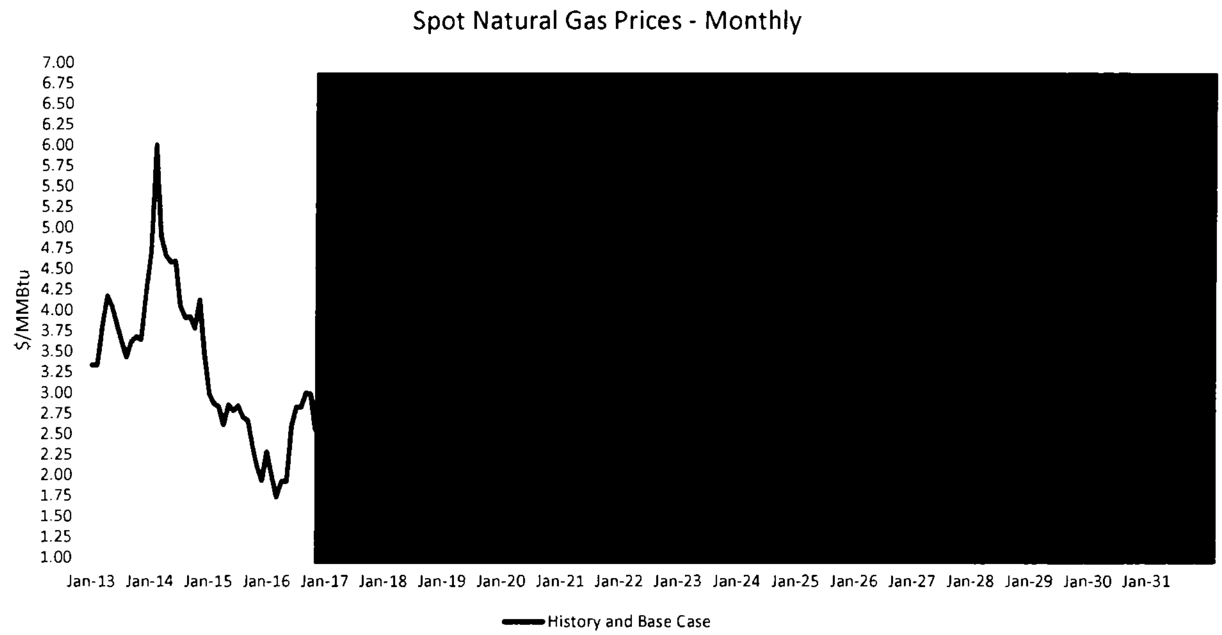
Year	Green Station Max Heat input = 4,764 MMBtu/Hr		HMP&L Station Two Max Heat input = 2,067 MMBtu/Hr	
	$/MMBtu	$M	$/MMBtu	$M
2020	[redacted]			
2021				
2022				
2023				
2024				
2025				
2026				
2027				
2028				
2029				
2030				
2031				

Annual Inflation Rate = [redacted]

- See Figure 7.4 below for monthly average spot natural gas prices with the Henry Hub historical prices from January 2013 to April 2017 and forecasted prices through December 2031. Note that historical gas prices are quite volatile while the forecast prices are [redacted].

Figure 7. 4

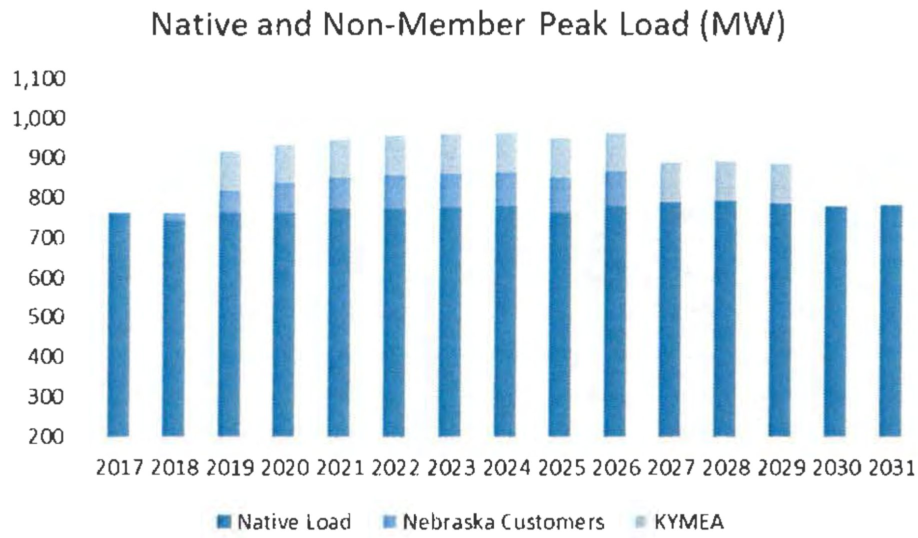
Natural Gas Prices



- **<u>Load Forecast:</u>** Load forecasts were provided by GDS. See Appendix A for Long Term Load Forecast Report.
- **<u>New Non-Member Load:</u>** Load forecasts for the Nebraska contracts and KyMEA contract were developed internally with the Nebraska contracts beginning in January 2018 and ending December 2026 and the KyMEA contract beginning in June 2019 and ending in May 2029. See Figure 7.5 below.

Figure 7.5

Non-Member Load included in Base Case



- **<u>Reserve Margin:</u>** The reserve margin constraints used in the LT Plan® were 15.8% minimum and 105% maximum. The minimum constraint was developed internally (and discussed in section 9.3 of this report). The maximum constraint was calculated to allow a new natural gas combined cycle unit (702 MW) to be constructed if existing units were retired and the new natural gas combined cycle could be constructed more cost effectively.
- **<u>SEPA:</u>** The SEPA price and volume forecast was developed internally based on the best information available. The model has the option of continuing the SEPA contract or exiting the contract beginning in 2020 or any year thereafter.

7.2.2 Base Case Results

The optimal (least cost) plan for the Base Case resulted in exiting the HMP&L Station Two contracts in 2020 (the first year possible under the model constraints) with no changes to the other units' operation and with no new generation resources being built. For years beyond 2020, the lowest reserve margin occurred in 2026 at 33.6% and in 2031 the reserve margin is 65.0%.

As noted, the model runs iterations to solve to the optimal solution. The lowest reserve margin occurred in 2026 at 33.6% and in 2031 the reserve margin is 65.0%; however, if reserve margin is calculated including only Big Rivers' base load resources, the reserve margins are drastically lower at 4.4% and 29.0%, respectively. Further, these reserve margins are calculated assuming only Big Rivers' current load and current contractual agreements. Big Rivers has made significant strides in the last few years to place available generation in long-term contracts and anticipates making significant strides in the coming years as well. See Tables 7.8, through 7.11, and Figures 7.6 and 7.7, below.

Table 7.8

Base Capacity Summary

Base Case Capacity Summary											
Year	Generation Resource Capacity, MW			Noncoincidence Peak Load, MW			Total Coincidence Peak Load	Reserve Capacity Margin		Baseload Reserve Capacity	
	Existing	New	Total	Native	Nebraska	KyMEA		MW	%	MW	%
2017	1,287	0	1,287	660	0	0	660	627	95.0%	408	61.8%
2018	1,287	0	1,287	645	19	0	659	628	95.3%	409	62.1%
2019	1,311	0	1,311	658	56	100	793	518	65.3%	275	34.7%
2020	1,114	0	1,114	661	75	100	809	305	37.7%	62	7.7%
2021	1,114	0	1,114	662	76	100	820	294	35.9%	51	6.2%
2022	1,114	0	1,114	663	85	100	828	286	34.5%	43	5.2%
2023	1,114	0	1,114	664	85	100	830	284	34.2%	41	4.9%
2024	1,114	0	1,114	665	86	100	832	282	33.9%	39	4.7%
2025	1,114	0	1,114	666	86	100	821	293	35.7%	50	6.1%
2026	1,114	0	1,114	667	87	100	834	280	33.6%	37	4.4%
2027	1,114	0	1,114	669	0	100	769	345	44.9%	102	13.3%
2028	1,114	0	1,114	670	0	100	770	344	44.7%	101	13.1%
2029	1,114	0	1,114	672	0	100	765	349	45.6%	106	13.9%
2030	1,114	0	1,114	674	0	0	674	440	65.3%	197	29.2%
2031	1,114	0	1,114	675	0	0	675	439	65.0%	196	29.0%

Table 7.9

Base Case Volume Summary

Base Case Volume Summary (MWh)								
Year	Generation Volume, MWh			Load, MWh				Length
	Existing	New	Total	Native	Nebraska	KyMEA	Total	Long/(Short)
2017	5,976,157	0	5,976,157	3,156,209	0	0	3,156,209	2,819,948
2018	5,219,133	0	5,219,133	3,343,329	59,408	0	3,402,737	1,816,396
2019	5,365,444	0	5,365,444	3,433,186	202,266	269,000	3,904,452	1,460,992
2020	4,410,265	0	4,410,265	3,473,018	275,474	574,500	4,322,992	87,273
2021	4,256,373	0	4,256,373	3,474,918	279,173	536,500	4,290,591	(34,218)
2022	3,911,451	0	3,911,451	3,478,707	314,596	519,900	4,313,203	(401,752)
2023	3,805,343	0	3,805,343	3,481,099	315,798	499,500	4,296,397	(491,054)
2024	3,806,880	0	3,806,880	3,490,022	316,976	513,200	4,320,198	(513,318)
2025	4,006,316	0	4,006,316	3,495,570	318,215	521,000	4,334,785	(328,469)
2026	4,120,041	0	4,120,041	3,501,955	319,484	564,200	4,385,639	(265,598)
2027	4,503,356	0	4,503,356	3,508,874	0	596,600	4,105,474	397,882
2028	4,515,088	0	4,515,088	3,520,656	0	624,500	4,145,156	369,932
2029	5,072,089	0	5,072,089	3,526,034	0	303,400	3,829,434	1,242,655
2030	5,326,338	0	5,326,338	3,535,249	0	0	3,535,249	1,791,089
2031	6,087,799	0	6,087,799	3,544,277	0	0	3,544,277	2,543,522

Table 7.10

Production Costs

System															
Production Cost -(1.95% Annual Inflation)		2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Production Cost (Nominal)	Total Production Cost, $000 (Incl. SEPA)	[redacted]													
	Total Production Cost, cents/kWh (Incl. SEPA)														
	Total Fixed O&M Cost, $000 (No SEPA)														
	Total Fixed O&M Cost, $/kW-yr (No SEPA)														
	Total Variable Cost, $000 (No SEPA)														
	Total Variable Cost, cents/kWh (No SEPA)														
Production Cost -(2017$)		2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Production Cost (Real)	Total Production Cost, $000 (Incl. SEPA)	[redacted]													
	Total Production Cost, cents/kWh (Incl. SEPA)														
	Total Fixed O&M Cost, $000 (No SEPA)														
	Total Fixed O&M Cost, $/kW-yr (No SEPA)														
	Total Variable Cost, $000 (No SEPA)														
	Total Variable Cost, cents/kWh (No SEPA)														
Operating Performance -KPIs		2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
KPIs	Net Capacity (Summer), MW	1,287	1,311	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114
	Net Capacity (Winter), MW	1,287	1,311	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114
	Net Generation, GWh	5,219	5,365	4,410	4,256	3,911	3,805	3,807	4,006	4,120	4,503	4,515	5,072	5,326	6,088

Table 7.11

Net Present Value Base Case

BIG RIVERS ELECTRIC CORPORATION
INTERGRATED RESOURCE PLAN
BASE CASE NET PRESENT VALUE

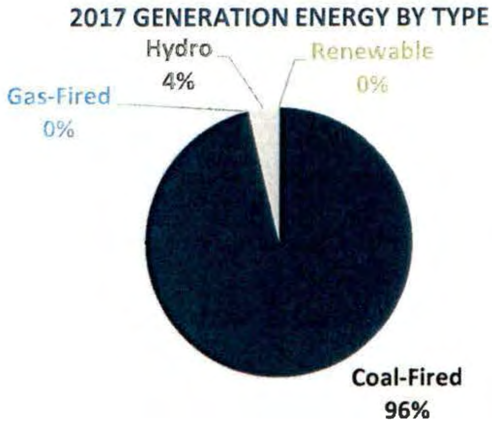
	Utility Costs ($000)											
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)=(1)th-u(9)-(10)-(11
	Load Cost (Energy)	Load Cost (Capacity)	Fuel Costs	FOM	Non-Fuel VOM	Emissions Cost	EE Program Costs	Annualized Build Costs	Retirement/Exit Costs	*Less: Market Revenue*	*Less: Capacity Revenue*	Net Utility Costs
	[redacted]						$000	[redacted]				
2018							1,000					
2019							1,000					
2020							1,000					
2021							1,000					
2022							1,000					
2023							1,000					
2024							1,000					
2025							1,000					
2026							1,000					
2027							1,000					
2028							1,000					
2029							1,000					
2030							1,000					
2031							1,000					
NPV							6,244					

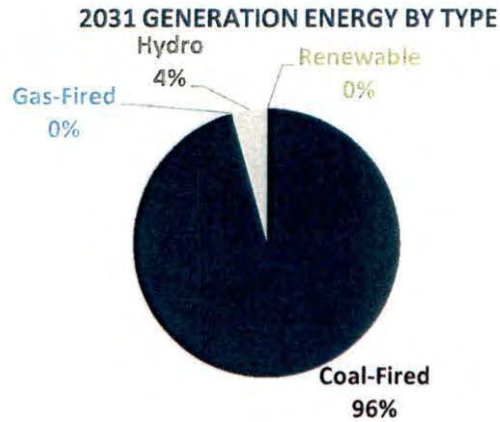
Figure 7.6

Base Case Generation Capacity (MW) by Fuel Type

Figure 7.7

Base Case Generation Energy (MWH) by Fuel Type





7.2.3 Scenario Modeling

Seven model scenarios were run with the descriptions and the results of the scenarios shown below.

7.2.3.1 Market Energy Price Scenarios

In this scenario, the market energy price forecast (Locational Marginal Pricing *or* LMP) was 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. For the higher price scenarios, there were no changes in the least-cost option from the Base Case at 10% higher prices and HMP&L Station Two remained in operation on coal at 20% higher prices. For the lower price scenarios, both Green Units were converted to natural gas at 10% and 20% lower prices. See Figure 7.8 and Table 7.12 below for prices and energy scenarios.

Figure 7.8

Market Energy Price IN Hub Average Prices

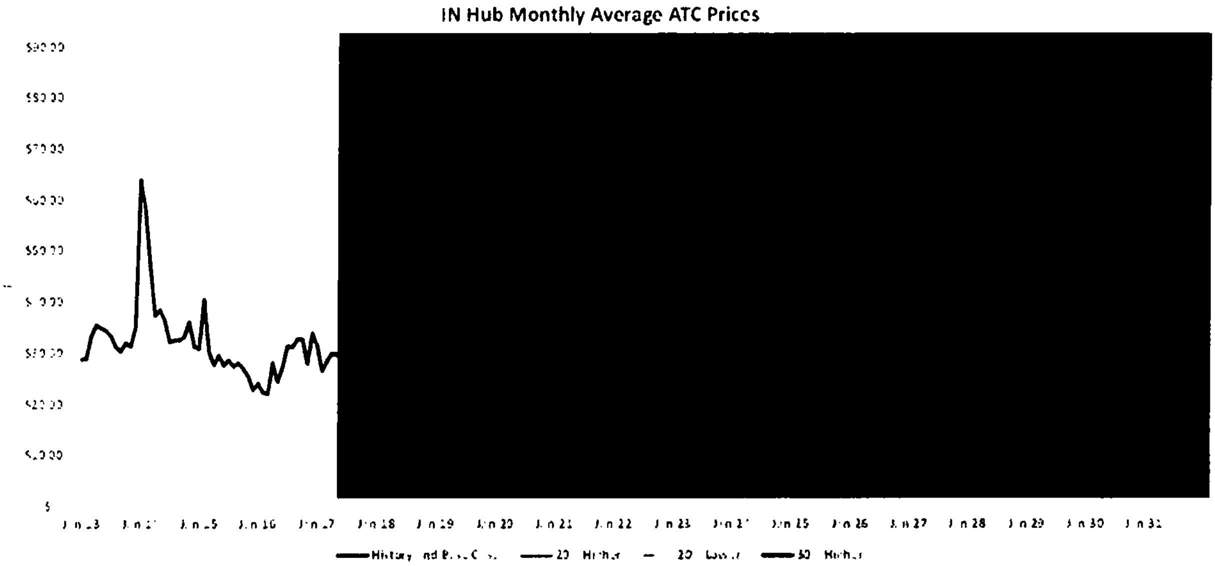


Table 7. 12

Energy Price Scenarios

Year	Base Case		Energy Price Scenarios							
			10% Higher		10% Lower		20% Higher		20% Lower	
	Capacity MW	Comment	Capacity MW	Comment	Capacity MW	Comment	Capacity MW	Comment	Capacity MW	Comment
2017	1,287		1,287	Same as Base Case	1,287		1,287		1,287	
2018	1,287		1,287		1,287		1,287		1,287	
2019	1,311	See Note*	1,311		1,311	SEPA FM ends	1,311	SEPA FM ends	1,311	SEPA FM ends
2020	1,114	Exit Contracts with HMP&L Station Two in 2020	1,114		1,069	Exit Contracts with HMP&L Station Two and Green Units converted to Natural Gas in 2020	1,311	Remain in HMP&L Station Two Contracts with coal operation	1,069	Exit Contracts with HMP&L Station Two and Green Units converted to Natural Gas in 2020
2021	1,114		1,114		1,069		1,311		1,069	
2022	1,114		1,114		1,069		1,311		1,069	
2023	1,114		1,114		1,069		1,311		1,069	
2024	1,114		1,114		1,069		1,311		1,069	
2025	1,114		1,114		1,069		1,311		1,069	
2026	1,114		1,114		1,069		1,311		1,069	
2027	1,114		1,114		1,069		1,311		1,069	
2028	1,114		1,114		1,069		1,311		1,069	
2029	1,114		1,114		1,069		1,311		1,069	
2030	1,114		1,114		1,069		1,311		1,069	
2031	1,114		1,114		1,069		1,311		1,069	

*Note: SEPA Force Majeure ends (SEPA FM Ends) in 2019 with capacity increasing 24 MW (to 178 MW from 154 MW)

7.2.3.2 Coal Price Scenarios

Coal prices were modeled at higher and lower percent differences from the Base Case. There were no changes to the least cost option at 10% lower coal prices. At 20% lower coal prices, Big Rivers remains in the HMP&L Station Two contracts and those units remain coal-fired units. At 10% and 20% higher coal prices, both Green Units were converted to natural gas. See Figure 7. 9 and Table 7.13 below.

Figure 7.9

Delivered Coal Prices

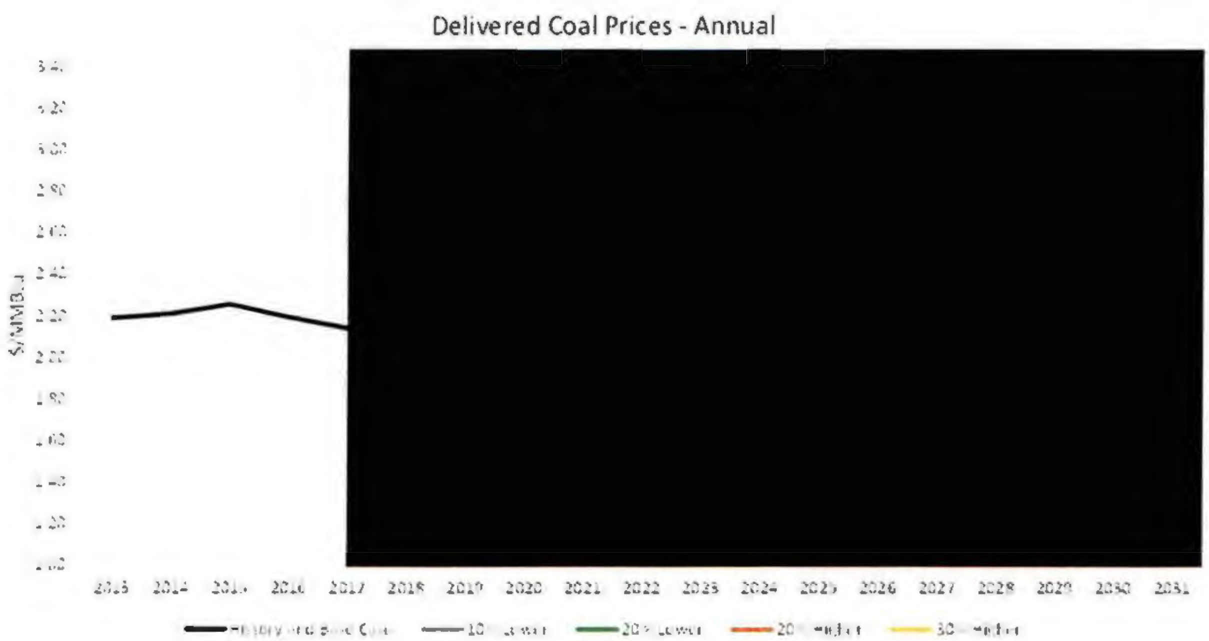


Table 7.13

Coal Price Scenarios

Year	Base Case		Coal Price Scenarios							
			10% Higher		10% Lower		20% Higher		20% Lower	
	Capacity MW	Comment	Capacity MW	Comment	Capacity MW	Comment	Capacity MW	Comment	Capacity MW	Comment
2017	1,287		1,287		1,287	Same as Base Case	1,287		1,287	
2018	1,287		1,287		1,287		1,287		1,287	
2019	1,311	See Note*	1,311	SEPA FM ends	1,311		1,311	SEPA FM ends	1,311	SEPA FM ends
2020	1,114	Exit Contracts with HMP&L Station Two in 2020	1,069	Exit Contracts with HMP&L Station Two and Green Units converted to Natural Gas in 2020	1,114		1,069	Exit Contracts with HMP&L Station Two and Green Units converted to Natural Gas in 2020	1,311	Remain in HMP&L Station Two Contracts with coal operation
2021	1,114		1,069		1,114		1,069		1,311	
2022	1,114		1,069		1,114		1,069		1,311	
2023	1,114		1,069		1,114		1,069		1,311	
2024	1,114		1,069		1,114		1,069		1,311	
2025	1,114		1,069		1,114		1,069		1,311	
2026	1,114		1,069		1,114		1,069		1,311	
2027	1,114		1,069		1,114		1,069		1,311	
2028	1,114		1,069		1,114		1,069		1,311	
2029	1,114		1,069		1,114		1,069		1,311	
2030	1,114		1,069		1,114		1,069		1,311	
2031	1,114		1,069		1,114		1,069		1,311	

7.2.3.3 Natural Gas Price Scenarios

This scenario modeled a change in the delivered natural gas price forecast from the Base Case. There were no changes to the least-cost option at 20% higher natural gas prices. At 10% lower natural gas prices, both Green Units were converted to natural gas in 2020. Additional scenarios were run at 20% and 30% lower natural gas prices and there were no changes from the 10% lower natural gas prices in the least cost option. See Figure 7.10 and Table 7.14 below.

Figure 7.10

Spot Natural Gas Prices

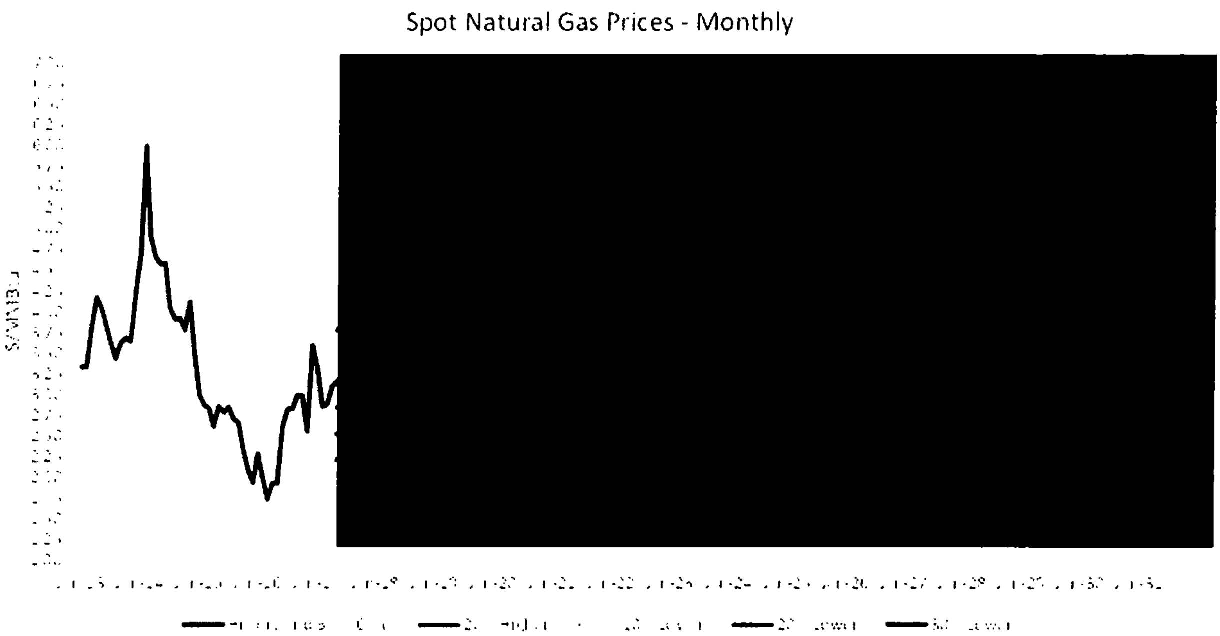


Table 7.14

Natural Gas Price Scenarios

Year	Base Case		Natural Gas Price Scenarios							
			20% Higher		10% Lower		20% Lower		30% Lower	
	Capacity MW	Comment	Capacity MW	Comment	Capacity MW	Comment	Capacity MW	Comment	Capacity MW	Comment
2017	1,287		1,287	Same as Base Case	1,287		1,287		1,287	
2018	1,287		1,287		1,287		1,287		1,287	
2019	1,311	See Note*	1,311		1,311	SEPA FM ends	1,311	SEPA FM ends	1,311	SEPA FM ends
2020	1,114	Exit Contracts with HMP&L Station Two in 2020	1,114		1,069	Exit Contracts with HMP&L Station Two and Green Units converted to Natural Gas in 2020	1,069	Exit Contracts with HMP&L Station Two and Green Units converted to Natural Gas in 2020	1,069	Exit Contracts with HMP&L Station Two and Green Units converted to Natural Gas in 2020
2021	1,114		1,114		1,069		1,069		1,069	
2022	1,114		1,114		1,069		1,069		1,069	
2023	1,114		1,114		1,069		1,069		1,069	
2024	1,114		1,114		1,069		1,069		1,069	
2025	1,114		1,114		1,069		1,069		1,069	
2026	1,114		1,114		1,069		1,069		1,069	
2027	1,114		1,114		1,069		1,069		1,069	
2028	1,114		1,114		1,069		1,069		1,069	
2029	1,114		1,114		1,069		1,069		1,069	
2030	1,114		1,114		1,069		1,069		1,069	
2031	1,114		1,114		1,069		1,069		1,069	

*Note: SEPA Force Majeure ends (SEPA FM Ends) in 2019 with capacity increasing 24 MW (to 178 MW from 154 MW)

7.2.3.4 Load Forecast Scenarios

Rather than modeling every load forecast scenario that was included in developing the load forecast, it was determined to model the extremes (the maximum and the minimum) load forecasts. In the 2017 Load Forecast, there were four sensitivities provided from the Base forecast: Optimistic Economy, Pessimistic Economy, Extreme Weather and Mild Weather. See Table 7.15 below displaying the annual native load peaks.

Table 7.15

Native Load Annual Peak (MW)

Big Rivers Native Load Annual Peak, MW

Year	Base	Optimistic Economy	Pessimistic Economy	Extreme Weather	Mild Weather
2018	645.2	692.6	603.6	716.5	603.3
2019	657.7	709.2	612.4	727.0	615.9
2020	660.6	715.9	611.8	739.2	618.7
2021	662.2	722.2	609.1	743.4	620.0
2022	663.0	726.9	606.5	744.3	620.8
2023	664.0	732.2	603.8	745.6	621.7
2024	665.0	737.3	601.4	746.7	622.6
2025	666.2	742.5	599.3	747.9	623.8
2026	667.5	748.1	597.0	749.0	624.9
2027	668.9	753.8	594.9	750.3	626.2
2028	670.3	759.9	592.8	751.6	627.5
2029	671.9	766.1	590.9	753.2	629.0
2030	673.5	772.5	589.0	754.9	630.6
2031	675.3	778.9	587.4	756.8	632.2

Big Rivers also has executed contracts for new Non-Member load with Nebraska entities beginning in 2018 and KyMEA beginning in 2019. The Nebraska contract is scheduled to end in 2026 and KyMEA in 2029. See the forecasted annual peaks in Table 7.16.

Table 7.16

New Non-Member Peak Load, MW

Big Rivers New Non-Member Peak Load, MW		
Year	Nebraska	KyMEA
2018	18.8	
2019	55.6	100.0
2020	75.1	100.0
2021	75.8	100.0
2022	84.9	100.0
2023	85.3	100.0
2024	85.7	100.0
2025	86.2	100.0
2026	86.6	100.0
2027		100.0
2028		100.0
2029		100.0
2030		
2031		

In the minimum load forecast, Big Rivers' native load was modeled at the pessimistic economy peaks and the Nebraska and KyMEA contracts are terminated at end of the contract. For the maximum load forecast, the Nebraska and KyMEA contracts are forecasted to continue through 2031 although no new Member or Non-Member load beyond native load growth included in the optimistic economy load forecast was included for energy and peak demand. To achieve the high "bookend" for peak load analysis, a combination of forecasts was used, including extreme weather from 2018-2026, switching to the optimistic economy from 2027-2031. Both the low load and the high load scenario results are the same as the Base Case. See Table 7.17 below.

Table 7.17

Load Scenarios

Year	Base Case				Load Scenarios							
					High Load				Low Load			
	Capacity MW	Load Req. MW	Res. Mar. %	Comment	Capacity MW	Load Req. MW	Res. Mar. %	Comment	Capacity MW	Load Req. MW	Res. Mar. %	Comment
2017	1,287	764	95.0%		1,287	764	95.0%	Same as Base Case	1,287	764	95.0%	Same as Base Case
2018	1,287	763	95.3%		1,287	843	76.8%		1,287	706	111.0%	
2019	1,311	918	65.3%	See Note*	1,311	976	55.5%		1,311	879	72.7%	
2020	1,114	937	37.7%	Exit Contracts with HMP&L Station Two in 2020	1,114	1,031	25.2%		1,114	900	43.4%	
2021	1,114	950	35.9%		1,114	1,036	24.5%		1,114	867	48.7%	
2022	1,114	959	34.5%		1,114	1,043	23.6%		1,114	873	47.7%	
2023	1,114	961	34.2%		1,114	1,046	23.4%		1,114	874	47.5%	
2024	1,114	963	33.9%		1,114	1,047	23.2%		1,114	865	49.1%	
2025	1,114	951	35.7%		1,114	1,050	22.8%		1,114	897	43.7%	
2026	1,114	966	33.6%		1,114	1,053	22.6%		1,114	864	49.3%	
2027	1,114	891	44.9%		1,114	1,068	20.8%		1,114	805	60.3%	
2028	1,114	892	44.7%		1,114	1,073	20.2%		1,114	802	60.8%	
2029	1,114	886	45.6%		1,114	1,084	19.0%		1,114	793	62.6%	
2030	1,114	780	65.3%		1,114	1,089	18.5%		1,114	682	89.1%	
2031	1,114	782	65.0%		1,114	1,099	17.4%		1,114	680	89.8%	

*Note: SEPA Force Majeure ends (SEPA FM Ends) in 2019 with capacity increasing 24 MW (to 178 MW from 154 MW)

7.2.3.5 Renewable Portfolio Standards Scenario

Big Rivers modeled a scenario assuming the Commonwealth of Kentucky adopted a renewable portfolio standard where 15% of peak native load capacity is sourced from renewable resources' capacity by 2020, 20% by 2025 and 25% by 2030. In analyzing the renewable resources that could be built in Big Rivers' territory, only fixed solar capacity was modeled in the LT Plan®. Although the model only evaluated adding solar, it is highly likely that Big Rivers would pursue purchase power agreements (PPA) to meet the requirements for the renewable portfolio standards. Also, western Kentucky is currently not a viable location for onshore wind. The tracking solar has not proven to be economical in western Kentucky. Due to the high capital investment, Big Rivers did not model any pulverized coal conversion to a percent biomass or new biomass generation. Big Rivers would build 100 MW of solar in 2020, 40 MW of solar in 2025, and 40 MW of solar (total of 180 MW) in 2030 in this scenario. See Table 7.18.

Table 7.18

Renewable Portfolio Standard Scenario

Year	Base Case		Renewable Portfolio Standard			
	Capacity MW	Comment	Capacity MW	Comment	Peak Native Load MW	% Renewable Capacity
2017	1,287		1,287		660	
2018	1,287		1,287		645	
2019	1,311	See Note*	1,311	SEPA FM ends	658	
2020	1,114	Exit Contracts with HMP&L Station Two in 2020	1,214	Exit HMP&L Station Two Contracts and build 100 MW Solar in 2020	661	15.1%
2021	1,114		1,214		662	15.1%
2022	1,114		1,214		663	15.1%
2023	1,114		1,214		664	15.1%
2024	1,114		1,214		665	15.0%
2025	1,114		1,254	Build additional 40 MW Solar in 2025 (140 MW total)	666	21.0%
2026	1,114		1,254		667	21.0%
2027	1,114		1,254		669	20.9%
2028	1,114		1,254		670	20.9%
2029	1,114		1,254		672	20.8%
2030	1,114		1,294	40 MW Solar (180 MW total)	674	26.7%
2031	1,114		1,294		675	26.7%

*Note: SEPA Force Majeure ends (SEPA FM Ends) in 2019 with capacity increasing 24 MW (to 178 MW from 154 MW)

7.2.3.6 Demand Side Management Scenario

The 2017 Load Forecast included DSM impacts. In the DSM scenario, additional DSM programs were modeled as an economic resource in the Base Case. This scenario evaluated if the additional DSM spend would provide a least cost resource. In the LT Plan®, the DSM project is modeled as an available generation resource that will receive revenue for the energy and capacity of the energy efficiency of the DSM savings. The costs include the additional one million dollar spend and the projected lost Member revenue. Therefore, the LT Plan® is evaluating the DSM projects equally with existing and new generation resource options and will select the DSM project if it provides an optimal (least cost) solution.

DSM impacts were determined to be fourteen years in length and forecasted energy efficiency savings were provided for an additional $1,000,000 annual spend. The LT Plan® modeled a total of fourteen possible DSM projects as shown in Table 7.19 that could be selected to provide a least cost solution. The results displayed in Table 7.19 determined that the additional DSM spend for any of the projects (years) did not provide a least cost solution with the base case inputs.

Table 7.19

DSM Scenario

Additional DSM Forecasted Energy Efficiency				
Years	Annual Energy Reduction (MWh)	Peak Demand Reduction Summer (MW)	Peak Demand Reduction Winter (MW)	EE Program Cost ($)
2018-2031	8,051	1.20	0.88	$ 1,000,000
2019-2032	8,277	1.22	0.91	$ 1,000,000
2020-2033	7,625	1.12	0.88	$ 1,000,000
2021-2034	2,377	0.36	0.31	$ 1,000,000
2022-2035	7,269	1.05	0.84	$ 1,000,000
2023-2036	7,261	1.05	0.83	$ 1,000,000
2024-2037	7,252	1.05	0.83	$ 1,000,000
2025-2038	6,128	0.89	0.72	$ 1,000,000
2026-2039	6,161	0.90	0.72	$ 1,000,000
2027-2040	6,042	0.87	0.70	$ 1,000,000
2028-2041	6,158	0.88	0.71	$ 1,000,000
2029-2042	5,769	0.83	0.67	$ 1,000,000
2030-2043	5,765	0.83	0.67	$ 1,000,000
2031-2044	5,683	0.82	0.66	$ 1,000,000

Table 7.20

Base Case and DSM Scenario

Year	Base Case		DSM Scenario	
	Capacity MW	Comment	Capacity MW	Comment
2017	1,287		1,287	Same as Base Case
2018	1,287		1,287	
2019	1,311	See Note*	1,311	
2020	1,114	Exit Contracts with HMP&L Station Two in 2020	1,114	
2021	1,114		1,114	
2022	1,114		1,114	
2023	1,114		1,114	
2024	1,114		1,114	
2025	1,114		1,114	
2026	1,114		1,114	
2027	1,114		1,114	
2028	1,114		1,114	
2029	1,114		1,114	
2030	1,114		1,114	
2031	1,114		1,114	

*Note: SEPA Force Majeure ends (SEPA FM Ends) in 2019 with capacity increasing 24 MW (to 178 MW from 154 MW)

7.2.3.7 HMP&L Station Two Contract Scenario

In the Base Case results, the least-cost plan had Big Rivers exiting the HMP&L Station Two contracts beginning in 2020, however, the Base Case had a constraint that limited the model to exiting the contracts with HMP&L Station Two no earlier than 2020. In this scenario, that constraint is removed allowing Big Rivers to exit the contracts in 2018. The least cost option did show exiting the contracts with HMP&L Station Two in 2018. See Table 7.21 below.

Table 7.21

Base Case and HMP&L Station 2 Exit Early

Year	Base Case		Exit Contracts with HMP&L Station Two Early	
	Capacity MW	Comment	Capacity MW	Comment
2017	1,287		1,287	
2018	1,287		1,090	Exit Contracts with HMP&L Station Two in 2018
2019	1,311	See Note*	1,114	
2020	1,114	Exit Contracts with HMP&L Station Two in 2020	1,114	
2021	1,114		1,114	
2022	1,114		1,114	
2023	1,114		1,114	
2024	1,114		1,114	
2025	1,114		1,114	
2026	1,114		1,114	
2027	1,114		1,114	
2028	1,114		1,114	
2029	1,114		1,114	
2030	1,114		1,114	
2031	1,114		1,114	

*Note: SEPA Force Majeure ends (SEPA FM Ends) in 2019 with capacity increasing 24 MW (to 178 MW from 154 MW)

7.3 Summary

Big Rivers' mission remains unchanged: to safely deliver low-cost, reliable wholesale power and the cost-effective shared services desired by its Members. In the Electrical Integration Analysis, Big Rivers utilized the LT Plan® to evaluate the generation resource options for existing generators to remain coal-fired, convert to natural gas or retire, and options to build new generation to provide the optimal or least cost option to serve Big Rivers' load requirements. The Base Case inputs and constraints were modeled using the best information available at the time this IRP was prepared. Big Rivers is long on generation capacity, and even though Big Rivers has had success in selling some of its excess capacity to new Non-Members (Nebraska and KyMEA), Big Rivers has conservatively opted to not rely on any additional Non-Member sales as part of the resource assessment. Big Rivers has even forecasted the existing contracts to end at their contract end dates. The energy market price forecasts included in the Base Case are [redacted] The Electrical Integration Analysis determined that the least cost option under the Base Case is to continue operation of Wilson and the Green Units as coal-fired generators, continue the contract with SEPA, not build any new generation and exit the contracts with HMP&L Station Two. 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.

Several alternative scenarios were evaluated. The least cost option was the same under the Base Case as it was under three scenarios where commodities were varied: 10% higher market energy prices, 10% lower coal prices, and 20% higher natural gas prices. In the load scenarios, there were no changes to the Base Case on the low load and high load scenarios.

Variations from the Base Case's least cost option occurred under other scenarios where commodities were varied. In two scenarios (20% higher market energy prices and 20% lower coal prices) the least cost option included Big Rivers remaining in the contracts with HMP&L Station Two, while both Green Units converted to natural gas firing in seven scenarios: 10% and 20% lower market energy prices, 10% and 20% higher coal prices, and 10%, 20%, and 30% lower natural gas prices.

Big Rivers ran three other scenarios that did not involve varying commodities or load. The DSM scenario evaluated Big Rivers spending an additional one million dollars for any of the next fourteen years, but the results of that scenario showed that the additional spend did not provide a benefit to production cost at the Base Case inputs. The hypothetical renewable portfolio standard (RPS) scenario had Big Rivers constructing 180 MW of solar capacity by 2030. The scenario evaluating exiting the contracts with HMP&L Station Two in 2018 determined that exiting the contracts with HMP&L Station Two in 2018 was a lower cost option. See the Table 7.22 below.

As discussed in Section 6.6 Environmental, Big Rivers opted to not model any environmental scenarios except for the RPS scenario. Instead, Big Rivers chose to model across all scenarios its "worst case" estimated compliance costs for current environmental regulations including CSAPR, MATS, CCR, ELG and CWA § 316(b) regulations as known today. By including these compliance costs in all scenarios, the LT Plan® modeled the least cost option for complying with the aforementioned regulations by evaluating whether existing generating resources should remain coal-fired, convert to natural gas or retire, or whether new generation resources should be constructed.

Financial Analysis

In each scenario, the LT Plan® generates a best integer solution where capacity and production related costs were minimized. The objective function of the LT Plan® is to find the optimal portfolio of future capacity and energy resources that minimize the cost of the energy assets. As discussed above, the Base Case was found to be the optimal solution for meeting Big Rivers' load requirements given the assumptions and constraints outlined above.

Table 7.22 below shows the calculated net present value (NPV) for each scenario included in this IRP. Details of the nominal and real market revenues and generation costs associated with each run by year are supplied in Appendix H of this 2017 IRP. As is noted, the NPV calculations are based on the inputs and constraints to the *Plexos*® model. It calculates the most effective means for serving Big Rivers' Member-Owners in an ISO market within the constraints noted throughout this chapter. The NPV amounts below were discounted with an [redacted] discount rate.

Table 7.22

Plexos® Model Results

Model Results	Net Utility Costs NPV ($000)	Resources changes from Current (2017) Operation
Base Case	[redacted]	Exit Contracts with HMP&L Station Two in 2020

Scenario		Net Utility Costs NPV ($000)	Resource Changes from Base Case
Energy LMP Prices	10% Higher	[redacted]	Same as Base Case
	20% Higher	[redacted]	Remain in HMP&L Station Two Contracts with coal operation
	10% Lower	[redacted]	Green Units converted to NG in 2020
	20% Lower	[redacted]	Green Units converted to NG in 2020
Coal Prices	10% Higher	[redacted]	Green Units converted to NG in 2020
	20% Higher	[redacted]	Green Units converted to NG in 2020
	10% Lower	[redacted]	Same as Base Case
	20% Lower	[redacted]	Remain in HMP&L Station Two Contracts with coal operation
Natural Gas Prices	20% Higher	[redacted]	Same as Base Case
	10% Lower	[redacted]	Green Units converted to NG in 2020
	20% Lower	[redacted]	Green Units converted to NG in 2020
	30% Lower	[redacted]	Green Units converted to NG in 2020
Load Scenarios	High Load	[redacted]	Same as Base Case
	Low Load	[redacted]	Same as Base Case
Other Scenarios	HMP&L Early Exit	[redacted]	Exit Contracts with HMP&L Station Two in 2018
	Renewal Portfolio Standard	[redacted]	Build Solar capacity (140 MW in 2020 and 40 MW in 2025)
	Additional DSM	[redacted]	Same as Base Case

Big Rivers' last Board-approved financial plan (approved in November 2016) projected Member rates as shown in Table 7.23 below.

Table 7.23

Projected Member Rates

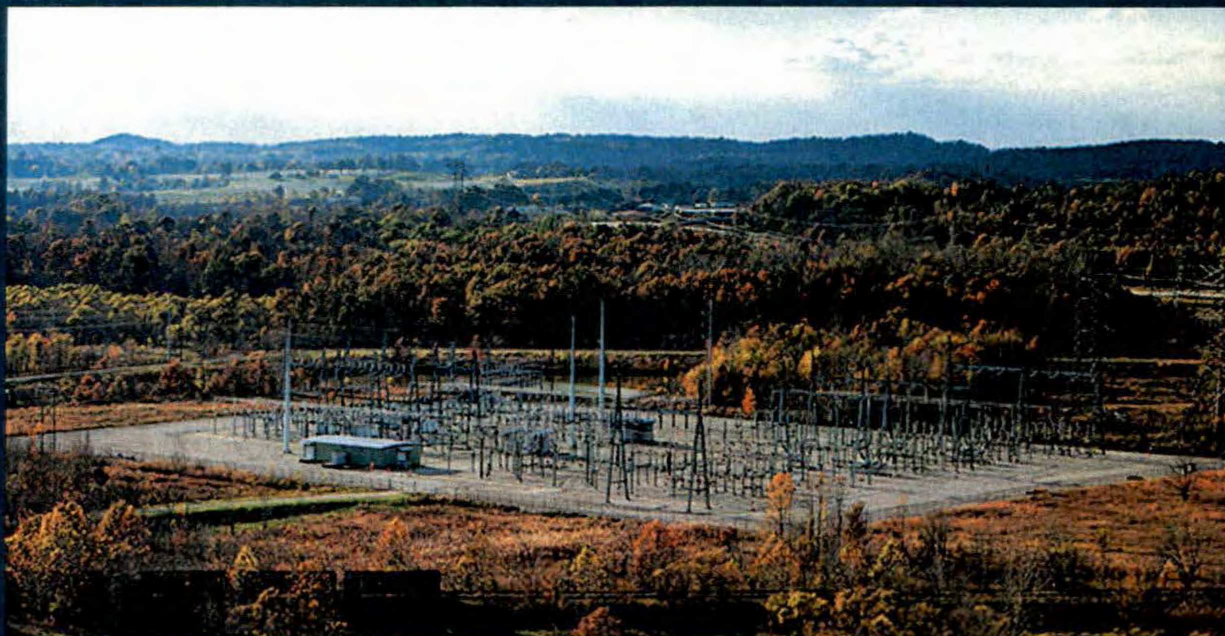
Big Rivers Electric Corporation
Projected Member Wholesale Rates*

2016	69.32	**2024**	[redacted]
2017	78.87	**2025**	
2018	[redacted]	**2026**	
2019		**2027**	
2020		**2028**	
2021		**2029**	
2022		**2030**	
2023		**2031**	

*Approved by Board of Directors in November 2016

The variables impacting Big Rivers' future rates are complex. Big Rivers' optimal plan (least cost option) for meeting Big Rivers' Members' load requirements under the base case scenario is to keep operating the same as today with the exception to exit the contracts with HMP&L Station Two. However, changes in commodity prices, market prices, environmental regulations, Non-Member sales volumes, among many other variables can impact Big Rivers' Members' rates.

As noted above, significant analysis has occurred surrounding the optimum use of Big Rivers' assets in the future. With the uncertainty surrounding future market prices for energy and commodities, at this point, the best option for Big Rivers remains patience. Greater clarity on the future of the power market, coal and natural gas, and environmental regulations will be paramount to Big Rivers' decision-making process. As is known, Big Rivers exists solely to safely and reliably serve its Members at the lowest reasonable cost, and management will continue to focus on the best options for the Members in the years to come.



Transmission Planning

CHAPTER 8

8. TRANSMISSION PLANNING

The Big Rivers transmission system consists of the physical facilities necessary to transmit power from its generating plants and interconnection points to all substations from which customers of its three Members are served. Transmission planning embodies making investment decisions required to maintain this system so that it can reliably and efficiently meet the power needs of the customers served. Justifications used in any transmission study and subsequent projects are based on technical and economic evaluations of options that may be implemented to meet the specific need. Transmission improvement projects are designed to meet all industry standards including those set forth by NERC and SERC.

8.1 MISO Transmission Planning

As a member of MISO, Big Rivers participates in MISO's coordinated short- and long-term planning processes. The transmission system expansion plans established for MISO and its member companies must ensure the reliable operation of the transmission system, support achievement of state and federal energy policy requirements, and enable a competitive energy market to benefit all customers. The planning process, in conjunction with an inclusive stakeholder process, must identify and support development of transmission infrastructure that is sufficiently robust to meet local and regional reliability standards, and enable competition among wholesale energy suppliers. The Guiding Principles of the MISO Transmission Expansion Planning (MTEP) process follow:

- **Guiding Principle 1:** Make the benefits of an economically efficient energy market available to customers by identifying transmission projects that provide access to electricity at the lowest total electric system cost.
- **Guiding Principle 2:** Provide a transmission infrastructure that meets all applicable NERC and Transmission Owner planning criteria and safeguards local and regional reliability through identification of transmission projects to meet those needs.

- **Guiding Principle 3:** Support state and federal energy policy requirements by planning for access to a changing resource mix.
- **Guiding Principle 4:** Provide an appropriate cost allocation mechanism that ensures that costs of transmission projects are allocated in a manner roughly commensurate with the projected benefits of those projects.
- **Guiding Principle 5:** Analyze system scenarios and make the results available to state and federal energy policy makers and other stakeholders to provide context and to inform choices.
- **Guiding Principle 6:** Coordinate transmission planning with neighboring planning regions to seek more efficient and cost-effective solutions.

8.2 Transmission Transfer Capability

Big Rivers routinely assesses its transmission system's ability to transfer power into and out of Big Rivers' local balancing area. Additionally, Big Rivers performs transfer capability studies as a participant in MISO and SERC seasonal assessments. While transfer capability values can vary significantly due to a number of factors, study results (simultaneous net import capability of approximately 900 MW) demonstrate that Big Rivers can import sufficient generation to satisfy all of its firm system demand requirements. Further, the existing transmission system is sufficient to support the export of all Big Rivers' generation power greater than the amount required to serve native load.

8.3 Transmission System Optimization and Expansion

With respect to the improvement and more efficient utilization of existing Big Rivers transmission facilities during the period from 2012 through August of 2017, Big Rivers constructed, and placed in-service, approximately six (6) miles of new transmission line to serve five (5) new delivery point substations of its Members. An additional seventeen (17) miles of 69 kV and two (2) miles of 161 kV lines were constructed to strengthen the transmission network and thus improve reliability. To increase transmission line current ratings, approximately seven (7) miles of 69 kV and eight (8) miles of 161 kV lines were reconductored with higher current capacity conductors.

Additionally, Kentucky Utilities Company (KU) and Big Rivers completed the construction necessary to loop an existing Big Rivers-owned 161 kV circuit through the new KU Matanzas substation in Ohio County, Kentucky. The first phase of the project was energized in 2013. This phase created a new high voltage 161 kV transmission interconnect between Big Rivers' Wilson substation near Centertown, Kentucky, and KU's new Matanzas substation in Ohio County, Kentucky. The second phase of the project was completed in 2016 and created a second Big Rivers 161 kV interconnect to the KU Matanzas substation.

Big Rivers has completed the replacement of the two-way radio system for Big Rivers and its three Members. Each of the four companies now operates its own two-way radio system, with the radio systems sharing a common backbone infrastructure. This new system accommodates two-way radio communication among the four companies during emergency situations.

A MISO market efficiency project is expected to be completed by 2021. This project consists of a new 345 kV circuit from the Duff Substation in Indiana (Vectren) to the Coleman EHV Substation in Kentucky (Big Rivers). The line is approximately thirty-one (31) miles in length and is expected to fully mitigate transmission congestion in the Coleman area. MISO and PJM have both approved a proposal made by American Electric Power (AEP) to loop this circuit through the AEP's Rockport substation potentially creating a Duff (Vectren/MISO) to Rockport (AEP/PJM) to Coleman EHV (Big Rivers/MISO) 345 kV circuit.

Work toward completion of other transmission system improvements is a continuous process. A list of completed and planned improvements to the Big Rivers system for the 2012-2031 time period is presented in Tables 8.1 and 8.2.

Table 8.1

Completed System Additions (2012 – 2017)

Project Description	*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 & metering	*2015*
Meade County 161/69 kV transformer replacements (2)	*2015*
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	*2016*
Coleman EHV – Aleris 161 kV line additions (2 circuits)	*2017*
Centerview 69 kV service	*2017*

Table 8.2

Planned System Additions (2017 – 2031)

Project Description	*Year*
[redacted]	
Coleman – Coleman EHV 161 kV lines 1 and 2 upgrade	*2020*
Coleman EHV – Duff (Vectren) 345 kV line addition	*2020*
[redacted]	

MISO Resource Adequacy Planning

CHAPTER 9

9. MISO RESOURCE ADEQUACY PLANNING

Big Rivers joined MISO on December 1, 2010, to meet its NERC-mandated Contingency Reserve requirements. By joining MISO and signing the MISO Transmission Owners Agreement, Big Rivers is obligated to follow MISO's FERC tariff. Per the Commission's Order approving Big Rivers' request to join MISO in Case No. 2010-00043,[58] Big Rivers retained an obligation to regularly file an IRP for Commission review, detailing Big Rivers' load, determining appropriate reserve requirements, and identifying sources of energy, demand-side resources, and projected need for new generation and transmission facilities.

9.1 MISO's Resource Adequacy Mechanism Overview (Module E-1)

One of MISO's resource planning principles is to maintain system reliability in operating and planning horizons while providing the lowest costs. MISO's resource adequacy mechanism, implemented in 2009, has three primary components: a MISO footprint-wide planning reserve margin, standardized resource qualifications, and facilitation of Load Serving Entity (LSE) compliance requirements.

- **Planning Reserve Margin (PRM):** MISO's broad-focused PRM aims to produce significant annual customer benefits through diversity and generation availability.
- **Resource Qualification:** include testing, measurement, verification, availability data (forced outage rates), performance requirements and obligations.
- **Compliance Requirements:** MISO monitors planning compliance and assesses an administrative penalty to LSE's it finds deficient. LSE is an industry term commonly used to describe utilities or others who provide electric service to customers.

[58] *In the Matter of: Application of Big Rivers Electric Corporation for Approval to Transfer Functional Control of its Transmission System to Midwest Independent Transmission System Operator, Inc.*, Case No. 201 0-00043. Subsequent to this proceeding, MISO changed its name from Midwest Independent Transmission System Operator, Inc., to Midcontinent Independent System Operator, Inc.

9.2 MISO Resource Adequacy Planning

Module E-1 (Resource Adequacy) of MISO's tariff[59] provides forward transparent capacity pricing signals, recognizes congestion that limits aggregate deliverability and complements state resource planning processes. Each year, MISO performs studies to evaluate current market conditions to forecast future planning environments. The MISO Loss of Load Expectation (LOLE) study is performed annually to set the minimum Planning Reserve Margin for the upcoming planning year and provide a nine (9) year Planning Reserve Margin forecast.

9.2.1 Annual Planning Resource Auction (PRA)

The annual capacity auction construct described in MISO Module E-1 allows Market Participants to achieve resource adequacy and allows for transparency. MISO's location-specific approach used in the Planning Resource Auction (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 Adequacy Plans, bilateral transactions, self-scheduling, capacity deficiency payments, and auction purchases.

9.2.2 Module E Capacity Tracking Tool (MECT)

Market Participants submit demand forecast information, qualify resources, track bilateral capacity transactions, designate capacity to meet their Planning Reserve Margin requirements, and participate in the PRA using the Module E Capacity Tracking Tool (MECT).

9.2.3 2017 Loss of Load Expectation Study

MISO conducts an annual LOLE study to determine a Planning Reserve Margin, Unforced Capacity (PRM (UCAP)), zonal per-unit Local Reliability Requirements (LRR), Capacity Import Limits (CIL) and

[59] https://www.misoenergy.org/Pages/Home.aspx

Capacity Export Limits (CEL). The results of the study and its deliverables supply inputs to the MISO Planning Resource Auction, including the local Planning Reserve Margin requirement.

Big Rivers is located in MISO's regional zone 6, along with entities in Indiana, as shown in Figure 9.1.

Figure 9.1

MISO Region Map

In accordance with the MISO tariff, the reliability objective of a LOLE study is to determine a minimum PRM that would result in the MISO system experiencing a less than one day loss of load event every ten (10) years. The MISO analysis for 2017 shows that the system would achieve this reliability level when the amount of installed capacity available is 1.158 times that of the MISO system coincident peak. This equates to a 15.8% Planning Reserve Margin requirement for 2017/2018 based on installed capacity (ICAP) per unit Local Reliability Requirements of Local Resource Zone Peak Demand.

9.2.5 LOLE Modeling Input Data and Assumptions

MISO utilizes a program developed by General Electric called Multi-Area Reliability Simulation (GE MARS) to calculate the LOLE for the applicable planning year. GE MARS uses a sequential Monte Carlo simulation to model a generation system and assess the system's reliability based on any number of interconnected areas. GE MARS 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 energy efficiency resources, equipment forced outages, planned and maintenance outages, load forecast uncertainty and external support.

MISO builds many cases using GE MARS and models different scenarios to determine how certain variables impact the results. The base case models determine the MISO PRM (ICAP), PRM (UCAP) and the LRR for each LRZ for year one, and forward years five and ten.

MISO utilizes existing systems and data for many of the GE MARS inputs, including MISO's Power Generating Availability Data System (GADS) for unit-specific information such as Generator Verification Test Capacities (GVTC), Monthly Net Dependable Capacities (NDC), Unit Forced Outage Rates (EFORd and XEFORd as defined by IEEE 762[60]), and Planned Maintenance Factor (average number of events and duration). The GVTC values, along with the monthly NDC values, are used to determine the capacity profile for each unit. Forced outage rates and planned maintenance factors were calculated over a five-year period (January 2011 to December 2015) and modeled as one value. Generating units that had filed suspensions or retirements (as of June 1, 2016) through MISO's Attachment Y process and were approved are accounted for in the LOLE analysis. Any unit retiring, suspending, or coming back online at any point during the Planning Year was excluded from the year-one analysis. This same methodology is used for the five- and ten-year analyses.

[60] EFOR = Equivalent Forced Outage Rate Demand; XEFOR = EFORd Outside Management Control; IEEE = Institute of Electrical and Electronics Engineers.

9.2.6 MISO Load Data

For the 2017-2018 LOLE analysis, the hourly LRZ load shape was a product of the historical load shape used as well as the 50/50 demand forecasts submitted by the LSEs through the MECT tool.

The non-coincident peak demand forecasts (with transmission losses) by LSEs were aggregated by their respective Local Balancing Authorities (LBA) and applied to the LBA's historical load shape in GE MARS. LRZs 1 through 7 (MISO North/Central region) used the 2005 historical load shape while zones 8, 9, and 10 (the MISO South region) used the 2006 historical load shape. For MISO North/Central, the 2005 load shape provides a typical load shape for the Midwest region. MISO chose to use the 2006 historical shape for the South region, as the 2005 shape represented an extreme weather year due to Hurricane Katrina.

9.2.7 Load Forecast Uncertainty

Load Forecast Uncertainty (LFU), a standard deviation statistical coefficient, is applied to the base 50/50 load forecast to represent the various probabilistic load levels. With transition into Module E1 in 2012, MISO determines two separate requirements: Local Reliability Requirement for each zone as well as an overall MISO-wide Planning Reserve Margin.

MISO's analysis method enabled modeling of each LRZs demand and generation uniquely, and the derivation of a MISO-wide PRM that aligns with the zonal construct using the same model and applying the same zonal LFUs for both footprint-wide and zonal calculations.

The method of modeling zones with a central hub ensures that the LRZ LRR is established in sync with MISO-wide PRM using the same model and applying the same zonal LFUs. Modeling the more granular zonal LFU values appropriately applies each LRZ's LFU to that LRZ's load. This application of LFU accurately reflects the uncertainty impacts of each LRZ's geographic area.

9.2.8 External System

The same methodology for treatment of external areas that was used in the 2016 LOLE analysis was employed in the 2017 LOLE study. Previous years' analyses saw year-over-year variance in the amount of non-firm external support. This variance was often due to changes in third-party vendor data and was not easily discernible. Within the study, a 1 MW increase of non-firm support leads to a 1 MW decrease in the reserve margin calculation. It is important to account for the benefit of being part of the Eastern Interconnection[61] while also providing a stable result. In order to provide a more stable result and remove the false sense of precision, the external non-firm support was set at the same amount as in the 2015 LOLE study. A detailed description of the methodology used in that study can be found in Section 4.4 of the 2015 LOLE study.[62]

Firm Imports from external areas to MISO are modeled at the individual generating unit level. The specific external units were modeled with their specific installed capacity amount and their corresponding Equivalent Forced Outage Rate demand (EFORd). This better captures the probabilistic reliability impact of firm external imports. These generating units are only modeled within the MISO PRM analysis and are not modeled when calculating the LRZ LRRs. The external resources to include for firm imports were based off of the amount offered into the 2016-17 Planning Year PRA. This is, historically, an accurate indicator of future imports. For 2016-17 Planning Year this amount was 4,529 MW ICAP. Firm exports from MISO to external areas were modeled the same as previous years. Capacity ineligible as MISO capacity due to transactions with external areas is removed from the model.

9.2.9 Loss of Load Expectation Analysis and Metric Calculations

Once the GE MARS input files were created, MISO determined the appropriate PRM (ICAP) and PRM (UCAP) for the 2017-2018 Planning Year as well as the appropriate Local Reliability Requirement for each of the ten LRZ's. These metrics were determined by a probabilistic LOLE analysis such that the LOLE for the planning year was one day in ten years, or 0.1 day per year.

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[61] The Eastern Interconnection is one of the two major alternating-current (AC) electrical grids in the continental U.S. power transmission grid.

[62]https://www.misoenergy.org/Planning/ResourceAdequacy/Pages/ResourceAdequacyStudies.aspx

9.2.10 Planning Year 2017-18 Results

For the 2017-2018 planning year, MISO had more than enough capacity to meet a LOLE of 0.1 days per year. In order to achieve a LOLE of 0.1 days per year, unforced capacity had to be removed from the MISO pool. This was done following an iterative process of removing the units with the smallest unforced capacity until MISO reached a LOLE of 0.1 days per year. The last unit removed was not completely removed but derated to a point where the reliability criterion was met.

The formulas for the PRM values for the MISO system are:

$$\text{PRM (ICAP)} = \frac{\begin{array}{c}[\text{ (Installed Capacity + Firm External Support + ICAP Adjustment)} \\ \textit{minus} \\ \text{MISO Coincident Peak Demand]}\end{array}}{\text{MISO Coincident Peak Demand}}$$

$$\text{PRM (UCAP)} = \frac{\begin{array}{c}[\text{ (Installed Capacity + Firm External Support + UCAP Adjustment)} \\ \textit{minus} \\ \text{MISO Coincident Peak Demand]}\end{array}}{\text{MISO Coincident Peak Demand}}$$

Where: ICAP Adjustment meets a LOLE of 0.1 days per year,
UCAP Adjustment meets a LOLE of 0.1 days per year, and
UCAP = ICAP x (1 – XEFORd).

For the 2017-2018 planning year, the ratio of MISO capacity to forecasted MISO system peak demand yielded a planning installed capacity reserve margin of 15.8 percent and a planning unforced capacity reserve margin of 7.8 percent. These PRM values assume 4,349 MW UCAP of firm and 2,331 MW UCAP of non-firm external support. Table 9.1 shows the footprint-wide values and the calculations that went into determining the MISO system PRM (ICAP) and PRM (UCAP).

Table 9.1

MISO Planning Reserve Margin (PRM)

MISO Planning Reserve Margin (PRM)	2017/2018 PY (June 2017 - May 2018)	Formula Key
MISO System Peak Demand (MW)	127,698	[A]
Time of System Peak (ESTHE)	8/2/2017 17:00	
Installed Capacity (ICAP) (MW)	150,915	[B]
Unforced Capacity (UCAP) (MW)	140,226	[C]
Firm External Support (ICAP) (MW)	4,529	[D]
Firm External Support (UCAP) (MW)	4,349	[E]
Adjustment to ICAP (MW)	-4,577	[F]
Adjustment to UCAP (MW)	-4,577	[G]
Non-Firm External Support (ICAP) (MW)	2,987	[H]
Non-Firm External Support (UCAP) (MW)	2,331	[I]
ICAP PRM Requirement (PRMR) (MW)	147,880	[J]=[B]+[D]+[F]-[H]
UCAP PRM Requirement (PRMR) (MW)	137,667	[K]=[C]+[E]+[G]-[I]
MISO PRM ICAP	15.8%	[L]=([J]-[A])/[A]
MISO PRM UCAP	7.8%	[M]=([K]-[A])/[A]

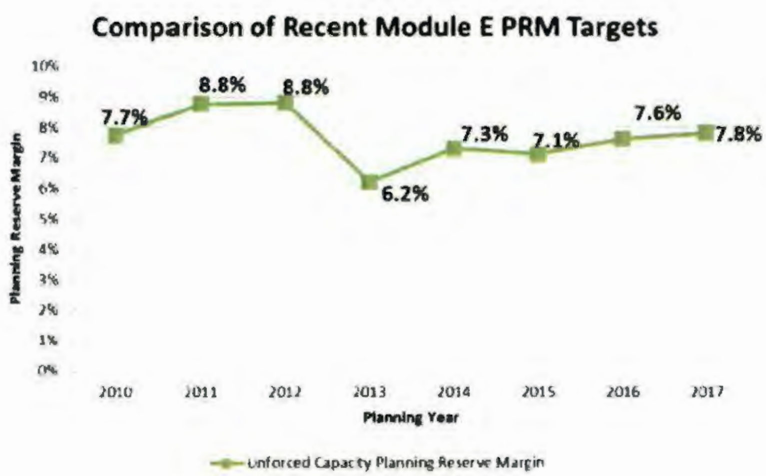
Table 5.1-1: Planning Year 2017-2018 MISO System Planning Reserve Margins

9.2.11 Comparison of PRM Targets across Five Years

Figure 9.2 below compares the PRM(UCAP) values over the last eight planning years. The last endpoints of the green line shows the planning year 2017-2018 PRM values.

Figure 9.2

Comparison of Recent Module E PRM Targets



9.2.12 Future Years 2017 through 2026 Planning Reserve Margins

Beyond the planning year 2017-2018 LOLE study analysis, a LOLE analysis was performed for the five-year-out planning year of 2020-2021 and the ten-year-out planning year of 2026-2027. The PRM (ICAP) and PRM (UCAP) results are shown in Table 9.2. The years in between were arrived at through interpolation of the results from the years 2017, 2019 and 2026. Note that the MISO system PRM results assume no limitations on transfers within MISO.

The 2019-2020 Planning Year PRM decreased from the 2017-2018 Planning Year due to changes in LSE peak load and diversity forecasts. This was the main driver in the decreased reserve margin. The forecasts for the 2026-2027 Planning Year more aligned with the 2017-2018 Planning Year forecasts, which drove the return to the 7.8 percent PRM UCAP

Table 9.2

MISO Planning Reserve Margin (PRM) 2018/2019 Planning Year

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%

Table 5.3-2: MISO System Planning Reserve Margins 2017 through 2026
(Years without underlined results indicate values that were calculated through interpolation)

9.3 Big Rivers' consideration of MISO Planning Reserve Margins in this IRP

Big Rivers used the MISO PRM ICAP Planning Reserve Margin of 15.8%. Evaluation of Big Rivers' own reserve margins showed reserves in excess of MISO's requirement (15.8% ICAP) over the 15-year IRP forward planning period. Big Rivers will continue to comply with MISO's tariff requirements, which include the possibility for varying amounts of planning reserves. As the MISO market evolves, Big

Rivers will continue to evaluate the proper reserve margin target by continuing participation in MISO Stakeholder groups such as Resource Adequacy Subcommittee, Loss of Load Expectation Working Group, and other groups, to ensure Big Rivers' participation in the MISO market provides optimum value to its Members.

9.4 Discussion of Utility-Specific Reserve Margin Study

This section will present Big Rivers' response to the Commission Staff's recommendation for Big Rivers to perform a utility-specific reserve margin study. In addition, this section will explain why the MISO Planning Reserve Margin requirement as determined by their Loss of Load Expectation Study is the appropriate reserve margin for Big Rivers to use in long-term generation planning.

According to the U.S. Energy Information Administration, the electric industry uses a simple strategy to maintain reliability: always have more generation supply available than may be required.[63] However, it is difficult to forecast future demand, and building new generating capacity can take years. The supply is monitored by using a measure called reserve margin.

$$\text{Reserve Margin} = \frac{\text{Capacity} - \text{Demand}}{\text{Demand}}$$

Where: capacity is the expected maximum available supply while demand is the expected peak demand.

Determining the appropriate reserve margin is a tradeoff of costs to build and maintain those reserves versus benefits of meeting customer expectations. In the United States, electric customers have grown to expect very reliable power, and the electric industry standard has evolved to an expectation of experiencing a less than one-day loss-of-load event every ten years. A reserve margin study determines

[63] http://www.eia.gov/todayinenergy/detail.php?id=6510

the appropriate amount of reserves that must be maintained to ensure that customer expectations of reliable power are met. A reserve margin study considers the anticipated load, resources, costs of capacity, and costs of unserved energy to conclude the appropriate level of reserves for an entity.

For Big Rivers to conduct such a study, the Commission would need a reasonable basis to rely on information Big Rivers can gather and analyze. Big Rivers is a member of MISO, which, according to its tariff, is required to study and determine a Planning Reserve Margin that would result in the MISO system experiencing a less than one-day loss-of-load event every ten years. The study determines this requirement for the whole MISO footprint as well as for the Local Reserve Zone including Kentucky and Indiana (Zone 6).

MISO utilizes sophisticated tools and information provided by its members and Market Participants to perform this analysis. Big Rivers is required by MISO's tariff to provide information that is necessary for performing the required studies. Big Rivers reviews the results of the MISO Loss of Load Expectation analysis, which determines a minimum Planning Reserve Margin requirement. This is a minimum reserve percentage that Big Rivers must maintain to meet MISO tariff obligations. Above this minimum requirement, Big Rivers would expose its Members to costs they would not otherwise pay. Therefore, the optimal Planning Reserve Margin for Big Rivers is one that provides an acceptable level of physical reliability while minimizing economic costs to Big Rivers' Members.

The Planning Reserve Margin determined in the MISO Loss of Load Expectation analysis is based on generally accepted industry practices and is appropriate for Big Rivers to use in lieu of a utility-specific reserve margin study.

9.4.1 Basic Explanation of Reserve Margin Study

Reliability planning, or resource adequacy planning, is historically based on the expectation that resources will be available to serve customer load almost all the time. In fact, the utility industry typically considers that only one load shed event every ten years is standard. Target Reserve Margins, or the capacity withheld in excess of load requirements, reflect that generating resources experience outages or derates, are thus not available at one hundred percent of capacity all the time, and are needed to serve demand, which varies somewhat since demand is largely driven by customer needs due to weather.

Reserve Margin is reflected as a percent and calculated by the amount of Resources minus the amount of Demand divided by the amount of Demand. Thus, Reserve margin is the percent of available capacity over and above expected load. Target margins set to maintain the expectation that customers will only experience one loss of load event every ten years are then used to plan system requirements. Big Rivers projected reserve margins have been between 10% and 125% since 2010 when Big Rivers turned over functional control of its transmission system to MISO. The projected reserve margins were reported to the Commission in Big Rivers' annual information filings pursuant to Appendix G of the Commission's Order, dated December 20, 2001, in Administrative Case No. 387.

In Case No. 2010-00043,[64] the Commission approved the transfer of functional control of Big Rivers' transmission system to MISO, under MISO's Open Access Transmission (Energy and Ancillary Services Market) Tariff. That tariff requires, among other things, that MISO coordinate with MISO Market Participants to determine the appropriate Planning Reserve Margin based on the probabilistic analysis of being able to reliably serve demand, using a Loss of Load Expectation study. MISO must calculate the minimum Planning Reserve Margin such that the LOLE is less than one day in ten years. This study is based on information provided by members, market participants, and information from neighboring systems.

The costs of withholding excess capacity is borne by Big Rivers' Members and consists of total system or customer costs, including the capital cost of adding resources to maintain that excess capacity, production costs, off-system and emergency purchase costs, and the cost of load shed events.

As a result of the loss of a large amount of demand as documented in Case Nos. 2012-0535 and 2013-00199, Big Rivers currently has excess reserves. At the time of this IRP filing, installed capacity of

[64] In the Matter of: Application of Big Rivers Electric Corporation for Approval to Transfer Functional Control of its Transmission System to Midwest Independent Transmission System Operator, Inc., Case No. 2010-00043

available generation plus purchases from HMP&L and SEPA (1,287 MW) exceeds existing demand requirements (without reserves) by 95%, or 764 MW; however, those numbers are tempered significantly when considering the baseload capacity available to Big Rivers to serve load. When considering baseload only (excluding SEPA and the natural gas CT), the 95% number is lowered to 68.1%. Big Rivers is implementing the Audit Action Plans identified in the 2014 Focused Audit Action Plan initiated by the Commission in Case No. 2013-00199. As outlined in the Mitigation Plan which was reviewed in this audit, Big Rivers is pursuing increased sales to existing and new load, including new members, as well as studying the strategic options around the currently idled Coleman Station. The flexibility offered by the systematic implementation of Big Rivers' Business Plan allows the Company to strategically develop only the amount of additional demand requirements that provide economic benefit to the Members in the form of minimized costs. As is noted in Table 7.8, Baseload Reserve Margins drop to 7.7% in 2020, signaling a reasonable use of Big Rivers' baseload resources to serve native load and long-term contracts in the future. As noted in Table 7.8, Big Rivers will have more than adequate reserves with the availability of peaking generation, but the utilization of Big Rivers' baseload is solid based on successes in growing internal load and achieving new contracts with counterparties.

The optimal reserve margin will maintain reliability while minimizing costs. Therefore, for the fifteen-year horizon of this 2017 IRP, the MISO PRM of 15.8% as determined by the LOLE analysis provides the minimum reserve margin to maintain reliability, and the minimum costs to Big Rivers' Members.

9.4.2 Supporting Evidence that MISO's study is comparable to a utility-specific study

There are numerous reasons MISO's LOLE study is comparable to a utility-specific reserve margin study for Big Rivers:

1. **LOLE is the industry standard for reserves**

   a. NERC has the authority to assure the reliability of the bulk power system in North America. NERC's jurisdiction includes users, owners, and operators of the bulk power system. NERC prepares seasonal and long term assessments to examine current and future adequacy and operational reliability of the North American bulk power system. These long-term assessments assess resource and transmission adequacy and assess emerging issues that have an impact on reliability over the next ten years. Reserve margins are typically developed using methods that calculate the loss of load expectation that could occur less than or equal to one time in ten years.[65]

b. NERC applies a 15% Reference Margin Level when an area does not assign one per NERC's 2016 Long-Term Reliability Assessment

2. MISO's analysis is robust

a. MISO's tariff requires broad gathering of data and analysis and includes zonal-specific results.[66]

i. MISO has tariff requirements including LOLE analysis, and MISO members are required to provide data. As the Transmission Provider, MISO provides reliability coordination services in accordance with the Independent System Operator (ISO) Agreement, the Balancing Authority Agreement, and other applicable tariffs, and per the MISO Transmission Owners' Agreement,[67] MISO must seek to minimize costs. Module F of the MISO tariff also requires Reliability Coordination Customers to provide MISO with all the operational data required by MISO to perform as Reliability Coordinator, and Section 68A.2.1 lays out the analysis required of MISO to determine the appropriate Planning Reserve Margin.

ii. LOLE analysis determines a minimum Planning Reserve Margin that would result in the MISO system experiencing a less than one-day loss-of-load event every ten years, as per the MISO tariff. The MISO analysis in its 2017 LOLE Study shows that the

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[65] NERC 2016 Long-Term Reliability Assessment available http://www.nerc.com/pa/RAPA/ra/Pages/default.aspx
[66] MISO Planning Year 2017-2018 Loss of Load Expectation Study Report prepared by the Loss of Load Expectation Working Group
[67] Transmission Owners' Agreement Article 3, Section I. C.

MISO system would achieve this reliability level when the amount of installed capacity available is 1.158 times that of the MISO system coincident peak.

iii. MISO's 2017 LOLE study was performed with the GE MARS software. For the 2017-2018 planning year, several modeling enhancements were made in order to ensure the Planning Reserve Margin and reliability requirements. These changes included maintenance of Load Forecast Uncertainty values to reduce unwarranted volatility, Fixed External Non-Firm support to reduce volatility, and removal of the 3 percent shift factor threshold in Capacity Import and Export Limit redispatch.[68]

iv. The LOLE determines a Planning Reserve Margin requirement for each of 10 Local Reserve Zones (LRZ), of which Big Rivers, as the only MISO entity in Kentucky, is logically grouped with Indiana in Zone 6.

b. Big Rivers has reviewed MISOs input assumptions, methodologies, and analysis used when conducting the annual LOLE Study. Big Rivers' participation in the MISO LOLE study included a review of the import and export capacity limits calculated by MISO. Based on the study information reviewed, and MISO's use of a minimum planning reserve that follows the accepted industry practice of basing reserve margins on experiencing a less than one-day loss-of-load event every ten years, Big Rivers considers the MISO results reasonable.

1. Load Modeling - MISO's models are the result of the inputs from across the Eastern Interconnection.

2. Load Forecast - MISO's Load Forecast includes result of the inputs from Load Serving Entities across the MISO footprint. Those entities are in the best position to determine the future loads of their own systems.

[68] MISO Planning Year 2017-2018 Loss of Load Expectation Study Report section 1.1

3. Resources and Dispatch - MISO is in the best position to determine the location, capability, and dispatch of generation across their footprint.

4. Unit Outage Data – The MISO Transmission Owner Agreement Appendix E requires all Transmission Owners to continuously provide MISO with all data required to assess the reliability of the Transmission System, including planned outages. MISO's Outage Operations Business Practices Manual[69] outlines how it also coordinates outage information with other RTO's. Therefore, MISO has access to the most accurate data regarding outages across a broad footprint, including the Big Rivers service territory.

5. Multi Area Modeling - MISO's LOLE analysis utilized the base model build for MTEP 16 analyses, along with further stakeholder review of models and input files. [70]

6. Cost of Unserved Energy - MISO calculates a reliability-based planning reserve where unserved energy is stated in terms of Megawatt-hours.

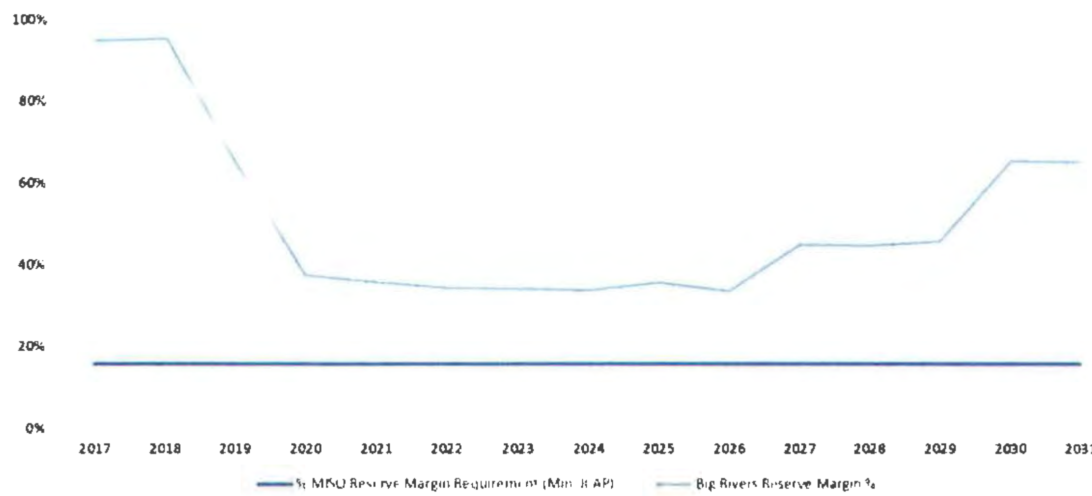
3. Big Rivers has significant reserves in excess of the MISO PRM.

Big Rivers' Base Case indicates sufficient resources not only to meet the MISO Planning Reserve Margin, but in excess of the current ICAP requirement of 15.8%. See Figure 9.3, below.

[69] MISO Outage Operations Business Practices Manual BPM-008-r11 Section 1.3.1
[70] LOLE Study section 3.2 Powerflow Models and Assumptions

Figure 9.3

Big Rivers ICAP Reserve Margin vs. MISO PRM Requirement



9.4.3 Divergent Views on Reserve Margin Study

While the MISO LOLE Analysis and Planning Reserve Margin is not strictly a utility-specific reserve margin analysis, a Big Rivers utility-specific study would be expected to return results consistent with the MISO analysis. At a high level, it is clear that comparing Big Rivers' load to its available resources would indicate sufficient reserves as discussed in Section 9.4.1, above. In addition, any reserve margin study would start with a definition of basic parameters, many of which are subject to interpretation. For example, the load forecast, which has already been mentioned as a function of weather, could be defined as average peak (over a period of time, in which case the time period would have to be defined), or all time one-hour peak, or fifteen-minute peak, *etc*. Resource capacity would need to be defined: based upon average availability, summer or winter availability, and again determining what time period to include in the average is important, etc. The costs and types of replacement power, capacity import and export capability, *etc*., would have to be determined. Input parameter accuracy, or lack thereof, influences the results of any analysis. Therefore, a variation of one or more parameters would lead to different results.

Assuming a reserve margin study's goal is to return the optimum reserve margin percentage, defining "optimum" would be another key input to the analysis. A minimum percentage would lead to least cost for holding back excess resources, and, therefore, the optimum reserve margin percentage would be the minimum reserve requirement. The MISO tariff defines the minimum reserve margin percentage, and is comparable, therefore, to any Big Rivers utility-specific reserve margin study. Any reserve margin intentionally maintained by Big Rivers above that required by MISO would partially negate the benefits of operating in MISO.

Total study costs, for a Big Rivers utility-specific reserve margin study, including any necessary professional services support and the costs associated with in-house subject matter experts, could exceed $100,000. It is difficult to justify the extra expense associated with a utility-specific study that would return subjective results with no offsetting benefit. Ultimately, Big Rivers must still adhere to the MISO minimum reserve margin.

9.4.4 Big Rivers Reserve Margin Study Conclusion

To meet the reliability expectations of its Members, reserves are necessary, but excess reserves are expensive. As a member of MISO, Big Rivers' Members receive benefits and are obligated to meet tariff requirements, a tariff which requires MISO to strive to minimize costs. That same tariff requires MISO to perform a study to determine a minimum amount of planning reserve requirements. Therefore, Big Rivers relies on MISO's analysis to determine an appropriate target reserve margin. Big Rivers easily satisfies any reasonable reserve margin requirement. Therefore, the uncertainty and cost of conducting a utility-specific reserve margin study outweighs the value of such a study.

Action Plan

CHAPTER 10

10. ACTION PLAN

Big Rivers' mission remains unchanged: to safely deliver low-cost, reliable wholesale power and the cost-effective shared services desired by Big Rivers' Member-Owners. The Company has a robust strategic planning process and works to incorporate corporate strategic planning of the Big Rivers system with respect to the integration of existing and future capacity resources to benefit Big Rivers' Members. This triennial IRP filing incorporates the best information available at the time of analysis, and as circumstances change, plans will be adjusted. This plan is not a commitment for certain actions now or at any future date.

10.1 Generation Portfolio

Big Rivers is long on generation capacity, even though Big Rivers has successfully sold some of its excess capacity to new Non-Members (See "Executed Sales" in Section 4.2.6). Energy market price forecasts are [redacted]. Big Rivers' current least-cost option is to continue operating its Wilson Station and the Green Units as coal-fired generators, continue its contract with SEPA, and to exit the HMP&L Station Two contracts. No new generation is required through 2031.

It must be noted that the HMP&L Station Two contracts are terminable only upon the occurrence of certain events which may or may not occur in 2018 or 2020, as assumed by this 2017 IRP's Base Case results. For example, the contract terms expire at such time as it is determined that the Station Two Units are no longer capable of normal, continuous reliable operation for the economically competitive production of electricity. Other reasons the contracts may be terminable include:

1. Occurrence of certain breaches of contract by either party and its failure to cure said breach in a timely manner,

2. Ninety days following the date Big Rivers' capacity allocation (as defined in the contract) from HMP&L Station Two is zero, and

3. By agreement of both parties.

Exiting the HMP&L contracts include terminating both the Power Sales Contract between the City of Henderson and the Power Plant Construction and Operation Agreement, as well as possible significant changes to other existing contracts between the City of Henderson and Big Rivers. At the time of this IRP, HMP&L and Big Rivers are exploring resolution of issues in Case No. 2016-00278,[71] and the outcome of those discussions may change the results of the analysis used in this IRP, due to potential changes in anticipated costs and benefits. Changes to the existing Power Sales Contract and/or the Power Plant Construction and Operation Agreement with HMP&L would be subject to Commission approval.

10.2 Business Plan Flexibility

Big Rivers' Business Plan includes determining a sales target for excess generation that will return value to its Members. This plan is frequently evaluated over time to fully optimize available Member resources. Optimization of resources includes evaluation of costs to deliver Big Rivers' generation versus buying from the market. When all-in costs of purchasing capacity and/or energy are more economical than transmission and associated generation costs, those purchases are made to bring the most value to Big Rivers' Members. As changes in available, economic resources occur, Big Rivers adjusts the Business Plan accordingly. This continued flexibility will leverage Big Rivers' excess generation to the benefit of its Members.

10.3 Three-Year Action Plan

No generating resource acquisition steps are necessary over the next three years of this 2017 IRP, and no additional resources are required to maintain adequate reliability throughout the planning horizon under base case assumptions. As part of its recurrent strategic planning process, Big Rivers will:

[71] *In the Matter of: Application of Big Rivers Electric Corporation for a Declaratory Order*, Case No. 2016-00278.

- Continue to monitor environmental rules and market conditions, to determine refinements to the analysis in this IRP;
- Continue to explore resolution of outstanding issues with HMP&L, resolution of which may change the results of the analysis in this IRP;
- Continue to emphasize generation efficiency;
- Continue marketing economic excess generation to benefit Big Rivers' Members;
- Continue progress on remaining open items from the Focused Audit:
    - Continue to develop in-house expertise in price forecasting and MISO market knowledge to help develop more informed price forecasts, but only to the degree that it supports Big Rivers' mission and core business,
    - Continue to evaluate the options around Coleman Station, and
    - Continue to pursue discussions with Lenders and the Commission to address restrictions around the sale of Coleman and address strategic options for the facility; and
- Continue to work with Big Rivers' Members on DSM implementation by:
    - Monitoring opportunities for demand response,
    - Looking for cost reductions or increases in the value of avoided-peaking generation,
    - Monitoring new technologies that may provide peak-demand reduction benefits at a lower cost than current DSM programs, and
    - Evaluating whether any of Big Rivers' Members' existing large commercial or industrial accounts would benefit from an interruptible rate arrangement, and if so, determining whether the Members desire to offer an interruptible rate tariff.

2017
Load Forecast

Big Rivers
ELECTRIC CORPORATION

Table of Contents

Appendix

1. Introduction

1.1 Overview

As an electric utility borrower with the USDA Rural Utilities Service ("RUS"), Big Rivers Electric Corporation ("Big Rivers") has historically filed load forecasts biennially. Additionally, as an electric utility under the jurisdiction of the Kentucky Public Service Commission ("Commission"), Big Rivers triennially files an Integrated Resource Plan ("IRP"), which is based on the most recently adopted load forecast. This 2017 Load Forecast is provided to comply with Big Rivers' obligations under RUS[1] and the Commission[2] regulations and provides a comprehensive overview of Big Rivers' energy and peak demand outlook for 2017-2036[3]. A glossary of terms and acronyms used throughout this report is included in Appendix D.

1.2 Introduction

The 2017 Load Forecast was prepared by Big Rivers with the assistance of GDS Associates, Inc. ("GDS"). The individuals responsible for preparation of the forecast and who are available to respond to inquiries are listed in Table 1.1.

Table 1.1
Project Team

Company	*Name*	*Team Role*
Big Rivers Electric Corporation	*Marlene Parsley*	*Project Manager*
	Russ Pogue	*DSM/Energy Efficiency*
Jackson Purchase Electric	*Dennis Cannon*	*Load Forecast Representative*
	Scott Ribble	*Load Forecast Representative*
Meade County Rural Electric Cooperative Corporation	*David Poe*	*Load Forecast Representative*
	Anna Swanson	*Load Forecast Representative*
	Mike French	*Load Forecast Representative*
Kenergy Corp	*John Newland*	*Load Forecast Representative*
	Travis Siewert	*Load Forecast Representative*
	Steve Thompson	*Load Forecast Representative*
GDS Associates, Inc.	*John Hutts*	*GDS Lead Consultant*
	Julia Jennings	*Model and Forecast Development*
	Harrison Sloan	*Model and Forecast Development*

This 2017 Load Forecast contains projected power requirements through 2036. This report presents the projections, the underlying forecast assumptions, and the methodologies used in developing the load forecast. Forecast scenarios are included to address the uncertainties associated with the factors

[1] Code of Federal Regulations, Title 7, Subtitle B, Chapter XVII, Part 1710.202, Subpart E – Load Forecasts.
[2] Kentucky Public Service Commission, 807 KAR 5:058
[3] Tables throughout this report reflect actual historical data through 2016, the base historical year.

expected to influence energy consumption in the future. Supporting figures and tables are provided throughout this document and in the Appendices.

The remainder of Section 1 of this report presents a description of Big Rivers and a summary of the load forecast. Section 2 describes changes made to the forecast since the 2015 Load Forecast. Section 3 presents the base case forecast by customer classification and provides summary results for multiple forecast scenarios. Section 4 describes the forecasting process and methodologies, including a description of the data used, a discussion on the key forecast assumptions, and details regarding the forecasting model specifications.

1.3 Description of the Utility

1.3.1 Overview

Big Rivers is a generation and transmission cooperative headquartered in Henderson, Kentucky. Big Rivers owns, operates and maintains electric generation and transmission facilities, and it purchases, transmits, and sells electricity at wholesale. It exists for the principal purpose of providing the wholesale electricity requirements of its three distribution cooperative Member-owners, which are Jackson Purchase Energy Corporation ("JPEC"), Kenergy Corp. ("Kenergy"), and Meade County Rural Electric Cooperative Corporation ("MCRECC") (collectively, the "Members"). The Members, in turn, provide retail electric service to approximately 116,000 consumer-Members located in all or parts of 22 western Kentucky counties: Ballard, Breckenridge, Caldwell, Carlisle, Crittenden, Daviess, Graves, Grayson, Hancock, Hardin, Henderson, Hopkins, Livingston, Lyon, Marshall, McCracken, McLean, Meade, Muhlenberg, Ohio, Union, and Webster. A map showing the Members' service territory is provided in Figure 1.1 on the following page.

Additionally, Big Rivers provides transmission and ancillary services to other entities under the Midcontinent Independent System Operator ("MISO") Tariff. Big Rivers' wholesale rates are presented in its tariff on file with the Commission. That tariff may be accessed from either the Commission's website (http://www.psc.ky.gov/tariffs/Electric/) or from the Regulatory webpage of Big River's internet site (http://www.bigrivers.com/regulatory.aspx). As shown in that tariff, these wholesale rates became effective on February 1, 2014. There have been revisions to selected tariff sheets subsequent to that date. Specifically, Big Rivers modified its Demand-Side Management ("DSM") tariff sheets effective September 11, 2015. Big Rivers also modified its Member Rate Stability Mechanism ("MRSM") rider tariff sheets effective September 29, 2015, and it Fuel Adjustment Clause ("FAC") rider tariff sheets effective October 30, 2016. On June 30, 2017, Big Rivers filed proposed changes to certain of its DSM tariff sheets.

1.3.2 Capacity Resources

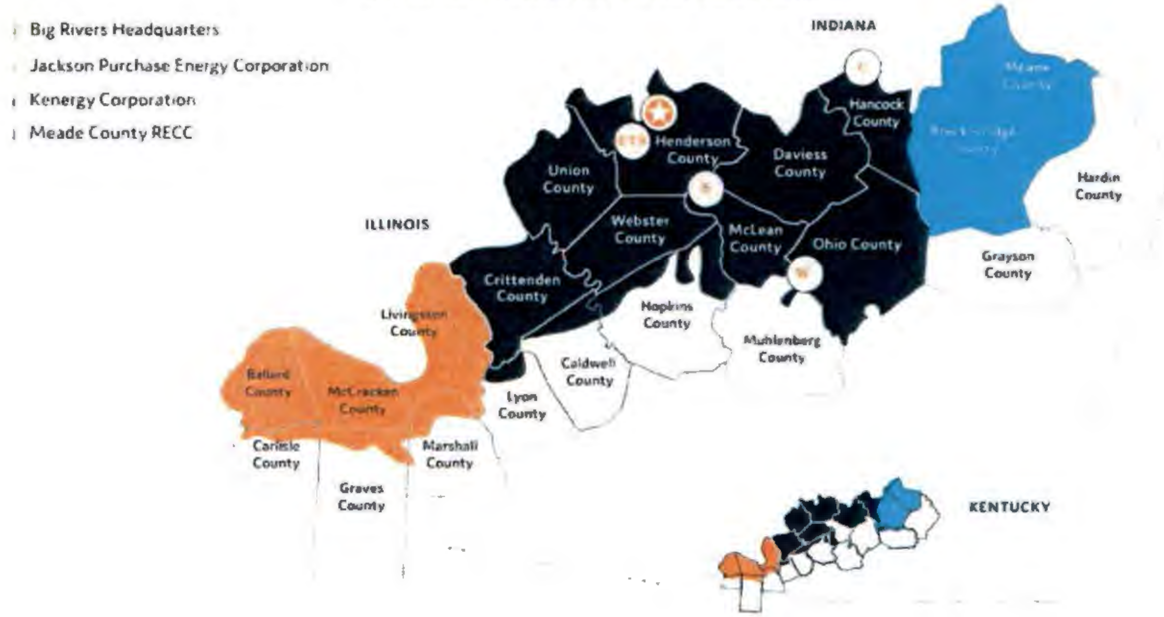
Big Rivers owns and operates the Robert A. Reid Plant (130 MW), the Kenneth C. Coleman Plant (443 MW), the Robert D. Green Plant (454 MW), and the D. B. Wilson Plant (417 MW), totaling 1,444 net MW of generating capacity. Total generation resources are 1,819 MW, including rights currently to 197 MW at Henderson Municipal Power and Light's ("HMP&L") William L. Newman Station Two facility ("HMP&L

Station Two")[4] and 178 MW of contracted hydro capacity from the Southeastern Power Administration ("SEPA").[5] Force majeure conditions due to dam safety issues on the SEPA Cumberland system have reduced Big Rivers' SEPA allotment to 154 MW, bringing Big Rivers' total generation capacity to 1,795 MW at the present time. Big Rivers expects the ongoing dam safety repairs to be completed and a return to full 178 MW capacity in 2019.

1.3.3 Transmission System

Big Rivers owns, operates and maintains its 1,297 mile transmission system and provides for the transmission of power to its Members and third party entities served under the MISO tariff.

Figure 1.1
Big Rivers' Members Service Area Map



1.3.4 Big Rivers' Load

References to total system energy and peak demand requirements in this 2017 Load Forecast are to Big Rivers' Members' native system, Big Rivers' non-Member load, and HMP&L requirements. Native system is the cumulative requirement of Members' customer base load that Big Rivers is obligated to serve. Non-Member load is defined as planned long-term load obligations that derive value for Big Rivers' Members. Forecasts of HMP&L's aggregated peak demands and net energy for load were

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[4] HMP&L has the contractual right to increase or decrease its current 115 MW capacity reservation from HMP&L Station Two up to 5 MW each year.

[5] In this analysis, both HMP&L load and generation are included. HMP&L has rights to 12MW of SEPA capacity, which is assumed in this analysis to directly offset HMP&L load. Force majeure conditions on the SEPA system have reduced HMPL&L's allocation to 10 MW.

provided by HMP&L management in response to requests from Big Rivers for purposes of preparing this report.

1.3.5 Big Rivers Consumer Classes:

Big Rivers categorizes energy and peak demand into two classes: rural system and direct serve. The rural system is comprised of all retail residential, commercial, and industrial customers served by Big Rivers' Members, except for retail customers served under Big Rivers' Large Industrial Customer ("LIC") tariff. Direct-serve customers are served under the Big Rivers' LIC tariff, which includes 20 large industrial customers in 2017.

Approximately 90% of the accounts served by Big Rivers' Members are residential. A breakdown of actual energy sales for 2016 and projected sales for 2036 is presented in Figure 1.2.

Historically, Big Rivers provided power to Kenergy for resale to two aluminum smelters. Due to the termination of the smelter contracts, effective in August 2013 and January 2014, respectively, Big Rivers no longer provides power for the smelters from its generation system, but power is transmitted to them over Big Rivers' transmission system, which is under the control of MISO[6]. Over the course of the forecast horizon, a portion of the sales previously associated with the smelters is projected to be absorbed by growth in Member load and non-Member sales, consistent with Big Rivers' strategic plan, including long-term transactions and short-term optimization.

Figure 1.2
Class Energy Sales Proportions

Figure 1.2 excludes Lighting and Irrigation classes, which account for less than 1% of total sales

1.4 Uses of the Load Forecast

Maintaining a current and reliable load forecast is a key objective of Big Rivers' planning process to reliably provide for its customers' electricity needs. This load forecast will be used for resource, distribution, reliability and financial planning to:

[6] https://www.misoenergy.org/Pages/Home.aspx

- Continue to offer competitively priced power and cost-effective DSM programs to Big Rivers' Members,
- Maintain adequate planning reserve margins, to maximize reliability while ensuring safety, minimizing costs, risks, and environmental impacts,
- Meet North American Electric Reliability Corporation ("NERC") guidelines and requirements

1.5 Load Forecast Summary

Big Rivers' total system energy and peak demand requirements are comprised of its native system load, non-Member load, and HMP&L load. Total requirements include transmission losses. Total system energy and peak demand requirements are projected to reach 4,372 GWH and 1,279 MW by 2036. Annual projections are presented in Table 1.2. Non-Member load enters the forecast in 2017, 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 intermittent bilateral transactions and daily interaction with organized energy markets during each year. Refer to Section 3.2.7 for details on non-Member sales. HMP&L projected requirements are based on a load forecast prepared by HMP&L and reflect average growth of less than 1% per year. Refer to Table 1.3 for a breakdown of the forecast by component.

Native system energy and peak demand requirements are projected to increase at average compound rates of 0.5% and 0.5%, respectively, per year from 2016 through 2036. Continued increases in appliance efficiencies, consumer energy conservation awareness, and [redacted] in the price of retail electricity are expected to dampen growth in native energy sales over the near term; however, increased sales to existing direct serve customers will have positive impacts on native sales over the near term. A record native peak of 748 MW was established during the winter of 2014. Under normal peaking weather conditions, that peak is estimated to have been 706 MW. Native peak requirements are projected to increase from 648 MW in 2017 to 700 MW by the summer of 2036.

Table 1.2
2017 Load Forecast - Total System Requirements

	Energy Requirements (MWH)	Peak Demand (MW)	Load Factor
2012	3,937,713	776	58.0%
2013	4,027,402	724	63.5%
2014	4,058,562	858	54.0%
2015	3,950,483	808	55.8%
2016	3,932,115	726	61.8%
2017	3,969,480	1,254	36.1%
2018	4,068,374	1,284	36.2%
2019	4,162,451	1,295	36.7%
2020	4,206,796	1,299	37.0%
2021	4,211,034	1,301	37.0%
2022	4,217,803	1,302	37.0%
2023	4,222,551	1,304	37.0%
2024	4,234,548	1,305	37.0%
2025	4,242,559	1,307	37.1%
2026	4,251,690	1,309	37.1%
2027	4,261,623	1,310	37.1%
2028	4,276,388	1,312	37.2%
2029	4,284,597	1,304	37.5%
2030	4,296,696	1,296	37.8%
2031	4,308,719	1,298	37.9%
2032	4,324,268	1,290	38.3%
2033	4,332,786	1,293	38.3%
2034	4,344,820	1,285	38.6%
2035	4,356,854	1,287	38.7%
2036	4,372,403	1,279	39.0%

Shaded year represents base year

Values include DSM impacts and transmission losses

Energy requirements do not include optimized economic sales

Non-member load begins in 2017

Table 1.3
2017 Load Forecast – Total System Requirements by Component

	Native System		*Non-Member*	*HMP&L*	
	Energy Requirements (MWH)	*Peak Demand (MW)*	*Peak Demand (MW)*	*Energy Requirements (MWH)*	*Peak Demand (MW)*
2012	*3,310,251*	*660*	*0*	*627,462*	*116*
2013	*3,404,208*	*615*	*0*	*623,194*	*109*
2014	*3,418,840*	*748*	*0*	*639,722*	*109*
2015	*3,316,430*	*697*	*0*	*634,054*	*111*
2016	*3,297,687*	*617*	*0*	*634,428*	*109*
2017	*3,326,730*	*648*	*497*	*642,750*	*109*
2018	*3,421,466*	*660*	*513*	*646,908*	*111*
2019	*3,512,955*	*673*	*512*	*649,496*	*111*
2020	*3,554,702*	*676*	*512*	*652,094*	*111*
2021	*3,556,331*	*678*	*512*	*654,703*	*111*
2022	*3,560,481*	*679*	*512*	*657,322*	*112*
2023	*3,562,600*	*680*	*512*	*659,951*	*112*
2024	*3,571,957*	*681*	*512*	*662,591*	*113*
2025	*3,577,318*	*682*	*512*	*665,241*	*113*
2026	*3,583,788*	*683*	*512*	*667,902*	*114*
2027	*3,591,049*	*685*	*512*	*670,574*	*114*
2028	*3,603,132*	*686*	*512*	*673,256*	*115*
2029	*3,608,648*	*688*	*501*	*675,949*	*115*
2030	*3,618,043*	*689*	*491*	*678,653*	*115*
2031	*3,627,351*	*691*	*491*	*681,367*	*116*
2032	*3,640,175*	*693*	*481*	*684,093*	*116*
2033	*3,645,968*	*695*	*481*	*686,818*	*117*
2034	*3,655,277*	*696*	*471*	*689,544*	*117*
2035	*3,664,585*	*698*	*471*	*692,269*	*118*
2036	*3,677,409*	*700*	*461*	*694,995*	*118*

Shaded year represents base year

Values include DSM impacts and transmission losses

Peak values represent load at the time of the Native System peak

Energy requirements do not include optimized economic sales

Key Economic and Demographic Influences - The key influences on the load forecast include economic activity, increases in heating and cooling equipment efficiencies, energy conservation, changes in retail electricity prices, and the continued stable base of large industrial load. With respect to the economic and demographic influences, number of households and total non-farm employment influence projections of the number of rural system customers. Average household income is one of the key inputs in the residential energy model. Number of households, employment, and average household income are projected to show low to moderate growth over the forecast period and are contributing factors to projected low growth in number of customers and average energy consumption per customer over the next 20 years. Refer to Section 4.3 for additional information regarding the economic outlook.

The forecast reflects an increase in the nominal price of retail electricity to rural system customers. Retail price projections were developed for each Member and are represented in the forecasting models as the quotient of annual revenue and annual kWh, by customer class. Projected retail prices reflect changes in Big Rivers' wholesale power cost to Members and changes in distribution system related costs at the Member level. The "all-in" average retail price at the Member level is projected to increase approximately 13% in 2017[7], followed by [redacted][8] For residential customers, the elasticity of energy consumption with respect to price is -0.21 and was derived using the regression models for each Member cooperative.[9] The forecast reflects no direct decreases in energy sales and peak demand for the small and large commercial classes resulting from price increases expected over the near term.

The forecast reflects impacts associated with changes in heating and cooling appliance market shares and increases in their respective efficiencies. Over the course of the forecast horizon, the market shares for both heating and cooling are projected to increase minimally. A combination of increases in electric appliance market shares and increases in appliance efficiencies is expected to produce essentially flat average consumption in electric heating and air-conditioning per household over the long term.

The forecast includes the impacts of existing and future DSM and energy efficiency programs. Impacts of existing programs are captured indirectly through the historical energy consumption data used in developing the forecasting models. The impacts of future program offerings are computed and captured in the load forecast as post-modeling adjustments. DSM programs are projected to reduce peak demand and energy consumption by 22 MW and 144,454 MWH by 2036.

The large commercial class, including both rural and direct serve customers, currently represents approximately 34% of total system energy consumption. Energy and peak projections for this class include only those customers that are currently being served. Following anticipated growth over the

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[7] Increase is due to the expiration of credits associated with the operation of Big Rivers' Member Rate Stability Mechanism (MRSM) which offset a base rate increase approved by the Commission in case No. 2013-00199.
[8] [redacted] are described in nominal terms for discussion purposes. Price is expressed in real, or deflated, terms in the forecasting models described in Section 4 of this report.
[9] Average elasticity for Big Rivers' three Members.

near term, energy and peak are held constant at 2021 levels through 2036 in the base case forecast. The optimistic economy forecast scenario reflects growth for new industrial load.[10]

The key economic and demographic assumptions upon which the load forecast is based are summarized below and discussed in greater detail in Section 4.3.

- Number of households will increase at an average rate of 0.1% per year from 2016-2036.
- Employment will increase at an average rate of 0.8% per year from 2016-2036.
- Real gross regional product will increase at an average rate of 1.6% per year from 2016-2036.
- Real average income per household will increase at an average rate of 1.7% per year from 2016-2036.
- Real retail sales will increase at an average rate of 1.0% per year from 2016-2036.
- Inflation, as measured by the Gross Domestic Product Price Index, will increase at an average compound rate of 2.0% per year from 2016-2036.
- Nominal retail price (no adjustment for inflation) charged by Members to their customers is projected to increase 13% by 2017. From 2017 to 2029, the price of electricity to rural system customers is projected to [redacted] resulting in a [redacted] in real price.
- Heating and cooling degree days for the service area will be equal to averages based on the twenty years ending 2016.
- The market shares for electric heating, electric water heating, and air conditioning will continue to increase throughout the forecast period, but at a declining rate as maximum saturation levels are approached.
- The average operating efficiencies of major appliances will continue to increase throughout the forecast period, but at a declining rate as maximum efficiencies are approached.
- Impacts of existing energy efficiency programs will increase during the forecast horizon and will impact both energy and peak demand requirements.

1.6 Load Forecast Process Summary

The load forecast has been historically produced every two years; however, Big Rivers makes updates as needed for planning purposes. The 2017 Load Forecast was completed in July 2017.

The 2017 Load Forecast was developed using a "bottom-up" approach. Forecasts were developed individually for each of Big Rivers' three Member distribution cooperatives and aggregated to the Big Rivers level. Preliminary forecasts were presented to each of the Members for review prior to

[10] Historically, due to the unpredictability of economic development successes and the significant increase in load resulting from the addition of new customers, Big Rivers' projections of energy and peak demand for the large industrial class reflect the base historical year values adjusted for known and measurable changes in consumption for existing customers, and new growth corresponding to potential customers that have a high likelihood of being served in future years.

development of the final Big Rivers forecast. Review meetings were held via webinars and teleconferences.

The forecast was developed using both quantitative and qualitative methods. A series of econometric models were used to forecast number of customers and energy consumption by customer class and peak demand at the rural system level. Projections for large industrial customers were based on historical consumption and peak demand, combined with information received from the management of Big Rivers' Members regarding future plans and operations.

Big Rivers continues to review its load forecasting process and make enhancements as new information and technologies become available. Big Rivers will continue to monitor industry advancements and best practices to continue to enhance future forecast accuracy. See Section 4 for details regarding load forecast methodologies.

2. Changes since the 2015 Load Forecast

Big Rivers' 2015 Load Forecast was approved by Big Rivers' Board of Directors on July 17, 2015, filed with the RUS on November 6, 2015, and approved by RUS on January 11, 2016.

2.1 Updated Methodology

No significant changes have been made to the load forecast methodology since the 2015 forecast.

2.2 Updated Projections

Tables 2.1 through 2.3 present projected system requirements from the 2013 Load Forecast, the 2015 Load Forecast, and the 2017 Load Forecast. The projected growth rate in number of customers is similar in all forecasts. The 2017 Load Forecast is slightly lower than 2015 forecast in terms of number of energy sales and peak demand.

This forecast reflects the current plans for up to 501 MW of load and capacity to non-Members. This load is comprised of Executed and Projected Sales of economic generation in excess of Native Load requirements. In addition to the non-Member sales, economic energy will be sold in the MISO spot market with hedged prices where appropriate. Further description of this load is found in section 3.2.7.

Table 2.1
Comparison of Projected Number of Customers

	Actual	2013 Load Forecast	2015 Load Forecast	2017 Load Forecast
2005	107,881			
2006	109,327			
2007	110,583			
2008	111,691			
2009	111,940			
2010	112,410			
2011	112,885			
2012	113,250			
2013	113,717	113,562		
2014	114,208	114,545		
2015	114,934	115,658	114,864	
2016	115,859	116,753	115,694	
2017		117,815	116,511	116,843
2018		118,818	117,529	117,809
2019		119,796	118,538	118,737
2020		120,784	119,523	119,781
2021		121,772	120,465	120,701
2022		122,734	121,386	121,568
2023		123,678	122,313	122,434
2024		124,582	123,206	123,299
2025		125,473	124,067	124,197
2026		126,366	124,910	125,044
2027			125,712	125,882
2028			126,511	126,786
2029				127,688
2030				128,589
2031				129,438
2032				130,286
2033				131,134
2034				131,983
2035				132,831
2036				133,680

Table 2.2
Comparison of Projected Native Energy Requirements (GWh)

	Actual	Weather Adjusted	2013 Load Forecast	2015 Load Forecast	2017 Load Forecast
2005	3,233	3,273			
2006	3,189	3,321			
2007	3,326	3,306			
2008	3,314	3,354			
2009	3,159	3,273			
2010	3,412	3,321			
2011	3,344	3,385			
2012	3,283	3,338			
2013	3,371	3,404	3,350		
2014	3,382	3,377	3,408		
2015	3,271	3,333	3,384	3,318	
2016	3,245	3,272	3,373	3,413	
2017			3,394	3,452	3,259
2018			3,416	3,469	3,343
2019			3,437	3,486	3,433
2020			3,460	3,496	3,473
2021			3,485	3,514	3,475
2022			3,511	3,536	3,479
2023			3,537	3,560	3,481
2024			3,562	3,581	3,490
2025			3,589	3,602	3,495
2026			3,616	3,624	3,502
2027			3,644	3,642	3,509
2028				3,669	3,521
2029				3,691	3,526
2030				3,714	3,535
2031				3,737	3,544
2032				3,760	3,557
2033				3,782	3,562
2034				3,805	3,572
2035					3,581
2036					3,593

Table 2.3
Comparison of Projected Native Peak Demand (MW)

	Actual	Weather Adjusted	2013 Load Forecast	2015 Load Forecast	2017 Load Forecast
2005	611	610			
2006	625	627			
2007	653	601			
2008	616	617			
2009	670	630			
2010	662	616			
2011	657	639			
2012	660	618			
2013	615	639	632		
2014	748	698	635		
2015	697	664	635	661	
2016	617	620	637	683	
2017			642	691	648
2018			645	693	660
2019			649	695	673
2020			653	697	676
2021			658	701	678
2022			663	704	679
2023			668	707	680
2024			673	711	681
2025			678	715	682
2026			683	720	683
2027				724	685
2028				729	686
2029				734	688
2030				740	689
2031				745	691
2032				750	693
2033				755	695
2034				761	696
2035					698
2036					700

2.3 Updates to Demand-Side Management Programs

The 2013 Load Forecast was the first to reflect projected impacts of DSM measures implemented by Big Rivers' Member cooperatives, and the 2017 Load Forecast reflects projected impacts from an updated DSM study completed by Big Rivers in 2017. Big Rivers continues to work with the Members to implement and monitor the performance of DSM programs. Much of the work is done through a DSM/EE Working Group consisting of Big Rivers' and its Members' employees. Further discussion of DSM is provided in Section 4.3.

3. Load Forecast Results

3.1 Total System Forecast

Total system energy and peak demand requirements are projected to reach 4,372 GWH and 1,279 MW by 2036. Total system requirements include native system, planned non-Member load, and HMP&L load. Energy Requirements do not include Non-Member economic sales of available on-line generation. Refer to Section 3.2.7 for a discussion of non-Member load.

Native system energy and peak demand requirements are projected to increase at average compound rates of 0.5% per year from 2016 through 2036. Native peak demand is projected to increase by approximately 3.5 MW per year from 2016 through 2036. Native system load factor is projected to be stable over the next 20 years, changing only slightly from 61% in 2016 to 60% in 2036. Tables 3.1 and 3.2 present projected total system energy and peak demand requirements. Tables 3.3 and 3.4 present monthly projections of energy requirements and peak demand for 2018 and 2019.

A review of the 2015 Load Forecast, which included an analysis and comparison of energy and peak demand projections for 2015 and 2016 to actual weather adjusted values for the year, was completed. Weather-adjusted native system energy net of transmission losses was 0.4% higher than projected in 2015 and 4.1% lower than projected in 2016. Weather-adjusted native system peak demand was 0.4% lower than projected in 2015 and 9.2% lower than projected in 2016. The forecast variance in 2016 is impacted significantly by reduced consumption for several large direct serve customers.

Table 3.1
Historical and Projected Energy Requirements

	Member Coop Retail Sales (MWH)	Distribution Losses (%)	Big Rivers Native Sales (MWH)	HMP&L (MWH)	Trans. Losses (MWH)	Total Energy Requirements (MWH)
2012	3,163,984	3.6%	3,282,776	622,254	32,683	3,937,713
2013	3,268,608	3.0%	3,371,187	617,149	39,066	4,027,402
2014	3,266,158	3.4%	3,381,575	632,749	44,238	4,058,562
2015	3,162,679	3.3%	3,270,995	625,367	54,122	3,950,483
2016	3,133,967	3.4%	3,244,594	624,214	63,307	3,932,115
2017	3,148,864	3.4%	3,258,532	629,574	81,374	3,969,480
2018	3,232,699	3.3%	3,343,114	632,094	93,166	4,068,374
2019	3,321,653	3.2%	3,432,508	634,623	95,320	4,162,451
2020	3,362,261	3.2%	3,473,299	637,161	96,336	4,206,796
2021	3,363,840	3.2%	3,474,891	639,710	96,433	4,211,034
2022	3,367,701	3.2%	3,478,946	642,269	96,588	4,217,803
2023	3,369,689	3.2%	3,481,017	644,838	96,696	4,222,551
2024	3,378,562	3.2%	3,490,159	647,417	96,971	4,234,548
2025	3,383,383	3.2%	3,495,398	650,007	97,155	4,242,559
2026	3,389,404	3.2%	3,501,719	652,607	97,364	4,251,690
2027	3,396,162	3.2%	3,508,814	655,218	97,591	4,261,623
2028	3,407,566	3.2%	3,520,620	657,838	97,929	4,276,388
2029	3,412,531	3.2%	3,526,010	660,470	98,117	4,284,597
2030	3,421,270	3.2%	3,535,190	663,112	98,394	4,296,696
2031	3,429,928	3.2%	3,544,285	665,764	98,670	4,308,719
2032	3,442,021	3.2%	3,556,815	668,427	99,026	4,324,268
2033	3,447,245	3.2%	3,562,475	671,090	99,221	4,332,786
2034	3,455,903	3.2%	3,571,571	673,753	99,496	4,344,820
2035	3,464,561	3.2%	3,580,666	676,416	99,772	4,356,854
2036	3,476,655	3.2%	3,593,196	679,079	100,128	4,372,403

Shaded year represents base year

HMP&L based on HMP&L load forecast

Values include DSM impacts

Total energy requirements do not include optimized economic sales

Table 3.2
Historical and Projected Peak Demand

	Rural System (MW)	Direct Serve (MW)	Native System (MW)	Non-Member Load (MW)	HMP&L (MW)	Trans. Losses (%)	Total Peak Demand (MW)
2012	534	120	654		115	0.83%	776
2013	480	129	609		108	0.97%	724
2014	612	128	740		102	1.09%	851
2015	568	120	688		100	1.37%	799
2016	487	120	607		107	1.61%	726
2017	502	133	635	487	107	2.05%	1,254
2018	502	143	645	501	108	2.29%	1,284
2019	503	155	658	500	108	2.29%	1,295
2020	504	157	661	500	108	2.29%	1,299
2021	505	157	662	500	109	2.29%	1,301
2022	506	157	663	500	109	2.29%	1,302
2023	507	157	664	500	110	2.29%	1,304
2024	508	157	665	500	110	2.29%	1,305
2025	509	157	666	500	111	2.29%	1,307
2026	510	157	667	500	111	2.29%	1,309
2027	512	157	669	500	112	2.29%	1,310
2028	513	157	670	500	112	2.29%	1,312
2029	515	157	672	490	112	2.29%	1,304
2030	516	157	674	480	113	2.29%	1,296
2031	518	157	675	480	113	2.29%	1,298
2032	520	157	677	470	114	2.29%	1,290
2033	522	157	679	470	114	2.29%	1,293
2034	523	157	680	460	115	2.29%	1,285
2035	525	157	682	460	115	2.29%	1,287
2036	527	157	684	450	116	2.29%	1,279

Shaded year represents base year

HMP&L based on HMP&L load forecast

Rural system demand includes DSM impacts and distribution losses

Table 3.3
Monthly Energy Requirements
2018-2019

Year	Month	Native Energy Requirements (MWH)	HMP&L (MWH)	Total System Energy Requirements (MWH)
2018	1	336,123	55,941	392,064
2018	2	294,226	54,321	348,547
2018	3	271,607	51,739	323,346
2018	4	235,032	49,334	284,365
2018	5	255,502	52,583	308,086
2018	6	297,663	58,483	356,146
2018	7	327,238	61,671	388,909
2018	8	313,905	59,386	373,291
2018	9	267,179	52,551	319,730
2018	10	247,310	48,709	296,019
2018	11	267,080	50,232	317,313
2018	12	308,601	51,957	360,558
2019	1	343,612	56,165	399,777
2019	2	300,884	54,538	355,422
2019	3	278,768	51,946	330,714
2019	4	242,819	49,531	292,350
2019	5	263,730	52,794	316,524
2019	6	305,625	58,717	364,342
2019	7	335,599	61,918	397,517
2019	8	320,828	59,623	380,452
2019	9	274,947	52,762	327,709
2019	10	255,426	48,904	304,330
2019	11	275,033	50,433	325,466
2019	12	315,684	52,166	367,849

Values include DSM impacts and transmission losses

Total energy requirements do not include optimized economic sales

Table 3.4
Monthly Peak Demand Requirements
2018-2019

Year	*Month*	*Native Peak Requirements (MW)*	*Non-Member Peak Requirements (MW)*	*HMP&L (MW)*	*Total System Demand Requirements (MW)*
2018	1	645	498	101	1,245
2018	2	595	498	98	1,191
2018	3	529	498	91	1,118
2018	4	441	498	84	1,023
2018	5	523	498	95	1,117
2018	6	622	513	105	1,240
2018	7	660	513	111	1,283
2018	8	654	513	111	1,277
2018	9	572	513	104	1,189
2018	10	458	513	93	1,064
2018	11	531	513	87	1,131
2018	12	584	513	96	1,192
2019	1	656	513	102	1,271
2019	2	605	513	98	1,216
2019	3	538	513	91	1,141
2019	4	448	513	85	1,046
2019	5	534	509	96	1,139
2019	6	634	512	105	1,251
2019	7	673	512	111	1,295
2019	8	667	512	111	1,290
2019	9	584	512	104	1,199
2019	10	467	512	93	1,071
2019	11	540	512	88	1,140
2019	12	594	512	96	1,201

Values include DSM impacts and transmission losses

3.2 Customer Class Forecasts

This section presents historical and projected number of customers and energy sales by Member retail classification. All values are net of DSM.

3.2.2 Residential

Residential sales MWH are projected to increase at an average rate of 0.5% per year from 2016 through 2036. Sales in 2017 are projected to decline due to continued increases in appliance efficiencies, energy conservation awareness, and an increase in the retail price of electricity (refer to section 1.5). The number of customers is projected to increase at an average rate of 0.6% through 2036. Customer growth in years 2013-2015 reflects a reclassification of accounts from the Residential to Small Commercial class. Average use per customer is projected to decline in 2017 due reasons stated above and then decline in most years through 2027 due to increased lighting standards and continued increases in appliance efficiencies and energy conservation awareness. Beyond 2024, average use per customer is projected to remain relatively flat as average appliance efficiencies approach maximum levels and the market share of various electric end-uses continue a slight increasing trend.

Table 3.5
Residential

	Number of Customers	Change per Yr.	% Change per Yr.	Energy Sales (MWH)	Normalized Energy Sales (MWH)	% Change per Yr.	Avg. kWh /Cust. /Mo.	% Change per Yr.
2012	97,675			1,465,749	1,477,663		1,261	
2013	97,773	98	0.1%	1,509,915	1,491,767	1.0%	1,271	0.9%
2014	97,851	78	0.1%	1,531,776	1,481,737	-0.7%	1,262	-0.8%
2015	97,971	120	0.1%	1,448,343	1,455,382	-1.8%	1,238	-1.9%
2016	98,583	611	0.6%	1,441,268	1,437,332	-1.2%	1,215	-1.9%
2017	99,290	707	0.7%		1,425,319	-0.8%	1,196	-1.5%
2018	100,046	756	0.8%		1,440,401	1.1%	1,200	0.3%
2019	100,806	760	0.8%		1,451,613	0.8%	1,200	0.0%
2020	101,619	813	0.8%		1,458,290	0.5%	1,196	-0.3%
2021	102,311	692	0.7%		1,456,582	-0.1%	1,186	-0.8%
2022	102,952	641	0.6%		1,462,945	0.4%	1,184	-0.2%
2023	103,594	642	0.6%		1,467,217	0.3%	1,180	-0.3%
2024	104,236	642	0.6%		1,474,969	0.5%	1,179	-0.1%
2025	104,913	677	0.6%		1,484,613	0.7%	1,179	0.0%
2026	105,542	629	0.6%		1,492,013	0.5%	1,178	-0.1%
2027	106,162	621	0.6%		1,500,024	0.5%	1,177	-0.1%
2028	106,852	689	0.6%		1,509,328	0.6%	1,177	0.0%
2029	107,542	691	0.6%		1,518,488	0.6%	1,177	0.0%
2030	108,233	691	0.6%		1,527,802	0.6%	1,176	0.0%
2031	108,874	641	0.6%		1,537,050	0.6%	1,176	0.0%
2032	109,514	641	0.6%		1,546,298	0.6%	1,177	0.0%
2033	110,155	641	0.6%		1,555,546	0.6%	1,177	0.0%
2034	110,795	641	0.6%		1,564,794	0.6%	1,177	0.0%
2035	111,436	641	0.6%		1,574,042	0.6%	1,177	0.0%
2036	112,077	641	0.6%		1,583,290	0.6%	1,177	0.0%

3.2.3 Small Commercial & Industrial ("Small C&I")

Small commercial & industrial customers are defined as all commercial and industrial customers with annual peak demand less than 1,000 kW. Small commercial sales are projected to increase at an average rate of 0.9% per year from 2016 through 2036. Customer growth in years 2013-2015 reflects a reclassification of accounts from the Residential to Small Commercial class. Growth in the number of customers, projected at 1.1% per year, is the primary influence on growth in total class sales. Consumption per customer is projected to decline by 0.3% per year from 2016-2036 due to increases in appliance efficiencies.

Table 3.6
Small Commercial & Industrial

	Number of Customers	Change per Yr.	% Change per Yr.	Energy Sales (MWH)	Normalized Energy Sales (MWH)	% Change per Yr.	Avg. kWh /Cust. /Mo.	% Change per Yr.
2012	15,435			595,342	594,981		3,212	
2013	15,797	362	2.3%	600,982	596,571	0.3%	3,147	-2.0%
2014	16,210	413	2.6%	609,780	597,097	0.1%	3,070	-2.5%
2015	16,806	596	3.7%	610,947	613,258	2.7%	3,041	-0.9%
2016	17,118	312	1.9%	620,471	617,093	0.6%	3,004	-1.2%
2017	17,398	280	1.6%		623,101	1.0%	2,985	-0.7%
2018	17,607	209	1.2%		629,211	1.0%	2,978	-0.2%
2019	17,774	167	1.0%		633,508	0.7%	2,970	-0.3%
2020	18,005	231	1.3%		639,695	1.0%	2,961	-0.3%
2021	18,234	228	1.3%		645,779	1.0%	2,951	-0.3%
2022	18,460	226	1.2%		651,797	0.9%	2,942	-0.3%
2023	18,684	224	1.2%		657,776	0.9%	2,934	-0.3%
2024	18,907	223	1.2%		663,726	0.9%	2,925	-0.3%
2025	19,128	221	1.2%		669,630	0.9%	2,917	-0.3%
2026	19,346	219	1.1%		675,453	0.9%	2,909	-0.3%
2027	19,563	217	1.1%		681,217	0.9%	2,902	-0.3%
2028	19,777	215	1.1%		686,926	0.8%	2,894	-0.3%
2029	19,990	212	1.1%		692,558	0.8%	2,887	-0.2%
2030	20,199	210	1.0%		698,122	0.8%	2,880	-0.2%
2031	20,407	208	1.0%		703,630	0.8%	2,873	-0.2%
2032	20,615	208	1.0%		709,138	0.8%	2,867	-0.2%
2033	20,823	208	1.0%		714,646	0.8%	2,860	-0.2%
2034	21,031	208	1.0%		720,154	0.8%	2,854	-0.2%
2035	21,239	208	1.0%		725,661	0.8%	2,847	-0.2%
2036	21,447	208	1.0%		731,169	0.8%	2,841	-0.2%

3.2.4 Large Commercial & Industrial ("Large C&I")

The large commercial & industrial class is defined as all commercial and industrial customers that have annual peak demand greater than or equal to 1,000 kW. The class includes rural system customers and direct serve customers. Even though Big Rivers maintains a robust economic development effort, Large C&I sales for Big Rivers' three Members are projected to be essentially flat after 2020.

Table 3.7
Large Commercial & Industrial

	Number of Customers	Change per Yr.	% Change per Yr.	Energy Sales (MWH)	% Change per Yr.	Avg. kWh /Cust. /Mo.	% Change per Yr.
2012	44			1,098,999		2,105,362	
2013	52	8	19.0%	1,153,723	5.0%	1,857,847	-11.8%
2014	51	(1)	-1.3%	1,121,005	-2.8%	1,828,719	-1.6%
2015	52	1	1.8%	1,099,899	-1.9%	1,762,658	-3.6%
2016	51	(1)	-1.8%	1,068,889	-2.8%	1,743,702	-1.1%
2017	48	(3)	-5.7%	1,106,507	3.5%	1,914,373	9.8%
2018	49	1	2.1%	1,179,003	6.6%	1,998,311	4.4%
2019	49	0	0.0%	1,261,771	7.0%	2,138,595	7.0%
2020	49	0	0.0%	1,298,788	2.9%	2,201,335	2.9%
2021	49	0	0.0%	1,299,566	0.1%	2,202,655	0.1%
2022	49	0	0.0%	1,299,566	0.0%	2,202,655	0.0%
2023	49	0	0.0%	1,299,566	0.0%	2,202,655	0.0%
2024	49	0	0.0%	1,303,001	0.3%	2,208,477	0.3%
2025	49	0	0.0%	1,299,566	-0.3%	2,202,655	-0.3%
2026	49	0	0.0%	1,299,566	0.0%	2,202,655	0.0%
2027	49	0	0.0%	1,299,566	0.0%	2,202,655	0.0%
2028	49	0	0.0%	1,303,001	0.3%	2,208,477	0.3%
2029	49	0	0.0%	1,299,566	-0.3%	2,202,655	-0.3%
2030	49	0	0.0%	1,299,566	0.0%	2,202,655	0.0%
2031	49	0	0.0%	1,299,566	0.0%	2,202,655	0.0%
2032	49	0	0.0%	1,303,001	0.3%	2,208,477	0.3%
2033	49	0	0.0%	1,299,566	-0.3%	2,202,655	-0.3%
2034	49	0	0.0%	1,299,566	0.0%	2,202,655	0.0%
2035	49	0	0.0%	1,299,566	0.0%	2,202,655	0.0%
2036	49	0	0.0%	1,303,001	0.3%	2,208,477	0.3%

3.2.5 Irrigation

Only one of Big Rivers' Members provides service to irrigation customers. Energy sales for the class account for less than 1% of total system sales. Energy sales are influenced by weather during growing seasons. No new customers are expected during the forecast period, and sales projections for the class are based on average sales for the most recent seven years.

Table 3.8
Irrigation

	Number of Customers	Change per Yr.	% Change per Yr.	Energy Sales (MWH)	% Change per Yr.	Avg. kWh /Cust. /Mo.	% Change per Yr.
2012	5			440		7,338	
2013	4	(1)	-15.0%	48	-89.2%	933	-87.3%
2014	4	(0)	-5.9%	136	186.9%	2,843	204.8%
2015	4	0	0.0%	62	-54.8%	1,286	-54.8%
2016	4	0	0.0%	47	-24.0%	977	-24.0%
2017	4	0	0.0%	194	313.8%	4,041	313.8%
2018	4	0	0.0%	194	0.0%	4,041	0.0%
2019	4	0	0.0%	194	0.0%	4,041	0.0%
2020	4	0	0.0%	194	0.0%	4,041	0.0%
2021	4	0	0.0%	194	0.0%	4,041	0.0%
2022	4	0	0.0%	194	0.0%	4,041	0.0%
2023	4	0	0.0%	194	0.0%	4,041	0.0%
2024	4	0	0.0%	194	0.0%	4,041	0.0%
2025	4	0	0.0%	194	0.0%	4,041	0.0%
2026	4	0	0.0%	194	0.0%	4,041	0.0%
2027	4	0	0.0%	194	0.0%	4,041	0.0%
2028	4	0	0.0%	194	0.0%	4,041	0.0%
2029	4	0	0.0%	194	0.0%	4,041	0.0%
2030	4	0	0.0%	194	0.0%	4,041	0.0%
2031	4	0	0.0%	194	0.0%	4,041	0.0%
2032	4	0	0.0%	194	0.0%	4,041	0.0%
2033	4	0	0.0%	194	0.0%	4,041	0.0%
2034	4	0	0.0%	194	0.0%	4,041	0.0%
2035	4	0	0.0%	194	0.0%	4,041	0.0%
2036	4	0	0.0%	194	0.0%	4,041	0.0%

3.2.6 Street Lighting

Energy sales for the class account for less than 1% of total system sales. Projections of number of customers is based on a historical trend, and energy sales are assumed to increase at a rate equal to the residential class.

Table 3.9
Street Lighting

	Number of Customers	Change per Yr.	% Change per Yr.	Energy Sales (MWH)	% Change per Yr.	Avg. kWh /Cust. /Mo.	% Change per Yr.
2012	92			3,454		3,146	
2013	91	(0)	-0.1%	3,486	0.9%	3,178	1.0%
2014	91	(0)	-0.5%	3,461	-0.7%	3,169	-0.3%
2015	100	9	10.1%	3,429	-0.9%	2,853	-10.0%
2016	103	3	3.2%	3,291	-4.0%	2,654	-7.0%
2017	103	0	0.0%	3,396	3.2%	2,739	3.2%
2018	103	0	0.0%	3,399	0.1%	2,741	0.1%
2019	103	0	0.0%	3,402	0.1%	2,744	0.1%
2020	103	0	0.0%	3,405	0.1%	2,746	0.1%
2021	103	0	0.0%	3,408	0.1%	2,749	0.1%
2022	103	0	0.0%	3,411	0.1%	2,751	0.1%
2023	103	0	0.0%	3,414	0.1%	2,753	0.1%
2024	103	0	0.0%	3,417	0.1%	2,756	0.1%
2025	103	0	0.0%	3,420	0.1%	2,758	0.1%
2026	103	0	0.0%	3,423	0.1%	2,761	0.1%
2027	103	0	0.0%	3,426	0.1%	2,763	0.1%
2028	103	0	0.0%	3,429	0.1%	2,766	0.1%
2029	103	0	0.0%	3,432	0.1%	2,768	0.1%
2030	103	0	0.0%	3,435	0.1%	2,771	0.1%
2031	103	0	0.0%	3,438	0.1%	2,773	0.1%
2032	103	0	0.0%	3,441	0.1%	2,775	0.1%
2033	103	0	0.0%	3,445	0.1%	2,778	0.1%
2034	103	0	0.0%	3,448	0.1%	2,780	0.1%
2035	103	0	0.0%	3,451	0.1%	2,783	0.1%
2036	103	0	0.0%	3,454	0.1%	2,785	0.1%

3.2.7 Non-Member

Big Rivers Optimizes available Member resources by selling excess available resources to Non-Members when those sales bring value to our Member-Owners.

Non-Member Sales will be served from economic capacity of Big Rivers' Member-owners, and are adjusted from time to time as resources and economics dictate. Economic capacity and energy will be sold either bilaterally or via participation in the MISO Day Ahead and Real Time energy market. Non-Member capacity sales included in this report are made up of Executed Sales of Capacity and Projected Sales. Projected sales are the difference between the forecasted Sales target and Executed Sales. The forecasted Sales target is frequently evaluated over time to fully optimize available Member resources. Optimization includes evaluation of costs to deliver Big Rivers' generation versus buying from the market, and when all-in costs of purchasing capacity and/or energy are more economical than transmission and associated generation costs, those purchases are made to bring the most value to our Members. Since normal operations involve periodic evaluation and results in frequent energy sales and purchases, this forecast report does not include energy sales made from on-line available economic resources, while sales of capacity are included because capacity is sold as an annual product. Projected Sales could be comprised of long term sales, short term optimization sales, and possibly new Member additions. (See Non-Member Sales Components Figure 3.1).

Figure 3.1
Non-Member Sales Components

Executed Long-term transactions include capacity sales to several Missouri Municipals beginning in 2017, contracts with Nebraska customers set to begin in 2018, a multi-year MISO [redacted] capacity sale to a power marketer beginning in 2018, and a ten-year sale to the Kentucky Municipal Energy Agency (KyMEA) to begin in 2019. Combined with around 50 MW of internal native load growth beginning in 2017 and extending through 2036, these projects further stabilize Big Rivers' revenue and help ensure competitive rates for our Member-Owners.

Short-term Optimization transactions are sales of available economic energy via bilateral hedging transactions and participation in the MISO capacity auction and Day Ahead and Real Time energy market. These transactions bring value to our Members during the lead time required for execution and delivery of Long Term contracts. Data in the table below do not include short-term Optimization sales of energy, as these transactions occur intermittently throughout the year. However, all available economic energy not dedicated to non-member sales will be sold in the MISO spot market with hedged prices where appropriate.

Table 3.10
Non-Member Load

	Peak Demand (MW)	*% Change per Yr.*
2012		
2013		
2014		
2015		
2016		
2017	*487*	
2018	*501*	*2.9%*
2019	*500*	*-0.2%*
2020	*500*	*0.0%*
2021	*500*	*0.0%*
2022	*500*	*0.0%*
2023	*500*	*0.0%*
2024	*500*	*0.0%*
2025	*500*	*0.0%*
2026	*500*	*0.0%*
2027	*500*	*0.0%*
2028	*500*	*0.0%*
2029	*490*	*-2.0%*
2030	*480*	*-2.0%*
2031	*480*	*0.0%*
2032	*470*	*-2.1%*
2033	*470*	*0.0%*
2034	*460*	*-2.1%*
2035	*460*	*0.0%*
2036	*450*	*-2.2%*

Excludes transmission losses

3.2.8 Rural System Peak Demand

Rural system peak demand represents the highest 1-hour rural system load during the summer and winter seasons.[11] Weather adjusted summer peak demand is projected to increase 28 MW by 2036, increasing at an average rate of 0.5% per year.[12] Winter peak is projected to increase 25 MW by 2036, increasing at an average rate of 0.5% per year.

Table 3.11
Rural System Peak Demand
(excluding transformer losses)

Year	Winter CP (MW)	Weather Adjusted CP	Load Factor	Summer CP (MW)	Weather Adjusted CP	Load Factor
2012	454	503	58.2%	534	487	49.5%
2013	480	501	56.0%	472	502	56.9%
2014	612	570	43.9%	483	485	55.6%
2015	568	544	46.9%	505	511	52.8%
2016	487	492	54.0%	487	499	54.0%
2017		495	53.0%		502	52.3%
2018		496	53.3%		502	52.6%
2019		496	53.4%		503	52.8%
2020		497	53.5%		504	52.8%
2021		498	53.4%		505	52.6%
2022		499	53.4%		506	52.6%
2023		500	53.4%		507	52.6%
2024		500	53.4%		508	52.6%
2025		501	53.5%		509	52.7%
2026		502	53.5%		510	52.7%
2027		503	53.6%		512	52.7%
2028		504	53.7%		513	52.7%
2029		506	53.7%		515	52.8%
2030		507	53.7%		516	52.8%
2031		509	53.8%		518	52.8%
2032		511	53.8%		520	52.9%
2033		512	53.8%		522	52.9%
2034		514	53.9%		523	52.9%
2035		516	53.9%		525	52.9%
2036		517	53.9%		527	53.0%

[11] Summer season includes June through September of each year. Winter season includes January through March of the current year and November and December of the prior year.

[12] Growth is based on weather normalized values for 2016 and 2036

3.2.9 Native System Peak Demand

Native system peak demand represents the sum of rural system 1-hour CP and Direct Serve demand coincident with rural system peak. Weather adjusted summer peak demand is projected to increase 64 MW by 2036, increasing at an average rate of 0.5% per year.[13] Winter peak is projected to increase 71 MW by 2036, increasing at an average rate of 0.6% per year. Direct serve customers are projected to contribute an additional 33 MW to Native system 1-hour peak by 2020.

Table 3.12
Native System Peak Demand
(excluding transmission losses)

Year	Winter CP (MW)	Weather Adjusted CP	Load Factor	Summer CP (MW)	Weather Adjusted CP	Load Factor
2012	569	618	65.9%	654	607	57.3%
2013	597	618	64.5%	609	639	63.2%
2014	740	698	52.2%	602	604	64.1%
2015	688	664	54.3%	617	623	60.5%
2016	600	605	61.7%	607	620	61.0%
2017		621	59.9%		635	58.6%
2018		630	60.5%		645	59.1%
2019		641	61.1%		658	59.6%
2020		654	60.7%		661	60.0%
2021		657	60.4%		662	59.9%
2022		658	60.4%		663	59.9%
2023		659	60.3%		664	59.8%
2024		659	60.4%		665	59.9%
2025		660	60.4%		666	59.9%
2026		661	60.5%		667	59.9%
2027		662	60.5%		669	59.9%
2028		663	60.6%		670	60.0%
2029		665	60.5%		672	59.9%
2030		666	60.6%		674	59.9%
2031		668	60.6%		675	59.9%
2032		670	60.6%		677	60.0%
2033		671	60.6%		679	59.9%
2034		673	60.6%		680	59.9%
2035		674	60.6%		682	59.9%
2036		676	60.7%		684	60.0%

[13] Growth in winter and summer demands are based on weather adjusted CP for years 2016 and 2036.

3.2.10 Total System Non-Coincident Peak Demand

Total system non-coincident peak demand represents the sum of the 1-hour peaks for Big Rivers' native load, Big Rivers' future non-Member load, and HMP&L load. Non-Member and HMP&L load is not coincident with Big Rivers' native load. Total system NCP demand is projected to reach 1,279 MW by 2036.

Table 3.13
Total System Peak Demand
(including transmission losses)

Year	*Winter NCP (MW)*	*Weather Adjusted NCP*	*Load Factor*	*Summer NCP (MW)*	*Weather Adjusted NCP*	*Load Factor*
2012	*663*	*720*	*67.8%*	*776*	*719*	*58.0%*
2013	*697*	*722*	*66.0%*	*724*	*759*	*63.5%*
2014	*851*	*803*	*54.4%*	*718*	*720*	*64.5%*
2015	*799*	*771*	*56.5%*	*736*	*743*	*61.3%*
2016	*705*	*711*	*63.6%*	*726*	*741*	*61.8%*
2017		*735*	*61.7%*		*757*	*59.8%*
2018		*1,245*	*37.3%*		*1,284*	*36.2%*
2019		*1,271*	*37.4%*		*1,295*	*36.7%*
2020		*1,283*	*37.4%*		*1,299*	*37.0%*
2021		*1,287*	*37.4%*		*1,301*	*37.0%*
2022		*1,288*	*37.4%*		*1,302*	*37.0%*
2023		*1,289*	*37.4%*		*1,304*	*37.0%*
2024		*1,290*	*37.5%*		*1,305*	*37.0%*
2025		*1,292*	*37.5%*		*1,307*	*37.1%*
2026		*1,293*	*37.5%*		*1,309*	*37.1%*
2027		*1,295*	*37.6%*		*1,310*	*37.1%*
2028		*1,296*	*37.7%*		*1,312*	*37.2%*
2029		*1,298*	*37.7%*		*1,304*	*37.5%*
2030		*1,290*	*38.0%*		*1,296*	*37.8%*
2031		*1,282*	*38.4%*		*1,298*	*37.9%*
2032		*1,284*	*38.5%*		*1,290*	*38.3%*
2033		*1,276*	*38.8%*		*1,293*	*38.3%*
2034		*1,278*	*38.8%*		*1,285*	*38.6%*
2035		*1,269*	*39.2%*		*1,287*	*38.7%*
2036		*1,272*	*39.3%*		*1,279*	*39.0%*

Total system load factor drops in 2018 because energy requirements do not include optimized economic sales

3.3 Weather Adjusted Energy and Peak Demand Requirements

Rural system energy consumption and peak demand are impacted by prevailing weather. Energy sales and peak demand for direct serve customers are not weather sensitive. Both extreme and mild weather conditions have been experienced over the most recent four years. As measured by degree days, 2010 was the hottest year in over 20 years, and 2010 was the coldest year since 1997. More recently, January 2014 represented one of the most extreme winter months Big Rivers has experienced in the last 20 years, resulting in a new all-time native system peak of 740 MW. Table 3.14 presents actual and weather adjusted energy and peak demand requirements for recent years.

Table 3.14
Weather Normalized Native System Energy and Peak Demand

	Energy (MWH)		*Winter Peak (MW)*		*Summer Peak (MW)*	
	Actual	*Normal*	*Actual*	*Normal*	*Actual*	*Normal*
2007	*3,325,859*	*3,306,150*	*597*	*601*	*648*	*594*
2008	*3,313,571*	*3,354,190*	*611*	*617*	*604*	*606*
2009	*3,159,286*	*3,272,941*	*665*	*630*	*594*	*608*
2010	*3,411,558*	*3,321,276*	*647*	*616*	*652*	*609*
2011	*3,344,199*	*3,385,423*	*621*	*576*	*652*	*639*
2012	*3,282,776*	*3,337,591*	*569*	*618*	*654*	*607*
2013	*3,371,187*	*3,403,524*	*597*	*618*	*609*	*639*
2014	*3,381,575*	*3,377,106*	*740*	*698*	*602*	*604*
2015	*3,270,995*	*3,333,037*	*688*	*664*	*618*	*624*
2016	*3,244,594*	*3,272,279*	*600*	*605*	*607*	*620*

Values represent energy and peak demand without transformer losses

Under normal peaking weather conditions, Big Rivers' annual peak demand is projected to occur during the summer season. Historical data shows, however, that Big Rivers' actual annual peak demand was set during winter months in 2008, 2009, 2014, and 2015. The impact of severe weather is greater during winter months than summer months due primarily to supplemental electric strip heating; therefore, while the base case forecast shows Big Rivers to be summer peaking, under the most extreme weather conditions, the system is most likely to be winter peaking.

3.4 Impact of Existing and Future Energy Efficiency and Demand-Side Management Programs

Big Rivers assisted its Members with the implementation of 10 energy efficiency programs in 2010, and added two additional programs in 2013 for a total of 12 programs. The projected impact of these programs beginning in 2017 is presented in Section 4.3, Table 4.6. Across the 2011-2016 timeframe, the programs continued to grow and yield increasing levels of deemed savings. The impacts of existing programs are quantified indirectly in the 2017 Load Forecast through historical sales and peak demand. The impacts of new programs and increased participation in existing programs are captured in the 2017 Load Forecast through post-modeling adjustments.

Below are programs that are not tracked for impact because they are educational in nature and/or not readily quantifiable.

- **Member websites:** Each of the Member distribution cooperative websites provides easy-to-use Home Energy Suites. The Suites provide education and calculation methods to improve efficiency and save energy in the home. Adjustable inputs specific to a home allows customers to compare their current energy use to estimated energy use resulting from various improvements in efficiency.
- **Energy Use Assessments:** These assessments are provided to commercial and industrial customers upon request. Walk-through energy audits help identify simple and low cost efficiency measures that customers can install or implement themselves. Third party service providers such as the Kentucky Pollution Prevention Center and Department for Energy Development and Independence[14] assist customers in achieving energy reduction goals[15]. Educational programs are also available for employees of commercial and industrial Members.
- **Renewable Energy:** Big Rivers offers renewable energy to its Members. Big Rivers is installing seven solar generators totaling 120 kW capacity in 2017
- **Energy Savings Analysis:** Big Rivers provided energy saving analyses to industrial and large commercial customers by combining efforts with the Members, the Department of Energy ("DOE"[16]), and the University of Louisville's Kentucky Pollution Prevention Center.[17]
- **Power Factor Correction:** Members' staffs provide assistance to correct lagging power factor at a Commercial or Industrial ("C&I") facility. These corrections save money for the customer and improve the efficiency of both transmission and distribution facilities.
- **Technology Evaluation:** Members' staffs assist in the evaluation and implementation of technologies that benefit the productivity, profitability and energy efficiency of a C&I facility.

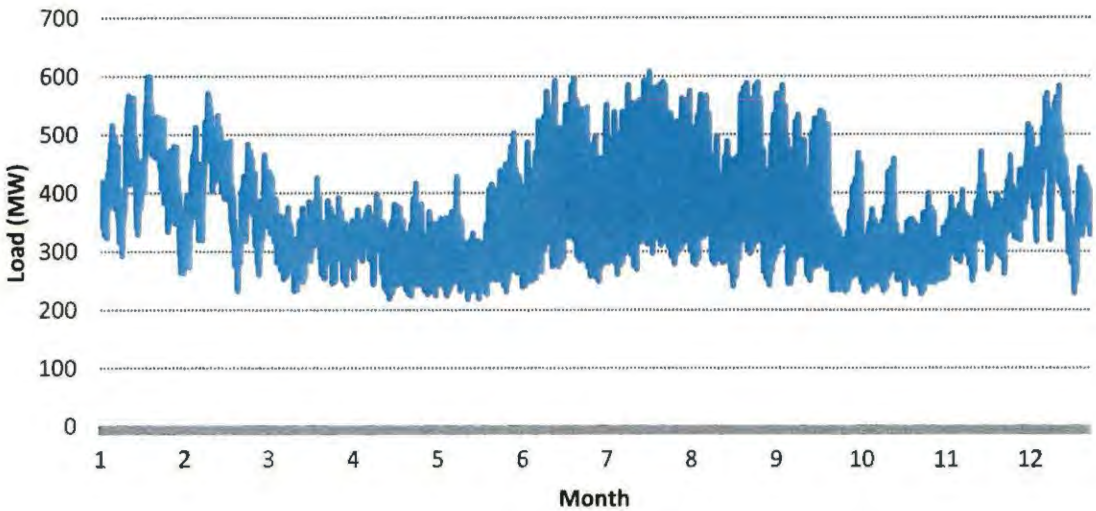
3.5 Anticipated Changes in Load Characteristics

The biggest anticipated change in future load characteristics is growth in non-Member sales, which begin in 2017 at 487 MW. Refer to Section 3.2.7 for details on Non-Member load.

Big Rivers' hourly native system load shape for 2016 is presented in Figure 3.1. The Big Rivers system can be summer or winter peaking depending on the severity of seasonal temperatures; however, the system is projected to be summer peaking over the next 20 years.

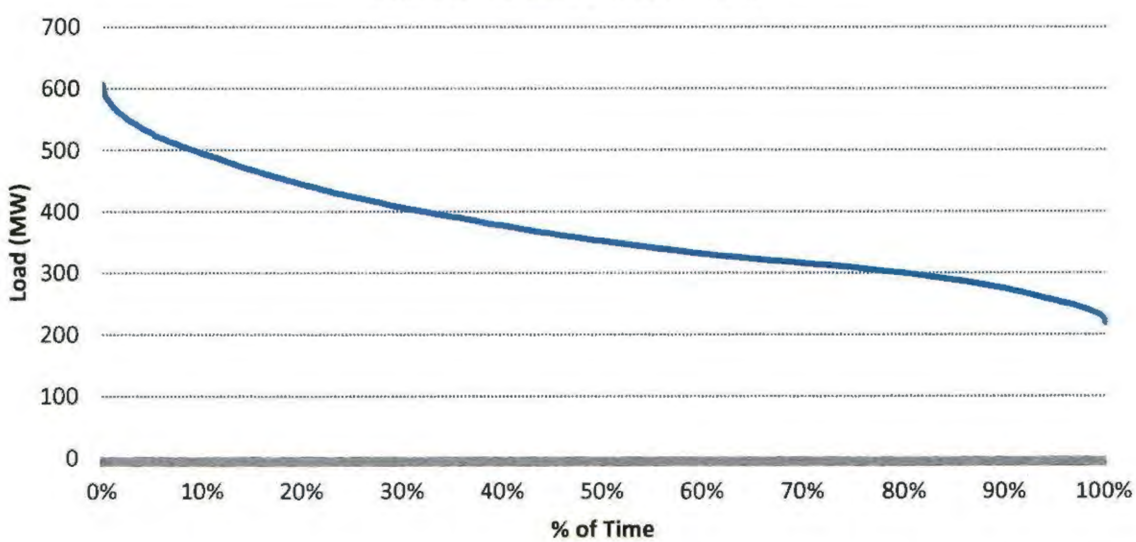
[14] http://energy.ky.gov/Pages/default.aspx
[15] Kentucky Pollution Prevention Center, https://louisville.edu/kppc/es/technical_services.html
Kentucky's Department for Energy Development and Independence, http://energy.ky.gov/Pages/default.aspx
[16] http://energy.gov/
[17] https://louisville.edu/kppc/

Figure 3.1
2016 Annual Load Shape



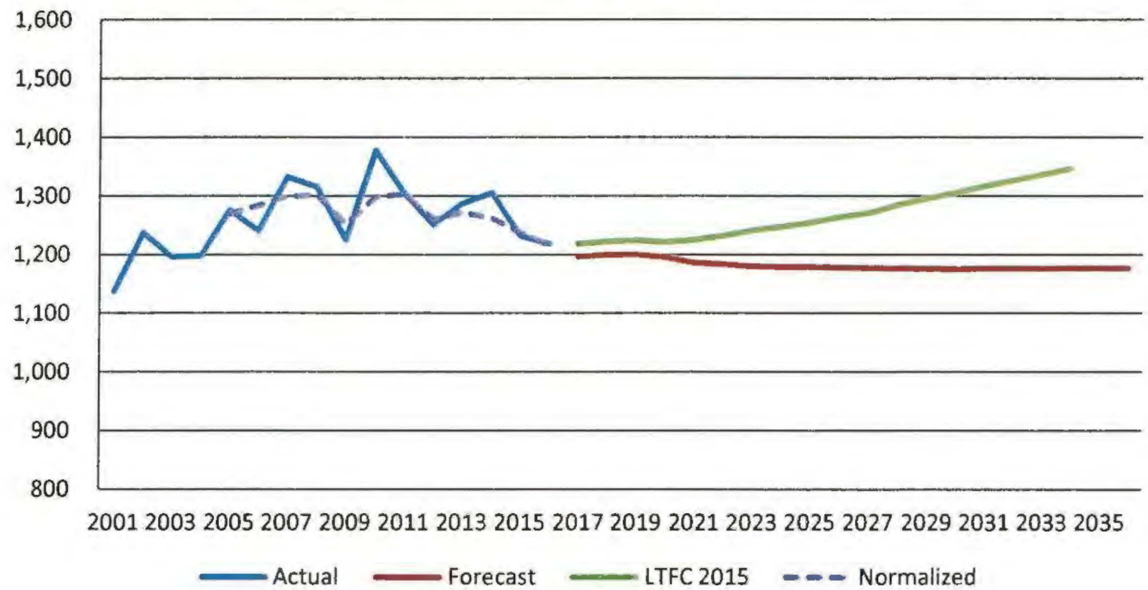
An annual load duration curve for 2016 native load is presented in Figure 3.2. Native system load factor for 2016 was 60.8%.

Figure 3.2
2016 Annual Load Duration Curve



Residential Consumption – Average kWh use per customer has leveled in recent years due primarily to energy conservation and increases in appliance efficiencies. Consumption is projected to decline over the next 20 years primarily as a result of continued increases in appliance efficiencies and minimal increases in electric heating, cooling, and water heating market shares. Figure 3.3 presents average monthly kWh per customer for historical and projected periods.

Figure 3.3
Average Monthly Residential kWh Consumption per Customer by Year



3.6 Load Forecast Scenarios

Big Rivers' base case forecast reflects expected economic growth and normal weather conditions. To address the inherent uncertainty related to these factors, long-term high and low range projections are developed. The range forecasts reflect the energy and demand requirements corresponding to more optimistic and pessimistic economic growth, and mild and extreme weather conditions. Tables 3.15 through 3.18 present the alternative forecast scenarios at the rural system and total system levels.[18] Results at the customer class level are presented in the Appendix B, pages B-9 through B-15.

3.6.1 Economy Scenarios

The optimistic and pessimistic economy scenarios reflect changes in energy sales at the class level and peak demand at the rural system and direct serve levels.

[18] Weather adjusted values for the base historical year, 2014, are presented in Tables 3.15 through 3.18 for comparison purposes

Residential - The energy sales forecast scenarios are based on an analysis of number of customers and average kWh use per customer. The optimistic customer forecast reflects average growth 50% above the base case forecast, and the pessimistic customer forecast reflects average growth 75% below the base case forecast. Inputs to the Residential average kWh use model were adjusted as follows in developing the optimistic/pessimistic scenarios:

- Average growth in household income was changed from 2.1% per year in the base case to 3.5% in the optimistic scenario and 0.5% in the pessimistic scenario.
- The price elasticity coefficient was changed from -0.21 in the base case to -0.11 in the optimistic scenario and -0.31 in the pessimistic scenario.

Residential energy sales are projected to increase at an average compound rate of 0.5% per year in the base case. Average growth increases to 1.6% per year in the optimistic scenario and falls to -0.4% per year in the pessimistic scenario.

Small Commercial - The energy sales forecast scenarios are based on an analysis of number of customers and average kWh use per customer. The optimistic customer forecast reflects average growth 50% above the base case forecast, and the pessimistic customer forecast reflects average growth 75% below the base case forecast. The high and low scenarios of average kWh use per customer for the Small Commercial class reflect average kWh use 10% above/below the base case forecast. Small Commercial energy sales are projected to increase at an average compound rate of 0.9% per year in the base case. Average growth increases to 1.6% per year in the optimistic scenario and falls to -0.2% per year in the pessimistic scenario.

Large Commercial-Rural – Energy sales in the optimistic and pessimistic scenarios are 20% higher or lower, respectively, than the base case. The addition or loss of 1 to 2 customers in this class could impact sales by 20%.

Large Commercial-Direct Serve – Energy sales in the optimistic and pessimistic scenarios are 5% higher and lower than the base case and reflect the assumption of the addition or loss of one customer.

Street Lighting – Energy sales for the optimistic and pessimistic scenarios are 5% higher or lower than the base case.

Irrigation - Energy sales for the optimistic and pessimistic scenarios are 20% higher or lower than the base case.

Rural Peak Demand – The optimistic and pessimistic scenarios in rural peak demand reflect the respective energy sales scenarios. Base case summer and winter load factors are applied to the optimistic and pessimistic rural system energy sales forecasts to derive the peak demand scenario forecasts.

Direct Serve Peak Demand – The optimistic and pessimistic scenarios reflect the base case values plus/minus 5%.

Table 3.15
Optimistic/Pessimistic Economy
Native System

	Energy (MWH)			*Winter Peak Demand*			*Summer Peak Demand*		
	Pessimistic	*Base*	*Optimistic*	*Pess.*	*Base*	*Opti.*	*Pess.*	*Base*	*Opti.*
2016	*3,272,279*	*3,272,279*	*3,272,279*	*605*	*605*	*605*	*620*	*620*	*620*
2021	*3,209,069*	*3,474,891*	*3,772,649*	*604*	*657*	*716*	*609*	*662*	*722*
2026	*3,155,483*	*3,501,719*	*3,894,838*	*592*	*661*	*741*	*597*	*667*	*748*
2031	*3,116,750*	*3,544,285*	*4,045,005*	*581*	*668*	*770*	*587*	*675*	*779*
2036	*3,087,352*	*3,593,196*	*4,204,585*	*573*	*676*	*801*	*579*	*684*	*811*

Table 3.16
Optimistic/Pessimistic Economy
Rural System

	Energy (MWH)			*Winter Peak Demand*			*Summer Peak Demand*		
	Pessimistic	*Base*	*Optimistic*	*Pess.*	*Base*	*Opti.*	*Pess.*	*Base*	*Opti.*
2016	*2,304,554*	*2,304,554*	*2,304,554*	*492*	*492*	*492*	*499*	*499*	*499*
2021	*2,120,358*	*2,328,879*	*2,569,336*	*454*	*498*	*550*	*460*	*505*	*557*
2026	*2,066,772*	*2,355,707*	*2,691,525*	*441*	*502*	*574*	*448*	*510*	*583*
2031	*2,028,039*	*2,398,273*	*2,841,693*	*430*	*509*	*603*	*438*	*518*	*614*
2036	*1,995,377*	*2,443,749*	*2,997,666*	*422*	*517*	*634*	*430*	*527*	*646*

Values for 2016 in Tables 3.15 and 3.16 represent weather normalized amounts

3.6.2 Weather Scenarios

Rural system energy and peak demand is weather sensitive. The impact of weather on industrial customers is insignificant. Under extreme weather conditions, rural system energy is projected to be 7% higher than normal, and peak demand is projected to be approximately 16% higher than normal. The impact of extreme weather conditions on winter peak demands is approximately twice that on summer peak demand.

Energy Sales - The extreme and mild weather scenarios were developed using the Residential and Small Commercial energy use models. The most extreme heating and cooling degree day values from the most recent 20 years were input into the regression models to estimate energy sales under extreme conditions. Heating degree days totaling 4,771 were recorded in 1996, and cooling degree days totaling 2,066 were recorded in 2010.[19]

Rural System Peak Demand – The extreme and mild weather scenarios were developed using base case energy and extreme load factors. Extreme winter season load factor was assumed at 45.2% in 2017,

[19] Average for Evansville, IN; Paducah, KY; and Louisville, KY

rising to 46.0% by 2036. Extreme summer load factor was assumed at 48.2% in 2017, rising to 48.6% by 2036.

Table 3.17
Mild/Extreme Weather
Native System

	Energy (MWH)			*Winter Peak Demand*			*Summer Peak Demand*		
	Mild	*Base*	*Extreme*	*Mild*	*Base*	*Extreme*	*Mild*	*Base*	*Extreme*
2016	*3,272,279*	*3,272,279*	*3,272,279*	*605*	*605*	*605*	*620*	*620*	*620*
2021	*3,347,168*	*3,474,891*	*3,629,644*	*582*	*657*	*743*	*620*	*662*	*706*
2026	*3,372,151*	*3,501,719*	*3,659,113*	*586*	*661*	*749*	*625*	*667*	*712*
2031	*3,413,284*	*3,544,285*	*3,704,569*	*592*	*668*	*757*	*632*	*675*	*721*
2036	*3,460,837*	*3,593,196*	*3,756,284*	*599*	*676*	*766*	*640*	*684*	*731*

Table 3.18
Mild/Extreme Weather
Rural System

	Energy (MWH)			*Winter Peak Demand*			*Summer Peak Demand*		
	Mild	*Base*	*Extreme*	*Mild*	*Base*	*Extreme*	*Mild*	*Base*	*Extreme*
2016	*2,304,554*	*2,304,554*	*2,304,554*	*492*	*492*	*492*	*499*	*499*	*499*
2021	*2,201,156*	*2,328,879*	*2,483,632*	*423*	*498*	*585*	*463*	*505*	*549*
2026	*2,226,139*	*2,355,707*	*2,513,101*	*427*	*502*	*590*	*468*	*510*	*555*
2031	*2,267,272*	*2,398,273*	*2,558,556*	*433*	*509*	*598*	*475*	*518*	*564*
2036	*2,311,390*	*2,443,749*	*2,606,837*	*440*	*517*	*607*	*483*	*527*	*574*

Values for 2016 in Tables 3.17 and 3.18 represent weather normalized amounts

3.7 Research and Development

Big Rivers conducts residential surveys periodically to monitor changes in household major appliances and various end-uses. This schedule is expected to continue in future years. Results from the surveys are used to develop key inputs for the load forecasting models.

Big Rivers will continue to utilize end-use data and information obtained from its appliance saturation studies, along with data available from the Energy Information Association ("EIA") and any other sources that may become available in the future.

Big Rivers will continue to review and test alternative forecasting model methodologies and model specifications. It is anticipated that statistically adjusted end-use models will be used to forecast average use per customer. Big Rivers will also evaluate developing models at the individual customer class level in addition to the higher level rural system and direct serve categories.

Big Rivers assists its three Members in evaluating the potential impacts of new energy efficiency and demand response programs. Big Rivers continues to monitor potential load management and other demand response type programs.

4. Forecast Methodology

The forecast was developed using quantitative and qualitative methods. Econometrics was used to develop forecasting models to project the number of customers and average energy consumption per customer for the Residential and Small Commercial classifications, and peak demand for the rural system. Informed judgment, combined with historical trends, was used to project energy consumption and peak demand for each large commercial customer. The number of customers and energy sales for the street lighting and irrigation classes were projected based on historical trends and judgement.

Big Rivers contracted with GDS to assist in developing the load forecast. The preliminary forecasts were reviewed with Member management. The Members' forecasts were finalized and aggregated to the Big Rivers level.

4.1 Load Forecast Database

Energy consumption and peak demand are influenced by a number of factors; therefore, a considerable amount of data was obtained in developing Big Rivers' load forecast. Energy, peak demand, and pricing data at the Big Rivers and Member levels were collected. Economic data was obtained to update the service area economic outlook. Various types of weather data for local weather stations were collected. Additionally, appliance market share and efficiency data were developed through surveys or obtained via independent sources. Table 4.1 identifies the data that are regularly collected and used in development of the load forecast.

Electric System Data – Number of customers, kWh sales, and sales revenue by customer class and month were collected from each Member distribution cooperative. Additionally, monthly rural system peak demand was collected. Hourly load data for the different components of Big Rivers' control area (rural system by distribution cooperative, HMP&L, and direct serve load) is available.

Economic Data - The economic outlook used in development of the 2015 Load Forecast was obtained from the University of Louisville and from Woods and Poole Economics.[20] Data representing those counties in which the vast majority of Big Rivers' Members' customers reside were used to develop service area economic outlooks for each of Big Rivers' Members[21]. Historical and projected data series for number of households, average household income, total employment, retail sales, and gross regional product were collected. The economic outlook contains data on a monthly basis for 1980 – 2040.

Weather Data – Monthly heating and cooling degree days, and maximum and minimum monthly temperatures were collected for the Evansville, Indiana; Paducah, Kentucky; and Louisville, Kentucky weather stations[22]. Additionally, Big Rivers subscribes to the MDA EarthSat Weather[23], which provides hourly observations for multiple weather variables.

[20] Moody's Analytics, March 2015.

[21] Kenergy (Caldwell, Crittenden, Daviess, Hancock, Henderson, Hopkins, Lyon, Mclean, Ohio, Union, Webster)
JPEC (Ballard, Carlisle, Graves, Livingston, Marshall, McCracken)
MCRECC (Breckinridge, Grayson, Meade, Ohio)

[22] National Oceanic and Atmospheric Administration, http://www.ncdc.noaa.gov/IPS/lcd/lcd.html

[23] http://weather.earthsat.com/

Table 4.1
Load Forecast Database

Data Category	Data Source	Data Element
Electric System	*Big Rivers and its three Member distribution cooperatives*	*Number of customers, kWh sales and revenues by class, system peak demand*
Economic	*Woods & Poole Economics* *University of Louisville*	*Number of households* *Total employment* *Average household income* *Retail sales* *Gross regional product* *Personal consumption expenditure index*
Weather	*National Oceanic and Atmospheric Administration*	*Heating and cooling degree days* *Temperature*
Price	*Big Rivers and its three Member distribution cooperatives*	*Average cents per kWh*
End-use	*Big Rivers* *Energy Information Administration*	*Appliance saturations* *Appliance efficiencies* *Appliance unit energy consumption (kWh)*
Housing Characteristics	*Big Rivers* *Energy Information Administration*	*Size of home* *Number of people per home*

End-Use Data – Big Rivers conducts residential customer surveys periodically to collect data needed to estimate market share for different types of heating, cooling, and water heating systems and various household appliances. Additionally, data regarding housing characteristics were collected. Surveys were conducted in 2017, 2013, and 2009.

Appliance Efficiency Data – Big Rivers collects appliance efficiency information published by the EIA in its Annual Energy Outlook[24]. Average efficiencies for heating, cooling, water heating and other household appliances were obtained and provided information used in developing projections of average energy use per customer for rural system customers.

Housing Characteristics Data – Big Rivers conducts residential customer surveys periodically to collect data needed to estimate housing characteristics. Surveys were conducted in 2017, 2013, and 2009.

4.2 Forecast Model Inputs

Electric System Data – Number of customers, kWh sales, and sales revenue were obtained by customer class from the RUS Form 7 for each Member distribution cooperative. The data is available on a monthly

[24] Energy Information Administration, 2017 Annual Energy Outlook, Table 31.

basis. Monthly peak demand for the rural system is available from the data used in preparing wholesale power bills to the Members. Monthly energy and peak demand for each large industrial customer was provided by the Members. Hourly load data is available at different levels, including the native system, rural system, HMP&L, and direct serve categories.

Retail Price of Electricity - The load forecast includes the impacts of projected [redacted] in the real retail price of electricity over the forecast horizon. Average price reflects class revenue divided by class kWh. The amount was then expressed in real, or deflated, terms by applying the GDP price index ($2009=100). Projected retail electricity prices were developed by Big Rivers in collaboration with the Members. The price of competing fuels is quantified indirectly in the forecast through changes in the markets shares of electric space heating and electric water heating.

Economic Impacts - The forecast captures changes in number of households, average household income, and total employment. Number of households is the independent variable in the long term residential customer models. Household income is one of the driver variables specified in the residential use per customer models. Employment is the driver variable in the long term small commercial customer models. The projected values for each of these demographic and economic variables were obtained from the University of Louisville and from Woods and Poole Economics.

Appliance Market Share - The Members' forecasts incorporate service-area specific market shares of electric appliances and changes in technology. Projections of market share were based on Big Rivers' appliance saturation survey data, census data, and data obtained from the EIA. The market shares for electric heating, electric water heating, and electric air conditioning are all projected to increase throughout the forecast horizon, but at a decreasing rate as maximum saturation levels are approached. Market shares for all other appliances were based on data obtained from EIA.

Appliance Efficiency – Appliance efficiencies are included in the forecast to account for changes in consumption due to changes in the average efficiency of the major electric equipment and appliances in use. Changes in appliance efficiencies occur when customers replace older equipment with newer models. The appliance efficiency information included in the 2017 Load Forecast was obtained from EIA's Annual Energy Outlook.[25]

Weather Data – The load forecasting models incorporate weather data for Paducah, Kentucky; Louisville, Kentucky; and Evansville, Indiana. Heating and cooling degree days are included in the model to forecast rural system average energy use per customer to account for changes in consumption resulting from changes in weather. Similarly, peak day degree days are included in the model to forecast rural system peak demand to quantify the extremity of weather during peaking periods.

DSM and Government Sponsored Programs – The forecast implicitly includes through the historical energy sales data the impacts of Big Rivers' existing DSM programs and current educational and conservation programs. Impacts from increased participation in existing programs and from new programs was obtained from Big Rivers' DSM studies and included in the forecast as a post-modeling adjustment.

[25] Energy Information Administration, *2017 Annual Energy Outlook*.

4.3 Key Load Forecast Assumptions

The key assumptions made during the development of the 2017 Load Forecast focused on changes in the economy, weather, retail electricity price, appliance market shares, and appliance efficiencies. The assumptions apply broadly to each of the three Members and to Big Rivers.

Economic Outlook – Big Rivers' management concluded that changes in economic activity over the forecast horizon are reasonably represented by the projections obtained from Moody's Analytics. Economic outlooks were developed individually for each Member and quantified in the forecasting models. Historical and projected values for the economic data are presented in Table 4.2.

Table 4.2
Economic Outlook

Year	*Employment (thousands)*	*Real Gross Metro Product ($2005 millions)*	*Households (thousands)*	*Real Total Personal Income ($2009 millions)*	*Real Average Household Income ($)*	*Real Retail Sales ($2009 millions)*	*Price Index - GDP, (2009=100)*
2007	122.0	$7,173	197,163	$7,185,104	$36,442	$2,967	92.0
2008	120.9	$7,178	197,085	$7,441,131	$37,756	$2,882	94.8
2009	117.1	$7,093	195,904	$7,459,116	$38,075	$2,699	97.3
2010	116.8	$7,494	195,010	$7,499,422	$38,457	$2,827	99.2
2011	118.7	$7,653	195,466	$7,800,877	$39,909	$2,995	100.0
2012	119.4	$7,659	196,114	$7,874,245	$40,151	$3,105	101.2
2013	119.5	$7,886	196,761	$8,055,572	$40,941	$3,148	103.3
2014	120.7	$8,084	197,409	$8,153,009	$41,300	$3,196	105.2
2015	122.3	$8,277	198,057	$8,309,992	$41,958	$3,239	106.7
2016	123.8	$8,438	198,647	$8,494,581	$42,762	$3,286	108.3
2017	125.3	$8,597	199,237	$8,678,401	$43,558	$3,330	109.9
2018	126.6	$8,754	199,826	$8,864,470	$44,361	$3,372	111.7
2019	128.0	$8,911	200,416	$9,054,686	$45,179	$3,413	114.2
2020	129.3	$9,068	201,006	$9,250,166	$46,019	$3,453	117.0
2021	130.6	$9,225	201,369	$9,445,056	$46,904	$3,491	119.8
2022	131.8	$9,383	201,731	$9,643,131	$47,802	$3,528	122.3
2023	133.1	$9,541	202,094	$9,840,612	$48,693	$3,564	124.9
2024	134.3	$9,698	202,456	$10,036,097	$49,572	$3,601	127.5
2025	135.4	$9,856	202,819	$10,235,810	$50,468	$3,637	130.2
2026	136.6	$10,013	202,982	$10,431,072	$51,389	$3,673	132.8
2027	137.7	$10,170	203,146	$10,620,620	$52,281	$3,709	135.4
2028	138.8	$10,328	203,309	$10,807,566	$53,158	$3,744	138.1
2029	139.9	$10,485	203,473	$10,991,799	$54,021	$3,778	140.9
2030	140.9	$10,643	203,636	$11,169,267	$54,849	$3,813	143.7
2031	141.9	$10,800	203,614	$11,332,728	$55,658	$3,847	146.6
2032	142.9	$10,958	203,592	$11,489,932	$56,436	$3,881	149.5
2033	143.8	$11,115	203,571	$11,644,683	$57,202	$3,916	152.4
2034	144.7	$11,272	203,549	$11,800,956	$57,976	$3,950	155.4
2035	145.6	$11,429	203,527	$11,964,820	$58,787	$3,985	158.6
2036	146.4	$11,586	203,294	$12,124,535	$59,640	$4,020	161.7

Weather – The forecast is based on the assumption that heating and cooling degree days during the forecast horizon would be equal to the most recent 20-year averages. It was assumed that degree days for Paducah, Kentucky; Louisville, Kentucky; and Evansville, Indiana provided reliable coverage of weather conditions for the Big Rivers service area. Values in the following table represent averages for the three stations.

Table 4.3
Degree Days

Year	*Heating Degree Days*	*Cooling Degree Days*	*Winter Peak Temperature*	*Summer Peak Temperature*
1997	*4,574*	*1,227*	*-2*	*99*
1998	*3,596*	*1,751*	*9*	*97*
1999	*3,840*	*1,512*	*3*	*101*
2000	*4,418*	*1,439*	*7*	*96*
2001	*3,997*	*1,514*	*2*	*97*
2002	*4,162*	*1,857*	*11*	*99*
2003	*4,284*	*1,249*	*0*	*95*
2004	*3,991*	*1,419*	*0*	*94*
2005	*4,096*	*1,678*	*-6*	*97*
2006	*3,801*	*1,440*	*6*	*95*
2007	*3,923*	*2,017*	*6*	*105*
2008	*4,399*	*1,559*	*8*	*96*
2009	*4,141*	*1,350*	*0*	*96*
2010	*4,452*	*2,066*	*3*	*103*
2011	*3,961*	*1,724*	*1*	*100*
2012	*3,460*	*1,925*	*15*	*107*
2013	*4,440*	*1,526*	*11*	*96*
2014	*4,674*	*1,608*	*-2*	*97*
2015	*3,886*	*1,688*	*-6*	*95*
2016	*3,671*	*1,937*	*8*	*97*
Average	*4,088*	*1,624*	*4*	*98*

End-Use Characteristics – Assumptions regarding future changes in appliance saturation levels are based on historical trends developed from Big Rivers' appliance saturation surveys and data obtained from the EIA. It was assumed that the market shares for central electric space heating, central air conditioning, and electric water heating will continue to increase over time, but at declining rates as their respective maximum saturation levels are approached. Assumptions regarding changes in appliance efficiencies were based on information obtained from EIA's 2017 Annual Energy Outlook.

Table 4.4
Major Electric Appliance Market Shares and Efficiencies

Year	*Electric Heating*	*Electric Air Conditioning*	*Electric Water Heating*	*Electric Heating Efficiency*	*Air Conditioning Efficiency*	*Electric Water Heating Efficiency*
2012	44.0%	86.0%	68.4%	7.94	12.80	0.91
2013	44.4%	86.0%	68.4%	8.03	13.04	0.90
2014	44.7%	86.0%	68.4%	8.13	13.27	0.91
2015	45.1%	86.0%	68.4%	8.22	13.50	0.91
2016	45.2%	86.1%	68.4%	8.31	13.72	0.91
2017	45.2%	86.1%	68.5%	8.40	13.94	0.92
2018	45.3%	86.6%	68.5%	8.49	14.16	0.92
2019	45.3%	86.6%	68.5%	8.58	14.37	0.93
2020	45.3%	86.7%	68.6%	8.67	14.58	0.93
2021	45.4%	86.7%	68.6%	8.75	14.79	0.94
2022	45.5%	86.8%	68.7%	8.84	14.99	0.95
2023	45.6%	86.8%	68.8%	8.92	15.19	0.95
2024	45.6%	86.9%	68.8%	9.00	15.39	0.96
2025	45.7%	86.9%	68.8%	9.08	15.58	0.97
2026	45.8%	87.0%	68.9%	9.16	15.77	0.97
2027	45.9%	87.0%	68.9%	9.24	15.95	0.98
2028	45.9%	87.1%	69.0%	9.31	16.14	0.98
2029	46.0%	87.1%	69.0%	9.39	16.31	0.99
2030	46.0%	87.2%	69.0%	9.46	16.49	0.99
2031	46.1%	87.2%	69.1%	9.53	16.66	1.00
2032	46.2%	87.3%	69.1%	9.60	16.83	1.00
2033	46.2%	87.3%	69.2%	9.67	17.01	1.00
2034	46.3%	87.4%	69.2%	9.74	17.18	1.00
2035	46.4%	87.4%	69.3%	9.81	17.35	1.00
2036	46.4%	87.4%	69.3%	9.88	17.52	1.00

Electric Heating Efficiency represented as Heating Seasonal Performance Factor (HSPF)
Air Conditioning Efficiency represented as Seasonal Energy Efficiency Ratio (SEER)
Electric Water Heating Efficiency represented as Efficiency Factor (EF)

Retail Electricity Prices – The average price of electricity to rural system customers is expected to [redacted] and then [redacted] Projections were developed internally by Big Rivers' staff and representatives from each Member and represent the quotient of total class revenue and total class kWh.

Demand Side Management – The DSM impacts included in the forecast are based on the *Big Rivers' Electric Demand-Side Management Potential Study*, completed in 2017. New measures were incorporated into the analysis of existing programs, but no new programs were added to the portfolio originally designed in 2010. Adjustments were made to the programs such as LED were added to the residential lighting and weatherization was changed from whole house to duct sealing in the ala-carte program. The basic programs are still intact, just modified to increase the cost effectiveness or introduce new technology. The load forecast is based on the assumption that the impacts of existing DSM programs are captured through the historical energy sales and peak demand data used to develop the forecast models. The impacts of new measures are applied to results of the modeling analysis to produce the final forecasts. Table 4.5 presents the energy and demand impacts associated with DSM.

Table 4.5
DSM Program Impacts

Year	*Rural Energy Sales (MWh)*	*Energy Efficiency Program Impact (MWh)*	*Adjusted Energy Sales (MWh)*	*Rural Peak Demand (MW)*	*Energy Efficiency Program Impact (MW)*	*Adjusted Peak Demand (MW)*
2017	2,200,164	9,654	2,190,511	503	1	502
2018	2,224,509	19,509	2,205,001	505	3	502
2019	2,242,272	28,836	2,213,436	507	4	503
2020	2,255,138	38,111	2,217,028	509	6	504
2021	2,259,518	41,690	2,217,828	511	6	505
2022	2,271,901	50,212	2,221,689	513	8	506
2023	2,282,155	58,478	2,223,677	516	9	507
2024	2,295,861	66,745	2,229,115	518	10	508
2025	2,311,411	74,040	2,237,371	520	11	509
2026	2,324,637	81,245	2,243,392	523	12	510
2027	2,338,416	88,266	2,250,150	525	13	512
2028	2,353,432	95,313	2,258,119	528	14	513
2029	2,368,227	101,708	2,266,519	530	15	515
2030	2,383,108	107,851	2,275,258	533	16	516
2031	2,397,867	113,951	2,283,916	535	17	518
2032	2,412,626	120,052	2,292,574	538	18	520
2033	2,427,385	126,152	2,301,233	541	19	522
2034	2,442,144	132,253	2,309,891	543	20	523
2035	2,456,902	138,353	2,318,549	546	21	525
2036	2,471,661	144,454	2,327,208	548	22	527

Program MW impacts reflect summer season

4.4 Forecast Model Specification

Forecast models were developed to forecast the number of customers and average use per customer for the residential and small commercial classes and peak demand for rural system requirements. The models were developed individually for each of Big Rivers' Member distribution cooperatives. A rural system peak demand model was also developed at the Big Rivers level. Regression techniques are used to develop the forecasting models. All models are expressed in linear functional form and are developed using monthly time series data. Itron's MetrixND software was used to perform the modeling analysis.

4.4.1 Residential Class

Residential Customers – Two models were used in developing the customer forecasts for the Member cooperatives, one for the short term and a second for the long term. The short-term models are based on the recent past and extrapolate the trend over the first three years of the forecast horizon. The long-term models for each Member distribution cooperative provide projections for 15 years and quantify the impacts of the number of households in counties served by the cooperatives and each cooperative's share of county households served. Additionally, an autoregressive parameter is included in each long-term model to correct for serial first-order autocorrelation, which is common in models specifying time series data. Theoretically, the number of residential customers increases when the number of households in the service area increases.

The short-term models were used to develop customer forecasts for up to three years. The long-term models are more appropriate for forecasting over the long term because they capture the impacts of long-term changes in the number of households. The same modeling approach is applicable for each of Big Rivers' three Members. The short-term models are expressed in linear form and take the specification:

$$\mathbf{RCUST} = \beta_0 + \beta_1\,\mathbf{(TREND)} + \varepsilon$$

RCUST	=	Number of residential customers
TREND	=	Time trend, the value for which increments by 1
β_0	=	Coefficient for the model constant, or intercept
β_1	=	Coefficient for the Trend parameter
ε	=	Unexplained model error

The long-term models are expressed in linear form and take the specification:

$$\mathbf{RCUST} = \beta_0 + \beta_1\,\mathbf{(HH)} + \beta_2\,\mathbf{(HHMKT)} + \beta_3\,\mathbf{(AR)} + \varepsilon$$

RCUST	=	Number of rural system customers
HH	=	Number of households
HHMKT	=	Market share of county households
β_0	=	Coefficient for the model constant, or intercept
β_1	=	Coefficient for the Households parameter
β_2	=	Coefficient for autoregressive parameter
ε	=	Unexplained model error

Refer to Appendix C, Forecast Model Specifications, for the statistical output for the individual customer models.

Residential Energy Use per Customer – A statistically adjusted end-use ("SAE") model was developed for each Member cooperative to forecast average use per customer. The SAE modeling structure combines the benefits of both end-use and econometric models. For this forecast, three main indices, each representing key end-use components, are incorporated in a regression model, which provide the framework for measuring changes in residential consumption based on changes in the three indexes. Separate indexes are developed for space heating, air conditioning, and base load appliances. The structure of an example SAE model is illustrated in Figure 1.

The data requirements for a true end-use model are relaxed in the SAE framework, as regional or national data for several inputs are utilized. Through regression techniques, these factors quantify changes in average monthly consumption. The response to multiple key drivers of electricity can be aggregated through the development of the three main indices, eliminating the primary weakness of a traditional econometric model, in which key factors are quantified individually.

Figure 1 –Statistically Adjusted End-Use Model

The indexes are quantified in the regression model; therefore, all the statistical diagnostics are produced, which provide a means for evaluating the SAE specification. The SAE model takes on the following form:

$$\textbf{RUSE} = \beta_0 + \beta_1\,\textbf{(HEAT)} + \beta_2\,\textbf{(COOL)} + \beta_3\,\textbf{(BASE)} + \beta_4 \ldots \beta_n\,\textbf{(Month)} + \varepsilon$$

RUSE	=	Residential kWh use per consumer per month
HEAT	=	Space heating index
COOL	=	Air conditioning index
BASE	=	Base appliance index
β_0	=	Coefficient for the model constant, or intercept
β_1	=	Coefficient for the Heat parameter
β_2	=	Coefficient for the Cool parameter
β_3	=	Coefficient for the Base parameter
$\beta_4 \ldots \beta_n$	=	Coefficients for monthly binary variable parameters
ε	=	Unexplained model error

The average use per customer model is developed using monthly data.

The indices are developed as described below. The coefficients are estimated using least squares regression procedures.

Space Heating Index - The space heating index combines the following appliance, household, price, economic, and weather factors that directly impact the level of space heating electricity consumption in a home:

- Market share of electric space heating devices
- Average device efficiency
- Home size
- Number of householders
- Real retail price of electricity
- Household income
- Heating degree days

These variables increase or decrease the index depending on how they impact space heating consumption. Market share, size of home, income, and degree days all increase consumption as they increase. Device efficiency, home efficiency, and price of electricity decrease consumption as they increase. When available, system-level data is used for each of the heating factors. If system-specific data is not available, such as device efficiency, regional or national trends that are easier to obtain can be utilized. The index is developed on a monthly basis.

Air Conditioning Index - The air conditioning index is built in the same manner as the space heating index, but focuses instead on air conditioning equipment. The key variables used to develop the air conditioning index include:

- Market share of electric air conditioning devices, including room units
- Average device efficiency
- Home size
- Number of householders
- Real retail price of electricity
- Household income
- Cooling degree days

Base Load Index - The base load index captures the general trend associated with increased penetration of plug appliances, lighting, and water heating in the home. The base load index takes into account use associated with the following appliances and influential factors:

- Water heaters
- Refrigerators
- Separate freezers
- Electric ranges and ovens
- Electric clothes washers and dryers
- Dishwashers
- Televisions and DVRs
- Computers
- Lighting
- Miscellaneous load

The index is modified to include impacts associated with price of electricity, household income, and number of people in the household. As the real price of electricity goes up, the base load index goes down. An increase in household income has a positive effect on the base load index as more money is available for plug load electronics. The number of people in the household also has a positive effect on usage. More people in the home leads to more loads of laundry, more showers, more loads of dishes, and more lighting usage. The impact of weather on use of these appliances is negligible, so weather is not included as a factor in the base load index.

Price Elasticity - The real price of electricity parameter is expressed in annual amounts (value for each month held constant at the annual value) to mitigate the monthly variation in average price, which is expressed as revenue per kWh. The elasticity of demand with respect to price is derived through independent regression models and input as one of the factors impacting all three indexes. For all three Member cooperatives, consumption is inelastic with respect to price, as a one percent change in average annual price does not produce a one percent or higher change in average annual consumption. The price elasticity coefficients for the three Members are listed below and compared to independent sources.

Table 4.6
Price Elasticity

Source	*Price Elasticity*
JPEC	*-0.13*
MCRECC	*-0.30*
Kenergy	*-0.20*
EIA	*-0.15*
RAND	*-0.30*
NREL	*-0.27*

EIA: Assumptions to the 2012 Annual Energy Outlook, Residential Demand Module

(http://www.eia.gov/forecasts/aeo/assumptions/pdf/0554(2012).pdf)

RAND: Rand Journal of Economics, Vol. 39, Nbr. 3, Autumn 2008, Peter Reiss and Mathew White

http://www.coursehero.com/file/5044646/21-Reiss-White-RJE-2008-Prices-And-Pressures/

NREL: National Renewable Energy Laboratory, February 2006

http://www.nrel.gov/docs/fy06osti/39512.pdf

The Base, Heat, and Cool parameters in each model are significant at the 0.05 alpha, 95% confidence level, and there are no indications of collinearity problems between any of the model inputs. Refer to Appendix D, Econometric Model Specifications, for the statistical output for the individual average use per residential customer models.

Total Residential Energy Sales – Total residential energy sales are computed as the product of number of customers and average energy use per customer.

4.4.2 Small Commercial Class

Small Commercial Customers – Models were developed to forecast number of customers for both the short term and long term horizons. The short-term models are based on the recent past and extrapolate the trend over the first three years of the forecast horizon. The long-term models quantify the impacts of the employment growth in the service areas for each Member and provide projections for 15 years.

The short-term models are expressed in linear form and take the specification:

$$\textbf{SCCUST} = \beta_0 + \beta_1 \textbf{(TREND)} + \varepsilon$$

SCCUST	=	Number of small commercial customers
TREND	=	Time trend, the value for which increments by 1
β_0	=	Coefficient for the model constant, or intercept
β_1	=	Coefficient for the Trend parameter
ε	=	Unexplained model error

The long-term models are expressed in linear form and take the specifications:

$$\textbf{SCCUST} = \beta_0 + \beta_1 \textbf{(EMP)} + \beta_2 \textbf{(AR)} + \varepsilon$$

SCCUST	=	Number of small commercial customers
EMP	=	Total non-farm employment
$SCCUST_{t-1}$	=	Number of small commercial customers from prior month
β_0	=	Coefficient for the model constant, or intercept
$\beta_1 \ldots \beta_n$	=	Coefficients for the respective model parameters
ε	=	Unexplained model error

See Appendix C, Econometric Model Specifications, for the statistical output for the customer models.

Small Commercial Energy Use per Customer - The Small Commercial classification consists of a wide variety of customers. Annual peak demands for customers in the class range from less than 5 kW for the smaller customers up to 999 kW for the largest customers. Factors impacting one group of customers in the class may not impact other groups. Average energy use per customer has been relatively flat or trending down over time. It is assumed that this trend will continue as older equipment is replaced with new, higher efficient units.

The models developed to forecast average use for each year of the forecast horizon quantify the impacts of increasing appliance efficiencies and weather conditions. The model for JPEC also includes average use from the prior year as an independent variable. The models are expressed in linear form and take the following specifications.

$$\textbf{SCUSE} = \beta_0 + \beta_1 \textbf{(WTCDD)} + \beta_2 \textbf{(WTHDD)} + \beta_3 \ldots \beta_n \textbf{(Month)} + \varepsilon$$

SCUSE	=	Small Commercial kWh use per consumer per month
WTCDD	=	Weighed cooling degree days (degree days x appliance efficiency)
WTHDD	=	Weighed heating degree days (degree days x appliance efficiency)
β_0	=	Coefficient for the model constant, or intercept
$\beta_1 \ldots \beta_n$	=	Coefficients for the respective model parameters
ε	=	Unexplained model error

Total Small Commercial Energy Sales – Total small commercial energy sales are computed as the product of number of customers and average energy use per customer.

4.4.3 Large Commercial Class – Rural System

The number of rural system large commercial customers is projected to increase from 28 to 29 in 2018 and then remain constant through 2036. Each is projected on an individual basis. Projections of number of customers, energy sales, and peak demand are set at the most recent historical values and adjusted for expected changes in operations that can be identified by Member management.

4.4.4 Large Commercial Class – Direct Serve

Beginning in 2017, there are 20 direct serve large commercial customers. Each is projected on an individual basis. Projections of number of customers, energy sales, and peak demand are set at the most recent historical values and adjusted for expected changes in operations that can be identified by Member management.

4.4.5 Street Lighting Class

Street Lighting sales comprise approximately 0.1% of rural system sales. Projections of number of customers and energy sales are based on historical trends and judgement.

4.4.6 Irrigation Class

Irrigation sales comprise less than 0.1% of rural system sales. Projections of number of customers and energy sales are based on historical trends and judgement.

4.4.7 Rural System Peak Demand

Regression models are developed to project rural system CP demand for each Member cooperative and aggregated to the Big Rivers total. Growth in long term rural system demand tracks energy sales more than other influential factors; therefore, trended rural system energy sales is specified in the model as the primary driver of long term growth over the forecast horizon. Trended energy reflects the non-linear trend in historical and projected sales and excludes variations in sales due to weather. Peak day average daily temperature parameters are included for each month to capture swings in monthly and annual peaks due to weather conditions.

The model specification is expressed in linear form and takes the following specification.

$$
\begin{aligned}
\mathbf{RURALPEAK} = {} & \beta_0 + \\
& \beta_1(\mathrm{EGY\_TREND}) + \\
& B_2(\mathrm{PEAKHDD}) + B_3(\mathrm{PEAKCDD}) + \\
& B_4(\mathrm{FEB}) + \beta_5(\mathrm{MAR}) + \beta_6(\mathrm{APR}) + \beta_7(\mathrm{MAY}) + \\
& B_8(\mathrm{JUN}) + \beta_9(\mathrm{JUL}) + \beta_{10}(\mathrm{AUG}) + \beta_{11}(\mathrm{SEP}) + \\
& \beta_{12}(\mathrm{OCT}) + \beta_{13}(\mathrm{NOV}) + \beta_{14}(\mathrm{DEC}) + \\
& \beta_{15}(\mathrm{AR}) + \\
& \varepsilon
\end{aligned}
$$

Where:

RURALPEAK	=	Rural system peak demand
EGY_TREND	=	Rural system energy trend
PEAKHDD	=	Peak day heating degree days for January based on a 55 degree base
PEAKCDD	=	Peak day heating degree days for February based on a 75 degree base
FEB...DEC	=	Binary variable equal to 1 in each respective month, 0 otherwise
β_0	=	Coefficient for the model constant, or intercept
$\beta_1 ... \beta_{15}$	=	Coefficients for the respective model parameters
ε	=	Unexplained model error

4.4.8 Native System Peak Demand

Native system peak demand is projected as the sum of rural system and direct serve peak demands. Direct serve peak demand is computed as the product of aggregate direct serve customer NCP and a projected coincidence factor, which represents the average of historical values.

4.4.9 Henderson Municipal Power & Light

Projections of Henderson Municipal Power & Light energy sales and peak demand were developed by HMP&L and provided to Big Rivers.

4.4.10 Non-Member Energy Sales and Peak Demand

Projections of non-Member energy sales and peak demand are based on internal analysis completed by Big Rivers' staff. Projections reflect information available from Big Rivers' Energy Services Department as of July, 2017.

Appendix A – Annual Forecast Tables & Graphs

BIG RIVERS ELECTRIC CORPORATION

2017 LONG-TERM LOAD FORECAST - BASE CASE FORECAST

SYSTEM REQUIREMENTS - ADJUSTED FOR DSM

	Member System Retail Sales					Distr. Losses	Native Sales (@distribution)		HMP&L (@ distr)	Non-Mbr (@distr)	Total Sales (@distribution)		Trans. Losses	Native Requirements (w/transmission losses)			Total Energy Requirements (w/transmission losses)		
Year	Actual (MWh)	Normal (MWh)	DSM (MWh)	DSM Adj. (MWh)	Percent Growth	(%)	Actual (MWh)	Normal (MWh)	(MWh)	(MWh)	Actual (MWh)	Normal (MWH)	(%)	Actual (MWh)	Normal (MWh)	Percent Growth	Actual (MWh)	Normal (MWh)	Percent Growth
2001	3,192,415	3,281,237				2.8%	3,284,432	3,375,813	643,295		3,927,727	4,037,007	1.78%	3,343,954	3,436,992		3,998,907	4,110,168	
2002	3,120,298	3,104,723			-2.3%	2.2%	3,191,176	3,175,247	673,932		3,865,108	3,845,815	1.56%	3,241,748	3,225,566	-3.1%	3,926,360	3,906,760	-4.9%
2003	3,004,389	3,121,567			-3.7%	1.6%	3,052,582	3,171,640	628,572		3,681,154	3,824,728	1.39%	3,095,611	3,216,347	-4.5%	3,733,043	3,878,641	-0.7%
2004	3,027,344	3,143,295			0.8%	3.3%	3,129,980	3,249,862	679,204		3,809,184	3,955,080	1.27%	3,170,242	3,291,666	2.4%	3,858,183	4,005,956	3.3%
2005	3,131,950	3,170,409			3.5%	3.1%	3,233,245	3,272,948	687,000		3,920,245	3,968,384	1.12%	3,269,867	3,310,020	3.1%	3,964,649	4,013,333	0.2%
2006	3,090,437	3,218,375			-1.3%	3.1%	3,188,986	3,321,004	673,114		3,862,100	4,021,983	0.89%	3,217,623	3,350,826	-1.6%	3,896,781	4,058,101	1.1%
2007	3,219,155	3,200,079			4.2%	3.2%	3,325,859	3,306,150	690,270		4,016,129	3,992,330	0.81%	3,353,018	3,333,149	4.2%	4,048,925	4,024,932	-0.8%
2008	3,204,376	3,243,657			-0.5%	3.3%	3,313,571	3,354,190	658,517		3,972,088	4,020,779	0.78%	3,339,620	3,380,558	-0.4%	4,003,314	4,052,388	0.7%
2009	3,092,391	3,203,640			-3.5%	2.1%	3,159,286	3,272,941	588,663		3,747,949	3,882,781	0.81%	3,185,085	3,299,668	-4.6%	3,778,555	3,914,488	-3.4%
2010	3,315,474	3,227,735			7.2%	2.8%	3,411,558	3,321,276	643,103		4,054,661	3,947,360	0.80%	3,439,070	3,348,060	8.0%	4,087,360	3,979,193	1.7%
2011	3,261,662	3,301,868			-1.6%	2.5%	3,344,199	3,385,423	622,844		3,967,043	4,015,945	0.78%	3,370,489	3,412,037	-2.0%	3,998,229	4,047,515	1.7%
2012	3,163,984	3,216,815			-3.0%	3.6%	3,282,776	3,337,591	622,254		3,905,030	3,970,235	0.83%	3,310,251	3,365,525	-1.8%	3,937,713	4,003,464	-1.1%
2013	3,268,608	3,299,961			3.3%	3.0%	3,371,187	3,403,524	617,149		3,988,336	4,026,593	0.97%	3,404,208	3,436,862	2.8%	4,027,402	4,066,033	1.6%
2014	3,266,158	3,261,842			-0.1%	3.4%	3,381,575	3,377,106	632,749		4,014,324	4,009,018	1.09%	3,418,840	3,414,322	0.4%	4,058,562	4,053,198	-0.3%
2015	3,162,679	3,222,667			-3.2%	3.3%	3,270,995	3,333,037	625,367		3,896,362	3,970,266	1.37%	3,316,430	3,379,334	-3.0%	3,950,483	4,025,414	-0.7%
2016	3,133,967	3,160,708			-0.9%	3.4%	3,244,594	3,272,279	624,214		3,868,808	3,901,820	1.61%	3,297,687	3,325,825	-0.6%	3,932,115	3,965,667	-1.5%
2017		3,158,517	9,654	3,148,864	-0.4%	3.4%		3,258,532	629,574			3,888,106	2.05%		3,326,730	0.0%		3,969,480	0.1%
2018		3,252,208	19,509	3,232,699	2.7%	3.3%		3,343,114	632,094	-		3,975,208	2.29%		3,421,466	2.8%		4,068,374	2.5%
2019		3,350,489	28,836	3,321,653	2.8%	3.2%		3,432,508	634,623	-		4,067,131	2.29%		3,512,955	2.7%		4,162,451	2.3%
2020		3,400,372	38,111	3,362,261	1.2%	3.2%		3,473,299	637,161	-		4,110,461	2.29%		3,554,702	1.2%		4,206,796	1.1%
2021		3,405,530	41,690	3,363,840	0.0%	3.2%		3,474,891	639,710	-		4,114,601	2.29%		3,556,331	0.0%		4,211,034	0.1%
2022		3,417,913	50,212	3,367,701	0.1%	3.2%		3,478,946	642,269	-		4,121,215	2.29%		3,560,481	0.1%		4,217,803	0.2%
2023		3,428,167	58,478	3,369,689	0.1%	3.2%		3,481,017	644,838	-		4,125,855	2.29%		3,562,600	0.1%		4,222,551	0.1%
2024		3,445,308	66,745	3,378,562	0.3%	3.2%		3,490,159	647,417	-		4,137,577	2.29%		3,571,957	0.3%		4,234,548	0.3%
2025		3,457,423	74,040	3,383,383	0.1%	3.2%		3,495,398	650,007	-		4,145,405	2.29%		3,577,318	0.2%		4,242,559	0.2%
2026		3,470,649	81,245	3,389,404	0.2%	3.2%		3,501,719	652,607	-		4,154,326	2.29%		3,583,788	0.2%		4,251,690	0.2%
2027		3,484,428	88,266	3,396,162	0.2%	3.2%		3,508,814	655,218	-		4,164,032	2.29%		3,591,049	0.2%		4,261,623	0.2%
2028		3,502,879	95,313	3,407,566	0.3%	3.2%		3,520,620	657,838	-		4,178,459	2.29%		3,603,132	0.3%		4,276,388	0.3%
2029		3,514,239	101,708	3,412,531	0.1%	3.2%		3,526,010	660,470	-		4,186,479	2.29%		3,608,648	0.2%		4,284,597	0.2%
2030		3,529,120	107,851	3,421,270	0.3%	3.2%		3,535,190	663,112	-		4,198,301	2.29%		3,618,043	0.3%		4,296,696	0.3%
2031		3,543,879	113,951	3,429,928	0.3%	3.2%		3,544,285	665,764	-		4,210,049	2.29%		3,627,351	0.3%		4,308,719	0.3%
2032		3,562,073	120,052	3,442,021	0.4%	3.2%		3,556,815	668,427	-		4,225,242	2.29%		3,640,175	0.4%		4,324,268	0.4%
2033		3,573,397	126,152	3,447,245	0.2%	3.2%		3,562,475	671,090	-		4,233,566	2.29%		3,645,968	0.2%		4,332,786	0.2%
2034		3,588,156	132,253	3,455,903	0.3%	3.2%		3,571,571	673,753	-		4,245,324	2.29%		3,655,277	0.3%		4,344,820	0.3%
2035		3,602,914	138,353	3,464,561	0.3%	3.2%		3,580,666	676,416	-		4,257,082	2.29%		3,664,585	0.3%		4,356,854	0.3%
2036		3,621,108	144,454	3,476,655	0.3%	3.2%		3,593,196	679,079	-		4,272,275	2.29%		3,677,409	0.3%		4,372,403	0.4%
ANNUAL GROWTH RATES																			
2001-2006	-0.6%	-0.4%					-0.6%	-0.3%	0.9%		-0.3%	-0.1%		-0.8%	-0.5%		-0.5%	-0.3%	
2006-2011	1.1%	0.5%					1.0%	0.4%	-1.5%		0.5%	0.0%		0.9%	0.4%		0.5%	-0.1%	
2011-2016	-0.8%	-0.9%					-0.6%	-0.7%	0.0%		-0.5%	-0.6%		-0.4%	-0.5%		-0.3%	-0.4%	
2016-2021		1.5%		1.3%				1.2%	0.5%			1.1%			1.3%			1.2%	
2021-2026		0.4%	14.3%	0.2%				0.2%	0.4%	#DIV/0!		0.2%			0.2%			0.2%	
2026-2031		0.4%	7.0%	0.2%				0.2%	0.4%	#DIV/0!		0.2%			0.2%			0.2%	
2031-2036		0.4%	4.9%	0.3%				0.3%	0.4%	#DIV/0!		0.3%			0.3%			0.3%	
2016-2036		0.7%		0.5%				0.5%	0.4%			0.5%			0.5%			0.5%	

Member system retail sales include only power supplied by Big Rivers
Total Energy Requirements include HMP&L requirements and sales to non-members and native sales anticipated from marketing efforts

BIG RIVERS ELECTRIC CORPORATION

2017 LONG-TERM LOAD FORECAST - BASE CASE FORECAST

SYSTEM REQUIREMENTS - ADJUSTED FOR DSM

	Native- Summer CP (@distribution)					HMP&L (@ distr)	Non-Mbr (@distr)	Total System Summer CP (@distribution)				Native Summer CP (w/transmisson losses)			Total System Summer NCP (w/transmission losses)		
Year	Actual (kW)	Normal (kW)	DSM (kW)	DSM Adj. (kW)	Load Factor	Actual (kW)	Actual (kW)	Actual (kW)	Normal (kW)	DSM Adj. (kW)	Load Factor	Actual (kW)	Normal (kW)	DSM Adj. (kW)	Actual (kW)	Normal (kW)	DSM Adj. (kW)
2001	596,310	-			62.9%	119,000		715,310			62.7%	607,117			728,273		
2002	602,623	587,317			60.5%	124,000		726,623	708,167		60.7%	612,173	596,624		738,138	719,390	
2003	583,906	592,266			59.7%	121,000		704,906	714,998		59.6%	592,137	600,614		714,842	725,077	
2004	604,155	618,850			59.1%	120,000		724,155	741,768		60.0%	611,927	626,810		733,471	751,310	
2005	603,783	609,740			61.1%	124,000		727,783	734,963		61.5%	610,622	616,646		736,026	743,288	
2006	619,258	627,399			58.8%	122,000		741,258	751,003		59.5%	624,819	633,033		747,914	757,747	
2007	647,502	594,279			58.6%	125,000		772,502	709,004		59.3%	652,789	599,132		778,810	714,794	
2008	604,334	605,923			62.6%	119,000		723,334	725,236		62.7%	609,085	610,686		729,021	730,937	
2009	594,126	608,201			60.7%	111,000		705,126	721,831		60.7%	598,978	613,168		710,884	727,725	
2010	656,634	613,675			59.3%	117,000		773,634	723,020		59.8%	661,929	618,624		779,873	728,851	
2011	652,127	638,938			58.5%	113,000		765,127	749,653		59.2%	657,253	643,961		771,142	755,546	
2012	654,200	606,718			57.3%	115,000		769,200	713,372		58.0%	659,675	611,796		775,638	719,342	
2013	609,000	638,743			63.2%	108,000		717,000	752,018		63.5%	614,965	644,999		724,023	759,384	
2014	601,935	603,617			64.1%	108,000		709,935	711,918		64.5%	608,569	610,269		717,759	719,764	
2015	616,732	622,689			60.5%	109,000		725,732	732,742		61.3%	625,299	631,338		735,813	742,920	
2016	607,440	619,950		619,950	61.0%	107,000		714,440	729,154	729,154	61.8%	617,380	630,095	630,095	726,131	741,085	741,085
2017		636,233	1,455	634,778	58.6%	107,000	487,000		1,230,233	1,228,778	36.1%		649,549	648,064		1,255,981	1,254,495
2018		648,174	2,925	645,249	59.1%	108,000	501,000		1,257,174	1,254,249	36.2%		663,365	660,371		1,286,638	1,283,644
2019		661,989	4,261	657,728	59.6%	108,000	500,000		1,269,989	1,265,728	36.7%		677,504	673,143		1,299,754	1,295,393
2020		666,304	5,666	660,639	60.0%	108,432	500,000		1,274,736	1,269,071	37.0%		681,920	676,122		1,304,612	1,298,813
2021		668,399	6,238	662,162	59.9%	108,866	500,000		1,277,265	1,271,027	37.0%		684,064	677,681		1,307,200	1,300,816
2022		670,549	7,513	663,036	59.9%	109,301	500,000		1,279,850	1,272,337	37.0%		686,264	678,575		1,309,846	1,302,156
2023		672,753	8,763	663,990	59.8%	109,738	500,000		1,282,492	1,273,729	37.0%		688,520	679,552		1,312,549	1,303,581
2024		675,013	10,006	665,006	59.9%	110,177	500,000		1,285,190	1,275,184	37.0%		690,833	680,592		1,315,310	1,305,070
2025		677,326	11,114	666,212	59.9%	110,618	500,000		1,287,945	1,276,830	37.1%		693,201	681,826		1,318,130	1,306,755
2026		679,695	12,219	667,476	59.9%	111,061	500,000		1,290,756	1,278,536	37.1%		695,625	683,119		1,321,007	1,308,501
2027		682,119	13,261	668,857	59.9%	111,505	500,000		1,293,623	1,280,362	37.1%		698,105	684,533		1,323,942	1,310,369
2028		684,597	14,307	670,290	60.0%	111,951	500,000		1,296,547	1,282,241	37.2%		700,641	685,999		1,326,934	1,312,292
2029		687,130	15,239	671,891	59.9%	112,399	490,000		1,289,528	1,274,289	37.5%		703,234	687,638		1,319,750	1,304,155
2030		689,717	16,169	673,549	59.9%	112,848	480,000		1,282,565	1,266,397	37.8%		705,882	689,334		1,312,624	1,296,077
2031		692,360	17,091	675,268	59.9%	113,300	480,000		1,285,659	1,268,568	37.9%		708,586	691,094		1,315,791	1,298,299
2032		695,002	18,014	676,988	60.0%	113,753	470,000		1,278,755	1,260,741	38.3%		711,291	692,854		1,308,725	1,290,288
2033		697,644	18,937	678,707	59.9%	114,206	470,000		1,281,850	1,262,913	38.3%		713,995	694,614		1,311,893	1,292,512
2034		700,287	19,860	680,427	59.9%	114,659	460,000		1,274,946	1,255,086	38.6%		716,699	696,374		1,304,826	1,284,501
2035		702,929	20,782	682,147	59.9%	115,112	460,000		1,278,041	1,257,259	38.7%		719,403	698,134		1,307,995	1,286,725
2036		705,571	21,705	683,866	60.0%	115,566	450,000		1,271,137	1,249,432	39.0%		722,108	699,894		1,300,928	1,278,715
ANNUAL GROWTH RATES																	
2001-2006	0.8%					0.5%		0.7%				0.6%			0.5%		
2006-2011	1.0%	0.4%				-1.5%		0.6%	0.0%			1.0%	0.3%		0.6%	-0.1%	
2011-2016	-1.4%	-0.6%				-1.1%		-1.4%	-0.6%			-1.2%	-0.4%		-1.2%	-0.4%	
2016-2021		1.5%		1.3%		0.3%			11.9%	11.8%			1.7%	1.5%		12.0%	11.9%
2021-2026		0.3%	14.4%	0.2%		0.4%	0.0%		0.2%	0.1%			0.3%	0.2%		0.2%	0.1%
2026-2031		0.4%	6.9%	0.2%		0.4%	-0.8%		-0.1%	-0.2%			0.4%	0.2%		-0.1%	-0.2%
2031-2036		0.4%	4.9%	0.3%		0.4%	-1.3%		-0.2%	-0.3%			0.4%	0.3%		-0.2%	-0.3%
2016-2036		0.6%		0.5%		0.4%			2.8%	2.7%			0.7%	0.5%		2.9%	2.8%

NCP represents the highest 1-hour peak demand recorded during the summer and winter seasons
Summer season is May to October
Total system peak includes native, HMP&L, and non-member load

BIG RIVERS ELECTRIC CORPORATION

2017 LONG-TERM LOAD FORECAST - BASE CASE FORECAST

SYSTEM REQUIREMENTS - ADJUSTED FOR DSM

	Native- Winter CP (@distribution)					HMP&L (@ distr)	Non-Mbr (@distr)	Total System Winter NCP (@distribution)				Native Winter CP (w/transmisson losses)			Total System Winter NCP (w/transmission losses)		
Year	Actual (kW)	Normal (kW)	DSM (kW)	DSM Adj. (kW)	Load Factor	Actual (kW)	Actual (kW)	Actual (kW)	Normal (kW)	DSM Adj. (kW)	Load Factor	Actual (kW)	Normal (kW)	DSM Adj. (kW)	Actual (kW)	Normal (kW)	DSM Adj. (kW)
2001	598,797				62.6%	95,000		693,797			64.6%	609,649			706,371		
2002	530,467	556,540			68.7%	100,000		630,467	661,455		70.0%	538,874	565,360		640,459	671,937	
2003	585,549	547,253			59.5%	92,000		677,549	633,236		62.0%	593,803	554,967		687,100	642,162	
2004	562,082	535,652			63.6%	96,000		658,082	627,138		66.1%	569,312	542,542		666,547	635,205	
2005	548,765	561,077			67.3%	98,000		646,765	661,276		69.2%	554,980	567,433		654,091	668,767	
2006	576,534	599,442			63.1%	98,000		674,534	701,336		65.4%	581,711	604,825		680,591	707,634	
2007	597,267	600,568			63.6%	101,000		698,267	702,126		65.7%	602,144	605,472		703,969	707,860	
2008	611,454	616,642			61.9%	100,000		711,454	717,491		63.7%	616,261	621,490		717,047	723,131	
2009	664,788	630,115			54.3%	95,000		759,788	720,161		56.3%	670,217	635,261		765,993	726,042	
2010	646,750	616,176			60.2%	95,000		741,750	706,685		62.4%	651,966	621,145		747,732	712,384	
2011	624,191	579,769			61.2%	92,000		716,191	665,222		63.2%	629,098	584,327		721,821	670,451	
2012	568,900	617,753			65.9%	89,000		657,900	714,396		67.8%	573,661	622,924		663,406	720,375	
2013	596,800	618,319			64.5%	93,000		689,800	714,673		66.0%	602,646	624,376		696,557	721,673	
2014	740,203	698,327			52.2%	102,000		842,203	794,556		54.4%	748,360	706,022		851,484	803,312	
2015	687,696	663,894			54.3%	100,000		787,696	760,433		56.5%	697,248	673,116		798,637	770,996	
2016	600,010	605,199		605,199	61.7%	94,000		694,010	700,012	700,012	63.6%	609,828	615,102	615,102	705,367	711,466	711,466
2017		622,068	1,272	620,796	59.9%	99,000	505,000		1,226,068	1,224,796	36.2%		635,087	633,789		1,251,728	1,250,430
2018		633,071	2,576	630,495	60.5%	99,000	487,000		1,219,071	1,216,495	37.3%		647,908	645,271		1,247,642	1,245,005
2019		645,039	3,785	641,254	61.1%	99,400	501,000		1,245,439	1,241,654	37.4%		660,157	656,283		1,274,628	1,270,755
2020		658,882	5,319	653,562	60.7%	99,798	500,000		1,258,679	1,253,360	37.4%		674,324	668,880		1,288,179	1,282,735
2021		663,224	6,216	657,008	60.4%	100,197	500,000		1,263,421	1,257,205	37.4%		678,768	672,406		1,293,032	1,286,670
2022		665,347	7,634	657,713	60.4%	100,598	500,000		1,265,944	1,258,310	37.4%		680,940	673,127		1,295,614	1,287,801
2023		667,524	9,011	658,513	60.3%	101,000	500,000		1,268,524	1,259,513	37.4%		683,168	673,946		1,298,254	1,289,031
2024		669,756	10,391	659,365	60.4%	101,404	500,000		1,271,160	1,260,768	37.5%		685,452	674,818		1,300,951	1,290,317
2025		672,042	11,688	660,354	60.4%	101,810	500,000		1,273,852	1,262,163	37.5%		687,793	675,830		1,303,707	1,291,744
2026		674,383	13,155	661,228	60.5%	102,217	500,000		1,276,600	1,263,445	37.5%		690,189	676,725		1,306,520	1,293,056
2027		676,779	14,508	662,271	60.5%	102,626	500,000		1,279,405	1,264,897	37.6%		692,641	677,793		1,309,390	1,294,542
2028		679,230	15,869	663,361	60.6%	103,036	500,000		1,282,266	1,266,398	37.7%		695,149	678,908		1,312,319	1,296,078
2029		681,736	16,967	664,769	60.5%	103,448	500,000		1,285,184	1,268,217	37.7%		697,713	680,349		1,315,305	1,297,940
2030		684,296	17,973	666,323	60.6%	103,862	490,000		1,278,158	1,260,186	38.0%		700,334	681,940		1,308,114	1,289,720
2031		686,911	18,966	667,945	60.6%	104,278	480,000		1,271,189	1,252,222	38.4%		703,010	683,599		1,300,981	1,281,570
2032		689,526	19,960	669,566	60.6%	104,695	480,000		1,274,221	1,254,261	38.5%		705,686	685,259		1,304,084	1,283,657
2033		692,141	20,953	671,188	60.6%	105,112	470,000		1,267,253	1,246,299	38.8%		708,363	686,918		1,296,953	1,275,509
2034		694,756	21,947	672,809	60.6%	105,529	470,000		1,270,285	1,248,338	38.8%		711,039	688,577		1,300,056	1,277,595
2035		697,371	22,941	674,430	60.6%	105,946	460,000		1,263,317	1,240,376	39.2%		713,715	690,237		1,292,925	1,269,447
2036		699,986	23,934	676,052	60.7%	106,363	460,000		1,266,349	1,242,415	39.3%		716,391	691,896		1,296,028	1,271,533

ANNUAL GROWTH RATES

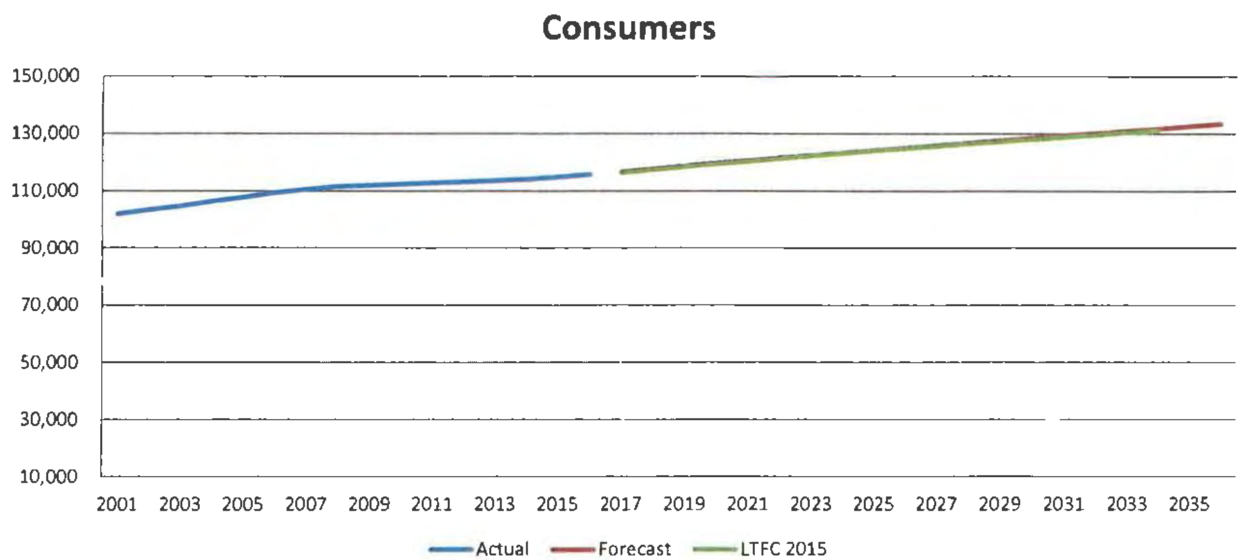
2001-2006	-0.8%					0.6%		-0.6%				-0.9%			-0.7%		
2006-2011	1.6%	-0.7%				-1.3%		1.2%	-1.1%			1.6%	-0.7%		1.2%	-1.1%	
2011-2016	-0.8%	0.9%				0.4%		-0.6%	1.0%			-0.6%	1.0%		-0.5%	1.2%	
2016-2021		1.8%		1.7%		1.3%			12.5%	12.4%			2.0%	1.8%		12.7%	12.6%
2021-2026		0.3%	16.2%	0.1%		0.4%	0.0%		0.2%	0.1%			0.3%	0.1%		0.2%	0.1%
2026-2031		0.4%	7.6%	0.2%		0.4%	-0.8%		-0.1%	-0.2%			0.4%	0.2%		-0.1%	-0.2%
2031-2036		0.4%	4.8%	0.2%		0.4%	-0.8%		-0.1%	-0.2%			0.4%	0.2%		-0.1%	-0.2%
2016-2036		0.7%		0.6%		0.6%			3.0%	2.9%			0.8%	0.6%		3.0%	2.9%

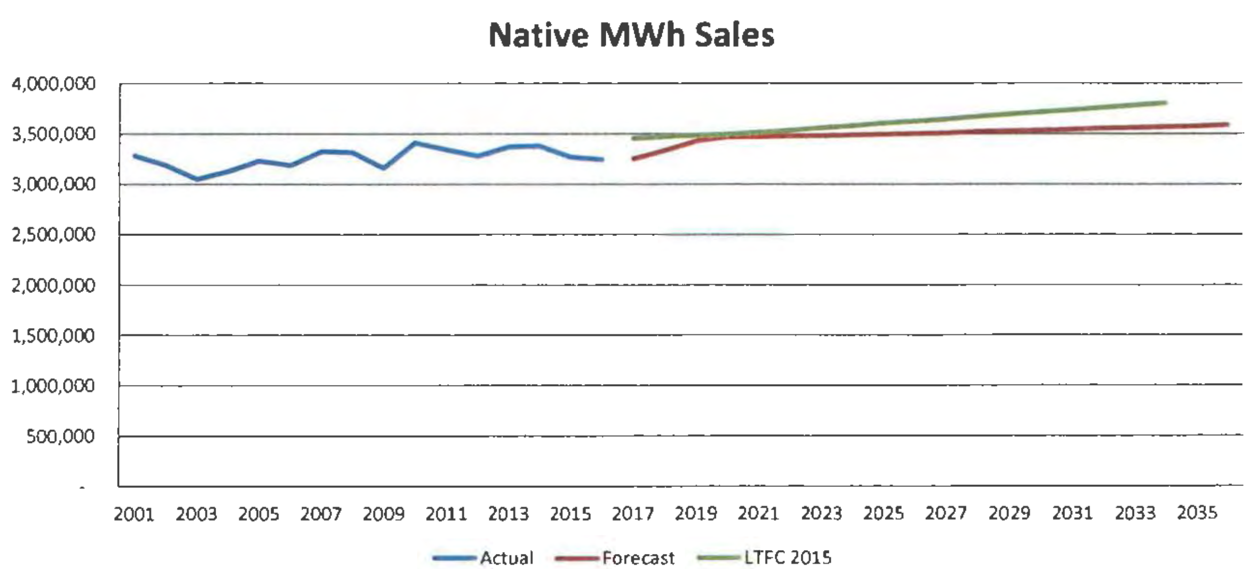
NCP represents the highest 1-hour peak demand recorded during the summer and winter seasons
Winter season is November of the prior year through April of the reported year
Total system peak includes native, HMP&L, and non-member load

BIG RIVERS ELECTRIC CORPORATION

2017 LONG-TERM LOAD FORECAST - BASE CASE FORECAST

SYSTEM REQUIREMENTS - ADJUSTED FOR DSM

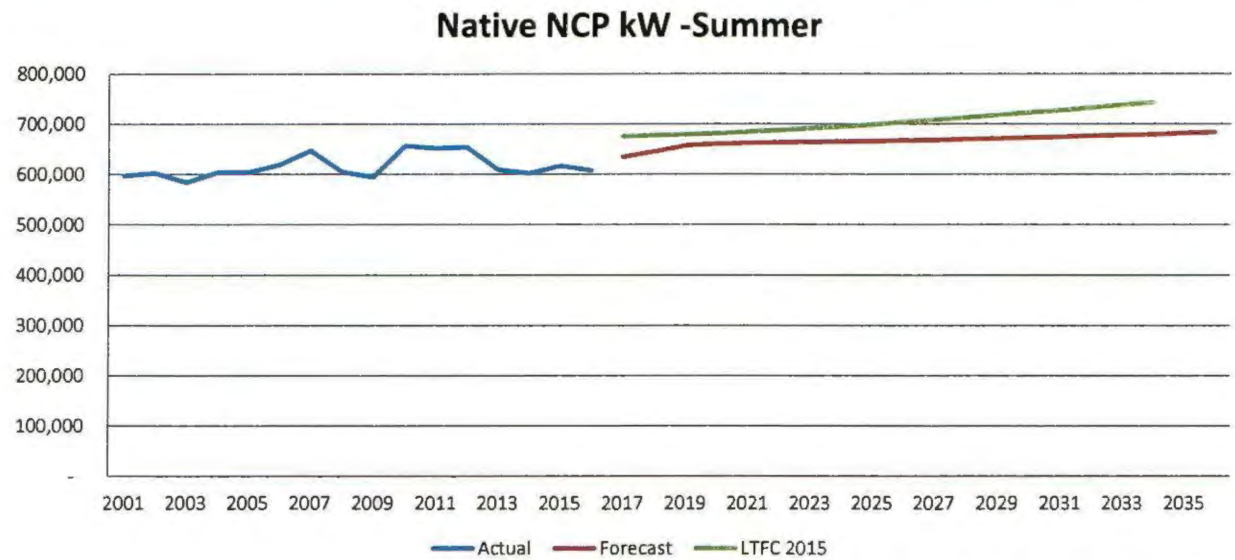


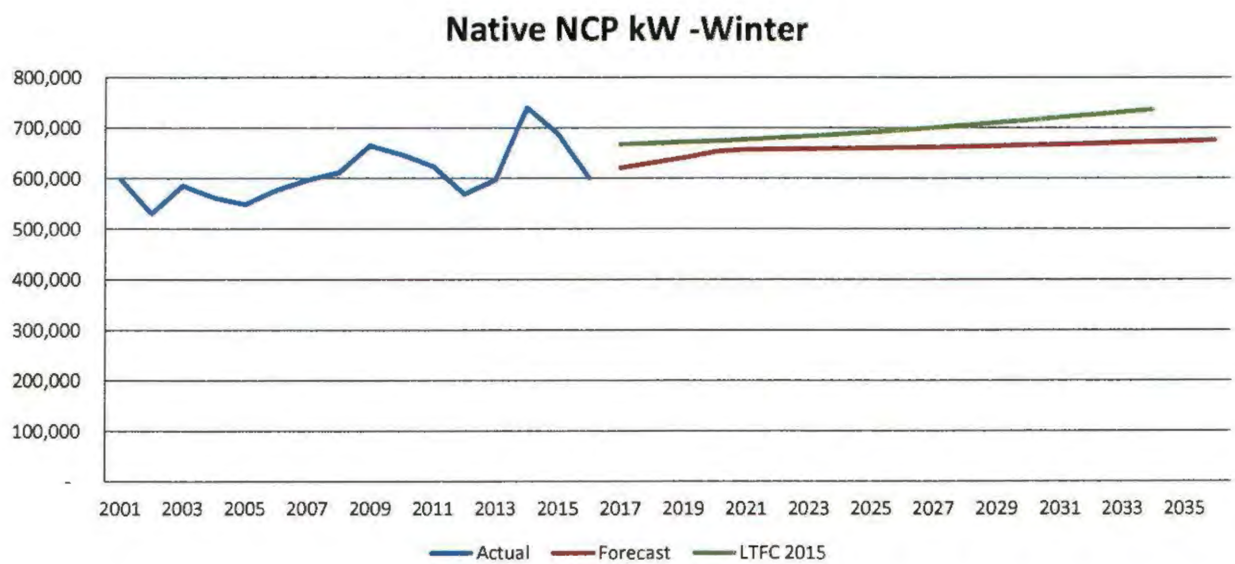


BIG RIVERS ELECTRIC CORPORATION

2017 LONG-TERM LOAD FORECAST - BASE CASE FORECAST

SYSTEM REQUIREMENTS - ADJUSTED FOR DSM





BIG RIVERS ELECTRIC CORPORATION

2017 LONG-TERM LOAD FORECAST - BASE CASE FORECAST

NATIVE SYSTEM SALES TO MEMBERS - NO DSM ADJUSTMENT

Year	Consumers	Percent Growth	Actual Mbr. Sales (MWh)	Normal Mbr. Sales (MWh)	Percent Growth	Distr. Line Loss	Actual Sales (MWh)	Normal Sales (MWh)	Percent Growth
2001	101,987		3,192,415	3,281,237		3.3%	3,301,563	3,391,056	
2002	103,480	1.5%	3,120,298	3,104,723	-5.4%	3.5%	3,233,105	3,214,144	-5.2%
2003	104,762	1.2%	3,004,389	3,121,567	0.5%	3.5%	3,112,481	3,230,277	0.5%
2004	106,412	1.6%	3,027,344	3,143,295	0.7%	3.4%	3,134,981	3,251,568	0.7%
2005	107,881	1.4%	3,131,950	3,170,409	0.9%	3.4%	3,243,103	3,279,879	0.9%
2006	109,327	1.3%	3,090,437	3,218,375	1.5%	3.3%	3,196,272	3,325,923	1.4%
2007	110,583	1.1%	3,219,155	3,200,079	-0.6%	3.4%	3,331,224	3,309,864	-0.5%
2008	111,691	1.0%	3,204,376	3,243,657	1.4%	3.5%	3,321,469	3,359,607	1.5%
2009	111,940	0.2%	3,092,391	3,203,640	-1.2%	3.6%	3,207,143	3,319,385	-1.2%
2010	112,410	0.4%	3,315,474	3,227,735	0.8%	2.8%	3,411,558	3,348,746	0.9%
2011	112,885	0.4%	3,261,662	3,301,868	2.3%	2.5%	3,344,199	3,408,810	1.8%
2012	113,250	0.3%	3,163,984	3,216,815	-2.6%	3.6%	3,282,776	3,337,273	-2.1%
2013	113,717	0.4%	3,268,608	3,299,961	2.6%	3.0%	3,371,187	3,401,465	1.9%
2014	114,208	0.4%	3,266,158	3,261,842	-1.2%	3.4%	3,381,575	3,374,586	-0.8%
2015	114,934	0.6%	3,162,679	3,222,667	-1.2%	3.3%	3,270,995	3,330,722	-1.3%
2016	115,859	0.8%	3,133,967	3,160,708	-1.9%	3.4%	3,244,594	3,269,780	-1.8%
2017	116,843	0.8%		3,158,517	-0.1%	3.4%		3,268,669	0.0%
2018	117,809	0.8%		3,252,208	3.0%	3.3%		3,363,600	2.9%
2019	118,737	0.8%		3,350,489	3.0%	3.2%		3,462,789	2.9%
2020	119,781	0.9%		3,400,372	1.5%	3.2%		3,513,319	1.5%
2021	120,701	0.8%		3,405,530	0.2%	3.2%		3,518,670	0.2%
2022	121,568	0.7%		3,417,913	0.4%	3.2%		3,531,673	0.4%
2023	122,434	0.7%		3,428,167	0.3%	3.2%		3,542,424	0.3%
2024	123,299	0.7%		3,445,308	0.5%	3.2%		3,560,248	0.5%
2025	124,197	0.7%		3,457,423	0.4%	3.2%		3,573,146	0.4%
2026	125,044	0.7%		3,470,649	0.4%	3.2%		3,587,034	0.4%
2027	125,882	0.7%		3,484,428	0.4%	3.3%		3,601,502	0.4%
2028	126,786	0.7%		3,502,879	0.5%	3.3%		3,620,708	0.5%
2029	127,688	0.7%		3,514,239	0.3%	3.3%		3,632,813	0.3%
2030	128,589	0.7%		3,529,120	0.4%	3.3%		3,648,443	0.4%
2031	129,438	0.7%		3,543,879	0.4%	3.3%		3,663,944	0.4%
2032	130,286	0.7%		3,562,073	0.5%	3.3%		3,682,880	0.5%
2033	131,134	0.7%		3,573,397	0.3%	3.3%		3,694,947	0.3%
2034	131,983	0.6%		3,588,156	0.4%	3.3%		3,710,448	0.4%
2035	132,831	0.6%		3,602,914	0.4%	3.3%		3,725,949	0.4%
2036	133,680	0.6%		3,621,108	0.5%	3.3%		3,744,885	0.5%

ANNUAL GROWTH RATES						
2001-2006	1.4%	-0.6%	-0.4%	-0.6%	-0.4%	
2006-2011	0.6%	1.1%	0.5%	0.9%	0.5%	
2011-2016	0.5%	-0.8%	-0.9%	-0.6%	-0.8%	
2016-2021	0.8%		1.5%		1.5%	
2021-2026	0.7%		0.4%		0.4%	
2021-2031	0.7%		0.4%		0.4%	
2026-2036	0.6%		0.4%		0.4%	
2016-2036	0.7%		0.7%		0.7%	

Member system retail sales include only power supplied by Big Rivers

BIG RIVERS ELECTRIC CORPORATION

2017 LONG-TERM LOAD FORECAST - BASE CASE FORECAST

NATIVE SYSTEM PEAK DEMAND - NO DSM ADJUSTMENT

Year	Summer Actual CP (kW)	Summer Normal NCP (kW)	Percent Growth	Load Factor	Winter Actual CP (kW)	Winter Normal NCP (kW)	Percent Growth	Load Factor
2001	596,310			63.2%	598,797			62.9%
2002	602,623	587,317	1.1%	61.2%	530,467	556,540	-11.4%	69.6%
2003	583,906	592,266	-3.1%	60.8%	585,549	547,253	10.4%	60.7%
2004	604,155	618,850	3.5%	59.2%	562,082	535,652	-4.0%	63.7%
2005	603,783	609,740	-0.1%	61.3%	548,765	561,077	-2.4%	67.5%
2006	619,258	627,399	2.6%	58.9%	576,534	599,442	5.1%	63.3%
2007	647,502	594,279	4.6%	58.7%	597,267	600,568	3.6%	63.7%
2008	604,334	605,923	-6.7%	62.7%	611,454	616,642	2.4%	62.0%
2009	594,126	608,201	-1.7%	61.6%	664,788	630,115	8.7%	55.1%
2010	656,634	613,675	10.5%	59.3%	646,750	616,176	-2.7%	60.2%
2011	652,127	638,938	-0.7%	58.5%	624,191	579,769	-3.5%	61.2%
2012	654,200	606,718	0.3%	57.3%	568,900	617,753	-8.9%	65.9%
2013	609,000	638,743	-6.9%	63.2%	596,800	618,319	4.9%	64.5%
2014	601,935	603,617	-1.2%	64.1%	740,203	698,327	24.0%	52.2%
2015	616,732	622,689	2.5%	60.5%	687,696	663,894	-7.1%	54.3%
2016	607,440	619,950	-1.5%	61.0%	600,010	605,199	-12.8%	61.7%
2017		636,233	2.6%	58.6%		622,068	2.8%	60.0%
2018		648,174	1.9%	59.2%		633,071	1.8%	60.7%
2019		661,989	2.1%	59.7%		645,039	1.9%	61.3%
2020		666,304	0.7%	60.2%		658,882	2.1%	60.9%
2021		668,399	0.3%	60.1%		663,224	0.7%	60.6%
2022		670,549	0.3%	60.1%		665,347	0.3%	60.6%
2023		672,753	0.3%	60.1%		667,524	0.3%	60.6%
2024		675,013	0.3%	60.2%		669,756	0.3%	60.7%
2025		677,326	0.3%	60.2%		672,042	0.3%	60.7%
2026		679,695	0.3%	60.2%		674,383	0.3%	60.7%
2027		682,119	0.4%	60.3%		676,779	0.4%	60.7%
2028		684,597	0.4%	60.4%		679,230	0.4%	60.9%
2029		687,130	0.4%	60.4%		681,736	0.4%	60.8%
2030		689,717	0.4%	60.4%		684,296	0.4%	60.9%
2031		692,360	0.4%	60.4%		686,911	0.4%	60.9%
2032		695,002	0.4%	60.5%		689,526	0.4%	61.0%
2033		697,644	0.4%	60.5%		692,141	0.4%	60.9%
2034		700,287	0.4%	60.5%		694,756	0.4%	61.0%
2035		702,929	0.4%	60.5%		697,371	0.4%	61.0%
2036		705,571	0.4%	60.6%		699,986	0.4%	61.1%

ANNUAL GROWTH RATES				
2001-2006	0.8%		-0.8%	
2006-2011	1.0%		1.6%	
2011-2016	-1.4%		-0.8%	
2016-2021		1.5%		1.8%
2021-2026		0.3%		0.3%
2021-2031		0.4%		0.4%
2026-2036		0.4%		0.4%
2016-2036		0.6%		0.7%

Native load includes rural system and direct serve (Domtar tariff)

CP represents the highest 1-hour peak demand recorded during the summer and winter seasons

Summer season is May to October. Winter season is November of the prior year through April of the reported year.

BIG RIVERS ELECTRIC CORPORATION

2017 LONG-TERM LOAD FORECAST - BASE CASE FORECAST

RURAL SYSTEM REQUIREMENTS - ADJUSTED FOR DSM

Year	Actual Sales (MWh)	Projected Sales (MWh)	DSM Sales (MWh)	DSM Adj. Sales (MWh)	Percent Growth	Line Loss	DSM Adj. Purchases (MWh)	Normalized (MWh)	Percent Growth
2001	1,891,730					5.5%	2,000,877	2,039,727	
2002	2,002,034				5.8%	5.3%	2,114,841	2,047,683	0.4%
2003	1,981,586				-1.0%	5.2%	2,089,678	2,163,616	5.7%
2004	2,025,554				2.2%	5.0%	2,133,190	2,203,603	1.8%
2005	2,150,864				6.2%	4.9%	2,262,017	2,247,952	2.0%
2006	2,126,746				-1.1%	4.7%	2,232,581	2,312,324	2.9%
2007	2,292,340				7.8%	4.8%	2,407,449	2,333,391	0.9%
2008	2,282,771				-0.4%	4.4%	2,387,974	2,371,708	1.6%
2009	2,124,010				-7.0%	5.1%	2,238,762	2,299,263	-3.1%
2010	2,354,830				10.9%	5.1%	2,481,390	2,330,705	1.4%
2011	2,263,573				-3.9%	4.5%	2,371,106	2,360,141	1.3%
2012	2,200,119				-2.8%	5.2%	2,321,478	2,318,050	-1.8%
2013	2,271,660				3.3%	4.3%	2,374,920	2,353,980	1.5%
2014	2,300,120				1.3%	4.8%	2,415,564	2,353,028	0.0%
2015	2,216,525				-3.6%	4.7%	2,325,204	2,334,790	-0.8%
2016	2,219,405	2,212,090	-	2,212,090	0.1%	4.7%	2,330,037	2,304,554	-1.3%
2017		2,200,164	9,654	2,190,511	-1.0%	4.8%		2,300,179	-0.2%
2018		2,224,509	19,509	2,205,001	0.7%	4.8%		2,315,416	0.7%
2019		2,242,272	28,836	2,213,436	0.4%	4.8%		2,324,291	0.4%
2020		2,255,138	38,111	2,217,028	0.2%	4.8%		2,328,066	0.2%
2021		2,259,518	41,690	2,217,828	0.0%	4.8%		2,328,879	0.0%
2022		2,271,901	50,212	2,221,689	0.2%	4.8%		2,332,934	0.2%
2023		2,282,155	58,478	2,223,677	0.1%	4.8%		2,335,005	0.1%
2024		2,295,861	66,745	2,229,115	0.2%	4.8%		2,340,712	0.2%
2025		2,311,411	74,040	2,237,371	0.4%	4.8%		2,349,386	0.4%
2026		2,324,637	81,245	2,243,392	0.3%	4.8%		2,355,707	0.3%
2027		2,338,416	88,266	2,250,150	0.3%	4.8%		2,362,802	0.3%
2028		2,353,432	95,313	2,258,119	0.4%	4.8%		2,371,173	0.4%
2029		2,368,227	101,708	2,266,519	0.4%	4.8%		2,379,998	0.4%
2030		2,383,108	107,851	2,275,258	0.4%	4.8%		2,389,178	0.4%
2031		2,397,867	113,951	2,283,916	0.4%	4.8%		2,398,273	0.4%
2032		2,412,626	120,052	2,292,574	0.4%	4.8%		2,407,368	0.4%
2033		2,427,385	126,152	2,301,233	0.4%	4.8%		2,416,463	0.4%
2034		2,442,144	132,253	2,309,891	0.4%	4.8%		2,425,559	0.4%
2035		2,456,902	138,353	2,318,549	0.4%	4.8%		2,434,654	0.4%
2036		2,471,661	144,454	2,327,208	0.4%	4.8%		2,443,749	0.4%

ANNUAL GROWTH RATES

	Actual Sales	Projected Sales	DSM Sales	DSM Adj. Sales	Percent Growth	Line Loss	DSM Adj. Purchases	Normalized	Percent Growth
2001-2006	2.4%						2.2%	2.5%	
2006-2011	1.3%						1.2%	0.4%	
2011-2016	-0.4%						-0.3%	-0.5%	
2016-2021		0.4%		0.0%				0.2%	
2021-2026		0.6%		0.2%				0.2%	
2021-2031		0.6%		0.4%				0.4%	
2026-2036		0.6%		0.4%				0.4%	
2016-2036		0.6%		0.3%				0.3%	

BIG RIVERS ELECTRIC CORPORATION

2017 LONG-TERM LOAD FORECAST - BASE CASE FORECAST

RURAL SYSTEM REQUIREMENTS - ADJUSTED FOR DSM

Year	Summer Actual NCP (kW)	Summer Normal NCP (kW)	DSM Impact (kW)	DSM Adj. NCP (kW)	Winter Actual NCP (kW)	Winter Normal NCP (kW)	DSM Impact (kW)	DSM Adj. NCP (kW)
2001	441,183				423,149			
2002	461,561	446,254			380,606	406,678		
2003	458,050	466,409			460,626	422,329		
2004	472,169	486,863			430,124	403,693		
2005	497,997	503,954			444,494	456,807		
2006	501,463	509,604			439,167	462,075		
2007	532,264	479,042			489,272	492,572		
2008	497,743	499,332			511,901	517,090		
2009	496,641	510,716			560,598	525,926		
2010	546,356	503,397			517,785	487,210		
2011	533,911	520,723			536,353	491,931		
2012	534,216	486,734			454,476	503,329		
2013	472,149	501,892			479,669	501,188		
2014	483,465	485,146			612,356	570,480		
2015	504,969	510,926			567,816	544,015		
2016	486,950	499,460	-	499,460	487,142	492,331	-	492,331
2017		503,269	1,455	501,814		496,380	1,272	495,109
2018		505,199	2,925	502,274		498,284	2,576	495,707
2019		507,185	4,261	502,924		500,242	3,785	496,457
2020		509,225	5,666	503,559		502,255	5,319	496,935
2021		511,320	6,238	505,082		504,322	6,216	498,106
2022		513,469	7,513	505,956		506,445	7,634	498,810
2023		515,674	8,763	506,911		508,622	9,011	499,610
2024		517,933	10,006	507,927		510,853	10,391	500,462
2025		520,247	11,114	509,133		513,140	11,688	501,452
2026		522,616	12,219	510,396		515,481	13,155	502,326
2027		525,039	13,261	511,778		517,877	14,508	503,369
2028		527,517	14,307	513,211		520,328	15,869	504,459
2029		530,050	15,239	514,811		522,834	16,967	505,867
2030		532,638	16,169	516,469		525,394	17,973	507,421
2031		535,280	17,091	518,189		528,009	18,966	509,043
2032		537,922	18,014	519,908		530,624	19,960	510,664
2033		540,565	18,937	521,628		533,239	20,953	512,285
2034		543,207	19,860	523,348		535,854	21,947	513,907
2035		545,850	20,782	525,067		538,469	22,941	515,528
2036		548,492	21,705	526,787		541,084	23,934	517,149

ANNUAL GROWTH RATES

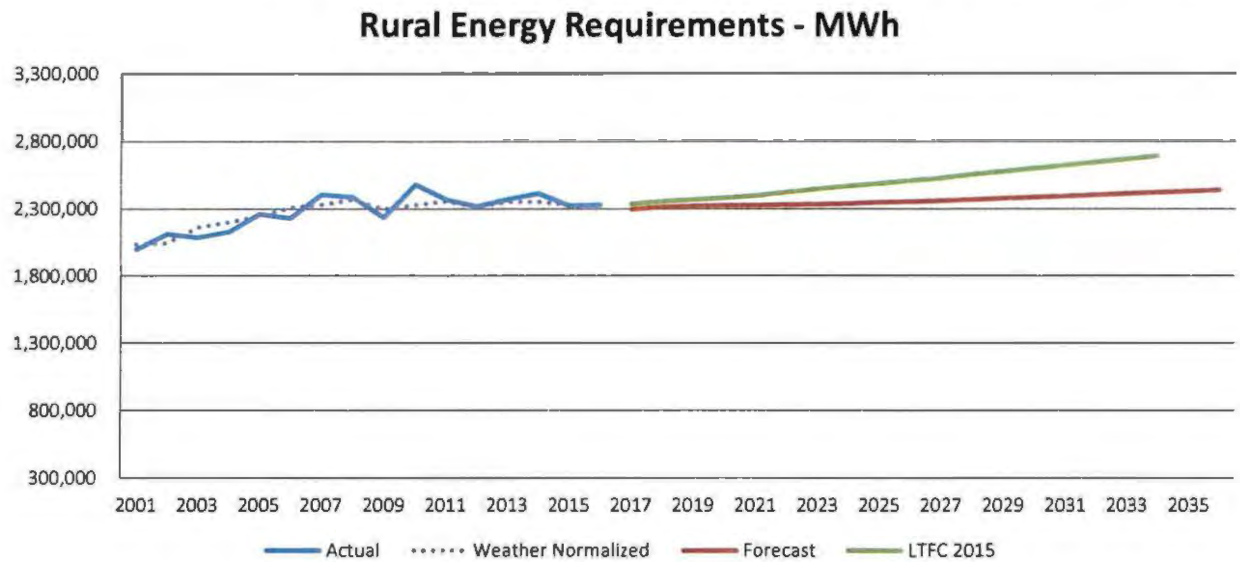
2001-2006	2.6%				0.7%			
2006-2011	1.3%				4.1%			
2011-2016	-1.8%				-1.9%			
2016-2021		0.5%		0.2%		0.2%		0.2%
2021-2026		0.4%		0.2%		0.4%		0.2%
2021-2031		0.5%		0.3%		0.5%		0.3%
2026-2036		0.5%		0.3%		0.5%		0.3%
2016-2036		0.5%		0.3%		0.5%		0.2%

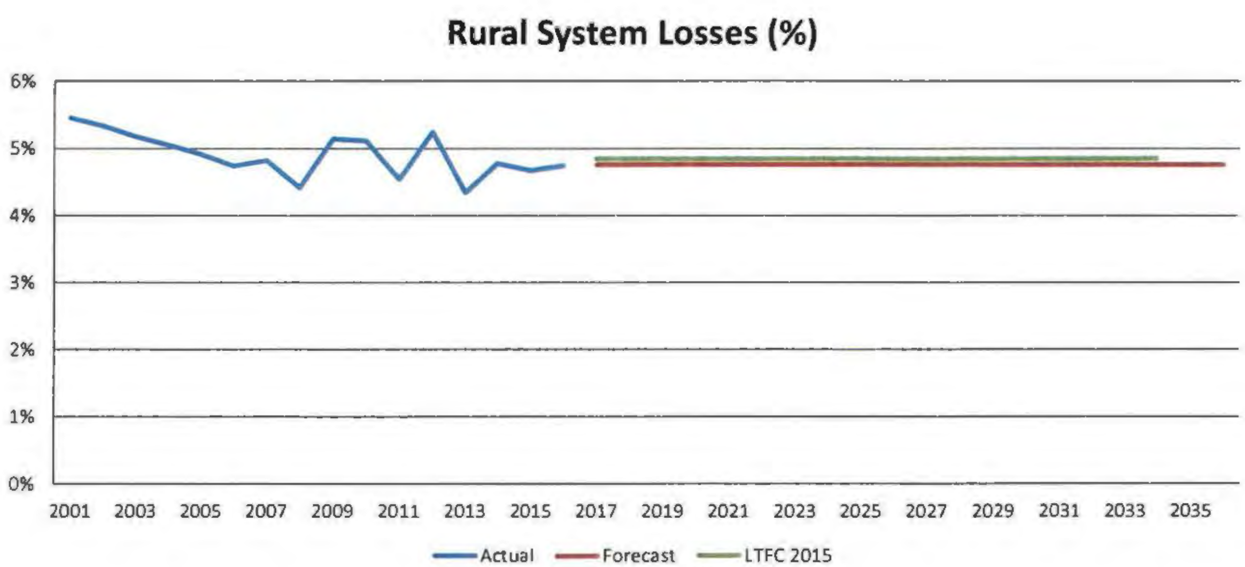
NCP values represent the highest 1-hour peak at the rural system level in each season
Summer season is May to October. Winter season is November of the prior year through April of the reported year.

BIG RIVERS ELECTRIC CORPORATION

2017 LONG-TERM LOAD FORECAST - BASE CASE FORECAST

RURAL SYSTEM REQUIREMENTS - ADJUSTED FOR DSM

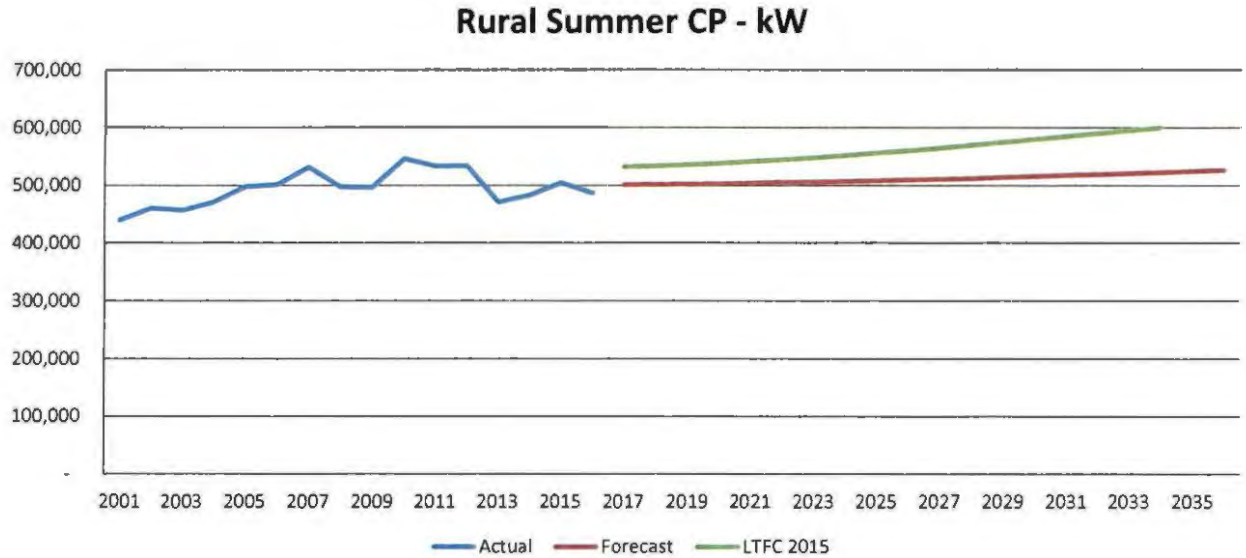


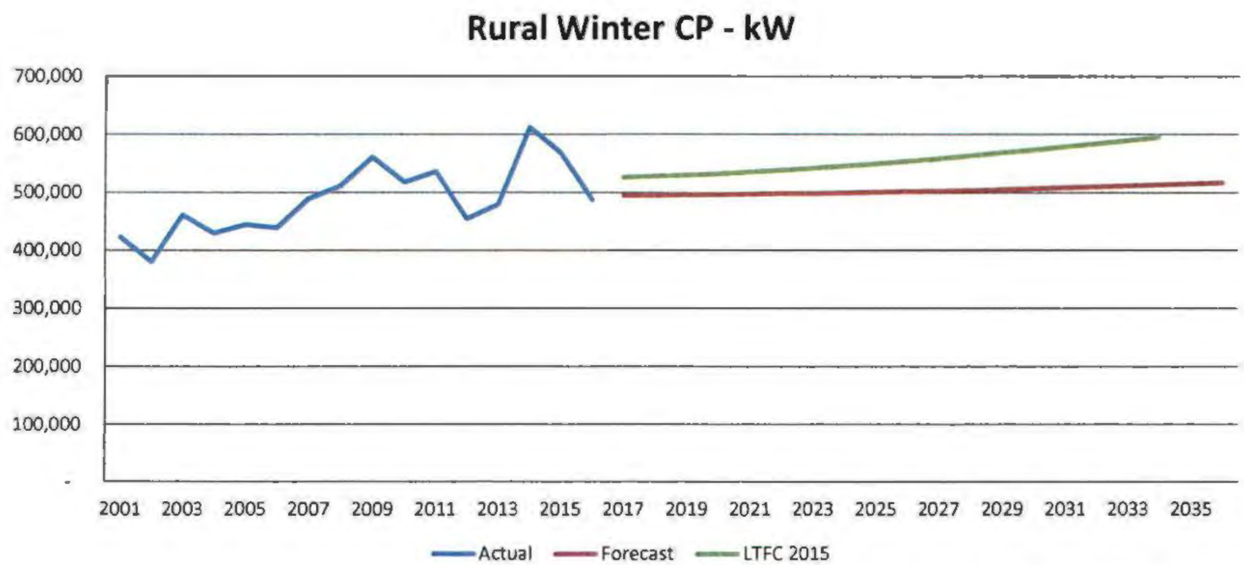


BIG RIVERS ELECTRIC CORPORATION

2017 LONG-TERM LOAD FORECAST - BASE CASE FORECAST

RURAL SYSTEM REQUIREMENTS - ADJUSTED FOR DSM





BIG RIVERS ELECTRIC CORPORATION

2017 LONG-TERM LOAD FORECAST - BASE CASE FORECAST

RESIDENTIAL CLASSIFICATION

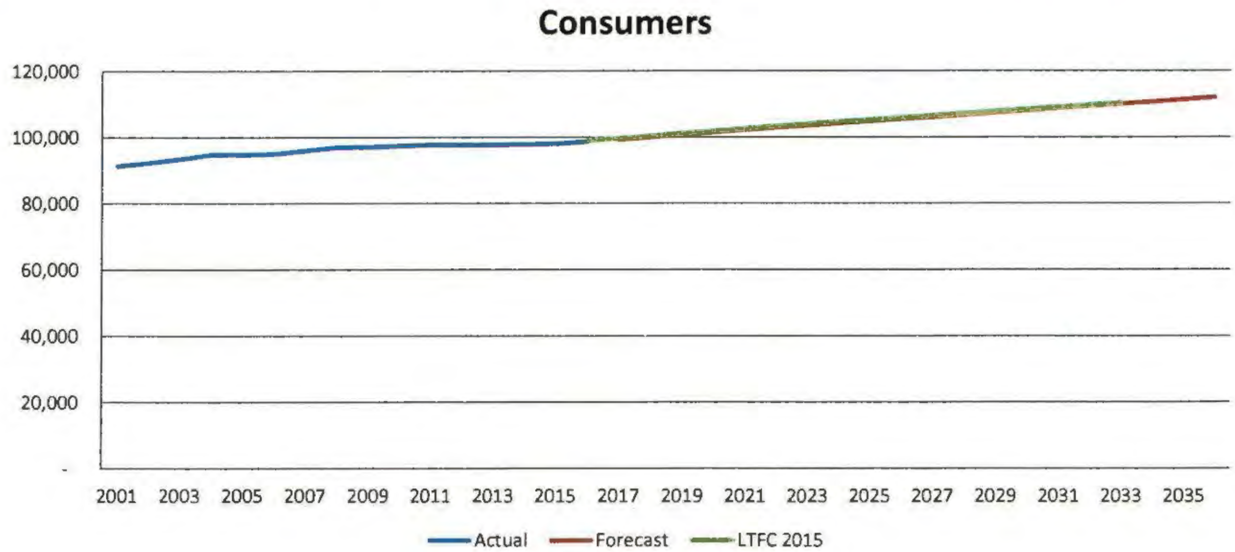
Year	Consumers	Consumer Growth	Percent Growth	Actual Sales (MWh)	Normal Sales (MWh)	Percent Growth	Actual Average Use (kWh/Cust/Mo)	Normal Average Use (kWh/Cust/Mo)	Percent Growth
2001	91,276			1,246,139			1,138		
2002	92,355	1,079	1.2%	1,371,067			1,237		
2003	93,405	1,050	1.1%	1,340,451			1,196		
2004	94,768	1,363	1.5%	1,362,667			1,198		
2005	94,877	109	0.1%	1,452,182	1,445,785		1,275	1,270	
2006	95,028	151	0.2%	1,415,359	1,464,119	1.3%	1,241	1,284	1.1%
2007	95,993	965	1.0%	1,534,506	1,496,342	2.2%	1,332	1,299	1.2%
2008	96,886	893	0.9%	1,529,478	1,513,522	1.1%	1,316	1,302	0.2%
2009	97,084	198	0.2%	1,426,775	1,458,897	-3.6%	1,225	1,252	-3.8%
2010	97,467	383	0.4%	1,611,212	1,517,821	4.0%	1,378	1,298	3.6%
2011	97,750	283	0.3%	1,530,090	1,527,824	0.7%	1,304	1,302	0.4%
2012	97,675	(74)	-0.1%	1,465,749	1,477,663	-3.3%	1,251	1,261	-3.2%
2013	97,773	98	0.1%	1,509,915	1,491,767	1.0%	1,287	1,271	0.9%
2014	97,851	78	0.1%	1,531,776	1,481,737	-0.7%	1,305	1,262	-0.8%
2015	97,971	120	0.1%	1,448,343	1,455,382	-1.8%	1,232	1,238	-1.9%
2016	98,583	611	0.6%	1,441,268	1,437,332	-1.2%	1,218	1,215	-1.9%
2017	99,290	707	0.7%		1,425,319	-0.8%		1,196	-1.5%
2018	100,046	756	0.8%		1,440,401	1.1%		1,200	0.3%
2019	100,806	760	0.8%		1,451,613	0.8%		1,200	0.0%
2020	101,619	813	0.8%		1,458,290	0.5%		1,196	-0.3%
2021	102,311	692	0.7%		1,456,582	-0.1%		1,186	-0.8%
2022	102,952	641	0.6%		1,462,945	0.4%		1,184	-0.2%
2023	103,594	642	0.6%		1,467,217	0.3%		1,180	-0.3%
2024	104,236	642	0.6%		1,474,969	0.5%		1,179	-0.1%
2025	104,913	677	0.6%		1,484,613	0.7%		1,179	0.0%
2026	105,542	629	0.6%		1,492,013	0.5%		1,178	-0.1%
2027	106,162	621	0.6%		1,500,024	0.5%		1,177	-0.1%
2028	106,852	689	0.6%		1,509,328	0.6%		1,177	0.0%
2029	107,542	691	0.6%		1,518,488	0.6%		1,177	0.0%
2030	108,233	691	0.6%		1,527,802	0.6%		1,176	0.0%
2031	108,874	641	0.6%		1,537,050	0.6%		1,176	0.0%
2032	109,514	641	0.6%		1,546,298	0.6%		1,177	0.0%
2033	110,155	641	0.6%		1,555,546	0.6%		1,177	0.0%
2034	110,795	641	0.6%		1,564,794	0.6%		1,177	0.0%
2035	111,436	641	0.6%		1,574,042	0.6%		1,177	0.0%
2036	112,077	641	0.6%		1,583,290	0.6%		1,177	0.0%

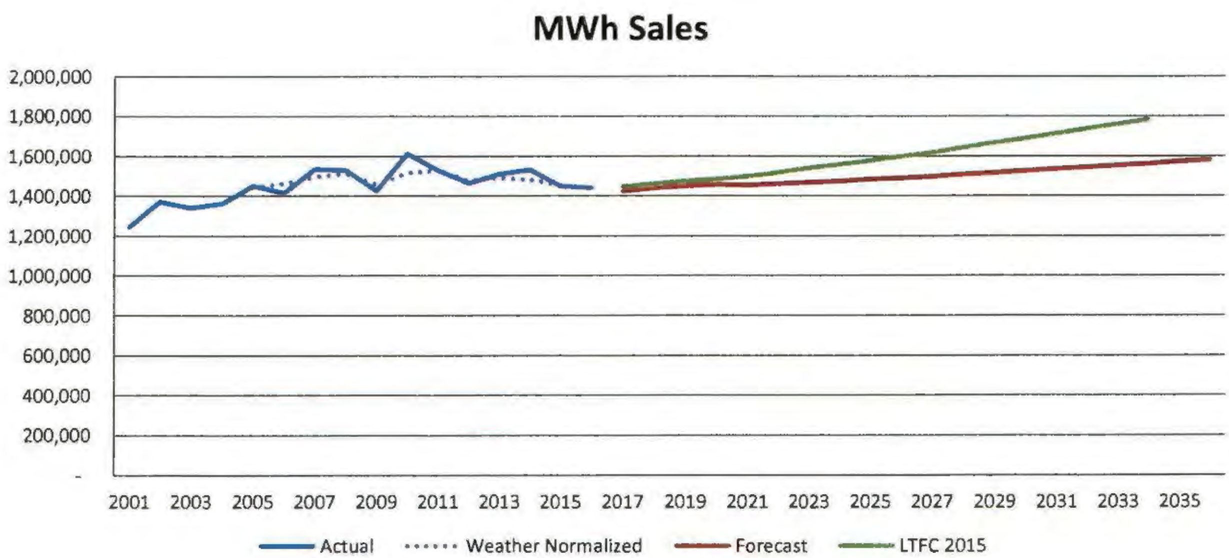
ANNUAL GROWTH RATES						
2001-2006	0.8%	750	2.6%	#DIV/0!	1.8%	#DIV/0!
2006-2011	0.6%	544	1.6%	0.9%	1.0%	0.3%
2011-2016	0.2%	167	-1.2%	-1.2%	-1.4%	-1.4%
2016-2021	0.7%	746		0.3%		-0.5%
2021-2026	0.6%	646		0.5%		-0.1%
2021-2031	0.6%	666		0.6%		0.0%
2026-2036	0.6%	641		0.6%		0.0%
2016-2036	0.6%	675		0.5%		-0.2%

BIG RIVERS ELECTRIC CORPORATION

2017 LONG-TERM LOAD FORECAST - BASE CASE FORECAST

RESIDENTIAL CLASSIFICATION

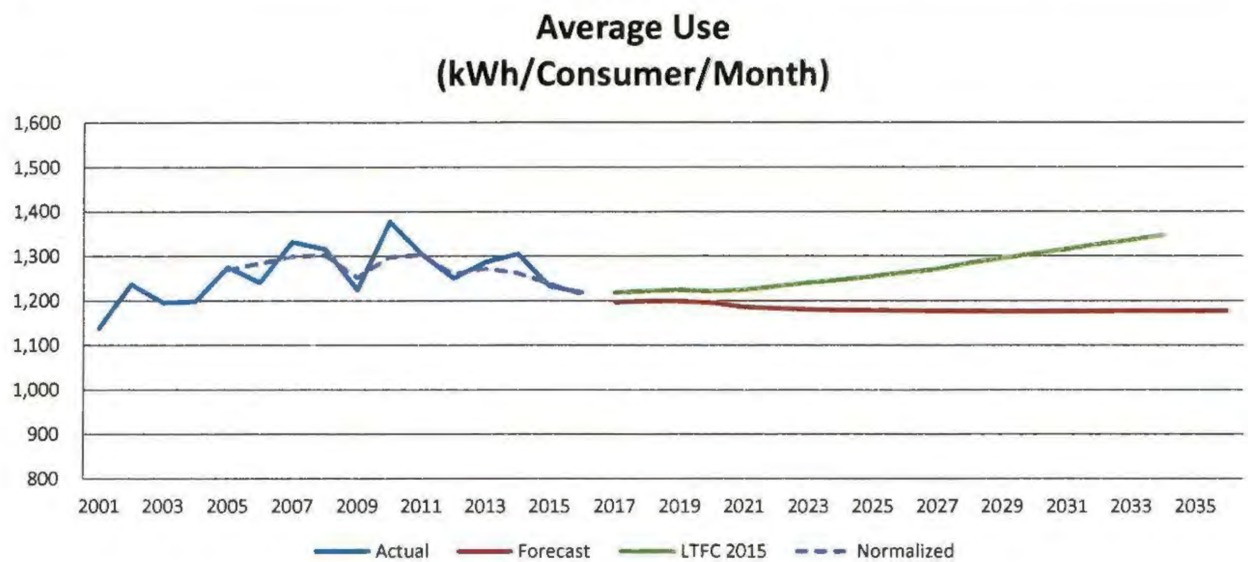




BIG RIVERS ELECTRIC CORPORATION

2017 LONG-TERM LOAD FORECAST - BASE CASE FORECAST

RESIDENTIAL CLASSIFICATION



BIG RIVERS ELECTRIC CORPORATION

2017 LONG-TERM LOAD FORECAST - BASE CASE FORECAST

SMALL COMMERCIAL CLASSIFICATION

Year	Consumers	Consumer Growth	Percent Growth	Actual Sales (MWh)	Normal Sales (MWh)	Percent Growth	Actual Average Use (kWh/Cust/Mo)	Normal Average Use (kWh/Cust/Mo)	Percent Growth
2001	10,487			528,560			4,200		
2002	10,899	412	3.9%	507,563			3,881		
2003	11,163	264	2.4%	509,312			3,802		
2004	11,518	355	3.2%	521,300			3,772		
2005	12,876	1,358	11.8%	553,496			3,582		
2006	14,168	1,291	10.0%	568,398			3,343		
2007	14,458	290	2.0%	608,391			3,507		
2008	14,672	214	1.5%	602,535	599,539		3,422	3,405	
2009	14,725	53	0.4%	569,297	579,376	-3.4%	3,222	3,279	-3.7%
2010	14,808	82	0.6%	618,684	593,262	2.4%	3,482	3,339	1.8%
2011	14,999	192	1.3%	599,542	597,645	0.7%	3,331	3,320	-0.5%
2012	15,435	435	2.9%	595,342	594,981	-0.4%	3,214	3,212	-3.3%
2013	15,797	362	2.3%	600,982	596,571	0.3%	3,170	3,147	-2.0%
2014	16,210	413	2.6%	609,780	597,097	0.1%	3,135	3,070	-2.5%
2015	16,806	596	3.7%	610,947	613,258	2.7%	3,029	3,041	-0.9%
2016	17,118	312	1.9%	620,471	617,093	0.6%	3,021	3,004	-1.2%
2017	17,398	280	1.6%		623,101	1.0%		2,985	-0.7%
2018	17,607	209	1.2%		629,211	1.0%		2,978	-0.2%
2019	17,774	167	1.0%		633,508	0.7%		2,970	-0.3%
2020	18,005	231	1.3%		639,695	1.0%		2,961	-0.3%
2021	18,234	228	1.3%		645,779	1.0%		2,951	-0.3%
2022	18,460	226	1.2%		651,797	0.9%		2,942	-0.3%
2023	18,684	224	1.2%		657,776	0.9%		2,934	-0.3%
2024	18,907	223	1.2%		663,726	0.9%		2,925	-0.3%
2025	19,128	221	1.2%		669,630	0.9%		2,917	-0.3%
2026	19,346	219	1.1%		675,453	0.9%		2,909	-0.3%
2027	19,563	217	1.1%		681,217	0.9%		2,902	-0.3%
2028	19,777	215	1.1%		686,926	0.8%		2,894	-0.3%
2029	19,990	212	1.1%		692,558	0.8%		2,887	-0.2%
2030	20,199	210	1.0%		698,122	0.8%		2,880	-0.2%
2031	20,407	208	1.0%		703,630	0.8%		2,873	-0.2%
2032	20,615	208	1.0%		709,138	0.8%		2,867	-0.2%
2033	20,823	208	1.0%		714,646	0.8%		2,860	-0.2%
2034	21,031	208	1.0%		720,154	0.8%		2,854	-0.2%
2035	21,239	208	1.0%		725,661	0.8%		2,847	-0.2%
2036	21,447	208	1.0%		731,169	0.8%		2,841	-0.2%

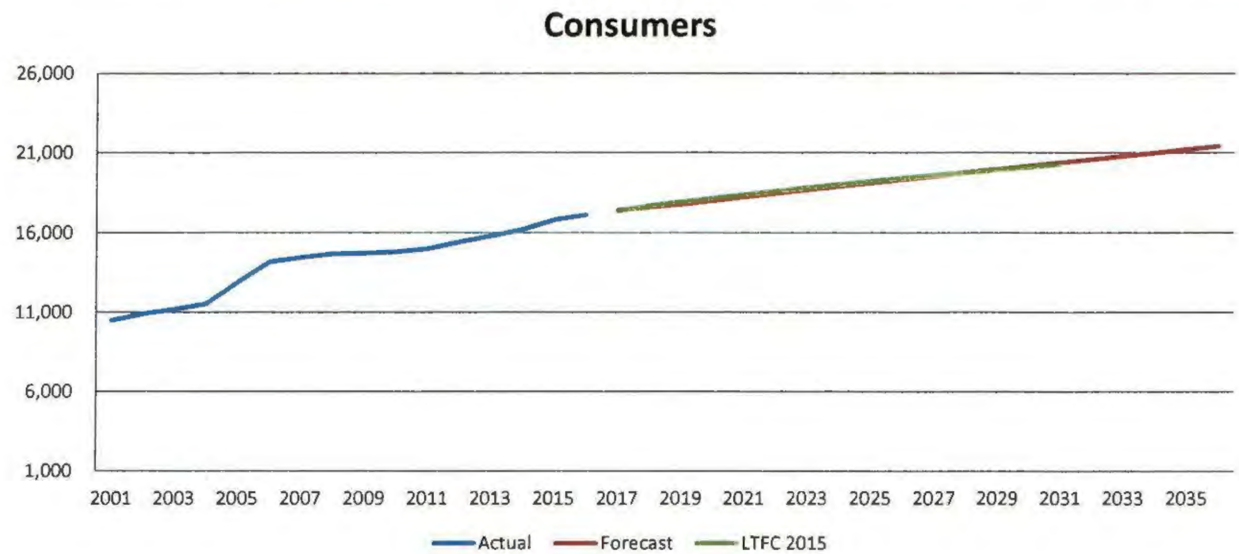
ANNUAL GROWTH RATES

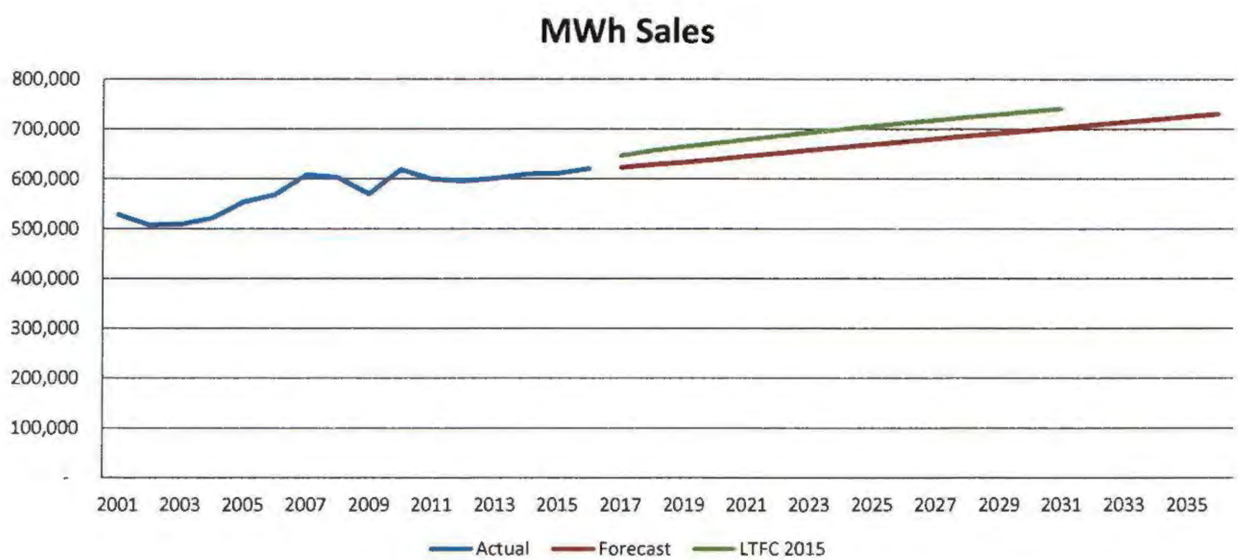
2001-2006	6.2%	736	1.5%		-4.5%	
2006-2011	1.1%	166	1.1%		-0.1%	
2011-2016	2.7%	424	0.7%	0.6%	-1.9%	-2.0%
2016-2021	1.3%	223		0.9%		-0.4%
2021-2026	1.2%	223		0.9%		-0.3%
2021-2031	1.1%	212		0.8%		-0.3%
2026-2036	1.0%	208		0.8%		-0.2%
2016-2036	1.1%	216		0.9%		-0.3%

BIG RIVERS ELECTRIC CORPORATION

2017 LONG-TERM LOAD FORECAST - BASE CASE FORECAST

SMALL COMMERCIAL CLASSIFICATION





BIG RIVERS ELECTRIC CORPORATION

2017 LONG-TERM LOAD FORECAST - BASE CASE FORECAST

LARGE COMMERCIAL CLASSIFICATION

Year	Consumers	Consumer Growth	Percent Growth	Sales (MWh)	Percent Growth	Average Use (kWh/Cust/Mo)	Percent Growth
2001	34			1,414,538		3,501,331	
2002	35	2	5.0%	1,238,353	-12.5%	2,920,644	-16.6%
2003	38	3	7.1%	1,151,279	-7.0%	2,535,856	-13.2%
2004	39	1	3.5%	1,140,217	-1.0%	2,425,995	-4.3%
2005	37	(2)	-5.1%	1,123,081	-1.5%	2,518,119	3.8%
2006	36	(1)	-2.0%	1,103,512	-1.7%	2,525,199	0.3%
2007	37	1	2.3%	1,071,969	-2.9%	2,398,142	-5.0%
2008	39	1	3.8%	1,080,619	0.8%	2,328,919	-2.9%
2009	38	(1)	-1.9%	1,092,667	1.1%	2,401,466	3.1%
2010	39	1	2.4%	1,081,785	-1.0%	2,321,426	-3.3%
2011	43	4	9.7%	1,128,352	4.3%	2,208,126	-4.9%
2012	44	1	2.2%	1,098,999	-2.6%	2,105,362	-4.7%
2013	52	8	19.0%	1,153,723	5.0%	1,857,847	-11.8%
2014	51	(1)	-1.3%	1,121,005	-2.8%	1,828,719	-1.6%
2015	52	1	1.8%	1,099,899	-1.9%	1,762,658	-3.6%
2016	51	(1)	-1.8%	1,068,889	-2.8%	1,743,702	-1.1%
2017	48	(3)	-5.7%	1,106,507	3.5%	1,914,373	9.8%
2018	49	1	2.1%	1,179,003	6.6%	1,998,311	4.4%
2019	49	0	0.0%	1,261,771	7.0%	2,138,595	7.0%
2020	49	0	0.0%	1,298,788	2.9%	2,201,335	2.9%
2021	49	0	0.0%	1,299,566	0.1%	2,202,655	0.1%
2022	49	0	0.0%	1,299,566	0.0%	2,202,655	0.0%
2023	49	0	0.0%	1,299,566	0.0%	2,202,655	0.0%
2024	49	0	0.0%	1,303,001	0.3%	2,208,477	0.3%
2025	49	0	0.0%	1,299,566	-0.3%	2,202,655	-0.3%
2026	49	0	0.0%	1,299,566	0.0%	2,202,655	0.0%
2027	49	0	0.0%	1,299,566	0.0%	2,202,655	0.0%
2028	49	0	0.0%	1,303,001	0.3%	2,208,477	0.3%
2029	49	0	0.0%	1,299,566	-0.3%	2,202,655	-0.3%
2030	49	0	0.0%	1,299,566	0.0%	2,202,655	0.0%
2031	49	0	0.0%	1,299,566	0.0%	2,202,655	0.0%
2032	49	0	0.0%	1,303,001	0.3%	2,208,477	0.3%
2033	49	0	0.0%	1,299,566	-0.3%	2,202,655	-0.3%
2034	49	0	0.0%	1,299,566	0.0%	2,202,655	0.0%
2035	49	0	0.0%	1,299,566	0.0%	2,202,655	0.0%
2036	49	0	0.0%	1,303,001	0.3%	2,208,477	0.3%

ANNUAL GROWTH RATES				
2001-2006	1.6%	1	-4.8%	-6.3%
2006-2011	3.2%	1	0.4%	-2.6%
2011-2016	3.7%	2	-1.1%	-4.6%
2016-2021	-0.8%	(0)	4.0%	4.8%
2021-2026	0.0%	-	0.0%	0.0%
2021-2031	0.0%	-	0.0%	0.0%
2026-2036	0.0%	-	0.1%	0.1%
2016-2036	-0.2%	(0)	1.0%	1.2%

BIG RIVERS ELECTRIC CORPORATION

2017 LONG-TERM LOAD FORECAST - BASE CASE FORECAST

RURAL LARGE COMMERCIAL CLASSIFICATION

Year	Consumers	Consumer Growth	Percent Growth	Sales (MWh)	Percent Growth	Average Use (kWh/Cust/Mo)	Percent Growth
2001	17			113,852		569,259	
2002	16	(0)	-2.0%	120,089	5.5%	612,700	7.6%
2003	17	1	3.1%	128,476	7.0%	636,018	3.8%
2004	18	1	7.9%	138,427	7.7%	634,985	-0.2%
2005	18	0	0.0%	141,995	2.6%	651,353	2.6%
2006	18	0	1.4%	139,821	-1.5%	632,675	-2.9%
2007	21	3	15.4%	145,200	3.8%	569,412	-10.0%
2008	20	(2)	-7.5%	147,038	1.3%	623,043	9.4%
2009	20	0	1.3%	124,286	-15.5%	520,024	-16.5%
2010	21	1	4.6%	121,141	-2.5%	484,563	-6.8%
2011	25	4	18.0%	130,264	7.5%	441,572	-8.9%
2012	26	1	3.7%	135,134	3.7%	441,615	0.0%
2013	32	6	24.5%	157,230	16.4%	412,677	-6.6%
2014	31	(1)	-2.1%	154,967	-1.4%	415,460	0.7%
2015	31	(0)	-0.3%	153,745	-0.8%	413,293	-0.5%
2016	30	(1)	-3.0%	154,328	0.4%	427,500	3.4%
2017	28	(2)	-6.4%	148,154	-4.0%	438,326	2.5%
2018	29	1	3.6%	151,304	2.1%	432,298	-1.4%
2019	29	0	0.0%	153,554	1.5%	438,727	1.5%
2020	29	0	0.0%	153,554	0.0%	438,727	0.0%
2021	29	0	0.0%	153,554	0.0%	438,727	0.0%
2022	29	0	0.0%	153,554	0.0%	438,727	0.0%
2023	29	0	0.0%	153,554	0.0%	438,727	0.0%
2024	29	0	0.0%	153,554	0.0%	438,727	0.0%
2025	29	0	0.0%	153,554	0.0%	438,727	0.0%
2026	29	0	0.0%	153,554	0.0%	438,727	0.0%
2027	29	0	0.0%	153,554	0.0%	438,727	0.0%
2028	29	0	0.0%	153,554	0.0%	438,727	0.0%
2029	29	0	0.0%	153,554	0.0%	438,727	0.0%
2030	29	0	0.0%	153,554	0.0%	438,727	0.0%
2031	29	0	0.0%	153,554	0.0%	438,727	0.0%
2032	29	0	0.0%	153,554	0.0%	438,727	0.0%
2033	29	0	0.0%	153,554	0.0%	438,727	0.0%
2034	29	0	0.0%	153,554	0.0%	438,727	0.0%
2035	29	0	0.0%	153,554	0.0%	438,727	0.0%
2036	29	0	0.0%	153,554	0.0%	438,727	0.0%

ANNUAL GROWTH RATES

2001-2006	2.0%	0	4.2%	2.1%
2006-2011	5.9%	1	-1.4%	-6.9%
2011-2016	4.1%	1	3.4%	-0.6%
2016-2021	-0.6%	(0)	-0.1%	0.5%
2021-2026	0.0%	-	0.0%	0.0%
2021-2031	0.0%	-	0.0%	0.0%
2026-2036	0.0%	-	0.0%	0.0%
2016-2036	-0.2%	(0)	0.0%	0.1%

BIG RIVERS ELECTRIC CORPORATION

2017 LONG-TERM LOAD FORECAST - BASE CASE FORECAST

DIRECT SERVE LARGE COMMERCIAL CLASSIFICATION

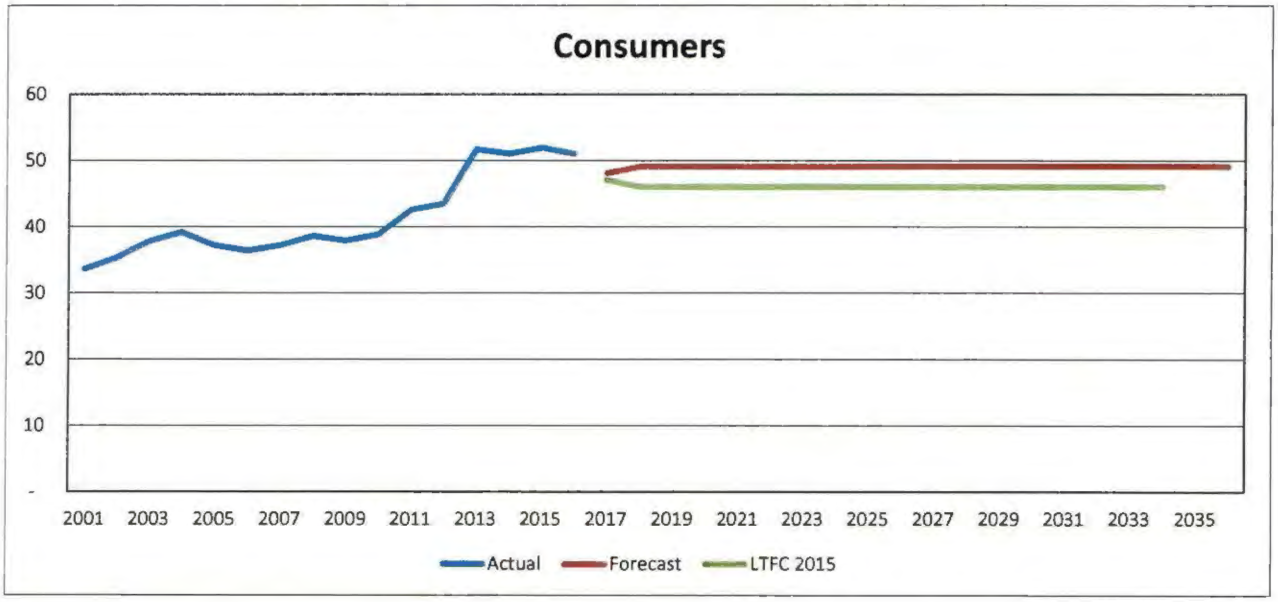
Year	Consumers	Consumer Growth	Percent Growth	Sales (MWh)	Percent Growth	Average Use (kWh/Cust/Mo)	Percent Growth
2001	17			1,300,686		6,375,911	
2002	19	2	11.8%	1,118,264	-14.0%	4,904,666	-23.1%
2003	21	2	10.5%	1,022,803	-8.5%	4,058,743	-17.2%
2004	21	0	0.0%	1,001,791	-2.1%	3,975,360	-2.1%
2005	19	(2)	-9.5%	981,086	-2.1%	4,303,010	8.2%
2006	18	(1)	-5.3%	963,691	-1.8%	4,461,532	3.7%
2007	16	(2)	-11.1%	926,769	-3.8%	4,826,924	8.2%
2008	19	3	18.8%	933,580	0.7%	4,094,651	-15.2%
2009	18	(1)	-5.3%	968,381	3.7%	4,483,246	9.5%
2010	18	0	0.0%	960,644	-0.8%	4,447,426	-0.8%
2011	18	0	0.0%	998,089	3.9%	4,620,782	3.9%
2012	18	0	0.0%	963,865	-3.4%	4,462,336	-3.4%
2013	20	2	11.1%	996,493	3.4%	4,152,054	-7.0%
2014	20	0	0.0%	966,038	-3.1%	4,025,159	-3.1%
2015	21	1	5.0%	946,154	-2.1%	3,754,579	-6.7%
2016	21	0	0.0%	914,562	-3.3%	3,629,214	-3.3%
2017	20	(1)	-4.8%	958,353	4.8%	3,993,138	10.0%
2018	20	0	0.0%	1,027,699	7.2%	4,282,079	7.2%
2019	20	0	0.0%	1,108,217	7.8%	4,617,571	7.8%
2020	20	0	0.0%	1,145,234	3.3%	4,771,806	3.3%
2021	20	0	0.0%	1,146,012	0.1%	4,775,050	0.1%
2022	20	0	0.0%	1,146,012	0.0%	4,775,050	0.0%
2023	20	0	0.0%	1,146,012	0.0%	4,775,050	0.0%
2024	20	0	0.0%	1,149,447	0.3%	4,789,362	0.3%
2025	20	0	0.0%	1,146,012	-0.3%	4,775,050	-0.3%
2026	20	0	0.0%	1,146,012	0.0%	4,775,050	0.0%
2027	20	0	0.0%	1,146,012	0.0%	4,775,050	0.0%
2028	20	0	0.0%	1,149,447	0.3%	4,789,362	0.3%
2029	20	0	0.0%	1,146,012	-0.3%	4,775,050	-0.3%
2030	20	0	0.0%	1,146,012	0.0%	4,775,050	0.0%
2031	20	0	0.0%	1,146,012	0.0%	4,775,050	0.0%
2032	20	0	0.0%	1,149,447	0.3%	4,789,362	0.3%
2033	20	0	0.0%	1,146,012	-0.3%	4,775,050	-0.3%
2034	20	0	0.0%	1,146,012	0.0%	4,775,050	0.0%
2035	20	0	0.0%	1,146,012	0.0%	4,775,050	0.0%
2036	20	0	0.0%	1,149,447	0.3%	4,789,362	0.3%

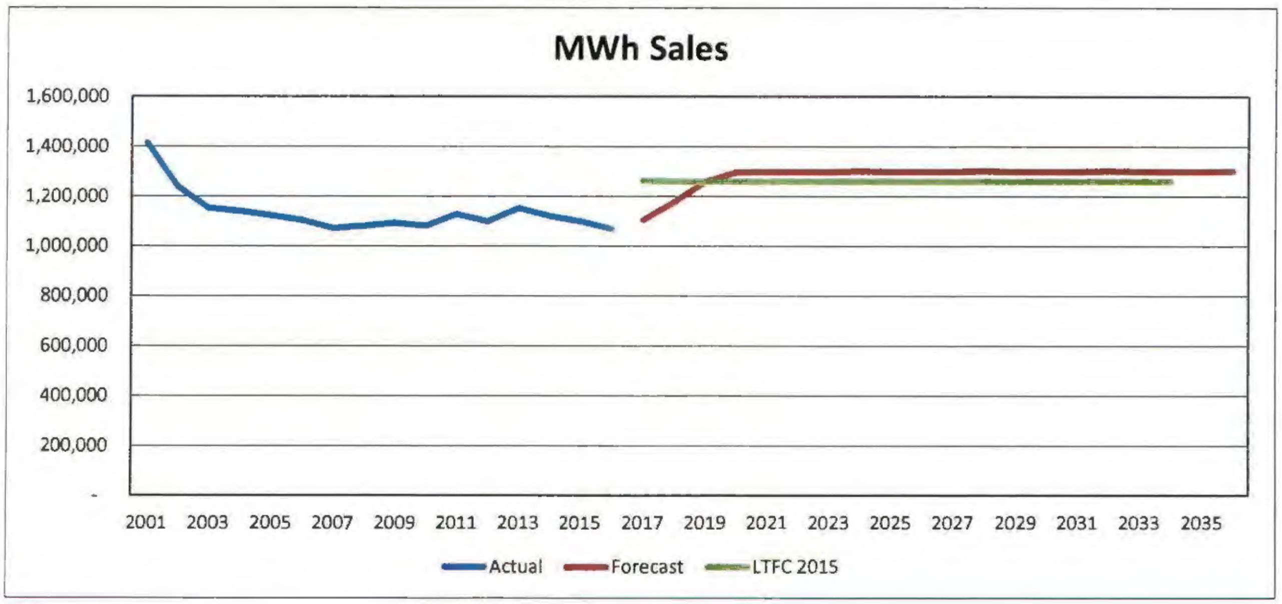
ANNUAL GROWTH RATES				
2001-2006	1.1%	0	-5.8%	-6.9%
2006-2011	0.0%	-	0.7%	0.7%
2011-2016	3.1%	1	-1.7%	-4.7%
2016-2021	-1.0%	(0)	4.6%	5.6%
2021-2026	0.0%	-	0.0%	0.0%
2021-2031	0.0%	-	0.0%	0.0%
2026-2036	0.0%	-	0.1%	0.1%
2016-2036	-0.2%	(0)	1.1%	1.4%

BIG RIVERS ELECTRIC CORPORATION

2017 LONG-TERM LOAD FORECAST - BASE CASE FORECAST

LARGE COMMERCIAL CLASSIFICATION





BIG RIVERS ELECTRIC CORPORATION

2017 LONG-TERM LOAD FORECAST - BASE CASE FORECAST

IRRIGATION CLASSIFICATION

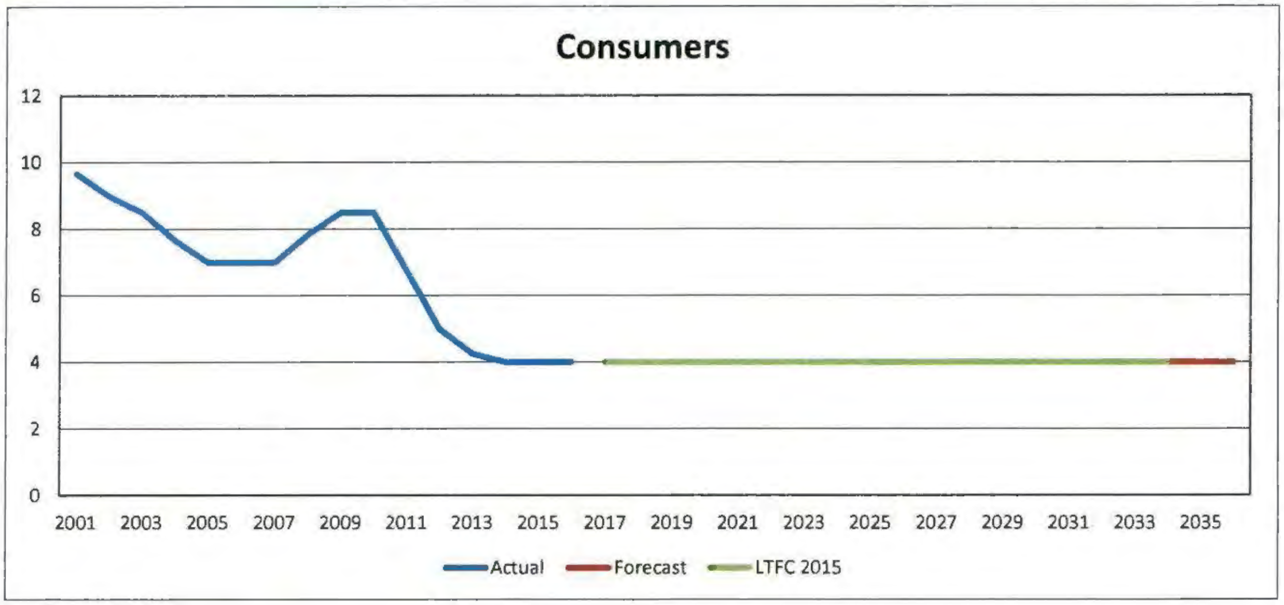
Year	Consumers	Consumer Growth	Percent Growth	Sales (MWh)	Percent Growth	Average Use (kWh/Cust/Mo)	Percent Growth
2001	10			75		644	
2002	9	(1)	-6.9%	38	-49.1%	352	-45.4%
2003	9	(1)	-5.6%	113	196.9%	1,106	214.4%
2004	8	(1)	-9.8%	164	45.1%	1,780	60.9%
2005	7	(1)	-8.7%	114	-30.4%	1,356	-23.8%
2006	7	0	0.0%	65	-43.2%	770	-43.2%
2007	7	0	0.0%	1,068	1551.4%	12,715	1551.4%
2008	8	1	11.9%	432	-59.6%	4,594	-63.9%
2009	9	1	8.5%	406	-5.9%	3,984	-13.3%
2010	9	0	0.0%	356	-12.4%	3,491	-12.4%
2011	7	(2)	-20.6%	269	-24.5%	3,321	-4.9%
2012	5	(2)	-25.9%	440	63.7%	7,338	121.0%
2013	4	(1)	-15.0%	48	-89.2%	933	-87.3%
2014	4	(0)	-5.9%	136	186.9%	2,843	204.8%
2015	4	0	0.0%	62	-54.8%	1,286	-54.8%
2016	4	0	0.0%	47	-24.0%	977	-24.0%
2017	4	0	0.0%	194	313.8%	4,041	313.8%
2018	4	0	0.0%	194	0.0%	4,041	0.0%
2019	4	0	0.0%	194	0.0%	4,041	0.0%
2020	4	0	0.0%	194	0.0%	4,041	0.0%
2021	4	0	0.0%	194	0.0%	4,041	0.0%
2022	4	0	0.0%	194	0.0%	4,041	0.0%
2023	4	0	0.0%	194	0.0%	4,041	0.0%
2024	4	0	0.0%	194	0.0%	4,041	0.0%
2025	4	0	0.0%	194	0.0%	4,041	0.0%
2026	4	0	0.0%	194	0.0%	4,041	0.0%
2027	4	0	0.0%	194	0.0%	4,041	0.0%
2028	4	0	0.0%	194	0.0%	4,041	0.0%
2029	4	0	0.0%	194	0.0%	4,041	0.0%
2030	4	0	0.0%	194	0.0%	4,041	0.0%
2031	4	0	0.0%	194	0.0%	4,041	0.0%
2032	4	0	0.0%	194	0.0%	4,041	0.0%
2033	4	0	0.0%	194	0.0%	4,041	0.0%
2034	4	0	0.0%	194	0.0%	4,041	0.0%
2035	4	0	0.0%	194	0.0%	4,041	0.0%
2036	4	0	0.0%	194	0.0%	4,041	0.0%

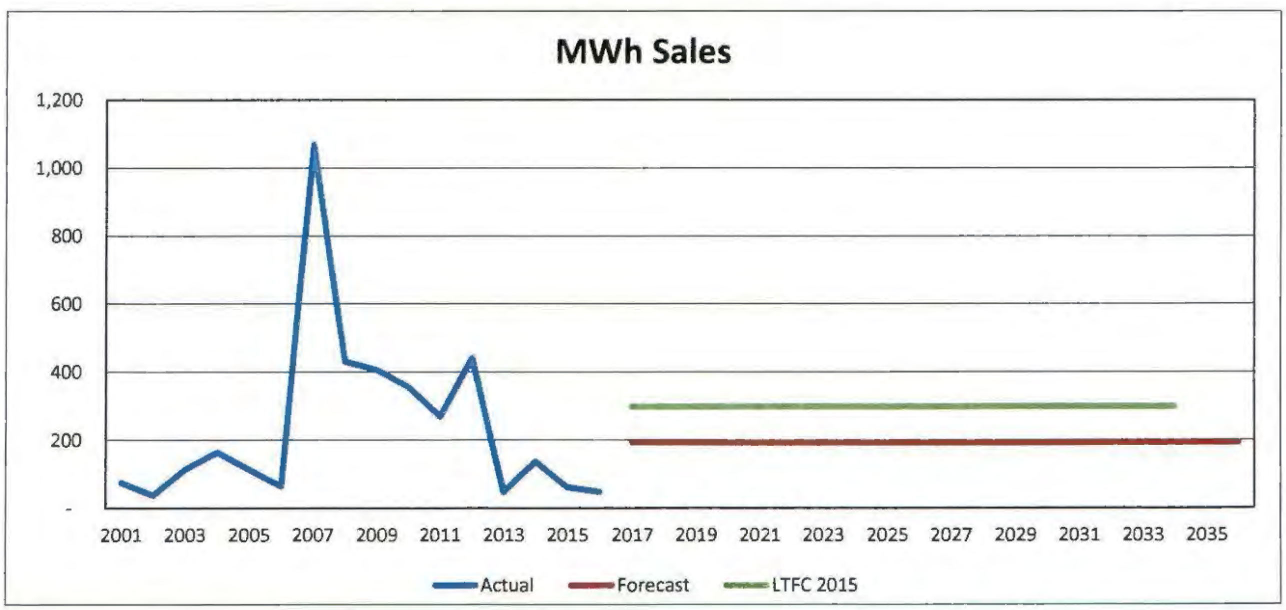
ANNUAL GROWTH RATES				
2001-2006	-6.3%	(1)	-2.8%	3.6%
2006-2011	-0.7%	(0)	33.0%	34.0%
2011-2016	-9.9%	(1)	-29.5%	-21.7%
2016-2021	0.0%	-	32.8%	32.8%
2021-2026	0.0%	-	0.0%	0.0%
2021-2031	0.0%	-	0.0%	0.0%
2026-2036	0.0%	-	0.0%	0.0%
2016-2036	0.0%	-	7.4%	7.4%

BIG RIVERS ELECTRIC CORPORATION

2017 LONG-TERM LOAD FORECAST - BASE CASE FORECAST

IRRIGATION CLASSIFICATION





BIG RIVERS ELECTRIC CORPORATION

2017 LONG-TERM LOAD FORECAST - BASE CASE FORECAST

STREET LIGHTING CLASSIFICATION

Year	Consumers	Consumer Growth	Percent Growth	Sales (MWh)	Percent Growth	Average Use (kWh/Cust/Mo)	Percent Growth
2001	181			3,104		1,427	
2002	182	0	0.1%	3,277	5.6%	1,505	5.4%
2003	147	(34)	-18.9%	3,235	-1.3%	1,831	21.7%
2004	79	(68)	-46.3%	2,997	-7.3%	3,158	72.5%
2005	84	5	6.4%	3,077	2.7%	3,047	-3.5%
2006	87	3	3.8%	3,104	0.9%	2,962	-2.8%
2007	88	1	0.8%	3,175	2.3%	3,007	1.5%
2008	88	(0)	-0.5%	3,287	3.5%	3,128	4.0%
2009	85	(2)	-2.8%	3,246	-1.2%	3,177	1.6%
2010	88	3	3.3%	3,438	5.9%	3,256	2.5%
2011	87	(1)	-1.3%	3,409	-0.8%	3,272	0.5%
2012	92	5	5.4%	3,454	1.3%	3,146	-3.9%
2013	91	(0)	-0.1%	3,486	0.9%	3,178	1.0%
2014	91	(0)	-0.5%	3,461	-0.7%	3,169	-0.3%
2015	100	9	10.1%	3,429	-0.9%	2,853	-10.0%
2016	103	3	3.2%	3,291	-4.0%	2,654	-7.0%
2017	103	0	0.0%	3,396	3.2%	2,739	3.2%
2018	103	0	0.0%	3,399	0.1%	2,741	0.1%
2019	103	0	0.0%	3,402	0.1%	2,744	0.1%
2020	103	0	0.0%	3,405	0.1%	2,746	0.1%
2021	103	0	0.0%	3,408	0.1%	2,749	0.1%
2022	103	0	0.0%	3,411	0.1%	2,751	0.1%
2023	103	0	0.0%	3,414	0.1%	2,753	0.1%
2024	103	0	0.0%	3,417	0.1%	2,756	0.1%
2025	103	0	0.0%	3,420	0.1%	2,758	0.1%
2026	103	0	0.0%	3,423	0.1%	2,761	0.1%
2027	103	0	0.0%	3,426	0.1%	2,763	0.1%
2028	103	0	0.0%	3,429	0.1%	2,766	0.1%
2029	103	0	0.0%	3,432	0.1%	2,768	0.1%
2030	103	0	0.0%	3,435	0.1%	2,771	0.1%
2031	103	0	0.0%	3,438	0.1%	2,773	0.1%
2032	103	0	0.0%	3,441	0.1%	2,775	0.1%
2033	103	0	0.0%	3,445	0.1%	2,778	0.1%
2034	103	0	0.0%	3,448	0.1%	2,780	0.1%
2035	103	0	0.0%	3,451	0.1%	2,783	0.1%
2036	103	0	0.0%	3,454	0.1%	2,785	0.1%

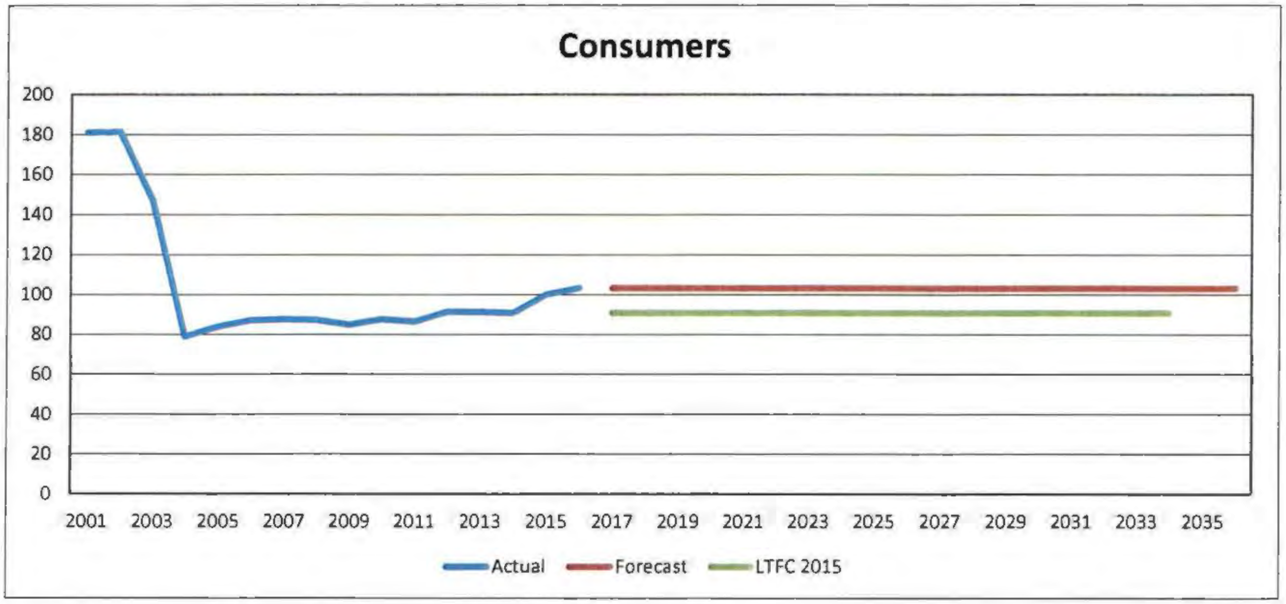
ANNUAL GROWTH RATES

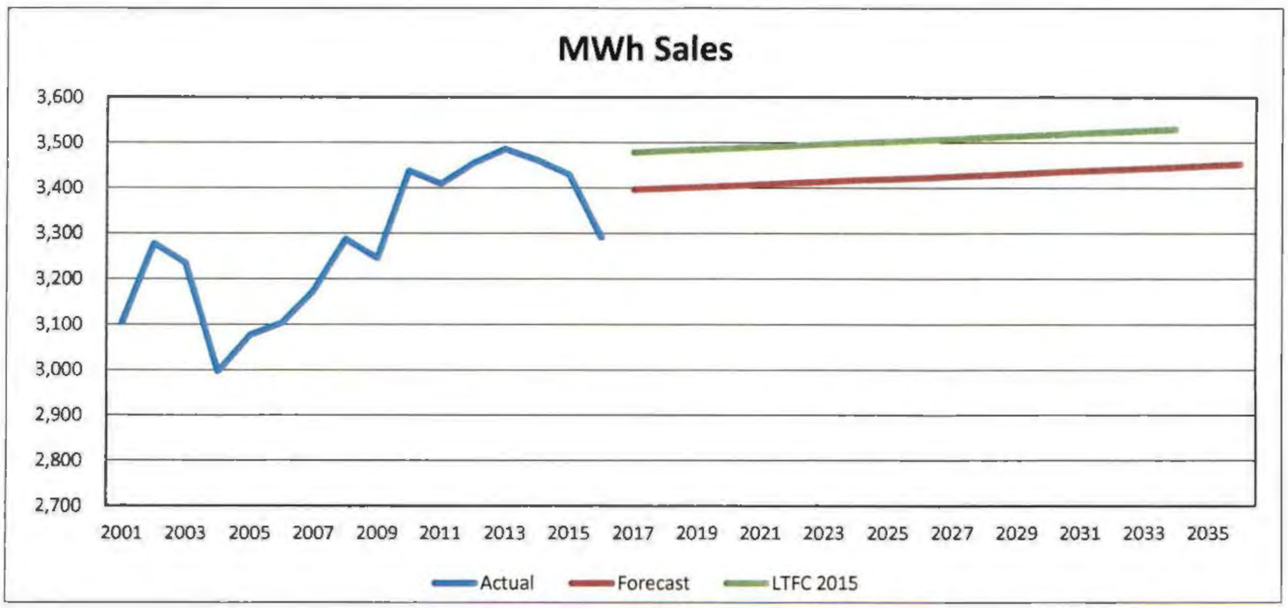
2001-2006	-13.6%	(19)	0.0%	15.7%
2006-2011	-0.1%	(0)	1.9%	2.0%
2011-2016	3.5%	3	-0.7%	-4.1%
2016-2021	0.0%	-	0.7%	0.7%
2021-2026	0.0%	-	0.1%	0.1%
2021-2031	0.0%	-	0.1%	0.1%
2026-2036	0.0%	-	0.1%	0.1%
2016-2036	0.0%	-	0.2%	0.2%

BIG RIVERS ELECTRIC CORPORATION

2017 LONG-TERM LOAD FORECAST - BASE CASE FORECAST

STREET LIGHTING CLASSIFICATION





Appendix B – Forecast Scenario Tables & Graphs

BIG RIVERS ELECTRIC CORPORATION

2017 LONG-TERM LOAD FORECAST - RANGE FORECASTS

NATIVE SYSTEM REQUIREMENTS

Year	Base Case (MWh)	Weather Adjusted (MWh)	ECONOMIC SCENARIOS Optimistic (MWh)	ECONOMIC SCENARIOS Pessimistic (MWh)	WEATHER SCENARIOS Extreme (MWh)	WEATHER SCENARIOS Mild (MWh)
2001	3,284,432	3,375,813				
2002	3,191,176	3,175,247				
2003	3,052,582	3,171,640				
2004	3,129,980	3,249,862				
2005	3,233,245	3,272,948				
2006	3,188,986	3,321,004				
2007	3,325,859	3,306,150				
2008	3,313,571	3,354,190				
2009	3,159,286	3,272,941				
2010	3,411,558	3,321,276				
2011	3,344,199	3,385,423				
2012	3,282,776	3,337,591				
2013	3,371,187	3,403,524				
2014	3,381,575	3,377,106				
2015	3,270,995	3,333,037				
2016	3,244,594	3,272,279				
2017		3,258,532	3,475,860	3,068,021	3,410,934	3,133,135
2018		3,343,114	3,579,695	3,132,650	3,496,327	3,217,172
2019		3,432,508	3,690,035	3,203,170	3,586,368	3,306,008
2020		3,473,299	3,749,644	3,226,326	3,628,026	3,345,681
2021		3,474,891	3,772,649	3,209,069	3,629,644	3,347,168
2022		3,478,946	3,794,590	3,197,346	3,634,199	3,350,745
2023		3,481,017	3,816,438	3,182,574	3,636,658	3,352,624
2024		3,490,159	3,844,513	3,175,803	3,646,386	3,361,351
2025		3,495,398	3,868,538	3,165,460	3,652,337	3,366,106
2026		3,501,719	3,894,838	3,155,483	3,659,113	3,372,151
2027		3,508,814	3,922,248	3,146,447	3,666,722	3,379,018
2028		3,520,620	3,955,618	3,141,369	3,679,126	3,390,533
2029		3,526,010	3,982,519	3,130,416	3,685,118	3,395,604
2030		3,535,190	4,013,811	3,123,283	3,694,912	3,404,460
2031		3,544,285	4,045,005	3,116,750	3,704,569	3,413,284
2032		3,556,815	4,079,806	3,113,481	3,717,660	3,425,542
2033		3,562,475	4,107,394	3,103,686	3,723,881	3,430,931
2034		3,571,571	4,138,589	3,097,153	3,733,537	3,439,755
2035		3,580,666	4,169,784	3,090,621	3,743,193	3,448,578
2036		3,593,196	4,204,585	3,087,352	3,756,284	3,460,837

ANNUAL GROWTH RATES						
2001-2006	-0.6%	-0.3%				
2006-2011	1.0%	0.4%				
2011-2016	-0.6%	-0.7%				
2016-2021		1.2%	2.9%	-0.4%	2.1%	0.5%
2021-2026		0.2%	0.6%	-0.3%	0.2%	0.1%
2026-2031		0.2%	0.8%	-0.2%	0.2%	0.2%
2031-2036		0.3%	0.8%	-0.2%	0.3%	0.3%
2016-2036		0.5%	1.3%	-0.3%	0.7%	0.3%

Excludes transmission losses

BIG RIVERS ELECTRIC CORPORATION

2017 LONG-TERM LOAD FORECAST - RANGE FORECASTS

NATIVE SYSTEM CP DEMAND - SUMMER

Year	Base Case (kW)	Weather Adjusted (MWh)	ECONOMIC SCENARIOS Optimistic (kW)	ECONOMIC SCENARIOS Pessimistic (kW)	WEATHER SCENARIOS Extreme (kW)	WEATHER SCENARIOS Mild (kW)
2001	596,310					
2002	602,623	587,317				
2003	583,906	592,266				
2004	604,155	618,850				
2005	603,783	609,740				
2006	619,258	627,399				
2007	647,502	594,279				
2008	604,334	605,923				
2009	594,126	608,201				
2010	656,634	613,675				
2011	652,127	638,938				
2012	654,200	606,718				
2013	609,000	638,743				
2014	601,935	603,617				
2015	616,732	622,689				
2016	607,440	619,950				
2017		634,778	678,385	597,022	677,988	592,680
2018		645,249	692,572	603,592	688,582	603,331
2019		657,728	709,202	612,354	700,987	615,853
2020		660,639	715,880	611,750	703,843	618,725
2021		662,162	722,165	609,084	705,891	620,018
2022		663,036	726,918	606,536	706,909	620,819
2023		663,990	732,222	603,786	708,198	621,656
2024		665,006	737,283	601,409	709,469	622,604
2025		666,212	742,512	599,276	710,950	623,761
2026		667,476	748,090	597,020	712,421	624,927
2027		668,857	753,849	594,926	713,995	626,205
2028		670,290	759,855	592,791	715,603	627,548
2029		671,891	766,097	590,862	717,383	629,039
2030		673,549	772,480	589,039	719,228	630,584
2031		675,268	778,931	587,419	721,128	632,179
2032		676,988	785,378	585,801	723,028	633,774
2033		678,707	791,821	584,186	724,928	635,370
2034		680,427	798,260	582,574	726,828	636,965
2035		682,147	804,695	580,965	728,728	638,560
2036		683,866	811,125	579,359	730,628	640,156

ANNUAL GROWTH RATES						
2001-2006	0.8%					
2006-2011	1.0%					
2011-2016	-1.4%					
2016-2021		1.3%	3.1%	-0.4%	2.6%	0.0%
2021-2026		0.2%	0.7%	-0.4%	0.2%	0.2%
2026-2031		0.2%	0.8%	-0.3%	0.2%	0.2%
2031-2036		0.3%	0.8%	-0.3%	0.3%	0.3%
2016-2036		0.5%	1.4%	-0.3%	0.8%	0.2%

Excludes transmission losses

BIG RIVERS ELECTRIC CORPORATION

2017 LONG-TERM LOAD FORECAST - RANGE FORECASTS

NATIVE SYSTEM CP DEMAND - WINTER

			ECONOMIC SCENARIOS		WEATHER SCENARIOS	
Year	Base Case (kW)	Weather Adjusted (MWh)	Optimistic (kW)	Pessimistic (kW)	Extreme (kW)	Mild (kW)
2001	598,797					
2002	530,467	556,540				
2003	585,549	547,253				
2004	562,082	535,652				
2005	548,765	561,077				
2006	576,534	599,442				
2007	597,267	600,568				
2008	611,454	616,642				
2009	664,788	630,115				
2010	646,750	616,176				
2011	624,191	579,769				
2012	568,900	617,753				
2013	596,800	618,319				
2014	740,203	698,327				
2015	687,696	663,894				
2016	600,010	605,199				
2017		620,796	663,546	583,819	706,997	545,766
2018		630,495	676,883	589,698	716,480	555,717
2019		641,254	691,665	596,865	727,002	566,511
2020		653,562	708,158	605,236	739,243	578,789
2021		657,008	716,383	604,464	743,444	581,931
2022		657,713	720,895	601,810	744,307	582,550
2023		658,513	725,966	598,971	745,557	583,184
2024		659,365	730,785	596,496	746,674	583,955
2025		660,354	735,712	594,217	747,896	584,905
2026		661,228	740,783	591,671	749,011	585,709
2027		662,271	746,087	589,335	750,284	586,655
2028		663,361	751,624	586,959	751,561	587,670
2029		664,769	757,565	584,920	753,173	588,926
2030		666,323	763,750	583,066	754,942	590,298
2031		667,945	770,007	581,416	756,786	591,716
2032		669,566	776,260	579,770	758,629	593,134
2033		671,188	782,507	578,128	760,472	594,552
2034		672,809	788,749	576,489	762,315	595,970
2035		674,430	794,986	574,853	764,159	597,387
2036		676,052	801,217	573,221	766,002	598,805

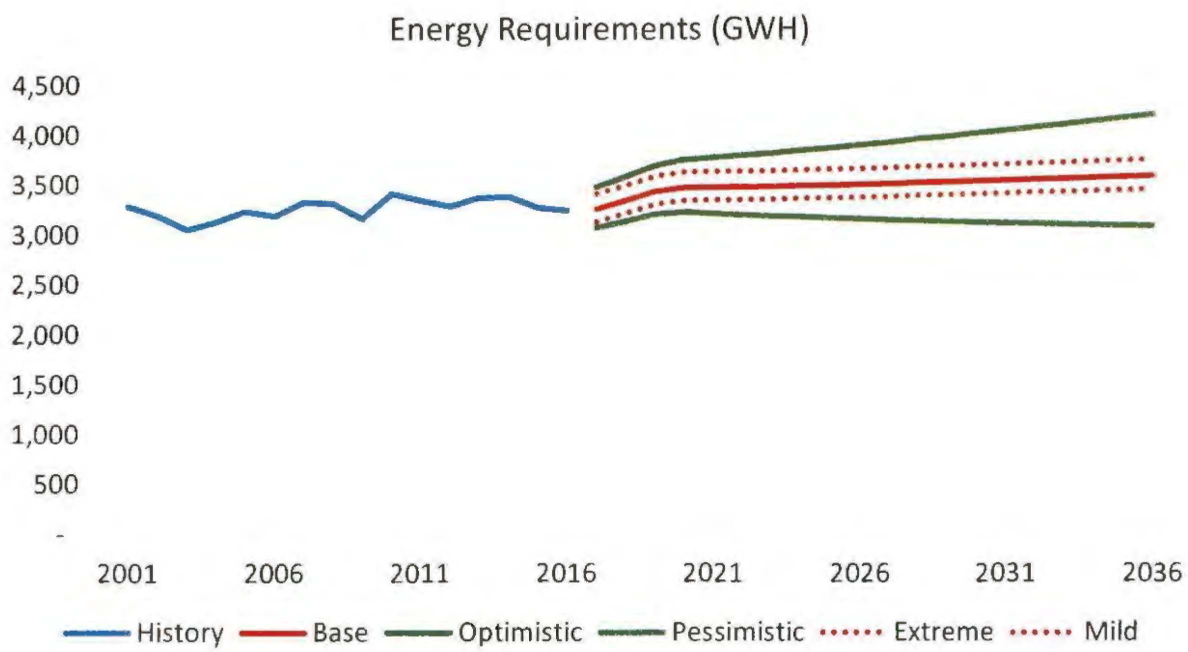
ANNUAL GROWTH RATES						
2001-2006	-0.8%					
2006-2011	1.6%					
2011-2016	-0.8%					
2016-2021		1.7%	3.4%	0.0%	4.2%	-0.8%
2021-2026		0.1%	0.7%	-0.4%	0.1%	0.1%
2026-2031		0.2%	0.8%	-0.3%	0.2%	0.2%
2031-2036		0.2%	0.8%	-0.3%	0.2%	0.2%
2016-2036		0.6%	1.4%	-0.3%	1.2%	-0.1%

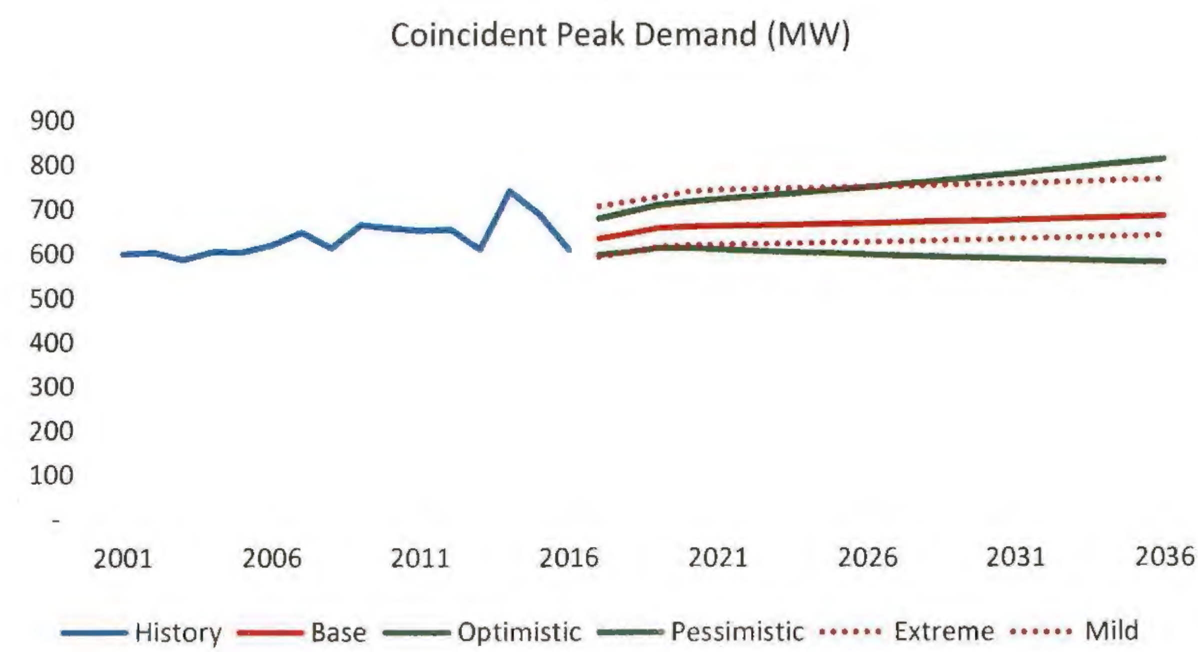
Excludes transmission losses

BIG RIVERS ELECTRIC CORPORATION

2017 LONG-TERM LOAD FORECAST - RANGE FORECASTS

NATIVE SYSTEM REQUIREMENTS





BIG RIVERS ELECTRIC CORPORATION

2017 LONG-TERM LOAD FORECAST - RANGE FORECASTS

RURAL SYSTEM REQUIREMENTS

Year	Base Case (MWh)	Weather Adjusted (MWh)	ECONOMIC SCENARIOS Optimistic (MWh)	ECONOMIC SCENARIOS Pessimistic (MWh)	WEATHER SCENARIOS Extreme (MWh)	WEATHER SCENARIOS Mild (MWh)
2001	2,000,877	2,039,727				
2002	2,114,841	2,047,683				
2003	2,089,678	2,163,616				
2004	2,133,190	2,203,603				
2005	2,262,017	2,247,952				
2006	2,232,581	2,312,324				
2007	2,407,449	2,333,391				
2008	2,387,974	2,371,708				
2009	2,238,762	2,299,263				
2010	2,481,390	2,330,705				
2011	2,371,106	2,360,141				
2012	2,321,478	2,318,050				
2013	2,374,920	2,353,980				
2014	2,415,564	2,353,028				
2015	2,325,204	2,334,790				
2016	2,330,037	2,304,554				
2017		2,300,179	2,469,589	2,157,586	2,452,581	2,174,782
2018		2,315,416	2,500,612	2,156,336	2,468,628	2,189,473
2019		2,324,291	2,526,408	2,150,364	2,478,151	2,197,791
2020		2,328,066	2,547,149	2,138,354	2,482,792	2,200,448
2021		2,328,879	2,569,336	2,120,358	2,483,632	2,201,156
2022		2,332,934	2,591,278	2,108,634	2,488,187	2,204,733
2023		2,335,005	2,613,125	2,093,862	2,490,646	2,206,611
2024		2,340,712	2,637,594	2,083,828	2,496,939	2,211,904
2025		2,349,386	2,665,225	2,076,749	2,506,325	2,220,094
2026		2,355,707	2,691,525	2,066,772	2,513,101	2,226,139
2027		2,362,802	2,718,936	2,057,736	2,520,710	2,233,006
2028		2,371,173	2,748,699	2,049,395	2,529,679	2,241,086
2029		2,379,998	2,779,206	2,041,705	2,539,106	2,249,592
2030		2,389,178	2,810,498	2,034,571	2,548,900	2,258,448
2031		2,398,273	2,841,693	2,028,039	2,558,556	2,267,272
2032		2,407,368	2,872,887	2,021,507	2,568,213	2,276,095
2033		2,416,463	2,904,082	2,014,974	2,577,869	2,284,919
2034		2,425,559	2,935,276	2,008,442	2,587,525	2,293,743
2035		2,434,654	2,966,471	2,001,909	2,597,181	2,302,566
2036		2,443,749	2,997,666	1,995,377	2,606,837	2,311,390

ANNUAL GROWTH RATES						
2001-2006	2.2%	2.5%				
2006-2011	1.2%	0.4%				
2011-2016	-0.3%	-0.5%				
2016-2021		0.2%	2.2%	-1.7%	1.5%	-0.9%
2021-2026		0.2%	0.9%	-0.5%	0.2%	0.2%
2026-2031		0.4%	1.1%	-0.4%	0.4%	0.4%
2031-2036		0.4%	1.1%	-0.3%	0.4%	0.4%
2016-2036		0.3%	1.3%	-0.7%	0.6%	0.0%

Excludes transmission losses

BIG RIVERS ELECTRIC CORPORATION

2017 LONG-TERM LOAD FORECAST - RANGE FORECASTS

RURAL SYSTEM CP DEMAND - SUMMER

Year	Base Case (MWh)	Weather Adjusted (MWh)	ECONOMIC SCENARIOS Optimistic (kW)	ECONOMIC SCENARIOS Pessimistic (kW)	WEATHER SCENARIOS Extreme (kW)	WEATHER SCENARIOS Mild (kW)
2001	441,183					
2002	461,561					
2003	458,050					
2004	472,169					
2005	497,997					
2006	501,463					
2007	532,264					
2008	497,743					
2009	496,641					
2010	546,356					
2011	533,911					
2012	534,216					
2013	472,149					
2014	483,465					
2015	504,969					
2016	486,950	499,460				
2017		501,814	538,773	470,705	545,023	459,715
2018		502,274	542,448	467,766	545,608	460,356
2019		502,924	546,657	465,290	546,182	461,049
2020		503,559	550,947	462,525	546,764	461,645
2021		505,082	557,232	459,858	548,811	462,938
2022		505,956	561,984	457,311	549,829	463,740
2023		506,911	567,289	454,561	551,119	464,576
2024		507,927	572,349	452,184	552,389	465,524
2025		509,133	577,578	450,050	553,871	466,681
2026		510,396	583,156	447,795	555,341	467,848
2027		511,778	588,915	445,701	556,915	469,126
2028		513,211	594,921	443,566	558,524	470,468
2029		514,811	601,163	441,636	560,304	471,959
2030		516,469	607,546	439,814	562,149	473,504
2031		518,189	613,997	438,193	564,049	475,099
2032		519,908	620,444	436,576	565,949	476,695
2033		521,628	626,887	434,961	567,849	478,290
2034		523,348	633,326	433,349	569,749	479,885
2035		525,067	639,761	431,740	571,649	481,481
2036		526,787	646,192	430,134	573,549	483,076

ANNUAL GROWTH RATES						
2001-2006	2.6%					
2006-2011	1.3%					
2011-2016	-1.8%					
2016-2021		0.2%	2.2%	-1.6%	1.9%	-1.5%
2021-2026		0.2%	0.9%	-0.5%	0.2%	0.2%
2026-2031		0.3%	1.0%	-0.4%	0.3%	0.3%
2031-2036		0.3%	1.0%	-0.4%	0.3%	0.3%
2016-2036		0.3%	1.3%	-0.7%	0.7%	-0.2%

Excludes transmission losses

BIG RIVERS ELECTRIC CORPORATION

2017 LONG-TERM LOAD FORECAST - RANGE FORECASTS

RURAL SYSTEM CP DEMAND - WINTER

Year	Base Case (MWh)	Weather Adjusted (MWh)	ECONOMIC SCENARIOS Optimistic (kW)	ECONOMIC SCENARIOS Pessimistic (kW)	WEATHER SCENARIOS Extreme (kW)	WEATHER SCENARIOS Mild (kW)
2001	423,149					
2002	380,606					
2003	460,626					
2004	430,124					
2005	444,494					
2006	439,167					
2007	489,272					
2008	511,901					
2009	560,598					
2010	517,785					
2011	536,353					
2012	454,476					
2013	479,669					
2014	612,356					
2015	567,816					
2016	487,142	492,331				
2017		495,109	531,574	464,416	581,309	420,079
2018		495,707	535,356	461,650	581,693	420,930
2019		496,457	539,628	459,307	582,205	421,714
2020		496,935	543,699	456,441	582,616	422,162
2021		498,106	549,536	453,507	584,542	423,029
2022		498,810	554,048	450,852	585,405	423,648
2023		499,610	559,119	448,014	586,655	424,282
2024		500,462	563,938	445,538	587,772	425,052
2025		501,452	568,864	443,260	588,993	426,003
2026		502,326	573,935	440,714	590,109	426,807
2027		503,369	579,239	438,378	591,382	427,753
2028		504,459	584,776	436,002	592,659	428,768
2029		505,867	590,718	433,963	594,271	430,024
2030		507,421	596,903	432,109	596,040	431,396
2031		509,043	603,160	430,459	597,883	432,814
2032		510,664	609,412	428,813	599,727	434,232
2033		512,285	615,659	427,170	601,570	435,650
2034		513,907	621,901	425,532	603,413	437,067
2035		515,528	628,138	423,896	605,257	438,485
2036		517,149	634,370	422,264	607,100	439,903

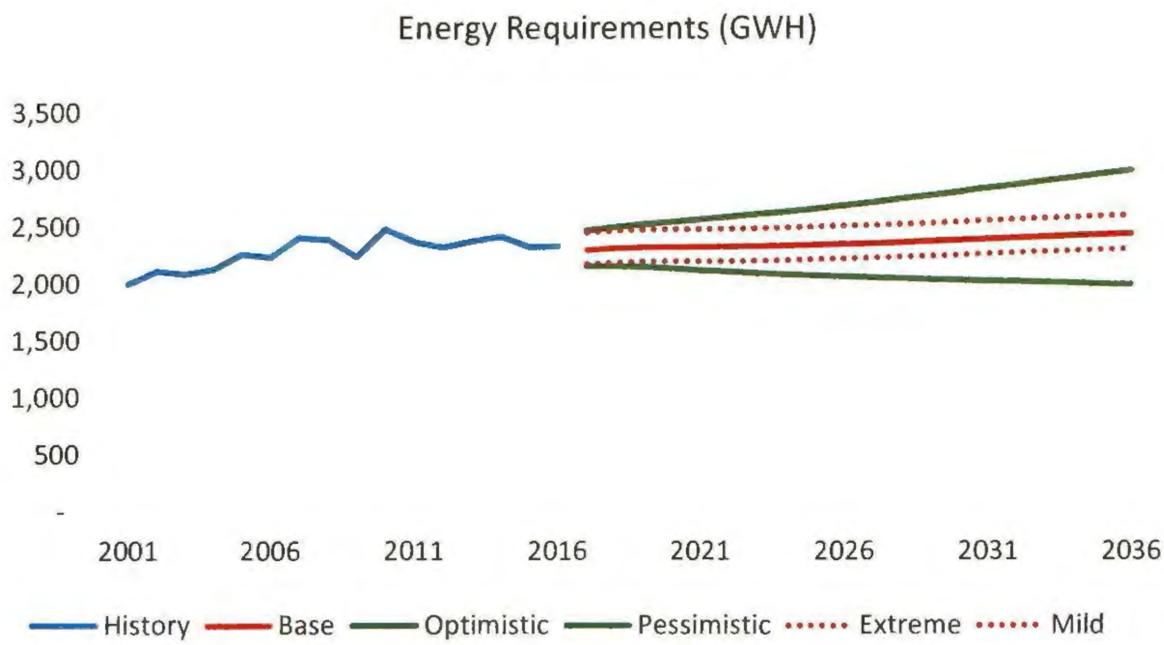
ANNUAL GROWTH RATES						
2001-2006	0.7%					
2006-2011	4.1%					
2011-2016	-1.9%					
2016-2021		0.2%	2.2%	-1.6%	3.5%	-3.0%
2021-2026		0.2%	0.9%	-0.6%	0.2%	0.2%
2026-2031		0.3%	1.0%	-0.5%	0.3%	0.3%
2031-2036		0.3%	1.0%	-0.4%	0.3%	0.3%
2016-2036		0.2%	1.3%	-0.8%	1.1%	-0.6%

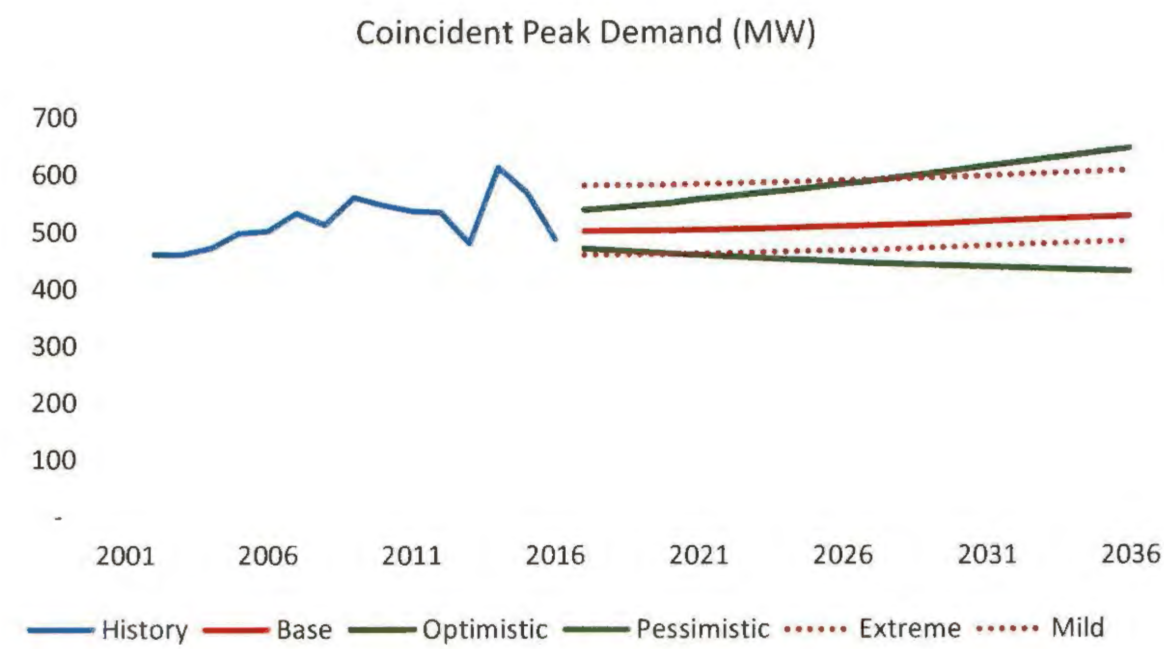
Excludes transmission losses

BIG RIVERS ELECTRIC CORPORATION

2017 LONG-TERM LOAD FORECAST - RANGE FORECASTS

RURAL SYSTEM REQUIREMENTS





BIG RIVERS ELECTRIC CORPORATION

2017 LONG-TERM LOAD FORECAST - RANGE FORECASTS

RESIDENTIAL ENERGY SALES

Year	Base Case (MWh)	Weather Normalized (MWh)	ECONOMIC SCENARIOS Optimistic (MWh)	Pessimistic (MWh)	WEATHER SCENARIOS Extreme (MWh)	Mild (MWh)
2001	1,246,139	-				
2002	1,371,067	-				
2003	1,340,451	-				
2004	1,362,667	-				
2005	1,452,182	1,445,785				
2006	1,415,359	1,464,119				
2007	1,534,506	1,496,342				
2008	1,529,478	1,513,522				
2009	1,426,775	1,458,897				
2010	1,611,212	1,517,821				
2011	1,530,090	1,527,824				
2012	1,465,749	1,477,663				
2013	1,509,915	1,491,767				
2014	1,531,776	1,481,737				
2015	1,448,343	1,455,382				
2016	1,441,268	1,437,332				
2017		1,425,319	1,520,288	1,357,805	1,536,066	1,340,532
2018		1,440,401	1,545,440	1,363,590	1,551,597	1,355,420
2019		1,451,613	1,568,818	1,365,781	1,563,200	1,366,331
2020		1,458,290	1,587,110	1,363,479	1,570,346	1,372,305
2021		1,456,582	1,601,315	1,349,780	1,568,315	1,370,852
2022		1,462,945	1,620,342	1,346,938	1,574,806	1,377,112
2023		1,467,217	1,639,139	1,340,913	1,579,104	1,381,552
2024		1,474,969	1,660,495	1,339,352	1,587,069	1,389,258
2025		1,484,613	1,683,990	1,339,593	1,597,050	1,398,790
2026		1,492,013	1,706,290	1,336,968	1,604,544	1,406,270
2027		1,500,024	1,729,585	1,335,028	1,612,710	1,414,405
2028		1,509,328	1,755,257	1,333,749	1,622,251	1,423,771
2029		1,518,488	1,781,133	1,332,419	1,631,655	1,432,963
2030		1,527,802	1,807,637	1,331,347	1,641,228	1,442,299
2031		1,537,050	1,834,119	1,330,786	1,650,687	1,451,617
2032		1,546,298	1,860,601	1,330,225	1,660,146	1,460,935
2033		1,555,546	1,887,083	1,329,665	1,669,605	1,470,253
2034		1,564,794	1,913,565	1,329,104	1,679,063	1,479,571
2035		1,574,042	1,940,047	1,328,544	1,688,522	1,488,890
2036		1,583,290	1,966,530	1,327,983	1,697,981	1,498,208

ANNUAL GROWTH RATES						
2001-2006	2.6%	#DIV/0!				
2006-2011	1.6%	0.9%				
2011-2016	-1.2%	-1.2%				
2016-2021		0.3%	2.2%	-1.2%	1.8%	-0.9%
2021-2026		0.5%	1.3%	-0.2%	0.5%	0.5%
2026-2031		0.6%	1.5%	-0.1%	0.6%	0.6%
2031-2036		0.6%	1.4%	0.0%	0.6%	0.6%
2016-2036		0.5%	1.6%	-0.4%	0.8%	0.2%

BIG RIVERS ELECTRIC CORPORATION

2017 LONG-TERM LOAD FORECAST - RANGE FORECASTS

SMALL COMMERCIAL ENERGY SALES

Year	Base Case (MWh)	Weather Normalized (MWh)	ECONOMIC SCENARIOS Optimistic (MWh)	ECONOMIC SCENARIOS Pessimistic (MWh)	WEATHER SCENARIOS Extreme (MWh)	WEATHER SCENARIOS Mild (MWh)
2001	528,560					
2002	507,563					
2003	509,312					
2004	521,300					
2005	553,496					
2006	568,398					
2007	608,391					
2008	602,535	599,539				
2009	569,297	579,376				
2010	618,684	593,262				
2011	599,542	597,645				
2012	595,342	594,981				
2013	600,982	596,571				
2014	609,780	597,097				
2015	610,947	613,258				
2016	620,471	617,093				
2017		623,101	659,625	584,660	657,315	588,644
2018		629,211	670,067	584,999	663,746	594,430
2019		633,508	677,861	584,628	668,269	598,499
2020		639,695	688,588	584,762	674,811	604,324
2021		645,779	699,117	584,924	681,246	610,052
2022		651,797	709,504	585,120	687,611	615,716
2023		657,776	719,794	585,354	693,935	621,343
2024		663,726	730,006	585,627	700,230	626,944
2025		669,630	740,112	585,932	706,475	632,500
2026		675,453	750,062	586,259	712,636	637,979
2027		681,217	759,889	586,612	718,736	643,403
2028		686,926	769,601	586,990	724,777	648,773
2029		692,558	779,166	587,386	730,739	654,071
2030		698,122	788,597	587,801	736,628	659,303
2031		703,630	797,916	588,236	742,459	664,483
2032		709,138	807,234	588,670	748,290	669,662
2033		714,646	816,553	589,105	754,121	674,841
2034		720,154	825,871	589,540	759,952	680,021
2035		725,661	835,190	589,974	765,783	685,200
2036		731,169	844,508	590,409	771,614	690,379

ANNUAL GROWTH RATES						
2001-2006	1.5%					
2006-2011	1.1%					
2011-2016	0.7%	0.6%				
2016-2021		0.9%	2.5%	-1.1%	2.0%	-0.2%
2021-2026		0.9%	1.4%	0.0%	0.9%	0.9%
2026-2031		0.8%	1.2%	0.1%	0.8%	0.8%
2031-2036		0.8%	1.1%	0.1%	0.8%	0.8%
2016-2036		0.9%	1.6%	-0.2%	1.1%	0.6%

BIG RIVERS ELECTRIC CORPORATION

2017 LONG-TERM LOAD FORECAST - RANGE FORECASTS

LARGE COMMERCIAL ENERGY SALES

Year	Base Case (MWh)	ECONOMIC SCENARIOS Optimistic (MWh)	ECONOMIC SCENARIOS Pessimistic (MWh)	WEATHER SCENARIOS Extreme (MWh)	WEATHER SCENARIOS Mild (MWh)
2001	1,414,538				
2002	1,238,353				
2003	1,151,279				
2004	1,140,217				
2005	1,123,081				
2006	1,103,512				
2007	1,071,969				
2008	1,080,619				
2009	1,092,667				
2010	1,081,785				
2011	1,128,352				
2012	1,098,999				
2013	1,153,723				
2014	1,121,005				
2015	1,099,899				
2016	1,068,889				
2017	1,106,507	1,184,056	1,028,959	1,106,507	1,106,507
2018	1,179,003	1,260,649	1,097,357	1,179,003	1,179,003
2019	1,261,771	1,347,893	1,175,650	1,261,771	1,261,771
2020	1,298,788	1,386,760	1,210,815	1,298,788	1,298,788
2021	1,299,566	1,387,578	1,211,555	1,299,566	1,299,566
2022	1,299,566	1,387,578	1,211,555	1,299,566	1,299,566
2023	1,299,566	1,387,578	1,211,555	1,299,566	1,299,566
2024	1,303,001	1,391,184	1,214,818	1,303,001	1,303,001
2025	1,299,566	1,387,578	1,211,555	1,299,566	1,299,566
2026	1,299,566	1,387,578	1,211,555	1,299,566	1,299,566
2027	1,299,566	1,387,578	1,211,555	1,299,566	1,299,566
2028	1,303,001	1,391,184	1,214,818	1,303,001	1,303,001
2029	1,299,566	1,387,578	1,211,555	1,299,566	1,299,566
2030	1,299,566	1,387,578	1,211,555	1,299,566	1,299,566
2031	1,299,566	1,387,578	1,211,555	1,299,566	1,299,566
2032	1,303,001	1,391,184	1,214,818	1,303,001	1,303,001
2033	1,299,566	1,387,578	1,211,555	1,299,566	1,299,566
2034	1,299,566	1,387,578	1,211,555	1,299,566	1,299,566
2035	1,299,566	1,387,578	1,211,555	1,299,566	1,299,566
2036	1,303,001	1,391,184	1,214,818	1,303,001	1,303,001

ANNUAL GROWTH RATES					
2001-2006	-4.8%				
2006-2011	0.4%				
2011-2016	-1.1%				
2016-2021		5.4%	2.5%	4.0%	4.0%
2021-2026		0.0%	0.0%	0.0%	0.0%
2026-2031		0.0%	0.0%	0.0%	0.0%
2031-2036		0.1%	0.1%	0.1%	0.1%
2016-2036		1.3%	0.6%	1.0%	1.0%

BIG RIVERS ELECTRIC CORPORATION

2017 LONG-TERM LOAD FORECAST - RANGE FORECASTS

LARGE COMMERCIAL ENERGY SALES - RURAL

Year	Base Case (MWh)	ECONOMIC SCENARIOS Optimistic (MWh)	ECONOMIC SCENARIOS Pessimistic (MWh)	WEATHER SCENARIOS Extreme (MWh)	WEATHER SCENARIOS Mild (MWh)
2001	113,852				
2002	120,089				
2003	128,476				
2004	138,427				
2005	141,995				
2006	139,821				
2007	145,200				
2008	147,038				
2009	124,286				
2010	121,141				
2011	130,264				
2012	135,134				
2013	157,230				
2014	154,967				
2015	153,745				
2016	154,328				
2017	148,154	177,785	118,523	148,154	148,154
2018	151,304	181,565	121,043	151,304	151,304
2019	153,554	184,265	122,843	153,554	153,554
2020	153,554	184,265	122,843	153,554	153,554
2021	153,554	184,265	122,843	153,554	153,554
2022	153,554	184,265	122,843	153,554	153,554
2023	153,554	184,265	122,843	153,554	153,554
2024	153,554	184,265	122,843	153,554	153,554
2025	153,554	184,265	122,843	153,554	153,554
2026	153,554	184,265	122,843	153,554	153,554
2027	153,554	184,265	122,843	153,554	153,554
2028	153,554	184,265	122,843	153,554	153,554
2029	153,554	184,265	122,843	153,554	153,554
2030	153,554	184,265	122,843	153,554	153,554
2031	153,554	184,265	122,843	153,554	153,554
2032	153,554	184,265	122,843	153,554	153,554
2033	153,554	184,265	122,843	153,554	153,554
2034	153,554	184,265	122,843	153,554	153,554
2035	153,554	184,265	122,843	153,554	153,554
2036	153,554	184,265	122,843	153,554	153,554

ANNUAL GROWTH RATES					
2001-2006	4.2%				
2006-2011	-1.4%				
2011-2016	3.4%				
2016-2021		3.6%	-4.5%	-0.1%	-0.1%
2021-2026		0.0%	0.0%	0.0%	0.0%
2026-2031		0.0%	0.0%	0.0%	0.0%
2031-2036		0.0%	0.0%	0.0%	0.0%
2016-2036		0.9%	-1.1%	0.0%	0.0%

BIG RIVERS ELECTRIC CORPORATION

2017 LONG-TERM LOAD FORECAST - RANGE FORECASTS

LARGE COMMERCIAL ENERGY SALES - DIRECT SERVE

Year	Base Case (MWh)	ECONOMIC SCENARIOS Optimistic (MWh)	ECONOMIC SCENARIOS Pessimistic (MWh)	WEATHER SCENARIOS Extreme (MWh)	WEATHER SCENARIOS Mild (MWh)
2001	1,300,686				
2002	1,118,264				
2003	1,022,803				
2004	1,001,791				
2005	981,086				
2006	963,691				
2007	926,769				
2008	933,580				
2009	968,381				
2010	960,644				
2011	998,089				
2012	963,865				
2013	996,493				
2014	966,038				
2015	946,154				
2016	914,562				
2017	958,353	1,006,271	910,435	958,353	958,353
2018	1,027,699	1,079,084	976,314	1,027,699	1,027,699
2019	1,108,217	1,163,628	1,052,806	1,108,217	1,108,217
2020	1,145,234	1,202,495	1,087,972	1,145,234	1,145,234
2021	1,146,012	1,203,313	1,088,711	1,146,012	1,146,012
2022	1,146,012	1,203,313	1,088,711	1,146,012	1,146,012
2023	1,146,012	1,203,313	1,088,711	1,146,012	1,146,012
2024	1,149,447	1,206,919	1,091,975	1,149,447	1,149,447
2025	1,146,012	1,203,313	1,088,711	1,146,012	1,146,012
2026	1,146,012	1,203,313	1,088,711	1,146,012	1,146,012
2027	1,146,012	1,203,313	1,088,711	1,146,012	1,146,012
2028	1,149,447	1,206,919	1,091,975	1,149,447	1,149,447
2029	1,146,012	1,203,313	1,088,711	1,146,012	1,146,012
2030	1,146,012	1,203,313	1,088,711	1,146,012	1,146,012
2031	1,146,012	1,203,313	1,088,711	1,146,012	1,146,012
2032	1,149,447	1,206,919	1,091,975	1,149,447	1,149,447
2033	1,146,012	1,203,313	1,088,711	1,146,012	1,146,012
2034	1,146,012	1,203,313	1,088,711	1,146,012	1,146,012
2035	1,146,012	1,203,313	1,088,711	1,146,012	1,146,012
2036	1,149,447	1,206,919	1,091,975	1,149,447	1,149,447

ANNUAL GROWTH RATES					
2001-2006	-5.8%				
2006-2011	0.7%				
2011-2016	-1.7%				
2016-2021		5.6%	3.5%	4.6%	4.6%
2021-2026		0.0%	0.0%	0.0%	0.0%
2026-2031		0.0%	0.0%	0.0%	0.0%
2031-2036		0.1%	0.1%	0.1%	0.1%
2016-2036		1.4%	0.9%	1.1%	1.1%

BIG RIVERS ELECTRIC CORPORATION

2017 LONG-TERM LOAD FORECAST - RANGE FORECASTS

STREET LIGHTING ENERGY SALES

Year	Base Case (MWh)	ECONOMIC SCENARIOS Optimistic (MWh)	Pessimistic (MWh)	WEATHER SCENARIOS Extreme (MWh)	Mild (MWh)
2001	3,104				
2002	3,277				
2003	3,235				
2004	2,997				
2005	3,077				
2006	3,104				
2007	3,175				
2008	3,287				
2009	3,246				
2010	3,438				
2011	3,409				
2012	3,454				
2013	3,486				
2014	3,461				
2015	3,429				
2016	3,291				
2017	3,396	3,566	3,226	3,396	3,396
2018	3,399	3,569	3,229	3,399	3,399
2019	3,402	3,572	3,232	3,402	3,402
2020	3,405	3,576	3,235	3,405	3,405
2021	3,408	3,579	3,238	3,408	3,408
2022	3,411	3,582	3,241	3,411	3,411
2023	3,414	3,585	3,244	3,414	3,414
2024	3,417	3,588	3,246	3,417	3,417
2025	3,420	3,591	3,249	3,420	3,420
2026	3,423	3,595	3,252	3,423	3,423
2027	3,426	3,598	3,255	3,426	3,426
2028	3,429	3,601	3,258	3,429	3,429
2029	3,432	3,604	3,261	3,432	3,432
2030	3,435	3,607	3,264	3,435	3,435
2031	3,438	3,610	3,267	3,438	3,438
2032	3,441	3,614	3,269	3,441	3,441
2033	3,445	3,617	3,272	3,445	3,445
2034	3,448	3,620	3,275	3,448	3,448
2035	3,451	3,623	3,278	3,451	3,451
2036	3,454	3,626	3,281	3,454	3,454

ANNUAL GROWTH RATES					
2001-2006	0.0%				
2006-2011	1.9%				
2011-2016	-0.7%				
2016-2021		1.7%	-0.3%	0.7%	0.7%
2021-2026		0.1%	0.1%	0.1%	0.1%
2026-2031		0.1%	0.1%	0.1%	0.1%
2031-2036		0.1%	0.1%	0.1%	0.1%
2016-2036		0.5%	0.0%	0.2%	0.2%

BIG RIVERS ELECTRIC CORPORATION

2017 LONG-TERM LOAD FORECAST - RANGE FORECASTS

IRRIGATION ENERGY SALES

Year	Base Case (MWh)	ECONOMIC SCENARIOS Optimistic (MWh)	ECONOMIC SCENARIOS Pessimistic (MWh)	WEATHER SCENARIOS Extreme (MWh)	WEATHER SCENARIOS Mild (MWh)
2001	75				
2002	38				
2003	113				
2004	164				
2005	114				
2006	65				
2007	1,068				
2008	432				
2009	406				
2010	356				
2011	269				
2012	440				
2013	48				
2014	136				
2015	62				
2016	47				
2017	194	233	155	369	19
2018	194	233	155	369	19
2019	194	233	155	369	19
2020	194	233	155	369	19
2021	194	233	155	369	19
2022	194	233	155	369	19
2023	194	233	155	369	19
2024	194	233	155	369	19
2025	194	233	155	369	19
2026	194	233	155	369	19
2027	194	233	155	369	19
2028	194	233	155	369	19
2029	194	233	155	369	19
2030	194	233	155	369	19
2031	194	233	155	369	19
2032	194	233	155	369	19
2033	194	233	155	369	19
2034	194	233	155	369	19
2035	194	233	155	369	19
2036	194	233	155	369	19

ANNUAL GROWTH RATES					
2001-2006	-2.8%				
2006-2011	33.0%				
2011-2016	-29.5%				
2016-2021		37.8%	27.1%	51.0%	-16.2%
2021-2026		0.0%	0.0%	0.0%	0.0%
2026-2031		0.0%	0.0%	0.0%	0.0%
2031-2036		0.0%	0.0%	0.0%	0.0%
2016-2036		8.3%	6.2%	10.9%	-4.3%

Appendix C – Forecast Model Specifications

Meade County Rural Electric Cooperative Corporation
Residential Customers
Short Term Model

Variable	Coefficient	StdErr	T-Stat	P-Value	Definition
CONST	20096.627	120.785	166.384	0.00%	Constant term
ModelData.Trend1	16.580	0.329	50.394	0.00%	
MonthlyModel.Reclass	-116.498	20.642	-5.644	0.00%	

Model Statistics	
Iterations	1
Adjusted Observations	108
Deg. of Freedom for Error	105
R-Squared	0.987
Adjusted R-Squared	0.987
AIC	8.015
BIC	8.090
F-Statistic	4,015.95
Prob (F-Statistic)	0.0000
Log-Likelihood	-583.07
Model Sum of Squares	23,654,310.92
Sum of Squared Errors	309,229.99
Mean Squared Error	2,945.05
Std. Error of Regression	54.27
Mean Abs. Dev. (MAD)	42.87
Mean Abs. % Err. (MAPE)	0.16%
Durbin-Watson Statistic	0.475
Durbin-H Statistic	#NA
Ljung-Box Statistic	217.82
Prob (Ljung-Box)	0.0000
Skewness	0.061
Kurtosis	2.857
Jarque-Bera	0.159
Prob (Jarque-Bera)	0.9238

Meade County Rural Electric Cooperative Corporation
Residential Customers
Long Term Model

Variable	Coefficient	StdErr	T-Stat	P-Value	Definition
CONST	(18,704.84)	1,068.32	(17.51)	0.00%	Constant term
ModelData.HH	497.075	28.558	17.406	0.00%	
ModelData.HHMKT	29596.733	1668.699	17.736	0.00%	
Res_Con_LT.LagDep(1)	0.214	0.044	4.878	0.00%	
MonthlyModel.Reclass	-154.766	12.672	-12.213	0.00%	
AR(1)	0.492	0.068770678	7.15608	0.00%	

Model Statistics	
Iterations	24
Adjusted Observations	203
Deg. of Freedom for Error	197
R-Squared	1.000
Adjusted R-Squared	1.000
AIC	6.364
BIC	6.461
F-Statistic	163,170.30
Prob (F-Statistic)	0.0000
Log-Likelihood	-927.94
Model Sum of Squares	459,849,526.18
Sum of Squared Errors	111,037.80
Mean Squared Error	563.64
Std. Error of Regression	23.74
Mean Abs. Dev. (MAD)	13.84
Mean Abs. % Err. (MAPE)	0.05%
Durbin-Watson Statistic	2.178
Durbin-H Statistic	-1.627951333
Ljung-Box Statistic	77.29
Prob (Ljung-Box)	0.0000
Skewness	-0.553
Kurtosis	9.019
Jarque-Bera	316.819
Prob (Jarque-Bera)	0.0000

Meade County Rural Electric Cooperative Corporation
Small Commercial Customers
Short Term Model

Variable	Coefficient	StdErr	T-Stat	P-Value	Definition
CONST	1488.587	20.102	74.050	0.00%	Constant term
ModelData.Trend1	1.570	0.060	25.983	0.00%	

Model Statistics	
Iterations	1
Adjusted Observations	132
Deg. of Freedom for Error	130
R-Squared	0.839
Adjusted R-Squared	0.837
AIC	6.566
BIC	6.609
F-Statistic	675.10
Prob (F-Statistic)	0.0000
Log-Likelihood	-618.64
Model Sum of Squares	472,387.55
Sum of Squared Errors	90,965.26
Mean Squared Error	699.73
Std. Error of Regression	26.45
Mean Abs. Dev. (MAD)	18.13
Mean Abs. % Err. (MAPE)	0.91%
Durbin-Watson Statistic	0.363
Durbin-H Statistic	#NA
Ljung-Box Statistic	311.07
Prob (Ljung-Box)	0.0000
Skewness	-1.950
Kurtosis	12.029
Jarque-Bera	531.964
Prob (Jarque-Bera)	0.0000

Meade County Rural Electric Cooperative Corporation
Small Commercial Customers
Long Term Model

Variable	Coefficient	StdErr	T-Stat	P-Value	Definition
CONST	1,220.11	874.32	1.395	16.48%	Constant term
ModelData.Emp	48.736	50.386	0.967	33.48%	
MonthlyModel.Reclass	-6.172	15.81971489	-0.390	69.70%	
AR(1)	0.942	0.0266677	35.311	0.00%	

Model Statistics	
Iterations	15
Adjusted Observations	167
Deg. of Freedom for Error	163
R-Squared	0.929
Adjusted R-Squared	0.928
AIC	5.550
BIC	5.625
F-Statistic	715.73
Prob (F-Statistic)	0.0000
Log-Likelihood	-696.39
Model Sum of Squares	539,468.05
Sum of Squared Errors	40,952.56
Mean Squared Error	251.24
Std. Error of Regression	15.85
Mean Abs. Dev. (MAD)	9.15
Mean Abs. % Err. (MAPE)	0.44%
Durbin-Watson Statistic	2.619
Durbin-H Statistic	#NA
Ljung-Box Statistic	59.82
Prob (Ljung-Box)	0.0001
Skewness	1.033
Kurtosis	20.515
Jarque-Bera	2164.411
Prob (Jarque-Bera)	0.0000

Meade County Rural Electric Cooperative Corporation
Residential kWh Use per Customer per Month

Variable	Coefficient	StdErr	T-Stat	P-Value	Definition
ModelData.BASE	193.67	8.06	24.017	0.00%	
ModelData.COOL	122.184	22.223	5.498	0.00%	
ModelData.HEAT	292.295	16.926	17.269	0.00%	
Binary.January	130.654	37.186	3.514	0.06%	
Binary.February	173.649	34.020	5.104	0.00%	
Binary.June	98.620	47.701	2.067	4.01%	
Binary.July	162.584	57.651	2.820	0.53%	
Binary.August	176.953	57.295	3.088	0.23%	
Binary.September	179.170	37.507	4.777	0.00%	
Binary.October	-72.321	31.059	-2.329	2.10%	

Model Statistics	
Iterations	1
Adjusted Observations	192
Deg. of Freedom for Error	182
R-Squared	0.848
Adjusted R-Squared	0.841
AIC	9.403
BIC	9.572
F-Statistic	#NA
Prob (F-Statistic)	#NA
Log-Likelihood	-1,165.08
Model Sum of Squares	11,725,335.21
Sum of Squared Errors	2,096,763.72
Mean Squared Error	11,520.68
Std. Error of Regression	107.33
Mean Abs. Dev. (MAD)	78.11
Mean Abs. % Err. (MAPE)	7.13%
Durbin-Watson Statistic	1.835
Durbin-H Statistic	#NA
Ljung-Box Statistic	194.01
Prob (Ljung-Box)	0.0000
Skewness	-0.176
Kurtosis	4.016
Jarque-Bera	9.247
Prob (Jarque-Bera)	0.0098

Meade County Rural Electric Cooperative Corporation
Small Commercial kWh Use per Customer per Month

Variable	Coefficient	StdErr	T-Stat	P-Value	Definition
CONST	3,722.05	165.70	22.463	0.00%	Constant term
MonthlyModel.WTHDDSC	0.170	0.175	0.971	33.28%	
MonthlyModel.WTCDDSC	1.391	0.342	4.072	0.01%	
Binary.February	65.192	66.178	0.985	32.59%	
Binary.March	-235.537	99.218	-2.374	1.87%	
Binary.April	-178.607	141.458	-1.263	20.84%	
Binary.May	-261.891	165.445	-1.583	11.52%	
Binary.June	-95.662	194.721	-0.491	62.39%	
Binary.July	9.199	211.442	0.044	96.53%	
Binary.August	262.544	210.763	1.246	21.45%	
Binary.September	379.352	177.302	2.140	3.38%	
Binary.October	-35.160	141.509	-0.248	80.41%	
Binary.November	-120.928	104.584	-1.156	24.91%	
Binary.December	-135.058	66.739	-2.024	4.45%	
MonthlyModel.Reclass	-680.000	54.223	-12.541	0.00%	
AR(1)	0.379	0.068	5.562	0.00%	

Model Statistics	
Iterations	13
Adjusted Observations	191
Deg. of Freedom for Error	175
R-Squared	0.850
Adjusted R-Squared	0.837
AIC	10.713
BIC	10.986
F-Statistic	66.07
Prob (F-Statistic)	0.0000
Log-Likelihood	-1,278.12
Model Sum of Squares	41,109,355.60
Sum of Squared Errors	7,259,542.96
Mean Squared Error	41,483.10
Std. Error of Regression	203.67
Mean Abs. Dev. (MAD)	152.12
Mean Abs. % Err. (MAPE)	4.03%
Durbin-Watson Statistic	2.165
Durbin-H Statistic	#NA
Ljung-Box Statistic	43.12
Prob (Ljung-Box)	0.0096
Skewness	0.011
Kurtosis	3.082
Jarque-Bera	0.057

Meade County Rural Electric Cooperative Corporation
Rural System Peak Demand

Variable	Coefficient	StdErr	T-Stat	P-Value	Definition
CONST	(52,430.92)	8,599.42	-6.097	0.00%	Constant term
ModelData.EGY_TREND	2.318	0.213	10.865	0.00%	
MonthlyModel.PeakHDD	1540.482	73.325	21.009	0.00%	
MonthlyModel.PeakCDD	1191.914	179.462	6.642	0.00%	
MonthlyModel.Jan2014	14003.596	5381.763	2.602	1.00%	
Binary.February	-291.812	1512.806	-0.193	84.73%	
Binary.March	-867.947	1734.179	-0.500	61.73%	
Binary.April	-414.553	2222.643	-0.187	85.22%	
Binary.May	17607.307	4193.073	4.199	0.00%	
Binary.June	27529.026	4782.243	5.757	0.00%	
Binary.July	29672.571	4952.104	5.992	0.00%	
Binary.August	30057.802	5022.914	5.984	0.00%	
Binary.September	25081.763	4591.890	5.462	0.00%	
Binary.October	19006.440	3582.188	5.306	0.00%	
MonthlyModel.Apr2012	-20260.014	5397.031	-3.754	0.02%	
MonthlyModel.April2015	-20069.099	5425.725	-3.699	0.03%	
MonthlyModel.Oct2015	-14116.115	5379.075	-2.624	0.94%	
MonthlyModel.April2016	-14352.885	5406.643	-2.655	0.86%	
AR(1)	0.337	0.070	4.835	0.00%	

Model Statistics	
Iterations	10
Adjusted Observations	203
Deg. of Freedom for Error	184
R-Squared	0.913
Adjusted R-Squared	0.905
AIC	17.315
BIC	17.625
F-Statistic	107.58
Prob (F-Statistic)	0.0000
Log-Likelihood	-2,026.51
Model Sum of Squares	58,635,797,743
Sum of Squared Errors	5,571,317,139.57
Mean Squared Error	30,278,897.50
Std. Error of Regression	5,502.63
Mean Abs. Dev. (MAD)	4,292.51
Mean Abs. % Err. (MAPE)	5.23%
Durbin-Watson Statistic	2.074
Durbin-H Statistic	#NA
Ljung-Box Statistic	81.85
Prob (Ljung-Box)	0.0000
Skewness	0.001

Jackson Purchase Energy Corporation
Residential Customers
Short Term Model

Variable	Coefficient	StdErr	T-Stat	P-Value	Units
CONST	12980.506	4114.159	3.155	0.50%	0
ModelData.Trend1	28.227	9.295	3.037	0.65%	0
AR(1)	0.823	0.052	15.984	0.00%	0

Model Statistics	
Iterations	12
Adjusted Observations	23
Deg. of Freedom for Error	20
R-Squared	0.935
Adjusted R-Squared	0.928
AIC	6.683
BIC	6.831
F-Statistic	142.97
Prob (F-Statistic)	0.0000
Log-Likelihood	-106.49
Model Sum of Squares	202,406.76
Sum of Squared Errors	14,157.15
Mean Squared Error	707.86
Std. Error of Regression	26.61
Mean Abs. Dev. (MAD)	18.43
Mean Abs. % Err. (MAPE)	0.07%
Durbin-Watson Statistic	1.991
Durbin-H Statistic	#NA
Ljung-Box Statistic	20.49
Prob (Ljung-Box)	0.6687
Skewness	-0.063
Kurtosis	3.507
Jarque-Bera	0.261
Prob (Jarque-Bera)	0.8774

Jackson Purchase Energy Corporation
Residential Customers
Long Term Model

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	(22,108.99)	333.3	-66.337	0.00%
ModelData.HH	567.475	6.956	81.583	0.00%
ModelData.HHMKT	39052.548	154.8587681	252.1817037	0.00%
AR(1)	0.992	0.002085672	475.8123156	0.00%

Model Statistics	
Iterations	32
Adjusted Observations	443
Deg. of Freedom for Error	439
R-Squared	1.000
Adjusted R-Squared	1.000
AIC	2.113
BIC	2.150
F-Statistic	200,166,451.95
Prob (F-Statistic)	0.0000
Log-Likelihood	-1,092.71
Model Sum of Squares	4,925,467,709.67
Sum of Squared Errors	3,600.80
Mean Squared Error	8.20
Std. Error of Regression	2.86
Mean Abs. Dev. (MAD)	2.10
Mean Abs. % Err. (MAPE)	0.01%
Durbin-Watson Statistic	1.460
Durbin-H Statistic	#NA
Ljung-Box Statistic	368.97
Prob (Ljung-Box)	0.0000
Skewness	0.093
Kurtosis	S.112
Jarque-Bera	83.006
Prob (Jarque-Bera)	0.0000

Jackson Purchase Energy Corporation
Small Commercial Customers
Short Term Model

Variable	Coefficient	StdErr	T-Stat	P-Value	Units
CONST	510.451	27.287	18.707	0.00%	Constant term
ModelData.Trend1	7.208	0.082	88.381	0.00%	

Model Statistics	
Iterations	1
Adjusted Observations	180
Deg. of Freedom for Error	178
R-Squared	0.978
Adjusted R-Squared	0.978
AIC	8.092
BIC	8.128
F-Statistic	7,811.25
Prob (F-Statistic)	0.0000
Log-Likelihood	-981.70
Model Sum of Squares	25,252,421.65
Sum of Squared Errors	575,443.35
Mean Squared Error	3,232.83
Std. Error of Regression	56.86
Mean Abs. Dev. (MAD)	43.49
Mean Abs. % Err. (MAPE)	1.45%
Durbin-Watson Statistic	0.101
Durbin-H Statistic	#NA
Ljung-Box Statistic	1136.22
Prob (Ljung-Box)	0.0000
Skewness	-0.322
Kurtosis	3.518
Jarque-Bera	5.126
Prob (Jarque-Bera)	0.0771

Jackson Purchase Energy Corporation
Small Commercial Customers
Long Term Model

Variable	Coefficient	StdErr	T-Stat	P-Value	Definition
CONST	(2,471.32)	124.03	-19.924	0.00%	Constant term
ModelData.Emp	142.670	3.796	37.580	0.00%	

Model Statistics	
Iterations	1
Adjusted Observations	408
Deg. of Freedom for Error	406
R-Squared	0.777
Adjusted R-Squared	0.776
AIC	11.505
BIC	11.525
F-Statistic	1,412.24
Prob (F-Statistic)	0.0000
Log-Likelihood	-2,923.92
Model Sum of Squares	139,406,946.26
Sum of Squared Errors	40,077,692.08
Mean Squared Error	98,713.53
Std. Error of Regression	314.19
Mean Abs. Dev. (MAD)	247.43
Mean Abs. % Err. (MAPE)	11.12%
Durbin-Watson Statistic	0.003
Durbin-H Statistic	#NA
Ljung-Box Statistic	7171.07
Prob (Ljung-Box)	0.0000
Skewness	0.579
Kurtosis	3.079
Jarque-Bera	22.880
Prob (Jarque-Bera)	0.0000

Jackson Purchase Energy Corporation
Residential kWh Use per Customer per Month

Variable	Coefficient	StdErr	T-Stat	P-Value	Definition
ModelData.BASE	178.42	6.93	25.758	0.00%	0
ModelData.COOL	291.952	22.269	13.110	0.00%	
ModelData.HEAT	373.701	12.616	29.621	0.00%	
Binary.February	-92.561	30.712	-3.014	0.29%	
Binary.June	139.901	50.487	2.771	0.61%	
Binary.July	187.173	60.951	3.071	0.24%	
Binary.August	145.219	58.752	2.472	1.43%	
Binary.September	131.195	36.240	3.620	0.04%	

Model Statistics	
Iterations	1
Adjusted Observations	204
Deg. of Freedom for Error	196
R-Squared	0.876
Adjusted R-Squared	0.872
AIC	9.471
BIC	9.601
F-Statistic	#NA
Prob (F-Statistic)	#NA
Log-Likelihood	-1,247.50
Model Sum of Squares	17,311,898.50
Sum of Squared Errors	2,447,618.66
Mean Squared Error	12,487.85
Std. Error of Regression	111.75
Mean Abs. Dev. (MAD)	84.50
Mean Abs. % Err. (MAPE)	6.96%
Durbin-Watson Statistic	2.397
Durbin-H Statistic	#NA
Ljung-Box Statistic	68.82
Prob (Ljung-Box)	0.0000
Skewness	0.133
Kurtosis	3.542
Jarque-Bera	3.106
Prob (Jarque-Bera)	0.2116

Jackson Purchase Energy Corporation
Small Commercial kWh Use per Customer per Month

Variable	Coefficient	StdErr	T-Stat	P-Value	Definition
CONST	3,344.21	326.43	10.245	0.00%	Constant term
MonthlyModel.WTHDD5C	2.136	0.372	5.739	0.00%	
MonthlyModel.WTCDD5C	4.659	0.729	6.390	0.00%	
Binary.February	-298.127	150.595	-1.980	4.99%	
Binary.March	112.844	201.335	0.560	57.61%	
Binary.April	252.836	276.470	0.915	36.21%	
Binary.May	542.724	327.301	1.658	9.97%	
Binary.June	402.109	397.024	1.013	31.30%	
Binary.July	438.646	420.384	1.043	29.87%	
Binary.August	523.352	416.671	1.256	21.14%	
Binary.September	683.077	348.038	1.963	5.18%	
Binary.October	457.900	273.738	1.673	9.68%	
Binary.November	-47.660	197.099	-0.242	80.93%	
Binary.December	-106.139	149.225	-0.711	47.82%	

Model Statistics	
Iterations	1
Adjusted Observations	144
Deg. of Freedom for Error	130
R-Squared	0.712
Adjusted R-Squared	0.683
AIC	11.835
BIC	12.123
F-Statistic	24.67
Prob (F-Statistic)	-0.0000
Log-Likelihood	-1,042.43
Model Sum of Squares	40,353,543.52
Sum of Squared Errors	16,356,221.91
Mean Squared Error	125,817.09
Std. Error of Regression	354.71
Mean Abs. Dev. (MAD)	266.26
Mean Abs. % Err. (MAPE)	5.67%
Durbin-Watson Statistic	0.863
Durbin-H Statistic	#NA
Ljung-Box Statistic	589.58
Prob (Ljung-Box)	0.0000
Skewness	-0.464
Kurtosis	3.112
Jarque-Bera	5.250
Prob (Jarque-Bera)	0.0724

Jackson Purchase Energy Corporation
Rural System Peak Demand

Variable	Coefficient	StdErr	T-Stat	P-Value	Definition
CONST	(42,759.25)	6,901.85	-6.195	0.00%	Constant term
ModelData.EGY_TREND	2.088	0.088	23.664	0.00%	
MonthlyModel.PeakHDD	1173.562	98.210	11.950	0.00%	
MonthlyModel.PeakCDD	1756.261	185.307	9.478	0.00%	
Binary.February	-4135.168	2147.075	-1.926	5.52%	
Binary.March	-7223.565	2373.839	-3.043	0.26%	
Binary.April	-8791.016	3105.871	-2.830	0.50%	
Binary.May	15889.099	5757.949	2.760	0.62%	
Binary.June	30223.632	6321.201	4.781	0.00%	
Binary.July	35211.743	6515.176	5.405	0.00%	
Binary.August	34745.128	6499.044	5.346	0.00%	
Binary.September	24148.166	6126.712	3.941	0.01%	
Binary.October	3443.136	5493.881	0.627	53.14%	
Binary.November	-8972.253	2490.720	-3.602	0.04%	
Binary.December	-4007.046	2146.547	-1.867	6.31%	

Model Statistics	
Iterations	1
Adjusted Observations	264
Deg. of Freedom for Error	249
R-Squared	0.906
Adjusted R-Squared	0.901
AIC	17.770
BIC	17.973
F-Statistic	171.49
Prob (F-Statistic)	0.0000
Log-Likelihood	-2,705.26
Model Sum of Squares	118,553,140,497
Sum of Squared Errors	12,295,244,360.61
Mean Squared Error	49,378,491.41
Std. Error of Regression	7,026.98
Mean Abs. Dev. (MAD)	5,284.21
Mean Abs. % Err. (MAPE)	4.83%
Durbin-Watson Statistic	1.413
Durbin-H Statistic	#NA
Ljung-Box Statistic	113.92
Prob (Ljung-Box)	0.0000
Skewness	-0.116
Kurtosis	3.724
Jarque-Bera	6.366
Prob (Jarque-Bera)	0.0415

Kenergy Corporation
Residential Customers
Short Term Model

Variable	Coefficient	StdErr	T-Stat	P-Value	Definition
CONST	31097.015	26938.702	1.154	25.18%	Constant term
ModelData.Trend1	32.209	52.062	0.619	53.79%	
AR(1)	0.984	0.033	29.479	0.00%	

Model Statistics	
Iterations	14
Adjusted Observations	83
Deg. of Freedom for Error	80
R-Squared	0.972
Adjusted R-Squared	0.971
AIC	7.514
BIC	7.602
F-Statistic	1,363.88
Prob (F-Statistic)	0.0000
Log-Likelihood	-426.62
Model Sum of Squares	4,828,972.95
Sum of Squared Errors	141,624.52
Mean Squared Error	1,770.31
Std. Error of Regression	42.08
Mean Abs. Dev. (MAD)	33.17
Mean Abs. % Err. (MAPE)	0.07%
Durbin-Watson Statistic	1.588
Durbin-H Statistic	#NA
Ljung-Box Statistic	26.29
Prob (Ljung-Box)	0.3385
Skewness	-0.722
Kurtosis	3.559
Jarque-Bera	8.282
Prob (Jarque-Bera)	0.0159

Kenergy Corporation
Residential Customers
Long Term Model

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	(44,764.13)	401.1	-111.615	0.00%
ModelData.HH	388.528	3.280	118.466	0.00%
ModelData.HHMKT	115135.559	135.993	846.62858	0.00%
AR(1)	0.987	0.002	606.37837	0.00%

Model Statistics	
Iterations	18
Adjusted Observations	323
Deg. of Freedom for Error	319
R-Squared	1.000
Adjusted R-Squared	1.000
AIC	1.817
BIC	1.864
F-Statistic	145,058,819.33
Prob (F-Statistic)	0.0000
Log-Likelihood	-747.84
Model Sum of Squares	2,646,323,086.89
Sum of Squared Errors	1,939.85
Mean Squared Error	6.08
Std. Error of Regression	2.47
Mean Abs. Dev. (MAD)	1.54
Mean Abs. % Err. (MAPE)	0.00%
Durbin-Watson Statistic	1.573
Durbin-H Statistic	#NA
Ljung-Box Statistic	221.69
Prob (Ljung-Box)	0.0000
Skewness	-0.037
Kurtosis	8.830
Jarque-Bera	457.507
Prob (Jarque-Bera)	0.0000

Kenergy Corporation
Small Commercial Customers
Short Term Model

Variable	Coefficient	StdErr	T-Stat	P-Value	Definition
CONST	4615.117	113.762	40.568	0.00%	Constant term
ModelData.Trend1	14.080	0.290	48.484	0.00%	

Model Statistics	
Iterations	1
Adjusted Observations	108
Deg. of Freedom for Error	106
R-Squared	0.957
Adjusted R-Squared	0.956
AIC	9.107
BIC	9.156
F-Statistic	2,350.70
Prob (F-Statistic)	0.0000
Log-Likelihood	-643.01
Model Sum of Squares	20,808,657.98
Sum of Squared Errors	938,323.24
Mean Squared Error	8,852.11
Std. Error of Regression	94.09
Mean Abs. Dev. (MAD)	78.87
Mean Abs. % Err. (MAPE)	0.79%
Durbin-Watson Statistic	0.065
Durbin-H Statistic	#NA
Ljung-Box Statistic	591.37
Prob (Ljung-Box)	0.0000
Skewness	0.124
Kurtosis	2.094
Jarque-Bera	3.969
Prob (Jarque-Bera)	0.1374

Kenergy Corporation
Small Commercial Customers
Long Term Model

Variable	Coefficient	StdErr	T-Stat	P-Value	Definition
CONST	458,246.18	78,854,842.68	0.006	99.54%	Constant term
ModelData.Emp	40.666	27.270	1.491	13.84%	
AR(1)	1.000	0.004	226.853	0.00%	

Model Statistics	
Iterations	99
Adjusted Observations	131
Deg. of Freedom for Error	128
R-Squared	0.998
Adjusted R-Squared	0.998
AIC	6.213
BIC	6.279
F-Statistic	32,020.00
Prob (F-Statistic)	0.0000
Log-Likelihood	-589.85
Model Sum of Squares	31,259,716.76
Sum of Squared Errors	62,480.39
Mean Squared Error	488.13
Std. Error of Regression	22.09
Mean Abs. Dev. (MAD)	14.72
Mean Abs. % Err. (MAPE)	0.15%
Durbin-Watson Statistic	1.449
Durbin-H Statistic	#NA
Ljung-Box Statistic	42.63
Prob (Ljung-Box)	0.0110
Skewness	2.108
Kurtosis	10.928
Jarque-Bera	440.101
Prob (Jarque-Bera)	0.0000

Kenergy Corporation
Residential kWh Use per Customer per Month

Variable	Coefficient	StdErr	T-Stat	P-Value	Definition
ModelData.BASE	245.06	4.12	59.435	0.00%	
ModelData.COOL	207.315	7.109	29.162	0.00%	
ModelData.HEAT	304.960	8.538	35.718	0.00%	
Binary.January	54.563	16.403	3.326	0.11%	
Binary.February	82.103	15.791	5.199	0.00%	
Binary.July	99.199	17.389	5.705	0.00%	
Binary.August	190.221	19.862	9.577	0.00%	
Binary.September	176.242	15.099	11.673	0.00%	
Binary.November	-143.803	12.688	-11.334	0.00%	
MonthlyModel.Jan2001	-204.209	56.158	-3.636	0.04%	
MonthlyModel.Feb2001	-154.002	55.812	-2.759	0.64%	
MonthlyModel.Jan2014	231.828	51.029	4.543	0.00%	
MonthlyModel.Dec2016	-162.005	55.767	-2.905	0.41%	
AR(1)	0.456	0.066	6.880	0.00%	

Model Statistics	
Iterations	17
Adjusted Observations	192
Deg. of Freedom for Error	178
R-Squared	0.959
Adjusted R-Squared	0.956
AIC	8.060
BIC	8.298
F-Statistic	#NA
Prob (F-Statistic)	#NA
Log-Likelihood	-1,032.21
Model Sum of Squares	12,174,968.69
Sum of Squared Errors	525,319.58
Mean Squared Error	2,951.23
Std. Error of Regression	54.33
Mean Abs. Dev. (MAD)	39.89
Mean Abs. % Err. (MAPE)	2.97%
Durbin-Watson Statistic	1.984
Durbin-H Statistic	#NA
Ljung-Box Statistic	48.80
Prob (Ljung-Box)	0.0020
Skewness	-0.137
Kurtosis	3.911
Jarque-Bera	7.250
Prob (Jarque-Bera)	0.0267

Kenergy Corporation
Small Commercial kWh Use per Customer per Month

Variable	Coefficient	StdErr	T-Stat	P-Value	Definition
CONST	1,473.92	132.99	11.083	0.00%	Constant term
MonthlyModel.WTHDD5C	1.602	0.134	11.955	0.00%	
MonthlyModel.WTCDD5C	3.319	0.262	12.672	0.00%	
Binary.February	-347.263	47.550	-7.303	0.00%	
Binary.March	-128.466	78.218	-1.642	10.32%	
Binary.April	-57.052	109.027	-0.523	60.18%	
Binary.May	394.407	128.091	3.079	0.26%	
Binary.June	684.031	149.558	4.574	0.00%	
Binary.July	573.608	157.480	3.642	0.04%	
Binary.August	398.282	156.287	2.548	1.21%	
Binary.September	365.359	135.907	2.688	0.82%	
Binary.October	411.415	109.456	3.759	0.03%	
Binary.November	536.285	77.376	6.931	0.00%	
Binary.December	485.557	50.749	9.568	0.00%	
MonthlyModel.Reclass2013	-86.453	37.242	-2.321	2.20%	
AR(1)	0.376	0.088	4.250	0.00%	

Model Statistics	
Iterations	14
Adjusted Observations	131
Deg. of Freedom for Error	115
R-Squared	0.948
Adjusted R-Squared	0.942
AIC	9.704
BIC	10.055
F-Statistic	140.67
Prob (F-Statistic)	0.0000
Log-Likelihood	-805.47
Model Sum of Squares	30,831,793.81
Sum of Squared Errors	1,680,348.67
Mean Squared Error	14,611.73
Std. Error of Regression	120.88
Mean Abs. Dev. (MAD)	84.55
Mean Abs. % Err. (MAPE)	3.26%
Durbin-Watson Statistic	1.946
Durbin-H Statistic	#NA
Ljung-Box Statistic	16.77
Prob (Ljung-Box)	0.8585
Skewness	-1.002
Kurtosis	6.746
Jarque-Bera	98.504

Kenergy Corporation
Rural System Peak Demand

Variable	Coefficient	StdErr	T-Stat	P-Value	Definition
CONST	(45,105.57)	19,632.54	-2.297	2.27%	Constant term
ModelData.EGY_TREND	2.212	0.201	11.026	0.00%	
MonthlyModel.PeakHDD	2233.825	188.934	11.823	0.00%	
MonthlyModel.PeakCDD	3580.481	339.508	10.546	0.00%	
MonthlyModel.Oct2010	-45135.009	12676.305	-3.561	0.05%	
Binary.January	-39885.877	12019.490	-3.318	0.11%	
Binary.February	-45954.011	11412.511	-4.027	0.01%	
Binary.March	-53489.422	10103.766	-5.294	0.00%	
Binary.April	-65816.559	8794.652	-7.484	0.00%	
Binary.May	-26609.165	3929.027	-6.772	0.00%	
Binary.October	-36912.286	4755.722	-7.762	0.00%	
Binary.November	-59692.691	9747.423	-6.124	0.00%	
Binary.December	-49701.680	11277.877	-4.407	0.00%	

Model Statistics	
Iterations	1
Adjusted Observations	193
Deg. of Freedom for Error	180
R-Squared	0.897
Adjusted R-Squared	0.890
AIC	18.871
BIC	19.091
F-Statistic	130.17
Prob (F-Statistic)	0.0000
Log-Likelihood	-2,081.89
Model Sum of Squares	229,594,556,794
Sum of Squared Errors	26,456,719,441.28
Mean Squared Error	146,981,774.67
Std. Error of Regression	12,123.60
Mean Abs. Dev. (MAD)	9,154.35
Mean Abs. % Err. (MAPE)	4.34%
Durbin-Watson Statistic	1.663
Durbin-H Statistic	#NA
Ljung-Box Statistic	54.05
Prob (Ljung-Box)	0.0004
Skewness	-0.063
Kurtosis	3.329
Jarque-Bera	1.000
Prob (Jarque-Bera)	0.6066

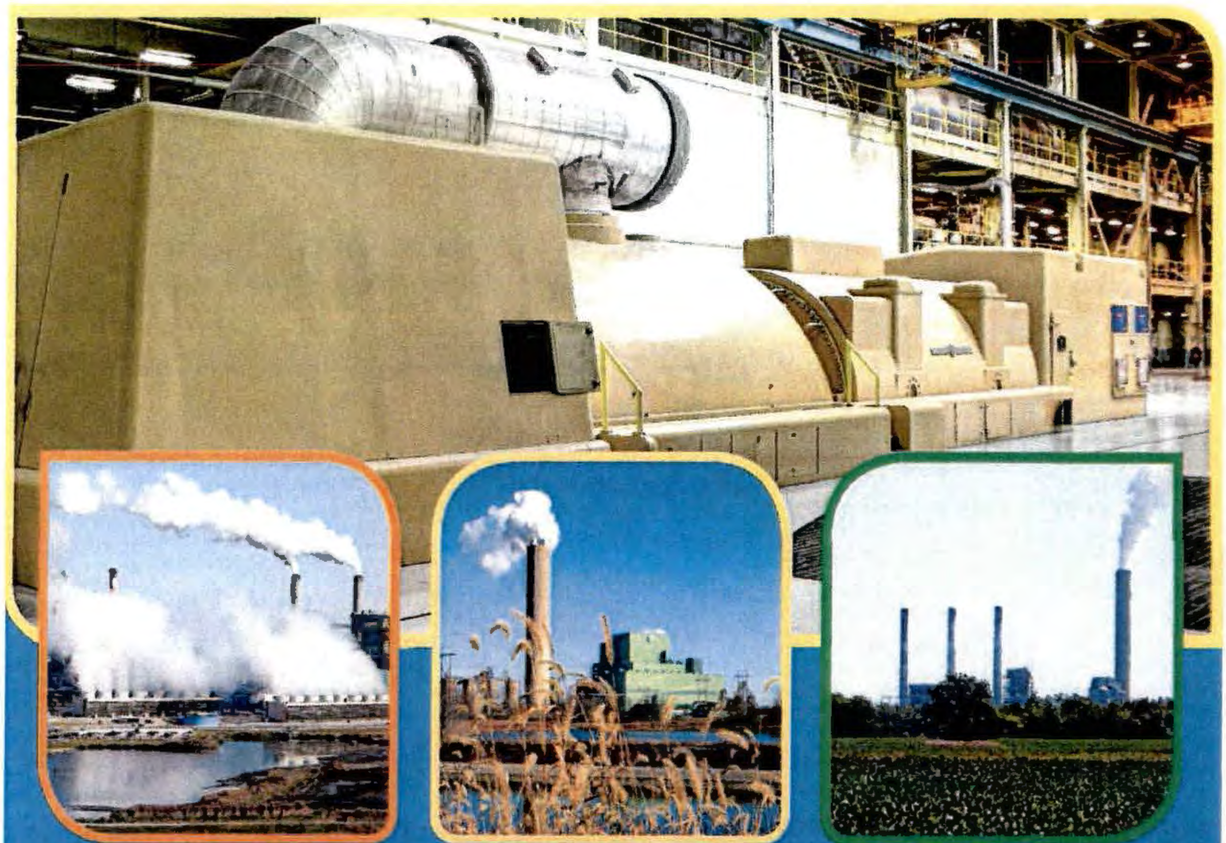
Appendix D – Glossary

Glossary

Big Rivers	Big Rivers Electric Corporation
C&I	Commercial and Industrial
CHP	Combined Heat and Power
Commission	Kentucky Public Service Commission
DOE	U. S. Department of Energy
DSM	Demand-Side Management
EE	Energy Efficiency
EF	Efficiency Factor
EIA	Energy Information Administration
EPA	Environmental Protection Agency
GDP	Gross Domestic Product
GDS	GDS Associates, Inc.
GWH	Gigawatt hours
HMP&L	Henderson Municipal Power & Light
HSPF	Heating Seasonal Performance Factor
IRP	Integrated Resource Plan
JPEC	Jackson Purchase Energy Corporation
Kenergy	Kenergy Corp.
KW	Kilowatt
kWh	Kilowatt hours
LIC	Large Industrial Customer Tariff
MCRECC	Meade County Rural Electric Cooperative Corporation
MDA	MDA EarthSat Weather data provider
Members	Collectively: MCRECC, Kenergy, JPEC
MISO	Midcontinent Independent System Operator, Inc.
MW	Megawatt
MWH	Megawatt hours
NERC	North American Electric Reliability Council
NCP	Non-coincident peak
RCUST	Rural system customers
RUS	Rural Utilities Services
RUSE	Rural system energy use per customer
SAE	Statistically Adjusted End-Use
SEER	Seasonal Energy Efficiency Ratio
SEPA	Southeastern Power Administration

Big Rivers 2015 Load Forecast

Big Rivers
ELECTRIC CORPORATION



Big Rivers Electric Corporation
2015 Load Forecast

July 2015

Prepared in collaboration with:

GDS Associates, Inc.
ENGINEERS & CONSULTANTS

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A – Annual Forecast Tables & Graphs

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1. Introduction

1.1 Overview

As an electric utility borrower with the Rural Utilities System ("RUS"), Big Rivers Electric Corporation ("Big Rivers") must biennially file a Load Forecast. Additionally, as an electric utility under the jurisdiction of the Kentucky Public Service Commission ("Commission"), Big Rivers must triennially file an Integrated Resource Plan ("IRP"), which is based on the most recent Board-approved load forecast. To gain efficiencies and align with the IRP process, Big Rivers intends to request triennial load forecasts for RUS' purposes in the future. This 2015 Load Forecast is provided to comply with Big Rivers' obligations under RUS[1] and the Commission[2] and gives a comprehensive overview of Big Rivers' energy and peak demand outlook for 2015-2034. A glossary of terms and acronyms used throughout this report are listed in Appendix D.

1.2 Introduction

This 2015 Load Forecast was prepared by Big Rivers with the assistance of GDS Associates, Inc. ("GDS"). The individuals responsible for preparation of the forecast and who are available to respond to inquiries are listed in Table 1.1.

Table 1.1
Project Team

Company	*Name*	*Title/Area of Expertise*
Big Rivers Electric Corporation	*Marlene Parsley*	*Director, Resources and Forecasting* *Project Manager*
	Russ Pogue	*Manager of Member Relations* *DSM/Energy Efficiency*
Jackson Purchase Electric	*Chuck Williamson*	*Vice President - Finance & Accounting* *Forecast Review*
Meade County Rural Electric Cooperative Corporation	*David Poe*	*V.P. Operations and Engineering* *Forecast Review*
	Anna Swanson	*Accounting Supervisor* *Forecast Review*
Kenergy Corp	*John Newland*	*Vice President – Engineering* *Forecast Review*
	Travis Siewert	*Manager of General Accounting* *Forecast Review*
	Steve Thompson	*Vice President – Finance* *Forecast Review*
GDS Associates, Inc.	*John Hutts*	*Principal* *GDS Lead Consultant*
	Julia Jennings	*Admin. Assistant* *Database, Reporting*
	Oguzhan Ozdemir	*Project Consultant* *Model Development*

[1] Code of Federal Regulations, Title 7, Subtitle B, Chapter XVII, Part 1710.202, Subpart E – Load Forecasts.
[2] Kentucky Public Service Commission, 807 KAR 5:058

This 2015 Load Forecast presents Big Rivers' projected power requirements through 2034. Big Rivers' financial forecast was used as input to develop load projections through 2029. Key model inputs were not available for years 2030-2034; therefore, projections of energy and peak demand for 2030-2034 are based on projected growth from 2028 to 2029. This report presents the projections, the underlying forecast assumptions, and the methodologies used in developing the load forecast. Forecast scenarios are included to address the uncertainties associated with the factors expected to influence energy consumption in the future. Supporting figures and tables are provided throughout this document and in the Appendices.

The remainder of Section 1 of this report presents a description of Big Rivers and a summary of the load forecast. Section 2 describes changes made to the forecast since the 2013 Load Forecast. Section 3 presents the base case forecast by customer classification and provides summary results for multiple forecast scenarios. Section 4 describes the forecasting process and methodologies, including a description of the data used, a discussion on the key forecast assumptions, and details regarding the forecasting model specifications.

1.3 Description of the Utility

1.3.1 Overview

Big Rivers is a generation and transmission cooperative headquartered in Henderson, Kentucky. Big Rivers owns, operates and maintains electric generation and transmission facilities, and it purchases, transmits, and sells electricity at wholesale. It exists for the principal purpose of providing the wholesale electricity requirements of its three distribution cooperative member-owners, which are Jackson Purchase Energy Corporation ("JPEC"), Kenergy Corp. ("Kenergy"), and Meade County Rural Electric Cooperative Corporation ("MCRECC") (collectively, the "Members"). The Members, in turn, provide retail electric service to approximately 114,000 consumer-members located in all or parts of 22 western Kentucky counties: Ballard, Breckenridge, Caldwell, Carlisle, Crittenden, Daviess, Graves, Grayson, Hancock, Hardin, Henderson, Hopkins, Livingston, Lyon, Marshall, McCracken, McLean, Meade, Muhlenberg, Ohio, Union, and Webster. A map showing the Members' service territory is provided in Figure 1.1 on the following page.

Additionally, Big Rivers provides transmission and ancillary services to other entities under the Midcontinent Independent System Operator ("MISO") Tariff. Big Rivers' wholesale rates are presented in its tariff, which has an effective date of February 1, 2014, and which is on file with the Commission. That tariff may be accessed from either the Commission's website (http://www.psc.ky.gov/tariffs/Electric/) or from the Regulatory webpage of Big River's internet site (http://www.bigrivers.com/regulatory.aspx).

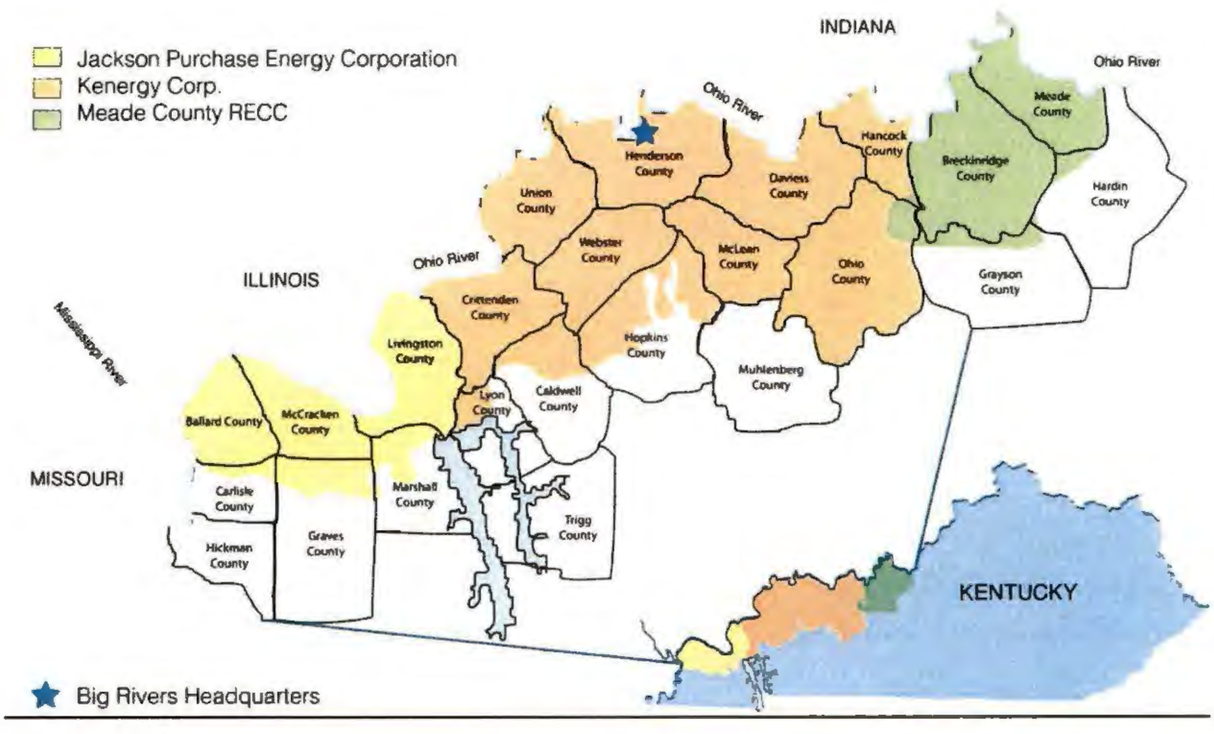
1.3.2 Capacity Resources

Big Rivers owns and operates the Robert A. Reid Plant (130 MW), the Kenneth C. Coleman Plant (443 MW), the Robert D. Green Plant (454 MW), and the D. B. Wilson Plant (417 MW), totaling 1,444 net MW of generating capacity. Total generation resources are 1,819 MW, including rights currently to 197 MW at Henderson Municipal Power and Light's ("HMP&L") William L. Newman Station Two facility ("HMP&L Station Two")[3] and 178 MW of contracted hydro capacity from the Southeastern Power Administration ("SEPA").[4] Force majeure conditions on the SEPA system have reduced Big Rivers' SEPA allotment to 154 MW, bringing Big Rivers' total generation capacity to 1,795 MW at the present time. Big Rivers expects SEPA to return to the full 178 MW capacity in 2018.

1.3.3 Transmission System

Big Rivers owns, operates and maintains its 1,298 mile transmission system and provides for the transmission of power to its Members and third party entities served under the MISO tariff.

Figure 1.1
Big Rivers' Members Service Area Map



1.3.4 Big Rivers' Load

References to total system energy and peak demand requirements in this 2015 Load Forecast are to Big Rivers' Members' native system, Big Rivers' non-member load, and HMP&L requirements. Native system is the cumulative requirement of Members' customer base load that Big Rivers is obligated to

[3] HMP&L has the contractual right to increase or decrease its capacity reservation from HMP&L Station Two up to 5 MW each year.

[4] In this analysis, both HMP&L load and generation are included. HMP&L has rights to 12MW of SEPA capacity, which is assumed in this analysis to directly offset HMP&L load.

serve. Non-member load is defined as planned long term load obligations that derive value for Big Rivers' Members. Forecasts of HMP&L's aggregated peak demands and net energy for load were provided by HMP&L management in response to requests from Big Rivers for purposes of preparing this report.

1.3.5 Big Rivers Consumer Classes:

Big Rivers categorizes energy and peak demand into two classes: rural system and direct serve. The rural system is comprised of all retail residential, commercial, and industrial customers served by Big Rivers' Members, except for retail customers served under Big Rivers' Large Industrial Customer ("LIC") tariff. Direct-serve customers are served under the Big Rivers' LIC tariff, which includes 21 large industrial customers in 2014.

Approximately 90% of the accounts served by Big Rivers' Members are residential. A breakdown of actual energy sales for 2014 and projected sales for 2034 is presented in Figure 1.2.

Historically, Big Rivers provided power to Kenergy for resale to two aluminum smelters. Due to the termination of the smelter contracts, effective in August 2013 and January 2014, respectively, Big Rivers no longer provides power for the smelters from its generation system, but power is transmitted to them over Big Rivers' transmission system, which is under the control of MISO[5]. Over the course of the forecast horizon, a portion of the sales previously associated with the smelters is projected to be absorbed by growth in member load and non-member sales.

[5] https://www.misoenergy.org/Pages/Home.aspx

Figure 1.2
Class Energy Sales Proportions

1.4 Uses of the Load Forecast

Maintaining a current and reliable load forecast is a key objective of Big Rivers' planning process to reliably provide for its customers' electricity needs. This load forecast will be used for resource, distribution, reliability and financial planning to:

- Continue to offer competitively priced power and cost-effective DSM programs to Big Rivers' Members,
- Maintain adequate planning reserve margins, to maximize reliability while ensuring safety, minimizing costs, risks, and environmental impacts,
- Meet North American Electric Reliability Corporation ("NERC") guidelines and requirements

1.5 Load Forecast Summary

Big Rivers' total system energy and peak demand requirements are comprised of its native system load, non-member load, and HMP&L load. Total requirements include transmission losses. Total system energy and peak demand requirements are projected to increase at average rates of 3.0% and 2.8%, respectively, over the next 20 years, reaching 1,330 MW and 7,482,726 MWH by 2034. Annual projections are presented in Table 1.2. Non-member load enters the forecast in 2018 at 66 MW and increases to 438 MW by 2034. Non-member load includes energy and peak demand requirements already under contract, beginning in 2018, plus future sales to non-members. HMP&L projected requirements are based on a load forecast prepared by HMP&L and reflect average growth of less than 1% per year. Refer to Table 1.3 for a breakdown of the forecast by component.

Native system energy and peak demand requirements are projected to increase at average compound rates of 0.6% and 0.8%, respectively, per year from 2014 through 2034. Continued increases in appliance efficiencies, consumer energy conservation awareness, and [redacted] in the price of retail electricity are expected to dampen growth in native energy sales over the near term; however, increased sales to two existing direct serve customers will have positive impacts on native sales over the near term. A record native peak of 752 MW was established during the winter of 2014. Under normal peaking weather conditions, that peak is estimated to have been 648 MW, and is projected to reach 761 MW by the summer of 2034.

Table 1.2
2015 Load Forecast - Total System Requirements

	Energy Requirements (MWH)	*Peak Demand (MW)*	*Load Factor*
2010	4,123,039	775	60.7%
2011	4,047,607	773	59.8%
2012	4,156,484	778	61.0%
2013	4,215,691	727	66.2%
2014	4,143,715	856	55.3%
2015	4,027,672	773	59.5%
2016	4,137,249	796	59.4%
2017	4,181,227	805	59.3%
2018	4,629,305	873	60.5%
2019	5,447,723	1,000	62.2%
2020	6,169,016	1,111	63.4%
2021	6,896,361	1,223	64.4%
2022	7,058,195	1,249	64.5%
2023	7,095,183	1,255	64.5%
2024	7,128,705	1,261	64.5%
2025	7,162,320	1,267	64.5%
2026	7,196,958	1,273	64.5%
2027	7,228,701	1,280	64.5%
2028	7,268,738	1,287	64.5%
2029	7,303,963	1,294	64.4%
2030	7,339,715	1,301	64.4%
2031	7,375,468	1,308	64.4%
2032	7,411,748	1,315	64.3%
2033	7,446,973	1,322	64.3%
2034	7,482,726	1,330	64.2%

Shaded year represents base year

Values are net of DSM and include transmission losses

Table 1.3
2015 Load Forecast – Total System Requirements by Component

	Native System		*Non-Member Sales*		*HMP&L*	
	Energy Requirements (MWH)	*Peak Demand (MW)*	*Energy Requirements (MWH)*	*Peak Demand (MW)*	*Energy Requirements (MWH)*	*Peak Demand (MW)*
2010	3,474,553	657			648,485	118
2011	3,418,662	659			628,945	114
2012	3,527,373	661			629,111	116
2013	3,589,970	617			625,721	110
2014	3,500,612	752			643,103	104
2015	3,387,684	661			639,988	112
2016	3,492,482	683			644,766	113
2017	3,533,234	691			647,993	114
2018	3,550,714	693	427,361	66	651,230	115
2019	3,567,353	695	1,225,883	191	654,487	115
2020	3,578,156	697	1,929,826	298	661,034	116
2021	3,595,907	701	2,632,811	405	667,643	117
2022	3,618,860	704	2,765,017	427	674,318	119
2023	3,643,750	707	2,770,368	428	681,064	120
2024	3,665,043	711	2,775,789	429	687,872	121
2025	3,686,289	715	2,781,280	430	694,751	122
2026	3,708,486	720	2,786,843	431	701,629	123
2027	3,727,716	724	2,792,477	432	708,508	124
2028	3,755,239	729	2,798,112	432	715,386	125
2029	3,777,951	734	2,803,747	433	722,265	126
2030	3,801,190	740	2,809,382	434	729,143	127
2031	3,824,429	745	2,815,017	435	736,022	128
2032	3,848,196	750	2,820,652	436	742,900	129
2033	3,870,908	755	2,826,287	437	749,779	130
2034	3,894,147	761	2,831,921	438	756,657	131

Shaded year represents base year

Values are net of DSM and include transmission losses

Peak values represent load at the time of the Native System peak

Key Economic and Demographic Influences - The key influences on the load forecast include economic activity, increases in heating and cooling equipment efficiencies, energy conservation, changes in retail electricity prices, and the continued stable base of large industrial load. With respect to the economic and demographic influences, number of households and total non-farm employment influence projections of the number of rural system customers. Average household income is one of the key inputs in the residential energy model. Number of households, employment, and average household income are projected to show low to moderate growth over the forecast period and are contributing factors to projected low growth in number of customers and average energy consumption per customer over the next 20 years. Refer to Section 4.3 for additional information regarding the economic outlook.

The forecast reflects an increase in the nominal price of retail electricity to rural system customers. Retail price projections were developed for each Member and are represented in the forecasting models as the quotient of annual revenue and annual kWh, by customer class. Projected retail prices reflect changes in Big Rivers' wholesale power cost to Members and changes in distribution system related costs at the Member level. The "all-in" average retail price at the Member level is projected to [redacted] Beyond 2018, nominal retail price is projected to [redacted][6] For residential customers, the elasticity of energy consumption with respect to price is -0.19 and was derived using the regression models for each Member cooperative.[7] The forecast reflects no direct decreases in energy sales and peak demand for the small and large commercial classes resulting from price [redacted] expected over the near term.

The forecast reflects impacts associated with changes in heating and cooling appliance market shares and increases in their respective efficiencies. Over the course of the forecast horizon, the market shares for both heating and cooling are projected to increase minimally. A combination of increases in electric appliance market shares and increases in appliance efficiencies is expected to produce essentially flat average consumption in electric heating and air-conditioning per household over the long term.

The forecast includes the impacts of existing and future DSM and energy efficiency programs. Impacts of existing programs are captured indirectly through the historical energy consumption data used in developing the forecasting models. The impacts of future program offerings are computed and captured in the load forecast as post-modeling adjustments. DSM programs are projected to reduce peak demand and energy consumption by 19 MW and 131,798 MWH by 2034.

The large commercial class, including both rural and direct serve customers, currently represents approximately 36% of total system energy consumption. Energy and peak projections for this class include only those customers that are currently being served. Aside from several small changes to

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[6] [redacted] are described in nominal terms for discussion purposes. Price is expressed in real, or deflated, terms in the forecasting models described in Section 4 of this report.
[7] Average elasticity for Big Rivers' 3 Members.

customer loads in 2015-2017, energy and peak are held constant at 2017 levels through 2034 in the base case forecast. The optimistic economy forecast scenario reflects growth for new industrial load.[8]

The key economic and demographic assumptions upon which the load forecast is based are summarized below and discussed in greater detail in Section 4.3.

- Number of households will increase at an average rate of 0.4% per year from 2014-2034.
- Employment will increase at an average rate of 0.3% per year from 2014-2034.
- Real gross regional product will increase at an average rate of 2.1% per year from 2014-2034.
- Real average income per household will increase at an average rate of 2.2% per year from 2014-2034.
- Real retail sales will increase at an average rate of 1.6% per year from 2014-2034.
- Inflation, as measured by the Gross Domestic Product Price Index, will increase at an average compound rate of 2.0% per year from 2014-2034.
- Nominal retail price (no adjustment for inflation) charged by Members to their customers is projected to [redacted] From 2018 to 2029, price is projected to [redacted]
- Heating and cooling degree days for the service area will be equal to averages based on the twenty years ending 2014.
- The market shares for electric heating, electric water heating, and air conditioning will continue to increase throughout the forecast period, but at a declining rate as maximum saturation levels are approached.
- The average operating efficiencies of major appliances will continue to increase throughout the forecast period, but at a declining rate as maximum efficiencies are approached.
- Impacts of existing energy efficiency programs will increase during the forecast horizon and will impact both energy and peak demand requirements.

1.6 Load Forecast Process Summary

The load forecast has been historically produced every two years; however, Big Rivers makes updates as needed for planning purposes. The 2015 Load Forecast was completed in June 2015 and approved by Big Rivers' Board of Directors in July 2015.

The 2015 Load Forecast was developed using a "bottom-up" approach. Forecasts were developed individually for each of Big Rivers' three Member distribution cooperatives and aggregated to the Big Rivers level. Preliminary forecasts were presented to each of the Members for review prior to

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[8] Historically, due to the unpredictability of economic development successes and the significant increase in load resulting from the addition of new customers, Big Rivers' projections of energy and peak demand for the large industrial class reflect the base historical year values adjusted for known and measureable changes in consumption for existing customers, and new growth corresponding to potential customers that have a high likelihood of being served in future years.

development of the final Big Rivers forecast. Review meetings were held via webinars and teleconferences.

The forecast was developed using both quantitative and qualitative methods. A series of econometric models were used to forecast number of customers and energy consumption by customer class and peak demand at the rural system level. Projections for large industrial customers were based on historical consumption and peak demand, combined with information received from the management of Big Rivers' Members regarding future plans and operations.

Big Rivers continues to review its load forecasting process and make enhancements as new information and technologies become available. Big Rivers will continue to monitor industry advancements and best practices to continue to enhance future forecast accuracy. See Section 4 for details regarding load forecast methodologies.

2. Changes since the 2013 Load Forecast

Big Rivers' 2013 Load Forecast was approved by Big Rivers' Board of Directors on April 18, 2013, filed with the RUS on May 6, 2013, and approved by RUS on June 26, 2013.

2.1 Updated Methodology

Since the 2013 Load Forecast, portions of the load forecast methodology have been updated. In the 2013 Load Forecast, number of customers and energy consumption were projected at the rural system level and then broken down by class based on historical proportions. In the 2015 Load Forecast, customers and energy consumption are projected by customer classification and aggregated to the rural system level. Previously, Members' rural system peak demand were based on projections of rural system energy requirements and assumed load factors. For the 2015 Load Forecast, econometric models are used to project rural system peak demand for Big Rivers and each Member. This modeling enhancement provides for the direct measurement of growth in energy sales and changes in temperature on peak demand.

2.2 Updated Projections

Tables 2.1 through 2.3 present projected native system requirements from the 2011, 2013, and 2015 Load Forecasts.

The growth rate in number of customers has fallen slightly with each new forecast, due to the lower trend in historical growth and the lower economic outlooks with respect to the number of projected households. Energy sales are higher in the 2015 Load Forecast than in the 2013 forecast, due primarily to higher growth in Direct-Serve and Small Commercial energy sales in the current forecast.

The forecast of total energy and peak demand requirements dropped significantly in the 2013 Load Forecast as energy consumption and peak demand for direct serve customers fell due to uncertainties regarding the economic recovery following the Great Recession. The current forecast reflects higher projections of energy sales and peak demand for direct serve customers that are comparable to actual amounts in 2014.

This forecast reflects the current plans for up to 428 MW of long term load to non-members. This supersedes the 2013 forecasted obligation of 800 MW "Projected New Load" to replace the majority of load and energy no longer under contract with two aluminum smelters.[9] Further description of this load is found in section 3.2.7.

[9] See Kentucky PUC - in the Matter of: Application of Big Rivers Electric Corporation for a General Adjustment in Rates, Case Nos. 2012-00535 and 2013-00199

Table 2.1
Comparison of Projected Number of Customers

	Actual	2011 Load Forecast	2013 Load Forecast	2015 Load Forecast
2003	104,764			
2004	106,414			
2005	107,883			
2006	109,329			
2007	110,585			
2008	111,693			
2009	111,923			
2010	112,391			
2011	112,888	112,972		
2012	113,252	113,995		
2013	113,553	115,512	113,562	
2014	114,210	117,033	114,545	
2015		118,522	115,658	114,864
2016		119,872	116,753	115,694
2017		121,078	117,815	116,511
2018		122,226	118,818	117,529
2019		123,348	119,796	118,538
2020		124,448	120,784	119,523
2021		125,515	121,772	120,465
2022		126,539	122,734	121,386
2023		127,522	123,678	122,313
2024		128,468	124,582	123,206
2025			125,473	124,067
2026			126,366	124,910
2027				125,712
2028				126,511
2029				127,313
2030				128,115
2031				128,917
2032				129,719
2033				130,521
2034				131,324

Table 2.2
Comparison of Projected Native Energy Requirements (GWh)

	Actual	*Weather Adjusted*	*2011 Load Forecast*	*2013 Load Forecast*	*2015 Load Forecast*
2003	*3,087*	*3,149*			
2004	*3,158*	*3,195*			
2005	*3,260*	*3,246*			
2006	*3,214*	*3,291*			
2007	*3,353*	*3,306*			
2008	*3,340*	*3,362*			
2009	*3,184*	*3,326*			
2010	*3,475*	*3,399*			
2011	*3,419*	*3,453*	*3,355*		
2012	*3,527*	*3,602*	*3,366*		
2013	*3,590*	*3,628*	*3,398*	*3,350*	
2014	*3,501*	*3,473*	*3,438*	*3,408*	
2015			*3,469*	*3,384*	*3,388*
2016			*3,509*	*3,373*	*3,492*
2017			*3,547*	*3,394*	*3,533*
2018			*3,574*	*3,416*	*3,551*
2019			*3,602*	*3,437*	*3,567*
2020			*3,637*	*3,460*	*3,578*
2021			*3,672*	*3,485*	*3,596*
2022			*3,709*	*3,511*	*3,619*
2023			*3,746*	*3,537*	*3,644*
2024			*3,785*	*3,562*	*3,665*
2025				*3,589*	*3,686*
2026				*3,616*	*3,708*
2027				*3,644*	*3,728*
2028					*3,755*
2029					*3,778*
2030					*3,801*
2031					*3,824*
2032					*3,848*
2033					*3,871*
2034					*3,894*

Table 2.3
Comparison of Projected Native Peak Demand (MW)

	Actual	Weather Adjusted	2011 Load Forecast	2013 Load Forecast	2015 Load Forecast
2003	592	588			
2004	610	641			
2005	609	608			
2006	624	638			
2007	653	616			
2008	616	625			
2009	670	644			
2010	657	651			
2011	659	635	657		
2012	661	625	664		
2013	617	626	672	632	
2014	752	638	679	635	
2015			688	635	661
2016			696	637	683
2017			702	642	691
2018			708	645	693
2019			715	649	695
2020			723	653	697
2021			730	658	701
2022			738	663	704
2023			747	668	707
2024			755	673	711
2025				678	715
2026				683	720
2027					724
2028					729
2029					734
2030					740
2031					745
2032					750
2033					755
2034					761

2.3 Updates to Demand-Side Management Programs

Big Rivers has taken a proactive approach to advance Strategy 1 of the 2008 Governor's Intelligent Energy Choices plan "to improve the efficiency of Kentucky's homes, buildings, industries and transportation fleet by establishing a goal of offsetting at least 18% of Kentucky's projected 2025 energy demand."[10] The 2013 Load Forecast was the first to reflect projected impacts of DSM measures implemented by Big Rivers' Member cooperatives, and the 2015 Load Forecast reflects projected impacts from an updated DSM study completed by Big Rivers in 2014.[11]

Big Rivers continues to work with the Members to implement and monitor the performance of DSM programs. Much of the work is done through a DSM/EE Working Group consisting of Big Rivers' and its Members' employees, which meets monthly. Further discussion of DSM is provided in Section 4.3.

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[10] *See http://energy.ky.gov/Documents/Final_Energy_Strategy.pdf.*

[11] The DSM Potential study is available as part of the 2014 Integrated Resource Plan of Big Rivers Electric Corporation Case No. 2014-00166

3. Load Forecast Results

3.1 Total System Forecast

Total system energy and peak demand requirements are projected to reach 7,483 GWH and 1,330 MW by 2034. Total system requirements include native system, non-member load, and HMP&L load. Refer to Section 3.2.7 below for a discussion of non-member load. Total system load factor is currently running just under 60% and is expected to increase to 64% by 2021, when 396 MW of non-member load is under contract.

Native system energy and peak demand requirements are projected to increase at average compound rates of 0.6% and 0.8%, respectively, per year from 2014 through 2034. Native peak demand is projected to increase by approximately 4 MW per year from 2014 through 2034. Non-member load enters the forecast in 2018 at 64 MW at 75% load factor, and increases to 428 MW by 2034. Tables 3.1 and 3.2 present projected total system energy and peak demand requirements. Tables 3.3 and 3.4 present monthly projections of energy requirements and peak demand for 2016 and 2017.

A review of the 2013 Load Forecast was completed, which included an analysis and comparison of energy and peak demand projections for 2013 and 2014 to actual weather adjusted values for the year. Weather adjusted native system energy requirements were 8.3% higher than projected in 2013 and 1.9% higher than projected in 2014. Weather adjusted native system peak demand requirements were 1.0% lower than projected in 2013 and 0.4% higher than projected in 2014.

Table 3.1
Historical and Projected Energy Requirements

	Member Coop Retail Sales (MWH)	Distribution Losses (%)	Big Rivers Native Sales (MWH)	Non-Member Sales (MWH)	HMP&L (MWH)	Trans. Losses (MWH)	Total Energy Requirements (MWH)
2010	3,317,423	3.7%	3,445,715		643,103	34,221	4,123,039
2011	3,279,929	3.1%	3,385,501		622,844	39,262	4,047,607
2012	3,367,558	3.5%	3,488,924		622,254	45,306	4,156,484
2013	3,438,437	2.9%	3,540,787		617,149	57,755	4,215,691
2014	3,330,195	3.3%	3,444,252		632,749	66,714	4,143,715
2015	3,203,889	3.4%	3,318,236		626,868	82,567	4,027,672
2016	3,298,793	3.3%	3,412,505		630,001	94,743	4,137,249
2017	3,338,884	3.3%	3,452,322		633,154	95,750	4,181,227
2018	3,355,010	3.3%	3,469,403	417,575	636,317	106,011	4,629,305
2019	3,370,485	3.3%	3,485,661	1,197,810	639,499	124,753	5,447,723
2020	3,380,565	3.3%	3,496,216	1,885,633	645,896	141,270	6,169,016
2021	3,397,049	3.3%	3,513,561	2,572,520	652,354	157,927	6,896,361
2022	3,418,388	3.3%	3,535,988	2,701,698	658,876	161,633	7,058,195
2023	3,441,526	3.3%	3,560,308	2,706,927	665,468	162,480	7,095,183
2024	3,461,351	3.3%	3,581,114	2,712,223	672,120	163,247	7,128,705
2025	3,481,077	3.4%	3,601,873	2,717,589	678,841	164,017	7,162,320
2026	3,501,711	3.4%	3,623,562	2,723,024	685,562	164,810	7,196,958
2027	3,519,592	3.4%	3,642,351	2,728,530	692,283	165,537	7,228,701
2028	3,545,197	3.4%	3,669,244	2,734,035	699,004	166,454	7,268,738
2029	3,566,281	3.4%	3,691,436	2,739,541	705,725	167,261	7,303,963
2030	3,587,880	3.4%	3,714,143	2,745,047	712,446	168,079	7,339,715
2031	3,609,480	3.4%	3,736,850	2,750,553	719,167	168,898	7,375,468
2032	3,631,595	3.4%	3,760,072	2,756,059	725,888	169,729	7,411,748
2033	3,652,678	3.4%	3,782,264	2,761,565	732,609	170,536	7,446,973
2034	3,674,278	3.4%	3,804,971	2,767,070	739,330	171,354	7,482,726

Shaded year represents base year
HMP&L based on HMP&L load forecast
Values are net of DSM

Table 3.2
Historical and Projected Peak Demand

	Rural System (MW)	Direct Serve (MW)	Native System (MW)	Non-Member Load (MW)	HMP&L (MW)	Trans. Losses (%)	Total Peak Demand (MW)
2010	540	112	652		117	0.83%	775
2011	533	120	652		113	0.97%	773
2012	542	112	654		115	1.09%	778
2013	494	115	609		108	1.37%	727
2014	616	124	740		102	1.61%	856
2015	530	117	647		110	2.05%	773
2016	531	136	667		110	2.29%	796
2017	533	143	675		111	2.29%	805
2018	534	143	677	64	112	2.29%	873
2019	536	143	679	186	112	2.29%	1,000
2020	539	143	681	291	113	2.29%	1,111
2021	542	143	685	396	114	2.29%	1,223
2022	545	143	688	417	116	2.29%	1,249
2023	548	143	691	418	117	2.29%	1,255
2024	552	143	695	419	118	2.29%	1,261
2025	556	143	699	420	119	2.29%	1,267
2026	561	143	703	421	120	2.29%	1,273
2027	565	143	708	422	121	2.29%	1,280
2028	570	143	713	423	122	2.29%	1,287
2029	575	143	718	423	123	2.29%	1,294
2030	580	143	723	424	124	2.29%	1,301
2031	585	143	728	425	125	2.29%	1,308
2032	590	143	733	426	126	2.29%	1,315
2033	595	143	738	427	127	2.29%	1,322
2034	600	143	743	428	128	2.29%	1,330

Shaded year represents base year

HMP&L based on HMP&L load forecast

Values are net of DSM

Table 3.3
Monthly Energy Requirements
2016-2017

Year	Month	Native Energy Requirements (MWH)	Non-Member Energy Requirements (MWH)	HMP&L (MWH)	Total System Energy Requirements (MWH)
2016	1	315,808	0	56,780	372,588
2016	2	279,328	0	51,538	330,866
2016	3	274,001	0	51,081	325,082
2016	4	246,038	0	47,444	293,483
2016	5	264,307	0	50,807	315,115
2016	6	298,907	0	58,781	357,688
2016	7	330,479	0	60,409	390,888
2016	8	333,797	0	63,500	397,297
2016	9	290,135	0	54,065	344,200
2016	10	264,086	0	49,720	313,805
2016	11	273,995	0	47,192	321,187
2016	12	321,601	0	53,448	375,048
2017	1	327,110	0	57,064	384,174
2017	2	285,525	0	51,796	337,322
2017	3	281,260	0	51,337	332,597
2017	4	253,118	0	47,682	300,799
2017	5	268,099	0	51,062	319,162
2017	6	302,502	0	59,076	361,578
2017	7	334,143	0	60,711	394,855
2017	8	333,316	0	63,818	397,134
2017	9	289,754	0	54,335	344,089
2017	10	263,730	0	49,968	313,698
2017	11	273,589	0	47,428	321,017
2017	12	321,087	0	53,715	374,802

Values are net of DSM and include transmission losses

Table 3.4
Monthly Peak Demand Requirements
2016-2017

Year	Month	Native Energy Requirements (MW)	Non-Member Energy Requirements (MW)	HMP&L (MW)	Total System Demand Requirements (MW)
2016	1	668	0	97	765
2016	2	615	0	95	710
2016	3	547	0	87	634
2016	4	456	0	85	541
2016	5	541	0	100	642
2016	6	643	0	110	752
2016	7	683	0	113	796
2016	8	677	0	115	791
2016	9	592	0	106	698
2016	10	474	0	85	559
2016	11	549	0	85	634
2016	12	604	0	92	696
2017	1	683	0	97	780
2017	2	630	0	96	726
2017	3	560	0	88	648
2017	4	466	0	85	551
2017	5	548	0	100	648
2017	6	650	0	111	761
2017	7	691	0	114	805
2017	8	685	0	116	800
2017	9	599	0	106	706
2017	10	479	0	85	564
2017	11	562	0	86	648
2017	12	618	0	93	711

Values are net of DSM and include transmission losses

3.2 Customer Class Forecasts

This section presents historical and projected number of customers and energy sales by Member retail classification. All values are net of DSM.

3.2.2 Residential

Residential sales MWH are projected to increase at an average rate of 1.0% per year from 2014 through 2034. Sales from 2014-2017 are projected to decline in the near term due to continued increases in appliance efficiencies, energy conservation awareness, and [redacted] in retail price. Growth in the number of customers is projected to remain low through 2017 and then increase at an average rate of 0.6% through 2034. Average use per customer is projected to decline through 2017, then is projected to be relatively flat between 2018 and 2021 as positive impacts from increasing electric market shares are negated by increases in appliance efficiencies. Average use per customer is projected to establish an increasing trend beyond 2021 as positive impacts of increasing electric market shares outweigh the negative impacts of appliance efficiencies, which are expected to level as average appliance efficiencies approach maximum levels.

Table 3.5
Residential

	Number of Customers	Change per Yr.	% Change per Yr.	Energy Sales (MWH)	Normalized Energy Sales (MWH)	% Change per Yr.	Avg. kWh /Cust. /Mo.	% Change per Yr.
2010	97,467			1,611,212	1,526,991		1,306	
2011	97,750	283	0.3%	1,530,090	1,529,904	0.2%	1,304	-0.1%
2012	97,675	(74)	-0.1%	1,465,749	1,480,285	-3.2%	1,263	-3.2%
2013	97,588	(87)	-0.1%	1,495,894	1,478,411	-0.1%	1,262	0.0%
2014	97,667	79	0.1%	1,517,068	1,467,145	-0.8%	1,252	-0.8%
2015	98,114	447	0.5%		1,470,062	0.2%	1,249	-0.3%
2016	98,561	447	0.5%		1,457,938	-0.8%	1,233	-1.3%
2017	99,007	447	0.5%		1,447,437	-0.7%	1,218	-1.2%
2018	99,692	685	0.7%		1,461,984	1.0%	1,222	0.3%
2019	100,456	763	0.8%		1,475,491	0.9%	1,224	0.2%
2020	101,209	754	0.8%		1,483,603	0.5%	1,222	-0.2%
2021	101,931	722	0.7%		1,497,662	0.9%	1,224	0.2%
2022	102,635	703	0.7%		1,517,257	1.3%	1,232	0.6%
2023	103,341	706	0.7%		1,538,630	1.4%	1,241	0.7%
2024	104,027	686	0.7%		1,556,728	1.2%	1,247	0.5%
2025	104,693	666	0.6%		1,576,452	1.3%	1,255	0.6%
2026	105,349	656	0.6%		1,597,333	1.3%	1,264	0.7%
2027	105,978	629	0.6%		1,616,338	1.2%	1,271	0.6%
2028	106,605	627	0.6%		1,643,253	1.7%	1,285	1.1%
2029	107,235	630	0.6%		1,666,646	1.4%	1,295	0.8%
2030	107,866	630	0.6%		1,690,039	1.4%	1,306	0.8%
2031	108,496	630	0.6%		1,713,432	1.4%	1,316	0.8%
2032	109,126	630	0.6%		1,736,825	1.4%	1,326	0.8%
2033	109,757	630	0.6%		1,760,218	1.3%	1,336	0.8%
2034	110,387	630	0.6%		1,783,611	1.3%	1,346	0.8%

3.2.3 Small Commercial & Industrial ("Small C&I")

Small commercial & industrial customers are defined as all commercial and industrial customers with annual peak demand less than 1,000 kW. Small commercial sales are projected to increase at an average rate of 1.1% per year from 2014 through 2034. Growth in the number of customers, projected at 1.2% per year, is the primary influence on growth in total class sales. Consumption per customer is projected decline by 0.1% per year from 2014-2034.

Table 3.6
Small Commercial & Industrial

	Number of Customers	Change per Yr.	% Change per Yr.	Energy Sales (MWH)	Normalized Energy Sales (MWH)	% Change per Yr.	Avg. kWh /Cust. /Mo.	% Change per Yr.
2010	14,808			618,684	594,230		3,344	
2011	14,999	192	1.3%	599,542	597,655	0.6%	3,320	-0.7%
2012	15,435	435	2.9%	595,342	594,448	-0.5%	3,209	-3.3%
2013	15,982	547	3.5%	615,002	611,247	2.8%	3,187	-0.7%
2014	16,394	412	2.6%	624,488	613,604	0.4%	3,119	-2.1%
2015	16,604	210	1.3%		622,642	1.5%	3,125	0.2%
2016	16,989	384	2.3%		634,930	2.0%	3,114	-0.3%
2017	17,360	371	2.2%		646,338	1.8%	3,103	-0.4%
2018	17,693	333	1.9%		656,633	1.6%	3,093	-0.3%
2019	17,940	247	1.4%		664,366	1.2%	3,086	-0.2%
2020	18,171	231	1.3%		671,691	1.1%	3,080	-0.2%
2021	18,391	220	1.2%		678,707	1.0%	3,075	-0.2%
2022	18,608	217	1.2%		685,679	1.0%	3,071	-0.2%
2023	18,829	221	1.2%		692,785	1.0%	3,066	-0.1%
2024	19,036	207	1.1%		699,499	1.0%	3,062	-0.1%
2025	19,231	195	1.0%		705,899	0.9%	3,059	-0.1%
2026	19,418	187	1.0%		712,077	0.9%	3,056	-0.1%
2027	19,591	173	0.9%		717,886	0.8%	3,054	-0.1%
2028	19,763	172	0.9%		723,680	0.8%	3,052	-0.1%
2029	19,934	172	0.9%		729,506	0.8%	3,050	-0.1%
2030	20,106	172	0.9%		735,331	0.8%	3,048	-0.1%
2031	20,278	172	0.9%		741,157	0.8%	3,046	-0.1%
2032	20,450	172	0.8%		746,983	0.8%	3,044	-0.1%
2033	20,622	172	0.8%		752,808	0.8%	3,042	-0.1%
2034	20,793	172	0.8%		758,634	0.8%	3,040	-0.1%

3.2.4 Large Commercial & Industrial ("Large C&I")

The large commercial & industrial class is defined as all commercial and industrial customers that have annual peak demand greater than or equal to 1,000 kW. The class includes rural system customers and direct serve customers. Large C&I sales for Big Rivers' three Members are projected to be essentially flat after 2016, as the forecast includes no new customers for this classification.

Table 3.7
Large Commercial & Industrial

	Number of Customers	Change per Yr.	% Change per Yr.	Energy Sales (MWH)	% Change per Yr.	Avg. kWh /Cust. /Mo.	% Change per Yr.
2010	39			1,083,734		2,325,609	
2011	43	4	9.7%	1,146,619	5.8%	2,243,874	-3.5%
2012	44	1	2.2%	1,302,573	13.6%	2,495,350	11.2%
2013	52	8	19.0%	1,323,552	1.6%	2,131,323	-14.6%
2014	51	(1)	-1.1%	1,185,042	-10.5%	1,930,035	-9.4%
2015	49	(2)	-4.1%	1,117,726	-5.7%	1,897,667	-1.7%
2016	48	(1)	-2.0%	1,217,976	9.0%	2,110,876	11.2%
2017	47	(1)	-2.1%	1,262,850	3.7%	2,235,133	5.9%
2018	46	(1)	-2.1%	1,260,004	-0.2%	2,278,488	1.9%
2019	46	0	0.0%	1,260,004	0.0%	2,278,488	0.0%
2020	46	0	0.0%	1,260,519	0.0%	2,279,420	0.0%
2021	46	0	0.0%	1,260,004	0.0%	2,278,488	0.0%
2022	46	0	0.0%	1,260,004	0.0%	2,278,488	0.0%
2023	46	0	0.0%	1,260,004	0.0%	2,278,488	0.0%
2024	46	0	0.0%	1,260,519	0.0%	2,279,420	0.0%
2025	46	0	0.0%	1,260,004	0.0%	2,278,488	0.0%
2026	46	0	0.0%	1,260,004	0.0%	2,278,488	0.0%
2027	46	0	0.0%	1,260,004	0.0%	2,278,488	0.0%
2028	46	0	0.0%	1,260,519	0.0%	2,279,420	0.0%
2029	46	0	0.0%	1,260,004	0.0%	2,278,488	0.0%
2030	46	0	0.0%	1,260,004	0.0%	2,278,488	0.0%
2031	46	0	0.0%	1,260,004	0.0%	2,278,488	0.0%
2032	46	0	0.0%	1,260,519	0.0%	2,279,420	0.0%
2033	46	0	0.0%	1,260,004	0.0%	2,278,488	0.0%
2034	46	0	0.0%	1,260,004	0.0%	2,278,488	0.0%

3.2.5 Irrigation

Only one of Big Rivers' Members provides service to irrigation customers. Energy sales for the class account for less than 1% of total system sales. Energy sales are influenced by weather during growing seasons. No new customers are expected during the forecast period, and sales projections for the class are based on average sales for the most recent seven years.

Table 3.8
Irrigation

	Number of Customers	Change per Yr.	% Change per Yr.	Energy Sales (MWH)	% Change per Yr.	Avg. kWh /Cust. /Mo.	% Change per Yr.
2010	9			356		3,491	
2011	7	(2)	-20.6%	269	-24.5%	3,321	-4.9%
2012	5	(2)	-25.9%	440	63.7%	7,338	121.0%
2013	4	(1)	-15.0%	48	-89.2%	933	-87.3%
2014	4	(0)	-5.9%	136	186.9%	2,843	204.8%
2015	4	0	0.0%	298	118.6%	6,213	118.6%
2016	4	0	0.0%	298	0.0%	6,213	0.0%
2017	4	0	0.0%	298	0.0%	6,213	0.0%
2018	4	0	0.0%	298	0.0%	6,213	0.0%
2019	4	0	0.0%	298	0.0%	6,213	0.0%
2020	4	0	0.0%	298	0.0%	6,213	0.0%
2021	4	0	0.0%	298	0.0%	6,213	0.0%
2022	4	0	0.0%	298	0.0%	6,213	0.0%
2023	4	0	0.0%	298	0.0%	6,213	0.0%
2024	4	0	0.0%	298	0.0%	6,213	0.0%
2025	4	0	0.0%	298	0.0%	6,213	0.0%
2026	4	0	0.0%	298	0.0%	6,213	0.0%
2027	4	0	0.0%	298	0.0%	6,213	0.0%
2028	4	0	0.0%	298	0.0%	6,213	0.0%
2029	4	0	0.0%	298	0.0%	6,213	0.0%
2030	4	0	0.0%	298	0.0%	6,213	0.0%
2031	4	0	0.0%	298	0.0%	6,213	0.0%
2032	4	0	0.0%	298	0.0%	6,213	0.0%
2033	4	0	0.0%	298	0.0%	6,213	0.0%
2034	4	0	0.0%	298	0.0%	6,213	0.0%

3.2.6 Street Lighting

Energy sales for the class account for less than 1% of total system sales. Projections of number of customers is based on a historical trend, and energy sales are assumed to increase at a rate equal to the residential class.

Table 3.9
Street Lighting

	Number of Customers	Change per Yr.	% Change per Yr.	Energy Sales (MWH)	% Change per Yr.	Avg. kWh /Cust. /Mo.	% Change per Yr.
2010	88			3,438		3,256	
2011	87	(1)	-1.3%	3,409	-0.8%	3,272	0.5%
2012	92	5	5.4%	3,454	1.3%	3,146	-3.9%
2013	91	(0)	-0.1%	3,486	0.9%	3,178	1.0%
2014	91	(0)	-0.5%	3,461	-0.7%	3,169	-0.3%
2015	91	0	0.0%	3,472	0.3%	3,179	0.3%
2016	91	0	0.0%	3,475	0.1%	3,182	0.1%
2017	91	0	0.0%	3,478	0.1%	3,185	0.1%
2018	91	0	0.0%	3,481	0.1%	3,188	0.1%
2019	91	0	0.0%	3,484	0.1%	3,190	0.1%
2020	91	0	0.0%	3,487	0.1%	3,193	0.1%
2021	91	0	0.0%	3,490	0.1%	3,196	0.1%
2022	91	0	0.0%	3,493	0.1%	3,199	0.1%
2023	91	0	0.0%	3,496	0.1%	3,201	0.1%
2024	91	0	0.0%	3,499	0.1%	3,204	0.1%
2025	91	0	0.0%	3,502	0.1%	3,207	0.1%
2026	91	0	0.0%	3,505	0.1%	3,210	0.1%
2027	91	0	0.0%	3,508	0.1%	3,213	0.1%
2028	91	0	0.0%	3,511	0.1%	3,215	0.1%
2029	91	0	0.0%	3,514	0.1%	3,218	0.1%
2030	91	0	0.0%	3,517	0.1%	3,221	0.1%
2031	91	0	0.0%	3,520	0.1%	3,224	0.1%
2032	91	0	0.0%	3,523	0.1%	3,226	0.1%
2033	91	0	0.0%	3,526	0.1%	3,229	0.1%
2034	91	0	0.0%	3,529	0.1%	3,232	0.1%

3.2.7 Non-Member

The 2015 Load Forecast includes sales to non-members, which is defined as long term future load that provides value to existing Member-owners. Non-member load will be served from on-line capacity of Big Rivers' Member-owners, and may be adjusted from time to time as resources and economics dictate. This load is projected to begin in 2018 and ramp in over several years as contracts are negotiated.

Table 3.10
Non-Member

	Energy Sales (MWH)	*% Change per Yr.*	*Peak Demand (MW)*	*% Change per Yr.*
2010				
2011				
2012				
2013				
2014				
2015				
2016				
2017				
2018	*417,575*		*64*	
2019	*1,197,810*	*186.8%*	*186*	*190.0%*
2020	*1,885,633*	*57.4%*	*291*	*56.3%*
2021	*2,572,520*	*36.4%*	*396*	*36.0%*
2022	*2,701,698*	*5.0%*	*417*	*5.3%*
2023	*2,706,927*	*0.2%*	*418*	*0.2%*
2024	*2,712,223*	*0.2%*	*419*	*0.2%*
2025	*2,717,589*	*0.2%*	*420*	*0.2%*
2026	*2,723,024*	*0.2%*	*421*	*0.2%*
2027	*2,728,530*	*0.2%*	*422*	*0.2%*
2028	*2,734,035*	*0.2%*	*423*	*0.2%*
2029	*2,739,541*	*0.2%*	*423*	*0.2%*
2030	*2,745,047*	*0.2%*	*424*	*0.2%*
2031	*2,750,553*	*0.2%*	*425*	*0.2%*
2032	*2,756,059*	*0.2%*	*426*	*0.2%*
2033	*2,761,565*	*0.2%*	*427*	*0.2%*
2034	*2,767,070*	*0.2%*	*428*	*0.2%*

3.2.8 Rural System Peak Demand

Rural system peak demand represents the highest 1-hour rural system load during the summer and winter seasons.[12] Weather adjusted summer peak demand is projected to increase 85 MW by 2034, increasing at an average rate of 0.8% per year.[13] Winter peak is projected to increase 81 MW by 2034, increasing at an average rate of 0.7% per year.

Table 3.11
Rural System Peak Demand
(excluding transformer losses)

Year	*Winter NCP (MW)*	*Weather Adjusted NCP*	*Load Factor*	*Summer NCP (MW)*	*Weather Adjusted NCP*	*Load Factor*
2010	*507*	*512*	*52.8%*	*540*	*506*	*49.6%*
2011	*533*	*506*	*50.4%*	*532*	*515*	*50.5%*
2012	*456*	*513*	*58.4%*	*542*	*510*	*49.2%*
2013	*484*	*477*	*55.6%*	*494*	*511*	*54.5%*
2014	*616*	*514*	*43.2%*	*481*	*515*	*55.3%*
2015		*522*	*51.5%*		*530*	*50.7%*
2016		*525*	*50.9%*		*531*	*50.3%*
2017		*526*	*50.7%*		*533*	*50.1%*
2018		*528*	*51.0%*		*534*	*50.4%*
2019		*530*	*51.1%*		*536*	*50.5%*
2020		*532*	*51.1%*		*539*	*50.5%*
2021		*535*	*51.2%*		*542*	*50.6%*
2022		*538*	*51.4%*		*545*	*50.8%*
2023		*542*	*51.6%*		*548*	*51.0%*
2024		*546*	*51.7%*		*552*	*51.0%*
2025		*550*	*51.7%*		*556*	*51.1%*
2026		*554*	*51.8%*		*561*	*51.1%*
2027		*559*	*51.7%*		*565*	*51.1%*
2028		*563*	*51.8%*		*570*	*51.2%*
2029		*569*	*51.8%*		*575*	*51.2%*
2030		*574*	*51.8%*		*580*	*51.2%*
2031		*579*	*51.7%*		*585*	*51.2%*
2032		*584*	*51.7%*		*590*	*51.2%*
2033		*590*	*51.7%*		*595*	*51.2%*
2034		*595*	*51.7%*		*600*	*51.2%*

[12] Summer season includes June through September of each year. Winter season includes January through March of the current year and November and December of the prior year.
[13] Growth is based on weather normalized values for 2014 and 2034

3.2.9 Native System Peak Demand

Native system peak demand represents to sum of rural system 1-hour NCP and Direct Serve demand coincident with rural system non coincident peak ("NCP"). There are minor changes expected in direct serve demand through 2017, after which direct serve peaks level out.

Table 3.12
Native System Peak Demand
(excluding transmission losses)

Year	*Winter NCP (MW)*	*Weather Adjusted NCP*	*Load Factor*	*Summer NCP (MW)*	*Weather Adjusted NCP*	*Load Factor*
2010	*647*	*651*	*60.8%*	*652*	*617*	*60.4%*
2011	*621*	*594*	*62.3%*	*652*	*635*	*59.3%*
2012	*569*	*625*	*70.0%*	*654*	*622*	*60.9%*
2013	*597*	*589*	*67.7%*	*609*	*626*	*66.4%*
2014	*740*	*638*	*53.1%*	*602*	*636*	*65.3%*
2015		*638*	*59.4%*		*647*	*58.5%*
2016		*652*	*59.7%*		*667*	*58.4%*
2017		*667*	*59.0%*		*675*	*58.4%*
2018		*669*	*59.2%*		*677*	*58.5%*
2019		*671*	*59.3%*		*679*	*58.6%*
2020		*673*	*59.3%*		*681*	*58.6%*
2021		*677*	*59.3%*		*685*	*58.6%*
2022		*680*	*59.4%*		*688*	*58.7%*
2023		*683*	*59.5%*		*691*	*58.8%*
2024		*687*	*59.5%*		*695*	*58.8%*
2025		*691*	*59.5%*		*699*	*58.8%*
2026		*695*	*59.5%*		*703*	*58.8%*
2027		*700*	*59.4%*		*708*	*58.7%*
2028		*705*	*59.4%*		*713*	*58.8%*
2029		*710*	*59.4%*		*718*	*58.7%*
2030		*715*	*59.3%*		*723*	*58.7%*
2031		*720*	*59.2%*		*728*	*58.6%*
2032		*726*	*59.2%*		*733*	*58.6%*
2033		*731*	*59.1%*		*738*	*58.5%*
2034		*736*	*59.0%*		*743*	*58.5%*

3.3.1 Total System Non-Coincident Peak Demand

Total system non-coincident peak demand represents to sum of the 1-hour peaks for Big Rivers' native load, Big Rivers' future non-member load, and HMP&L load. Non-member and HMP&L load is not coincident with Big Rivers' native load. Total system NCP demand is projected to reach 1,330 MW by 2034.

Table 3.13
Total System Peak Demand
(including transmission losses)

Year	Winter NCP (MW)	Weather Adjusted NCP	Load Factor	Summer NCP (MW)	Weather Adjusted NCP	Load Factor
2010	748	753	62.9%	775	734	60.7%
2011	720	689	64.2%	773	753	59.8%
2012	665	731	71.3%	778	740	61.0%
2013	699	691	68.8%	727	747	66.2%
2014	856	738	55.3%	722	763	65.6%
2015		747	61.5%		773	59.5%
2016		765	61.8%		796	59.4%
2017		780	61.2%		805	59.3%
2018		848	62.3%		873	60.5%
2019		971	64.0%		1,000	62.2%
2020		1,082	65.1%		1,111	63.4%
2021		1,193	66.0%		1,223	64.4%
2022		1,217	66.2%		1,249	64.5%
2023		1,223	66.2%		1,255	64.5%
2024		1,228	66.2%		1,261	64.5%
2025		1,234	66.2%		1,267	64.5%
2026		1,241	66.2%		1,273	64.5%
2027		1,247	66.2%		1,280	64.5%
2028		1,254	66.2%		1,287	64.5%
2029		1,261	66.1%		1,294	64.4%
2030		1,269	66.0%		1,301	64.4%
2031		1,276	66.0%		1,308	64.4%
2032		1,283	65.9%		1,315	64.3%
2033		1,290	65.9%		1,322	64.3%
2034		1,297	65.8%		1,330	64.2%

3.4 Weather Adjusted Energy and Peak Demand Requirements

Rural system energy consumption and peak demand are impacted by prevailing weather. Energy sales and peak demand for direct serve customers are not weather sensitive. Both extreme and mild weather conditions have been experienced over the most recent four years. As measured by degree days, 2010 was the hottest year in over 20 years, and 2010 was the coldest year since 1997. More recently, January 2014 represented one of the most extreme winter months Big Rivers has experienced in the last 20 years, resulting in a new all-time native system peak of 740 MW. Table 3.14 presents actual and weather adjusted energy and peak demand requirements for recent years.

Table 3.14
Weather Normalized Native System Energy and Peak Demand

	Energy (MWH)		*Winter Peak (MW)*		*Summer Peak (MW)*	
	Actual	*Normal*	*Actual*	*Normal*	*Actual*	*Normal*
2005	*3,233,245*	*3,219,363*	*549*	*565*	*604*	*608*
2006	*3,188,986*	*3,265,332*	*577*	*608*	*619*	*638*
2007	*3,325,859*	*3,279,063*	*597*	*597*	*648*	*616*
2008	*3,313,571*	*3,334,646*	*611*	*625*	*604*	*614*
2009	*3,159,286*	*3,299,898*	*665*	*644*	*594*	*607*
2010	*3,445,715*	*3,371,007*	*647*	*651*	*652*	*617*
2011	*3,385,501*	*3,419,160*	*621*	*594*	*652*	*635*
2012	*3,488,924*	*3,562,315*	*569*	*625*	*654*	*622*
2013	*3,540,787*	*3,578,596*	*597*	*589*	*609*	*626*
2014	*3,444,252*	*3,416,701*	*740*	*638*	*602*	*636*

Values represent energy and peak demand without transformer losses

Under normal peaking weather conditions, Big Rivers' annual peak demand is projected to occur during the summer season. Historical data shows, however, that Big Rivers' actual annual peak demand was set during winter months in 2008, 2009, and 2014. The impact of severe weather is greater during winter months than summer months due to supplemental electric strip heating; therefore, while the base case forecast shows Big Rivers to be summer peaking, under the most extreme weather conditions, the system is most likely to be winter peaking.

3.5 Impact of Existing and Future Energy Efficiency and Demand-Side Management Programs

Big Rivers assisted its Members with the implementation of 10 energy efficiency programs in 2010, and added two additional programs in 2013 for a total of 12 programs. The projected impact of these programs beginning in 2015 is presented in Section 4.3, Table 4.6. Across the 2011-2014 timeframe, the programs continued to grow and yield increasing levels of deemed savings. The impacts of existing programs are quantified indirectly in the 2015 Load Forecast through historical sales. The impacts of new programs and increased participation in existing programs are captured in the 2015 Load Forecast through post-modeling adjustments.

Below are programs that are not tracked for impact because they are educational in nature and/or not readily quantifiable.

- **Member websites:** Each of the Member distribution cooperative websites provides easy-to-use Home Energy Suites. The Suites provide education and calculation methods to improve efficiency and save energy in the home. Adjustable inputs specific to a home allows customers to compare their current energy use to estimated energy use resulting from various improvements in efficiency.
- **Energy Use Assessments:** These assessments are provided to commercial and industrial customers upon request. Walk-through energy audits help identify simple and low cost efficiency measures that customers can install or implement themselves. Third party service providers such as the Kentucky Pollution Prevention Center and Department for Energy Development and Independence[14] assist customers in achieving energy reduction goals[15]. Educational programs are also available for employees of commercial and industrial members.
- **Renewable Energy:** Big Rivers offers renewable energy to its Members. Big Rivers has purchased energy from an ENERGY STAR® certified Combined Heat and Power ("CHP") project operated by Domtar, Inc., a specialty paper manufacturer. The power is generated from wood chips that are waste byproducts of the paper manufacturing process. Customers wishing to purchase this renewable energy can contract with any of the Members.
- **Energy Savings Analysis:** Big Rivers provided energy saving analyses to industrial and large commercial customers by combining efforts with the Members, the Department of Energy ("DOE"[16]), and the University of Louisville's Kentucky Pollution Prevention Center.[17]
- **Power Factor Correction:** Members' staffs provide assistance to correct lagging power factor at a Commercial or Industrial ("C&I") facility. These corrections save money for the customer and improve the efficiency of both transmission and distribution facilities.
- **Technology Evaluation:** Members' staffs assist in the evaluation and implementation of technologies that benefit the productivity, profitability and energy efficiency of a C&I facility.

3.6 Anticipated Changes in Load Characteristics

The biggest anticipated change in future load characteristics is growth in non-member sales, which begin in 2018. The majority of non-member sales ramp in over a 4 year period, and are expected to reach 396 MW and just over 2,572 GWH by 2021. Non-member sales result from capacity that became available following the two aluminum smelter contract terminations in 2013 and 2014.

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[14] http://energy.ky.gov/Pages/default.aspx

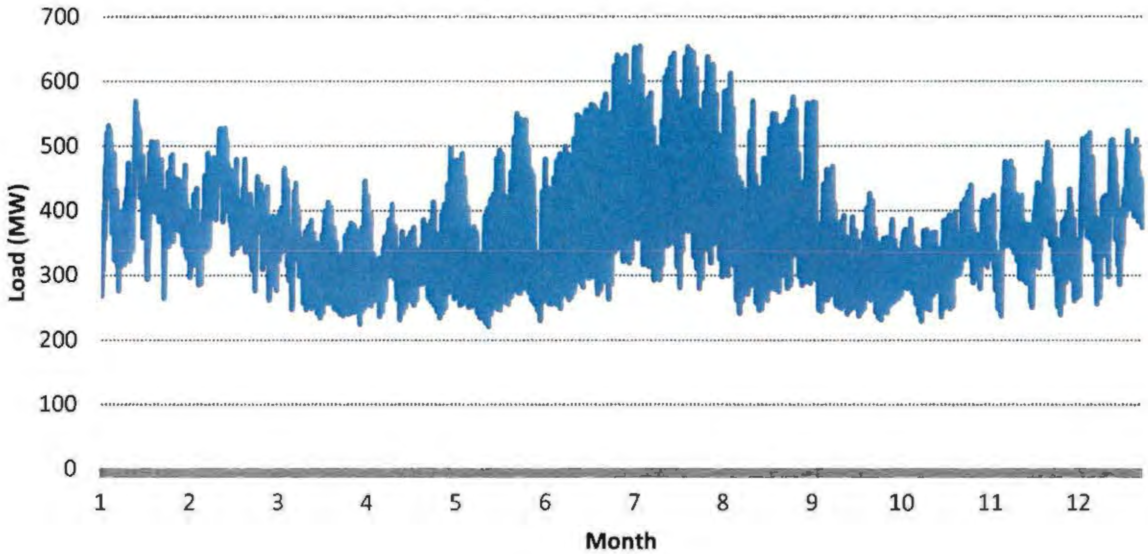
[15] Kentucky Pollution Prevention Center, https://louisville.edu/kppc/es/technical_services.html
Kentucky's Department for Energy Development and Independence, http://energy.ky.gov/Pages/default.aspx

[16] http://energy.gov/

[17] https://louisville.edu/kppc/

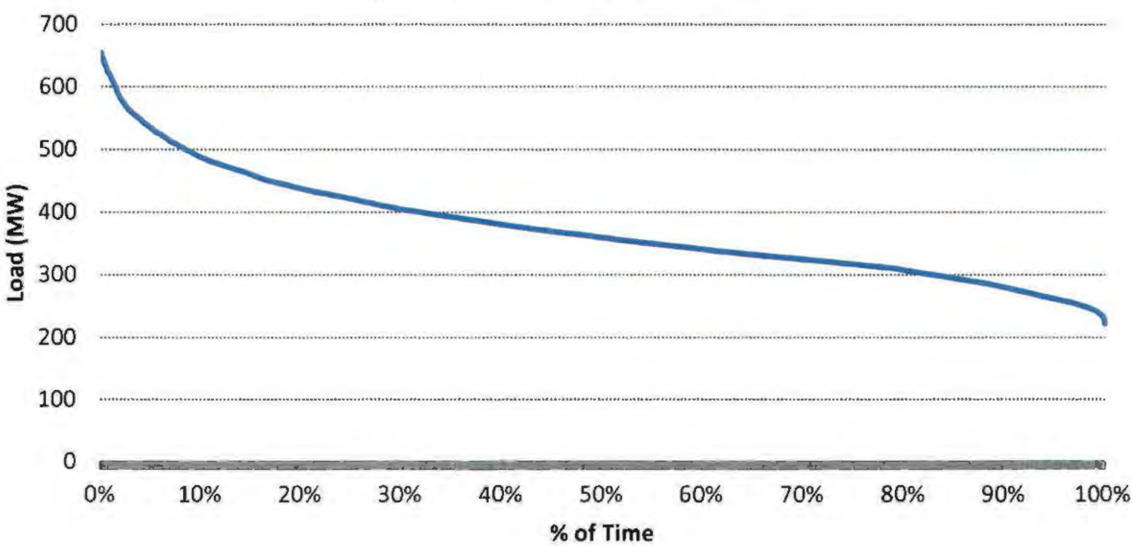
Big Rivers' hourly native system load shape for 2012 is presented in Figure 3.1. The Big Rivers system can be summer or winter peaking depending on the severity of seasonal temperatures; however, the system is projected to be summer peaking over the next 20 years.

Figure 3.1
2012 Annual Load Shape[18]



An annual load duration curve for 2012 native load is presented in Figure 3.2. Native system load factor for 2012 was approximately 60.9%.

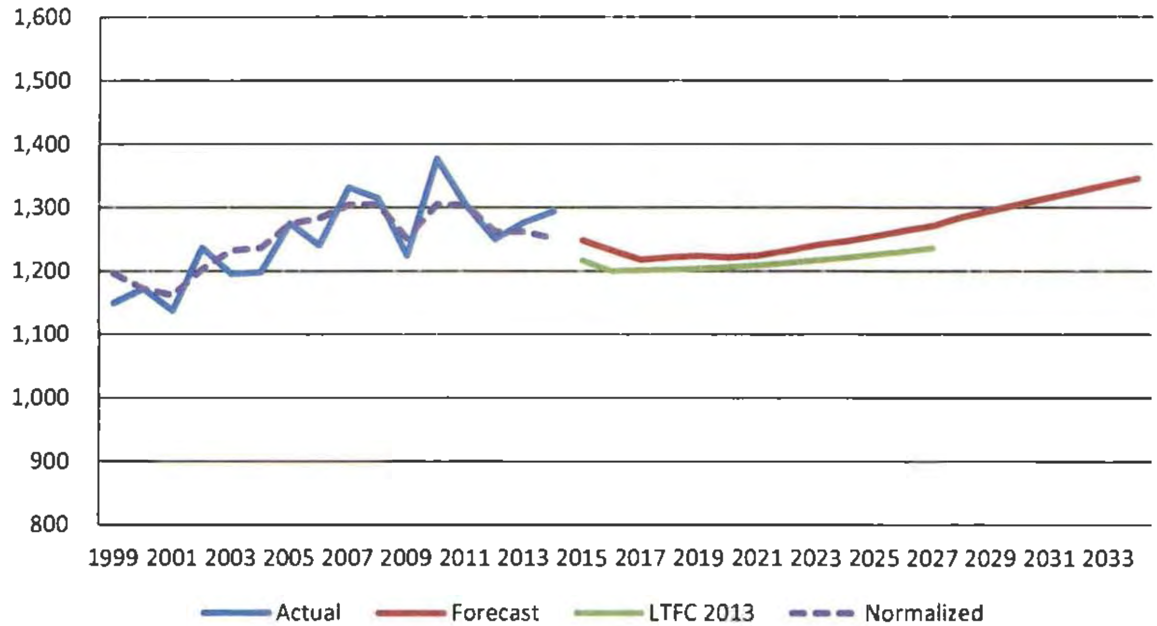
Figure 3.2
2012 Annual Load Duration Curve



[18] The load shape for 2012 displays a typical annual load shape with a summer peak.

Residential Consumption – Average kWh use per customer has leveled in recent years due primarily to energy conservation, reductions in lighting consumption associated with federal lighting standards, and increases in appliance efficiencies. Consumption is projected to decline over the near term as a result of continued increases in appliance efficiencies, energy conservation awareness, and [redacted] in retail price. Figure 3.3 presents average monthly kWh per customer for historical and projected periods.

Figure 3.3
Average Monthly Residential kWh Consumption per Customer by Year



3.7 Load Forecast Scenarios

Big Rivers' base case forecast reflects expected economic growth, normal weather conditions, and current EPA regulations. To address the inherent uncertainty related to these factors, long-term high and low range projections are developed. The range forecasts reflect the energy and demand requirements corresponding to more optimistic and pessimistic economic growth, and mild and extreme weather conditions. Tables 3.15 through 3.18 present the alternative forecast scenarios at the rural system and total system levels.[19] Results at the customer class level are presented in the Appendix B, pages B-9 through B-15.

3.7.1 Economy Scenarios

The optimistic and pessimistic economy scenarios reflect changes in energy sales at the class level and peak demand at the rural system and direct serve levels.

[19] Weather adjusted values for the base historical year, 2014, are presented in Tables 3.15 through 3.18 for comparison purposes

Residential - The energy sales forecast scenarios are based on an analysis of number of customers and average kWh use per customer. The optimistic customer forecast reflects average growth 50% above the base case forecast, and the pessimistic customer forecast reflects average growth 75% below the base case forecast. Inputs to the Residential average kWh use model were adjusted as follows in developing the optimistic/pessimistic scenarios:

- Average growth in household income was changed from 2.1% per year in the base case to 3.5% in the optimistic scenario and 0.5% in the pessimistic scenario.
- The price elasticity coefficient was changed from -0.19 in the base case to -0.09 in the optimistic scenario and -0.28 in the pessimistic scenario.

Residential energy sales are projected to increase at an average compound rate of 1.0% per year in the base case. Average growth increases to 1.7% per year in the optimistic scenario and falls to 0.2% per year in the pessimistic scenario.

Small Commercial - The energy sales forecast scenarios are based on an analysis of number of customers and average kWh use per customer. The optimistic customer forecast reflects average growth 50% above the base case forecast, and the pessimistic customer forecast reflects average growth 75% below the base case forecast. The high and low scenarios of average kWh use per customer for the Small Commercial class reflect average kWh use 10% above/below the base case forecast. Small Commercial energy sales are projected to increase at an average compound rate of 1.1% per year in the base case. Average growth increases to 2.1% per year in the optimistic scenario and falls to -0.3% per year in the pessimistic scenario.

Large Commercial-Rural – Energy sales in the optimistic and pessimistic scenarios are 20% higher or lower, respectively, than the base case. The addition or loss of 1 to 2 customers in this class could impact sales by 20%.

Large Commercial-Direct Serve – Energy sales in the optimistic and pessimistic scenarios are 5% higher and lower than the base case and reflect the assumption of the addition or loss of one customer.

Street Lighting – Energy sales for the optimistic and pessimistic scenarios are 5% higher or lower than the base case.

Irrigation - Energy sales for the optimistic and pessimistic scenarios are 20% higher or lower than the base case.

Rural Peak Demand – The optimistic and pessimistic scenarios in rural peak demand reflect the respective energy sales scenarios. Base case summer and winter load factors are applied to the optimistic and pessimistic rural system energy sales forecasts to derive the peak demand scenario forecasts.

Direct Serve Peak Demand – The optimistic and pessimistic scenarios reflect the base case values plus/minus 5 MW, which represents load associated with one direct serve customer.

Table 3.15
Optimistic/Pessimistic Economy
Total Native System

	Energy (MWH)			*Winter Peak Demand*			*Summer Peak Demand*		
	Pessimistic	*Base*	*Optimistic*	*Pess.*	*Base*	*Opti.*	*Pess.*	*Base*	*Opti.*
2014	*3,416,701*	*3,416,701*	*3,416,701*	*750*	*750*	*750*	*636*	*636*	*636*
2019	*3,216,429*	*3,485,661*	*3,821,015*	*618*	*671*	*739*	*625*	*679*	*748*
2024	*3,259,875*	*3,581,114*	*4,020,722*	*623*	*687*	*778*	*630*	*695*	*787*
2029	*3,331,796*	*3,691,436*	*4,240,800*	*637*	*710*	*825*	*644*	*718*	*834*
2034	*3,408,478*	*3,804,971*	*4,473,515*	*655*	*736*	*878*	*661*	*743*	*886*

Table 3.16
Optimistic/Pessimistic Economy
Rural System

	Energy (MWH)			*Winter Peak Demand*			*Summer Peak Demand*		
	Pessimistic	*Base*	*Optimistic*	*Pess.*	*Base*	*Opti.*	*Pess.*	*Base*	*Opti.*
2014	*2,330,615*	*2,330,615*	*2,330,615*	*514*	*514*	*514*	*515*	*515*	*515*
2019	*2,158,238*	*2,373,402*	*2,655,765*	*482*	*530*	*593*	*488*	*536*	*600*
2024	*2,200,487*	*2,468,340*	*2,856,438*	*486*	*546*	*631*	*492*	*552*	*639*
2029	*2,272,460*	*2,579,177*	*3,078,534*	*501*	*569*	*679*	*507*	*575*	*686*
2034	*2,348,757*	*2,692,712*	*3,312,775*	*519*	*595*	*732*	*524*	*600*	*739*

Values for 2014 in Tables 3.15 and 3.16 represent weather normalized amounts

3.7.2 Weather Scenarios

Rural system energy and peak demand is weather sensitive. The impact of weather on industrial customers is insignificant. Under extreme weather conditions, rural system energy is projected to be 5% higher than normal, and peak demand is projected to be approximately 8% higher than normal. The impact of extreme weather conditions on winter peak demands is approximately one and one-half times greater than the impact on summer peak demand.

Energy Sales - The extreme and mild weather scenarios were developed using the Residential and Small Commercial energy use models. The most extreme heating and cooling degree day values from the most recent 20 years were input into the regression models to estimate energy sales under extreme conditions. Heating degree days totaling 4,771 were recorded in 1996, and cooling degree days totaling 2,066 were recorded in 2010.[20]

Rural System Peak Demand – The extreme and mild weather scenarios were developed using base case energy and extreme load factors. Extreme winter season load factor was assumed at 42.7% in 2015,

[20] Average for Evansville, IN; Paducah, KY; and Louisville, KY

rising to 43.5% by 2034. Extreme summer load factor was assumed at 46.8% in 2015, rising to 47.6% by 2034.

Table 3.17
Mild/Extreme Weather
Total Native System

	Energy (MWH)			*Winter Peak Demand*			*Summer Peak Demand*		
	Mild	*Base*	*Extreme*	*Mild*	*Base*	*Extreme*	*Mild*	*Base*	*Extreme*
2014	*3,416,701*	*3,416,701*	*3,416,701*	*750*	*750*	*750*	*636*	*636*	*636*
2019	*3,337,359*	*3,485,661*	*3,630,685*	*583*	*671*	*778*	*627*	*679*	*721*
2024	*3,425,748*	*3,581,114*	*3,732,592*	*597*	*687*	*798*	*642*	*695*	*740*
2029	*3,527,621*	*3,691,436*	*3,850,411*	*617*	*710*	*823*	*662*	*718*	*763*
2034	*3,631,711*	*3,804,971*	*3,972,529*	*638*	*736*	*849*	*685*	*743*	*789*

Table 3.18
Mild/Extreme Weather
Rural System

	Energy (MWH)			*Winter Peak Demand*			*Summer Peak Demand*		
	Mild	*Base*	*Extreme*	*Mild*	*Base*	*Extreme*	*Mild*	*Base*	*Extreme*
2014	*2,330,615*	*2,330,615*	*2,330,615*	*514*	*514*	*514*	*515*	*515*	*515*
2019	*2,225,101*	*2,373,402*	*2,518,426*	*442*	*530*	*637*	*484*	*536*	*578*
2024	*2,312,974*	*2,468,340*	*2,619,818*	*456*	*546*	*656*	*499*	*552*	*597*
2029	*2,415,362*	*2,579,177*	*2,738,152*	*475*	*569*	*681*	*520*	*575*	*621*
2034	*2,519,452*	*2,692,712*	*2,860,270*	*497*	*595*	*708*	*543*	*600*	*646*

Values for 2014 in Tables 3.17 and 3.18 represent weather normalized amounts

3.8 Research and Development

Big Rivers conducts residential surveys periodically to monitor changes in household major appliances and various end-uses. This schedule is expected to continue in future years. Results from the surveys are used to develop key inputs for the load forecasting models.

Big Rivers will continue to utilize end-use data and information obtained from its appliance saturation studies, along with data available from the Energy Information Association ("EIA") and any other sources that may become available in the future.

Big Rivers will continue to review and test alternative forecasting model methodologies and model specifications. It is anticipated that statistically adjusted end-use models will be used to forecast average use per customer. Big Rivers will also evaluate developing models at the individual customer class level in addition to the higher level rural system and direct serve categories.

Big Rivers assists its three Members in evaluating the potential impacts of new energy efficiency and demand response programs. Big Rivers continues to monitor potential load management and other demand response type programs.

4. Forecast Methodology

The forecast was developed using quantitative and qualitative methods. Econometrics was used to develop forecasting models to project the number of customers and average energy consumption per customer for the Residential and Small Commercial classifications, and peak demand for the rural system. Informed judgment, combined with historical trends, was used to project energy consumption and peak demand for each large commercial customer. Number of customers and energy sales for the street lighting and irrigation classes were projected based on historical trends and judgement.

Big Rivers contracted with GDS to assist in developing the load forecast. The preliminary forecasts were reviewed with Member management. The Members' forecasts were finalized and aggregated to the Big Rivers level.

4.1 Load Forecast Database

Energy consumption and peak demand are influenced by a number of factors; therefore, a considerable amount of data was obtained in developing Big Rivers' load forecast. Energy, peak demand, and pricing data at the Big Rivers and Member levels were collected. Economic data was obtained to update the service area economic outlook. Various types of weather data for local weather stations were collected. Additionally, appliance market share and efficiency data were developed through surveys or obtained via independent sources. Table 4.1 identifies the data that are regularly collected and used in development of the load forecast.

Electric System Data – Number of customers, kWh sales, and sales revenue by customer class and month were collected from each Member distribution cooperative. Additionally, monthly rural system peak demand were collected. Hourly load data for the different components of Big Rivers' control area (rural system by distribution cooperative, HMP&L, and direct serve load) is available.

Economic Data - The economic outlook used in development of the 2015 Load Forecast was obtained from Moody's Analytics.[21] Data representing those counties in which the vast majority of Big Rivers' Members' customers reside was used to develop service area economic outlooks for each of Big Rivers' Members[22]. Historical and projected data series for number of households, average household income, total employment, retail sales, and gross regional product were collected. The economic outlook contains data on a monthly basis for 1980 – 2040.

Weather Data – Monthly heating and cooling degree days, and maximum and minimum monthly temperatures were collected for the Evansville, Indiana; Paducah, Kentucky; and Louisville, Kentucky weather stations[23]. Additionally, Big Rivers subscribes to the MDA EarthSat Weather[24], which provides hourly observations for multiple weather variables.

[21] Moody's Analytics, March 2015.

[22] Kenergy (Caldwell, Crittenden, Daviess, Hancock, Henderson, Hopkins, Lyon, Mclean, Ohio, Union, Webster)
JPEC (Ballard, Carlisle, Graves, Livingston, Marshall, McCracken)
MCRECC (Breckinridge, Grayson, Meade, Ohio)

[23] National Oceanic and Atmospheric Administration, http://www.ncdc.noaa.gov/IPS/lcd/lcd.html

[24] http://weather.earthsat.com/

Table 4.1
Load Forecast Database

Data Category	*Data Source*	*Data Element*
Electric System	*Big Rivers and its three member distribution cooperatives*	*Number of customers, kWh sales and revenues by class, system peak demand*
Economic	*Moody's Analytics*	*Number of households* *Total employment* *Average household income* *Retail sales* *Gross regional product* *Personal consumption expenditure index*
Weather	*National Oceanic and Atmospheric Administration*	*Heating and cooling degree days* *Temperature*
Price	*Big Rivers and its three member distribution cooperatives*	*Average cents per kWh*
End-use	*Big Rivers* *Energy Information Administration*	*Appliance saturations* *Appliance efficiencies* *Appliance unit energy consumption (kWh)*
Housing Characteristics	*Big Rivers* *Energy Information Administration*	*Size of home* *Number of people per home*

End-Use Data – Big Rivers conducts residential customer surveys periodically to collect data needed to estimate market share for different types of heating, cooling, and water heating systems and various household appliances. Additionally, data regarding housing characteristics were collected. Surveys were conducted in 2013 and 2009.

Appliance Efficiency Data – Big Rivers collects appliance efficiency information published by the EIA in its Annual Energy Outlook [25]. Average efficiencies for heating, cooling, water heating and other household appliances were obtained and provided information used in developing projections of average energy use per customer for rural system customers.

Housing Characteristics Data – Big Rivers conducts residential customer surveys periodically to collect data needed to estimate housing characteristics. Surveys were conducted in 2013 and 2009.

4.2 Forecast Model Inputs

Electric System Data – Number of customers, kWh sales, and sales revenue were obtained by customer class from the RUS Form 7 for each Member distribution cooperative. The data is available on a monthly

[25] http://www.eia.gov/analysis/projection-data.cfm#annualproj, Table 31.

basis. Monthly peak demand for the rural system is available from the data used in preparing wholesale power bills to the Members. Monthly energy and peak demand for each large industrial customer was provided by the Members. Hourly load data is available at different levels, including the native system, rural system, HMP&L, and direct serve categories.

Retail Price of Electricity - The load forecast includes the impacts of projected [redacted] in the real retail price of electricity over the forecast horizon. Average price reflects class revenue divided by class kWh. The amount was then expressed in real, or deflated, terms by applying the GDP price index ($2009=100). Projected retail electricity prices were developed by Big Rivers in collaboration with the Members. The price of competing fuels is quantified indirectly in the forecast through changes in the markets shares of electric space heating and electric water heating.

Economic Impacts - The forecast captures changes in number of households, average household income, and total employment. Number of households is the independent variable in the long term residential customer models. Household income is one of the driver variables specified in the residential use per customer models. Employment is the driver variable in the long term small commercial customer models. The projected values for each of these demographic and economic variables were obtained from Moody's Analytics.[26]

Appliance Market Share - The Members' forecasts incorporate service-area specific market shares of electric appliances and changes in technology. Projections of market share were based on Big Rivers' appliance saturation survey data, census data, and data obtained from the EIA. The market shares for electric heating, electric water heating, and electric air conditioning are all projected to increase throughout the forecast horizon, but at a decreasing rate as maximum saturation levels are approached. Market shares for all other appliances were based on data obtained from EIA.

Appliance Efficiency – Appliance efficiencies are included in the forecast to account for changes in consumption due to changes in the average efficiency of the major electric equipment and appliances in use. Changes in appliance efficiencies occur when customers replace older equipment with newer models. The appliance efficiency information included in the 2015 Load Forecast was obtained from EIA's Annual Energy Outlook.[27]

Weather Data – The load forecasting models incorporate weather data for Paducah, Kentucky; Louisville, Kentucky; and Evansville, Indiana. Heating and cooling degree days are included in the model to forecast rural system average energy use per customer to account for changes in consumption resulting from changes in weather. Similarly, peak day degree days are included in the model to forecast rural system peak demand to quantify the extremity of weather during peaking periods.

DSM and Government Sponsored Programs – The forecast implicitly includes through the historical energy sales data the impacts of Big Rivers' existing DSM programs and current educational and conservation programs. Impacts from increased participation in existing programs and from new

[26] Moody's Analytics, March 2015

[27] Energy Information Administration, *2015 Annual Energy Outlook*.

programs was obtained from Big Rivers' DSM studies and included in the forecast as a post-modeling adjustment.

4.3 Key Load Forecast Assumptions

The key assumptions made during the development of the 2015 Load Forecast focused on changes in the economy, weather, retail electricity price, appliance market shares, and appliance efficiencies. The assumptions apply broadly to each of the three Members and to Big Rivers.

Economic Outlook – Big Rivers' management concluded that changes in economic activity over the forecast horizon are reasonably represented by the projections obtained from Moody's Analytics. Economic outlooks were developed individually for each Member and quantified in the forecasting models. Historical and projected values for the economic data are presented in Table 4.2.

Table 4.2
Economic Outlook

Year	*Employment (thousands)*	*Real Gross Metro Product ($2005 millions)*	*Households (thousands)*	*Real Total Personal Income ($2009 millions)*	*Real Average Household Income ($)*	*Real Retail Sales ($2009 millions)*	*Price Index - GDP, (2009=100)*
2005	163.5	$14,231	158.9	$12,193	$77	$5,691	92.0
2006	164.3	$14,759	159.3	$12,328	$77	$5,713	94.8
2007	166.0	$14,429	159.9	$12,500	$78	$5,817	97.3
2008	164.8	$14,412	160.9	$13,062	$81	$5,599	99.2
2009	157.7	$13,863	161.1	$12,892	$80	$5,111	100.0
2010	158.3	$14,801	161.7	$13,016	$80	$5,364	101.2
2011	162.1	$15,216	162.6	$13,681	$84	$5,668	103.3
2012	163.9	$15,328	163.2	$13,976	$86	$5,715	105.2
2013	162.9	$15,575	163.2	$14,187	$87	$5,744	106.7
2014	163.5	$15,917	163.2	$14,552	$89	$5,807	108.3
2015	166.6	$16,293	164.0	$15,054	$92	$5,980	109.9
2016	169.3	$16,801	165.7	$15,657	$95	$6,187	111.7
2017	170.9	$17,355	167.3	$16,180	$97	$6,342	114.2
2018	171.6	$17,769	168.8	$16,647	$99	$6,471	117.0
2019	171.8	$18,085	169.5	$16,950	$100	$6,576	119.8
2020	171.8	$18,381	170.1	$17,278	$102	$6,670	122.3
2021	171.8	$18,713	170.7	$17,673	$104	$6,762	124.9
2022	172.1	$19,092	171.2	$18,122	$106	$6,860	127.5
2023	172.5	$19,479	171.8	$18,567	$108	$6,954	130.2
2024	172.6	$19,861	172.3	$19,021	$110	$7,051	132.8
2025	172.6	$20,247	172.7	$19,488	$113	$7,148	135.4
2026	172.5	$20,623	173.1	$19,969	$115	$7,238	138.1
2027	172.3	$20,999	173.4	$20,464	$118	$7,318	140.9
2028	172.3	$21,401	173.8	$20,967	$121	$7,417	143.7
2029	172.2	$21,817	174.1	$21,464	$123	$7,518	146.6
2030	172.2	$22,231	174.5	$21,964	$126	$7,615	149.5
2031	172.2	$22,661	174.9	$22,487	$129	$7,719	152.4
2032	172.3	$23,108	175.2	$23,042	$132	$7,822	155.4
2033	172.6	$23,562	175.6	$23,604	$134	$7,922	158.6
2034	173.2	$24,045	175.9	$24,178	$137	$8,037	161.7

Weather – The forecast is based on the assumption that heating and cooling degree days during the forecast horizon would be equal to the most recent 20-year averages. It was assumed that degree days for Paducah, Kentucky; Louisville, Kentucky; and Evansville, Indiana provided reliable coverage of weather conditions for the Big Rivers service area. Values in the following table represent averages for the three stations.

Table 4.3
Degree Days

Year	*Heating Degree Days*	*Cooling Degree Days*	*Winter Peak Temperature*	*Summer Peak Temperature*
1995	*4,258*	*1,672*		
1996	*4,771*	*1,314*		
1997	*4,574*	*1,227*		
1998	*3,596*	*1,751*		
1999	*3,840*	*1,512*	*3*	*101*
2000	*4,418*	*1,439*	*7*	*96*
2001	*3,997*	*1,514*	*2*	*95*
2002	*4,162*	*1,857*	*16*	*99*
2003	*4,284*	*1,249*	*0*	*95*
2004	*3,991*	*1,419*	*0*	*94*
2005	*4,096*	*1,678*	*-3*	*95*
2006	*3,801*	*1,440*	*7*	*95*
2007	*3,923*	*2,017*	*6*	*105*
2008	*4,399*	*1,559*	*8*	*96*
2009	*4,141*	*1,350*	*0*	*96*
2010	*4,452*	*2,066*	*3*	*103*
2011	*3,961*	*1,724*	*4*	*100*
2012	*3,460*	*1,925*	*15*	*107*
2013	*4,440*	*1,526*	*11*	*95*
2014	*4,674*	*1,608*	*-2*	*96*
Average	*4,162*	*1,592*	*5*	*98*

End-Use Characteristics – Assumptions regarding future changes in appliance saturation levels are based on historical trends developed from Big Rivers' appliance saturation surveys and data obtained from the EIA. It was assumed that the market shares for central electric space heating, central air conditioning, and electric water heating will continue to increase over time, but at declining rates as their respective maximum saturation levels are approached. Assumptions regarding changes in appliance efficiencies were based on information obtained from EIA's 2015 Annual Energy Outlook.

Table 4.4
Major Electric Appliance Market Shares and Efficiencies

Year	*Electric Heating*	*Electric Air Conditioning*	*Electric Water Heating*	*Electric Heating Efficiency*	*Air Conditioning Efficiency*	*Electric Water Heating Efficiency*
2010	*45.8%*	*87.5%*	*68.6%*	*7.39*	*12.28*	*0.90*
2011	*46.4%*	*87.6%*	*68.6%*	*7.46*	*12.44*	*0.90*
2012	*47.1%*	*87.6%*	*68.6%*	*7.53*	*12.58*	*0.90*
2013	*47.7%*	*87.6%*	*68.6%*	*7.59*	*12.72*	*0.91*
2014	*47.9%*	*87.6%*	*68.6%*	*7.65*	*12.86*	*0.91*
2015	*48.0%*	*87.6%*	*68.7%*	*7.70*	*12.98*	*0.91*
2016	*48.2%*	*87.7%*	*68.7%*	*7.76*	*13.11*	*0.92*
2017	*48.3%*	*87.8%*	*68.7%*	*7.81*	*13.22*	*0.93*
2018	*48.6%*	*87.8%*	*68.8%*	*7.86*	*13.33*	*0.94*
2019	*48.8%*	*87.9%*	*68.8%*	*7.91*	*13.43*	*0.94*
2020	*49.1%*	*88.0%*	*68.9%*	*7.95*	*13.53*	*0.95*
2021	*49.3%*	*88.1%*	*68.9%*	*7.99*	*13.62*	*0.96*
2022	*49.5%*	*88.2%*	*69.0%*	*8.03*	*13.71*	*0.96*
2023	*49.8%*	*88.3%*	*69.0%*	*8.07*	*13.79*	*0.97*
2024	*50.0%*	*88.4%*	*69.0%*	*8.10*	*13.86*	*0.98*
2025	*50.2%*	*88.4%*	*69.1%*	*8.13*	*13.92*	*0.98*
2026	*50.4%*	*88.5%*	*69.1%*	*8.16*	*13.99*	*0.99*
2027	*50.6%*	*88.6%*	*69.2%*	*8.19*	*14.04*	*0.99*
2028	*50.8%*	*88.7%*	*69.2%*	*8.21*	*14.09*	*0.99*
2029	*51.0%*	*88.7%*	*69.2%*	*8.23*	*14.13*	*1.00*
2030	*51.1%*	*88.8%*	*69.3%*	*8.25*	*14.17*	*1.00*
2031	*51.3%*	*88.9%*	*69.3%*	*8.27*	*14.21*	*1.00*
2032	*51.5%*	*88.9%*	*69.3%*	*8.29*	*14.26*	*1.00*
2033	*51.7%*	*89.0%*	*69.4%*	*8.32*	*14.30*	*1.00*
2034	*51.9%*	*89.1%*	*69.4%*	*8.34*	*14.34*	*1.00*

Electric Heating Efficiency represented as Heating Seasonal Performance Factor (HSPF)
Air Conditioning Efficiency represented as Seasonal Energy Efficiency Ratio (SEER)
Electric Water Heating Efficiency represented as Efficiency Factor (EF)

Retail Electricity Prices – The average price of electricity to rural system customers is expected to [redacted] and then [redacted] Projections were developed internally by Big Rivers' staff and representatives from each Member and represent the quotient of total class revenue and total class kWh.

Demand Side Management – The DSM impacts included in the forecast are based on the *Big Rivers' Electric Demand-Side Management Potential Study*, dated May 8, 2014. New measures were incorporated into the analysis of existing programs, but no new programs were added to the portfolio originally designed in 2010. The load forecast is based on the assumption that the impacts of existing DSM programs are captured through the historical energy sales a peak demand data used to develop the forecast models. The impacts of new measures are applied to results of the modeling analysis to produce the final forecasts. Table 4.5 presents the energy and demand impacts associated with DSM.

Table 4.5
DSM Program Impacts

Year	*Rural Energy Sales (MWh)*	*Energy Efficiency Program Impact (MWh)*	*Adjusted Energy Sales (MWh)*	*Rural Peak Demand (MW)*	*Energy Efficiency Program Impact (MW)*	*Adjusted Peak Demand (MW)*
2015	2,251,389	10,311	2,241,078	532	2	530
2016	2,244,386	15,823	2,228,562	534	3	531
2017	2,245,296	21,518	2,223,779	536	4	533
2018	2,270,141	27,389	2,242,752	539	4	534
2019	2,291,385	33,158	2,258,226	542	5	536
2020	2,306,824	39,034	2,267,791	545	6	539
2021	2,327,902	43,111	2,284,790	549	7	542
2022	2,354,472	48,343	2,306,129	552	7	545
2023	2,382,954	53,686	2,329,268	557	8	548
2024	2,407,769	59,192	2,348,577	561	9	552
2025	2,433,896	65,078	2,368,818	566	10	556
2026	2,460,959	71,506	2,389,452	571	11	561
2027	2,485,776	78,443	2,407,333	577	12	565
2028	2,518,488	86,065	2,432,423	583	13	570
2029	2,547,709	93,687	2,454,022	589	14	575
2030	2,576,931	101,309	2,475,622	595	15	580
2031	2,606,152	108,931	2,497,221	601	16	585
2032	2,635,374	116,554	2,518,820	607	17	590
2033	2,664,596	124,176	2,540,420	614	18	595
2034	2,693,817	131,798	2,562,019	620	19	600

Program MW impacts reflect summer season

4.4 Forecast Model Specification

Forecast models were developed to forecast the number of customers and average use per customer for the residential and small commercial classes and peak demand for rural system requirements. The models were developed individually for each of Big Rivers' Member distribution cooperatives. A rural system peak demand model was also developed at the Big Rivers level. Regression techniques are used to develop the forecasting models. All models are expressed in linear functional form and are developed using monthly time series data. Itron's MetrixND software was used to perform the modeling analysis.

4.4.1 Residential Class

Residential Customers – Two models were used in developing the customer forecasts for the member cooperatives, one for the short term and a second for the long term. The short term models are based on the recent past and extrapolate the trend over the first three years of the forecast horizon. The long term models quantify the impacts of the number of households in the service areas for each cooperative and produce projections for 15 years. Additionally, an autoregressive parameter is included in each long term model to correct for serial first-order autocorrelation, which is common in models specifying time series data. Theoretically, the number of residential customers increases when the number of households in the service area increases.

The short-term models produced forecasts that are slightly lower than projections based on the long-term models and project growth similar to that in recent years. The short term models were used to develop customer forecasts for up to three years. The long term models are more appropriate for forecasting over the long term because they capture the impacts of long term changes in the number of households.

The same modeling approach is applicable for each of Big Rivers' three Members. The short term models are expressed in linear form and take the specification:

$$\mathbf{RCUST} = \beta_0 + \beta_1\,\mathbf{(TREND)} + \varepsilon$$

RCUST	=	Number of residential customers
TREND	=	Time trend, the value for which increments by 1
β_0	=	Coefficient for the model constant, or intercept
β_1	=	Coefficient for the Trend parameter
ε	=	Unexplained model error

The long term models are expressed in linear form and take the specification:

$$\mathbf{RCUST} = \beta_0 + \beta_1\,\mathbf{(HH)} + \beta_2\,\mathbf{(AR)} + \varepsilon$$

RCUST	=	Number of rural system customers
HH	=	Number of households
β_0	=	Coefficient for the model constant, or intercept
β_1	=	Coefficient for the Households parameter
β_2	=	Coefficient for autoregressive parameter
ε	=	Unexplained model error

Refer to Appendix C, Forecast Model Specifications, for the statistical output for the individual customer models.

Residential Energy Use per Customer – A statistically adjusted end-use ("SAE") model was developed for each member cooperative to forecast average use per customer. The SAE modeling structure combines the benefits of both end-use and econometric models. For this forecast, three main indices, each representing key end-use components, are incorporated in a regression model, which provide the framework for measuring changes in residential consumption based on changes in the three indexes. Separate indexes are developed for space heating, air conditioning, and base load appliances. The structure of an example SAE model is illustrated in Figure 1 on the following page.

The data requirements for a true end-use model are relaxed in the SAE framework, as regional or national data for several inputs are utilized. Through regression techniques, these factors quantify changes in average monthly consumption. The response to multiple key drivers of electricity can be aggregated through the development of the three main indices, eliminating the primary weakness of a traditional econometric model, in which key factors are quantified individually.

Figure 1 –Statistically Adjusted End-Use Model

The indexes are quantified in the regression model; therefore, all the statistical diagnostics are produced, which provide a means for evaluating the SAE specification. The SAE model takes on the following form:

$$\textbf{RUSE} = \beta_0 + \beta_1\,\textbf{(HEAT)} + \beta_2\,\textbf{(COOL)} + \beta_3\,\textbf{(BASE)} + \beta_4 \ldots \beta_n\,\textbf{(Month)} + \varepsilon$$

Where

RUSE	=	Residential kWh use per consumer per month
HEAT	=	Space heating index
COOL	=	Air conditioning index
BASE	=	Base appliance index
β_0	=	Coefficient for the model constant, or intercept
β_1	=	Coefficient for the Heat parameter
β_2	=	Coefficient for the Cool parameter
β_3	=	Coefficient for the Base parameter
$\beta_4 \ldots \beta_n$	=	Coefficients for monthly binary variable parameters
ε	=	Unexplained model error

The average use per customer model is developed using monthly data.

The indices are developed as described below. The coefficients are estimated using least squares regression procedures.

Space Heating Index - The space heating index combines the following appliance, household, price, economic, and weather factors that directly impact the level of space heating electricity consumption in a home:

- Market share of electric space heating devices
- Average device efficiency
- Home size
- Number of householders
- Real retail price of electricity
- Household income
- Heating degree days

These variables increase or decrease the index depending on how they impact space heating consumption. Market share, size of home, income, and degree days all increase consumption as they increase. Device efficiency, home efficiency, and price of electricity decrease consumption as they increase. When available, system-level data is used for each of the heating factors. If system-specific data is not available, such as device efficiency, regional or national trends that are easier to obtain can be utilized. The index is developed on a monthly basis.

Air Conditioning Index - The air conditioning index is built in the same manner as the space heating index, but focuses instead on air conditioning equipment. The key variables used to develop the air conditioning index include:

- Market share of electric air conditioning devices, including room units
- Average device efficiency
- Home size
- Number of householders
- Real retail price of electricity
- Household income
- Cooling degree days

Base Load Index - The base load index captures the general trend associated with increased penetration of plug appliances, lighting, and water heating in the home. The base load index takes into account use associated with the following appliances and influential factors:

- Water heaters
- Refrigerators
- Separate freezers
- Electric ranges and ovens
- Electric clothes washers and dryers
- Dishwashers
- Televisions and DVRs
- Computers
- Lighting
- Miscellaneous load

The index is modified to include impacts associated with price of electricity, household income, and number of people in the household. As the real price of electricity goes up, the base load index goes down. An increase in household income has a positive effect on the base load index as more money is available for plug load electronics. The number of people in the household also has a positive effect on usage. More people in the home leads to more loads of laundry, more showers, more loads of dishes, and more lighting usage. The impact of weather on use of these appliances is negligible, so weather is not included as a factor in the base load index.

Price Elasticity - The real price of electricity parameter is expressed in annual amounts (value for each month held constant at the annual value) to mitigate the monthly variation in average price, which is expressed as revenue per kWh. The elasticity of demand with respect to price is derived through independent regression models and input as one of the factors impacting all three indexes. For all three member cooperatives, consumption is inelastic with respect to price, as a one percent change in average annual price does not produce a one percent or higher change in average annual consumption. The price elasticity coefficients for the three Members are listed below and compared to independent sources.

Table 4.6
Price Elasticity

Source	*Price Elasticity*
JPEC	*-0.18*
MCRECC	*-0.20*
Kenergy	*-0.19*
EIA	*-0.15*
RAND	*-0.30*
NREL	*-0.27*

EIA: Assumptions to the 2012 Annual Energy Outlook, Residential Demand Module
(http://www.eia.gov/forecasts/aeo/assumptions/pdf/0554(2012).pdf)
RAND: Rand Journal of Economics, Vol. 39, Nbr. 3, Autumn 2008, Peter Reiss and Mathew White
http://www.coursehero.com/file/5044646/21-Reiss-White-RJE-2008-Prices-And-Pressures/
NREL: National Renewable Energy Laboratory, February 2006
http://www.nrel.gov/docs/fy06osti/39512.pdf

Each of the Base, Heat, and Cool parameters in each model are significant at the 0.05 alpha, 95% confidence level, and there are no indications of collinearity problems between any of the model inputs. Refer to Appendix D, Econometric Model Specifications, for the statistical output for the individual average use per residential customer models.

Total Residential Energy Sales – Total residential energy sales are computed as the product of number of customers and average energy use per customer.

4.4.2 Small Commercial Class

Small Commercial Customers – Models were developed to forecast number of customers for both the short term and long term horizons. The short term models are based on the recent past and extrapolate the trend over the first three years of the forecast horizon. The long term models quantify the impacts of the employment growth in the service areas for each Member and provide projections for 15 years. Number of customers from the prior year was included in the JPEC and MCRECC long term models as independent variables to quantify impacts on customer growth that were not completely captured by employment. Similarly, changes in the number of residential customers were included in the Kenergy long term model as an independent variable. Additionally, an autoregressive parameter was used to correct for serial first-order autocorrelation.

The short term models are expressed in linear form and take the specification:

$$SCCUST = \beta_0 + \beta_1(TREND) + \varepsilon$$

SCCUST	=	Number of small commercial customers
TREND	=	Time trend, the value for which increments by 1
β_0	=	Coefficient for the model constant, or intercept
β_1	=	Coefficient for the Trend parameter
ε	=	Unexplained model error

The long term models are expressed in linear form and take the specifications:

Kenergy: $SCCUST = \beta_0 + \beta_1(EMP) + \beta_2(RCUST) + \beta_3(AR) + \varepsilon$

JPEC: $SCCUST = \beta_0 + \beta_1(EMP) + \beta_2(SCCUST_{t-1}) + \varepsilon$

MCRECC: $SCCUST = \beta_0 + \beta_1(EMP) + \beta_2(SCCUST_{t-1}) + \varepsilon$

SCCUST	=	Number of small commercial customers
EMP	=	Total non-farm employment
$SCCUST_{t-1}$	=	Number of small commercial customers from prior month
β_0	=	Coefficient for the model constant, or intercept
$\beta_1 \ldots \beta_n$	=	Coefficients for the respective model parameters
ε	=	Unexplained model error

See Appendix C, Econometric Model Specifications, for the statistical output for the customer models.

Small Commercial Energy Use per Customer - The Small Commercial classification consists of a wide variety of customers. Annual peak demands for customers in the class range from less than 5 kW for the smaller customers up to 999 kW for the largest customers. Factors impacting one group of customers in the class may not impact other groups. Average energy use per customer has been relatively flat or trending down over time. It is assumed that this trend will continue as older equipment is replaced with new, higher efficient units.

The models developed to forecast average use for each year of the forecast horizon quantify the impacts of increasing appliance efficiencies and weather conditions. The model for JPEC also includes average use from the prior year as an independent variable. The models are expressed in linear form and take the following specifications.

Kenergy: $SCUSE = \beta_0 + \beta_1(WTCDD) + \beta_2(WTHDD) + \beta_4 \ldots \beta_n(Month) + \varepsilon$

JPEC: $SCUSE = \beta_0 + \beta_1(WTCDD) + \beta_2(WTHDD) + \beta_2(SCUSE_{t-1}) + \beta_4 \ldots \beta_n(Month) + \varepsilon$

MCRECC: $SCUSE = \beta_0 + \beta_1(WTCDD) + \beta_2(WTHDD) + \beta_4 \ldots \beta_n(Month) + \varepsilon$

SCUSE	=	Small Commercial kWh use per consumer per month
WTCDD	=	Weighed cooling degree days (degree days x appliance efficiency)
WTHDD	=	Weighed heating degree days (degree days x appliance efficiency)
$SCUSE_{t-1}$	=	Small Commercial kWh use per consumer per month from prior month
β_0	=	Coefficient for the model constant, or intercept
$\beta_1 \ldots \beta_n$	=	Coefficients for the respective model parameters
ε	=	Unexplained model error

Total Small Commercial Energy Sales – Total small commercial energy sales are computed as the product of number of customers and average energy use per customer.

4.4.3 Large Commercial Class – Rural System

There are 29 rural system large commercial customers. Each is projected on an individual basis. Projections of number of customers, energy sales, and peak demand are set at the most recent historical values and adjusted for expected changes in operations that can be identified by Member management.

4.4.4 Large Commercial Class – Direct Serve

Beginning in 2015, there are 20 direct serve large commercial customers. The number drops to 19 in 2018. Each is projected on an individual basis. Projections of number of customers, energy sales, and peak demand are set at the most recent historical values and adjusted for expected changes in operations that can be identified by Member management.

4.4.5 Street Lighting Class

Street Lighting sales comprise approximately 0.1% of rural system sales. Projections of number of customers and energy sales are based on historical trends and judgement.

4.4.6 Irrigation Class

Irrigation sales comprise less than 0.1% of rural system sales. Projections of number of customers and energy sales are based on historical trends and judgement.

4.4.7 Rural System Peak Demand

Regression models are developed to project rural system peak demand for Big Rivers and for each Member. The Member system peaks may or may not occur with Big Rivers' one-hour rural system peak each month; therefore, Big Rivers' forecast for rural system peak is based on a model at the G&T level rather than the aggregate Member peaks. Growth in long term rural system demand tracks energy sales more than other influential factors; therefore, trended rural system energy sales is specified in the model as the primary driver of long term growth over the forecast horizon. Trended energy reflects the non-linear trend in historical and projected sales and excludes variations in sales due to weather. Peak day average daily temperature parameters are included for each month to capture swings in monthly and annual peaks due to weather conditions. Additionally, the square of peak day heating degree days is included to capture impacts from periods of extremely cold peaking conditions.

The model for Big Rivers is expressed in linear form and takes the following specification.

$$
\begin{aligned}
\mathbf{RURALPEAK} = \; & \beta_0 + \beta_1(\mathbf{EGY\_TREND}) \; + \\
& B_1(\mathbf{JANHEAT}) \; + \\
& B_2(\mathbf{FEBHEAT}) \; + \\
& \beta_3(\mathbf{MARHEAT}) \; + \\
& \beta_4(\mathbf{APRHEAT}) \; + \\
& \beta_5(\mathbf{APRCOOL}) \; + \\
& \beta_6(\mathbf{MAYCOOL}) \; +
\end{aligned}
$$

β_7 (JUNCOOL)	+	
β_8 (JULCOOL)	+	
β_9 (AUGCOOL)	+	
β_{10} (SEPCOOL)	+	
β_{11} (OCTCOOL)	+	
β_{12} (NOVHEAT)	+	
β_{13} (DECHEAT)	+	
β_{14} (PKHDD60SQ)	+	
β_{15} (AR)	+	ε

RURALPEAK	=	Rural system peak demand
EGY_TREND	=	Rural system energy trend
JANHEAT	=	Peak day heating degree days for January based on a 65 degree base
FEBHEAT	=	Peak day heating degree days for February based on a 65 degree base
MARHEAT	=	Peak day heating degree days for March based on a 65 degree base
APRHEAT	=	Peak day heating degree days for April based on a 65 degree base
APRCOOL	=	Peak day cooling degree days for April based on a 65 degree base
MAYCOOL	=	Peak day cooling degree days for May based on a 65 degree base
JUNCOOL	=	Peak day cooling degree days for June based on a 65 degree base
JULCOOL	=	Peak day cooling degree days for July based on a 65 degree base
AUGCOOL	=	Peak day cooling degree days for August based on a 65 degree base
SEPCOOL	=	Peak day cooling degree days for September based on a 65 degree base
OCTCOOL	=	Peak day cooling degree days for October based on a 65 degree base
NOVHEAT	=	Peak day heating degree days for November on a 65 degree base
DECHEAT	=	Peak day heating degree days for December based on a 65 degree base
PKHDD60SQ	=	Peak day heating degree days based on a 60 degree base
β_0	=	Coefficient for the model constant, or intercept
$\beta_1 \ldots \beta_{14}$	=	Coefficients for the respective model parameters
β_{15}	=	Coefficient for autoregressive parameter
ε	=	Unexplained model error

4.4.8 Native System Peak Demand

Native system peak demand is projected as the sum of rural system and direct serve peak demands. Direct serve peak demand is computed as the product of aggregate direct serve customer NCP and a projected coincidence factor, which represents the average of historical values.

4.4.9 Henderson Municipal Power & Light

Projections of Henderson Municipal Power & Light energy sales and peak demand are equal to those developed by HMP&L and provided to Big Rivers.

4.4.10 Non-Member Energy Sales and Peak Demand

Projections of non-member energy sales and peak demand are based on internal analysis completed by Big Rivers' staff. Projections reflect information available from Big Rivers' Energy Services Department as of July, 2015.

Appendix A – Annual Forecast Tables & Graphs

BIG RIVERS ELECTRIC CORPORATION

2015 LONG-TERM LOAD FORECAST - BASE CASE FORECAST

SYSTEM REQUIREMENTS - ADJUSTED FOR DSM

	Member System Retail Sales					Distr. Losses	Native Sales (@ distribution)		HMP&L (@ distr)	Non-Mbr (@distr)	Total (@distribution)		Trans. Losses	Native Energy Rquirements (w/transmission losses)			Total Energy Requirements (w/transmission losses)		
Year	Actual (MWh)	Normal (MWh)	DSM (MWh)	DSM Adj. (MWh)	Percent Growth	(%)	Actual (MWh)	Normal (MWh)	(MWh)	(MWh)	Actual (MWh)	Normal (MWH)	(%)	Actual (MWh)	Normal (MWh)	Percent Growth	Actual (MWh)	Normal (MWh)	Percent Growth
1999	3,354,913	3,360,125				3.3%	3,468,661	3,474,050	660,258		4,128,919	4,135,334	1.78%	3,531,522	3,537,009		4,203,746	4,210,276	
2000	3,419,939	3,379,802			1.9%	3.4%	3,540,719	3,499,164	659,001		4,199,720	4,150,431	1.56%	3,596,830	3,554,617	1.8%	4,266,274	4,216,204	0.1%
2001	3,192,415	3,247,382			-6.7%	2.8%	3,284,432	3,340,982	643,295		3,927,727	3,995,353	1.39%	3,330,729	3,388,076	-7.4%	3,983,091	4,051,671	-3.9%
2002	3,120,298	3,090,232			-2.3%	2.2%	3,191,176	3,160,427	673,932		3,865,108	3,827,865	1.27%	3,232,226	3,201,080	-3.0%	3,914,827	3,877,104	-4.3%
2003	3,004,389	3,064,453			-3.7%	1.6%	3,052,582	3,113,609	628,572		3,681,154	3,754,748	1.12%	3,087,158	3,148,877	-4.5%	3,722,850	3,797,277	-2.1%
2004	3,027,344	3,062,721			0.8%	3.3%	3,129,980	3,166,556	679,204		3,809,184	3,853,697	0.89%	3,158,087	3,194,992	2.3%	3,843,390	3,888,303	2.4%
2005	3,131,950	3,118,503			3.5%	3.1%	3,233,245	3,219,363	687,000		3,920,245	3,903,414	0.81%	3,259,648	3,245,653	3.2%	3,952,258	3,935,290	1.2%
2006	3,090,437	3,164,424			-1.3%	3.1%	3,188,986	3,265,332	673,114		3,862,100	3,954,561	0.78%	3,214,055	3,291,002	-1.4%	3,892,461	3,985,649	1.3%
2007	3,219,155	3,173,861			4.2%	3.2%	3,325,859	3,279,063	690,270		4,016,129	3,959,621	0.81%	3,353,018	3,305,841	4.3%	4,048,925	3,991,956	0.2%
2008	3,204,376	3,224,757			-0.5%	3.3%	3,313,571	3,334,646	658,517		3,972,088	3,997,351	0.80%	3,340,293	3,361,538	-0.4%	4,004,121	4,029,588	0.9%
2009	3,092,391	3,230,026			-3.5%	2.1%	3,159,286	3,299,898	588,663		3,747,949	3,914,761	0.78%	3,184,122	3,325,840	-4.7%	3,777,413	3,945,536	-2.1%
2010	3,317,423	3,245,497			7.3%	3.7%	3,445,715	3,371,007	643,103		4,088,818	4,000,166	0.83%	3,474,553	3,399,220	9.1%	4,123,039	4,033,645	2.2%
2011	3,279,929	3,312,538			-1.1%	3.1%	3,385,501	3,419,160	622,844		4,008,345	4,048,196	0.97%	3,418,662	3,452,651	-1.6%	4,047,607	4,087,848	1.3%
2012	3,367,558	3,438,395			2.7%	3.5%	3,488,924	3,562,315	622,254		4,111,178	4,197,658	1.09%	3,527,373	3,601,572	3.2%	4,156,484	4,243,916	3.8%
2013	3,438,437	3,475,152			2.1%	2.9%	3,540,787	3,578,596	617,149		4,157,936	4,202,335	1.37%	3,589,970	3,628,303	1.8%	4,215,691	4,260,706	0.4%
2014	3,330,195	3,303,556			-3.1%	3.3%	3,444,252	3,416,701	632,749		4,077,001	4,044,389	1.61%	3,500,612	3,472,610	-2.5%	4,143,715	4,110,569	-3.5%
2015		3,214,200	10,311	3,203,889	-3.8%	3.4%		3,318,236	626,868			3,945,104	2.05%		3,387,684	-3.2%		4,027,672	-2.0%
2016		3,314,616	15,823	3,298,793	3.0%	3.3%		3,412,505	630,001			4,042,506	2.29%		3,492,482	3.1%		4,137,249	2.7%
2017		3,360,401	21,518	3,338,884	1.2%	3.3%		3,452,322	633,154			4,085,476	2.29%		3,533,234	1.2%		4,181,227	1.1%
2018		3,382,399	27,389	3,355,010	0.5%	3.3%		3,469,403	636,317	417,575		4,523,294	2.29%		3,550,714	0.5%		4,629,305	10.7%
2019		3,403,643	33,158	3,370,485	0.5%	3.3%		3,485,661	639,499	1,197,810		5,322,970	2.29%		3,567,353	0.5%		5,447,723	17.7%
2020		3,419,599	39,034	3,380,565	0.3%	3.3%		3,496,216	645,896	1,885,633		6,027,746	2.29%		3,578,156	0.3%		6,169,016	13.2%
2021		3,440,161	43,111	3,397,049	0.5%	3.3%		3,513,561	652,354	2,572,520		6,738,435	2.29%		3,595,907	0.5%		6,896,361	11.8%
2022		3,466,731	48,343	3,418,388	0.6%	3.3%		3,535,988	658,876	2,701,698		6,896,563	2.29%		3,618,860	0.6%		7,058,195	2.3%
2023		3,495,213	53,686	3,441,526	0.7%	3.3%		3,560,308	665,468	2,706,927		6,932,703	2.29%		3,643,750	0.7%		7,095,183	0.5%
2024		3,520,543	59,192	3,461,351	0.6%	3.3%		3,581,114	672,120	2,712,223		6,965,457	2.29%		3,665,043	0.6%		7,128,705	0.5%
2025		3,546,155	65,078	3,481,077	0.6%	3.4%		3,601,873	678,841	2,717,589		6,998,303	2.29%		3,686,289	0.6%		7,162,320	0.5%
2026		3,573,217	71,506	3,501,711	0.6%	3.4%		3,623,562	685,562	2,723,024		7,032,148	2.29%		3,708,486	0.6%		7,196,958	0.5%
2027		3,598,034	78,443	3,519,592	0.5%	3.4%		3,642,351	692,283	2,728,530		7,063,164	2.29%		3,727,716	0.5%		7,228,701	0.4%
2028		3,631,262	86,065	3,545,197	0.7%	3.4%		3,669,244	699,004	2,734,035		7,102,284	2.29%		3,755,239	0.7%		7,268,738	0.6%
2029		3,659,968	93,687	3,566,281	0.6%	3.4%		3,691,436	705,725	2,739,541		7,136,702	2.29%		3,777,951	0.6%		7,303,963	0.5%
2030		3,689,190	101,309	3,587,880	0.6%	3.4%		3,714,143	712,446	2,745,047		7,171,636	2.29%		3,801,190	0.6%		7,339,715	0.5%
2031		3,718,411	108,931	3,609,480	0.6%	3.4%		3,736,850	719,167	2,750,553		7,206,570	2.29%		3,824,429	0.6%		7,375,468	0.5%
2032		3,748,148	116,554	3,631,595	0.6%	3.4%		3,760,072	725,888	2,756,059		7,242,019	2.29%		3,848,196	0.6%		7,411,748	0.5%
2033		3,776,854	124,176	3,652,678	0.6%	3.4%		3,782,264	732,609	2,761,565		7,276,437	2.29%		3,870,908	0.6%		7,446,973	0.5%
2034		3,806,076	131,798	3,674,278	0.6%	3.4%		3,804,971	739,330	2,767,070		7,311,371	2.29%		3,894,147	0.6%		7,482,726	0.5%

ANNUAL GROWTH RATES

Period	Actual	Normal	DSM	DSM Adj.	Percent Growth	Distr. Losses	Native Actual	Native Normal	HMP&L	Non-Mbr	Total Actual	Total Normal	Trans. Losses	NER Actual	NER Normal	NER Growth	TER Actual	TER Normal	TER Growth
1999-2004	-2.0%	-1.8%					-2.0%	-1.8%	0.6%		-1.6%	-1.4%		-2.2%	-2.0%		-1.8%	-1.6%	
2004-2009	0.4%	1.1%					0.2%	0.8%	-2.8%		-0.3%	0.3%		0.2%	0.8%		-0.3%	0.3%	
2009-2014	1.5%	0.5%					1.7%	0.7%	1.5%		1.7%	0.7%		1.9%	0.9%		1.9%	0.8%	
2014-2019		0.6%		0.4%				0.4%	0.2%			5.6%			0.5%			5.8%	
2019-2024		0.7%	12.3%	0.5%				0.5%	1.0%	17.8%		5.5%			0.5%			5.5%	
2024-2029		0.8%	12.3%	0.6%				0.5%	1.0%	17.8%		5.5%			0.5%			5.5%	
2029-2034		0.8%	7.1%	0.6%				0.6%	0.9%	0.2%		0.5%			0.6%			0.5%	
2014-2034		0.7%		0.5%				0.5%	0.8%			3.0%			0.6%			3.0%	

Member system retail sales include only power supplied by Big Rivers

Total Energy Requirements include HMP&L requirements and sales to non-members and native sales anticipated from marketing efforts

BIG RIVERS ELECTRIC CORPORATION

2015 LONG-TERM LOAD FORECAST - BASE CASE FORECAST

SYSTEM REQUIREMENTS - ADJUSTED FOR DSM

	Native Summer NCP (@distribution)					HMP&L (@ distr)	Non-Mbr (@distr)	Total Summer NCP (@distribution)				Native Summer NCP (w/transmisson losses)			Total System Summer NCP (w/transmission losses)		
Year	Actual (kW)	Normal (kW)	DSM (kW)	DSM Adj. (kW)	Load Factor	Actual (kW)	Actual (kW)	Actual (kW)	Normal (kW)	DSM Adj. (kW)	Load Factor	Actual (kW)	Normal (kW)	DSM Adj. (kW)	Actual (kW)	Normal (kW)	DSM Adj. (kW)
1999	663,890	-			59.6%	123,000		786,890			59.9%	675,922			801,151		
2000	655,248	665,330			61.7%	123,000		778,248	790,223		61.6%	665,632	675,874		790,582	802,745	
2001	596,310	637,285			62.9%	119,000		715,310	764,462		62.7%	604,716	646,268		725,393	775,238	
2002	602,623	610,846			60.5%	124,000		726,623	736,538		60.7%	610,375	618,704		735,970	746,012	
2003	583,906	587,666			59.7%	121,000		704,906	709,445		59.6%	590,520	594,323		712,890	717,481	
2004	604,155	641,432			59.1%	120,000		724,155	768,836		60.0%	609,581	647,192		730,658	775,740	
2005	603,783	607,926			61.1%	124,000		727,783	732,777		61.5%	608,713	612,890		733,726	738,761	
2006	619,258	638,279			58.8%	122,000		741,258	764,026		59.5%	624,126	643,297		747,085	770,033	
2007	647,502	616,033			58.6%	125,000		772,502	734,958		59.3%	652,789	621,064		778,810	740,960	
2008	604,334	613,863			62.6%	119,000		723,334	734,739		62.7%	609,208	618,813		729,168	740,664	
2009	594,126	607,076			60.7%	111,000		705,126	720,496		60.7%	598,797	611,849		710,669	726,160	
2010	651,634	617,337			60.4%	117,000		768,634	728,180		60.7%	657,087	622,504		775,067	734,274	
2011	652,127	635,368			59.3%	113,000		765,127	745,464		59.8%	658,514	641,591		772,621	752,766	
2012	654,218	622,159			60.9%	115,000		769,218	731,524		61.0%	661,427	629,016		777,695	739,586	
2013	608,899	625,912			66.4%	108,000		716,899	736,929		66.2%	617,356	634,606		726,856	747,165	
2014	601,935	636,118		636,118	65.3%	108,000		709,935	750,251	750,251	65.6%	611,785	646,527	646,527	721,552	762,528	762,528
2015		649,159	1,747	647,412	58.5%	110,000			759,159	757,412	59.5%		662,745	660,962		775,048	773,264
2016		669,945	2,653	667,293	58.4%	110,000			779,945	777,293	59.4%		685,647	682,932		798,225	795,510
2017		678,867	3,567	675,299	58.4%	111,000			789,867	786,299	59.3%		694,777	691,126		808,378	804,728
2018		681,541	4,494	677,047	58.5%	112,000	64,274		857,815	853,322	60.5%		697,514	692,915		877,919	873,321
2019		684,436	5,355	679,080	58.6%	112,000	186,406		982,841	977,486	62.2%		700,476	694,996		1,005,876	1,000,395
2020		687,660	6,224	681,436	58.6%	113,000	291,318		1,091,977	1,085,754	63.4%		703,776	697,407		1,117,570	1,111,200
2021		691,213	6,677	684,536	58.6%	114,000	396,156		1,201,369	1,194,692	64.4%		707,413	700,579		1,229,525	1,222,691
2022		695,096	7,414	687,682	58.7%	116,000	417,171		1,228,267	1,220,853	64.5%		711,387	703,798		1,257,054	1,249,465
2023		699,308	8,159	691,149	58.8%	117,000	418,044		1,234,352	1,226,194	64.5%		715,697	707,347		1,263,281	1,254,931
2024		703,849	8,938	694,912	58.8%	118,000	418,929		1,240,778	1,231,841	64.5%		720,345	711,198		1,269,858	1,260,711
2025		708,720	9,777	698,943	58.8%	119,000	419,825		1,247,545	1,237,768	64.5%		725,330	715,324		1,276,783	1,266,777
2026		713,920	10,700	703,220	58.8%	120,000	420,733		1,254,653	1,243,953	64.5%		730,652	719,702		1,284,058	1,273,107
2027		719,449	11,687	707,762	58.7%	121,000	421,652		1,262,102	1,250,414	64.5%		736,311	724,350		1,291,681	1,279,720
2028		725,308	12,781	712,527	58.8%	122,000	422,572		1,269,880	1,257,099	64.5%		742,307	729,226		1,299,641	1,286,561
2029		731,496	13,875	717,621	58.7%	123,000	423,491		1,277,987	1,264,113	64.4%		748,640	734,440		1,307,939	1,293,739
2030		737,684	14,968	722,716	58.7%	124,000	424,411		1,286,095	1,271,126	64.4%		754,973	739,654		1,316,236	1,300,917
2031		743,872	16,062	727,810	58.6%	125,000	425,330		1,294,202	1,278,140	64.4%		761,306	744,867		1,324,534	1,308,096
2032		750,060	17,155	732,904	58.6%	126,000	426,250		1,302,310	1,285,154	64.3%		767,639	750,081		1,332,831	1,315,274
2033		756,248	18,249	737,999	58.5%	127,000	427,169		1,310,417	1,292,168	64.3%		773,972	755,295		1,341,129	1,322,452
2034		762,436	19,343	743,093	58.5%	128,000	428,089		1,318,524	1,299,182	64.2%		780,305	760,509		1,349,426	1,329,630

ANNUAL GROWTH RATES

1999-2004	-1.9%					-0.5%		-1.6%				-2.0%			-1.8%		
2004-2009	-0.3%	-1.1%				-1.5%		-0.5%	-1.3%			-0.4%	-1.1%		-0.6%	-1.3%	
2009-2014	0.3%	0.9%				-0.5%		0.1%	0.8%			0.4%	1.1%		0.3%	1.0%	
2014-2019		1.5%		1.3%		0.7%			5.5%	5.4%			1.6%	1.5%		5.7%	5.6%
2019-2024		0.6%	10.8%	0.5%		1.0%	17.6%		4.8%	4.7%			0.6%	0.5%		4.8%	4.7%
2024-2029		0.8%	9.2%	0.6%		0.8%	0.2%		0.6%	0.5%			0.8%	0.6%		0.6%	0.5%
2029-2034		0.8%	6.9%	0.7%		0.8%	0.2%		0.6%	0.5%			0.8%	0.7%		0.6%	0.5%
2014-2034		0.9%		0.8%		0.9%			2.9%	2.8%			0.9%	0.8%		2.9%	2.8%

NCP represents the highest 1-hour peak demand recorded during the summer and winter seasons
Summer season is May to October
Total system peak includes native, HMP&L, and non-member load

BIG RIVERS ELECTRIC CORPORATION

2015 LONG-TERM LOAD FORECAST - BASE CASE FORECAST

SYSTEM REQUIREMENTS - ADJUSTED FOR DSM

	Native Winter NCP (@distribution)					HMP&L (@ distr)	Non-Mbr (@distr)	Total Winter NCP (@distribution)				Native Winter NCP (w/transmisson losses)			Total System Winter NCP (w/transmission losses)		
Year	Actual (kW)	Normal (kW)	DSM (kW)	DSM Adj. (kW)	Load Factor	Actual (kW)	Actual (kW)	Actual (kW)	Normal (kW)	DSM Adj. (kW)	Load Factor	Actual (kW)	Normal (kW)	DSM Adj. (kW)	Actual (kW)	Normal (kW)	DSM Adj. (kW)
1999	577,320				68.6%	92,000		669,320			70.4%	587,783			681,450		
2000	614,496	626,702			65.8%	96,000		710,496	724,609		67.5%	624,234	636,634		721,756	736,092	
2001	598,797	582,446			62.6%	95,000		693,797	674,852		64.6%	607,238	590,656		703,577	684,364	
2002	530,467	564,796			68.7%	100,000		630,467	671,267		70.0%	537,291	572,061		638,577	679,902	
2003	585,549	559,149			59.5%	92,000		677,549	647,002		62.0%	592,182	565,483		685,224	654,330	
2004	562,082	550,700			63.6%	96,000		658,082	644,756		66.1%	567,130	555,645		663,992	650,545	
2005	548,765	565,400			67.3%	98,000		646,765	666,371		69.2%	553,246	570,017		652,046	671,813	
2006	576,534	608,047			63.1%	98,000		674,534	711,403		65.4%	581,066	612,827		679,837	716,996	
2007	597,267	596,590			63.6%	101,000		698,267	697,475		65.7%	602,144	601,462		703,969	703,171	
2008	611,454	625,449			61.9%	100,000		711,454	727,738		63.7%	616,385	630,493		717,191	733,606	
2009	664,788	643,585			54.3%	95,000		759,788	735,555		56.3%	670,014	648,645		765,761	741,338	
2010	646,750	651,364			60.8%	95,000		741,750	747,041		62.9%	652,163	656,815		747,958	753,294	
2011	620,588	594,196			62.3%	92,000		712,588	682,283		64.2%	626,666	600,016		719,567	688,966	
2012	569,006	625,199			70.0%	89,000		658,006	722,989		71.3%	575,276	632,089		665,257	730,956	
2013	596,831	589,426			67.7%	93,000		689,831	681,272		68.8%	605,121	597,613		699,412	690,735	
2014	740,203	637,849		637,849	53.1%	102,000		842,203	725,744	725,744	55.3%	752,315	648,286	648,286	855,984	737,620	737,620
2015		639,390	1,530	637,860	59.4%	94,000			733,390	731,860	61.5%		652,772	651,210		748,739	747,177
2016		654,597	2,333	652,264	59.7%	95,000			749,597	747,264	61.8%		669,938	667,551		767,165	764,777
2017		670,612	3,150	667,463	59.0%	95,000			765,612	762,463	61.2%		686,329	683,106		783,556	780,332
2018		673,185	3,978	669,207	59.2%	96,000	63,628		832,813	828,835	62.3%		688,962	684,891		852,332	848,260
2019		675,915	4,750	671,165	59.3%	96,000	181,778		953,694	948,943	64.0%		691,756	686,895		976,045	971,183
2020		678,975	5,535	673,439	59.3%	97,000	286,470		1,062,444	1,056,909	65.1%		694,888	689,222		1,087,345	1,081,679
2021		682,363	5,666	676,697	59.3%	98,000	391,083		1,171,447	1,165,780	66.0%		698,356	692,557		1,198,902	1,193,102
2022		686,082	6,330	679,752	59.4%	99,000	410,769		1,195,851	1,189,521	66.2%		702,161	695,683		1,223,878	1,217,399
2023		690,129	7,005	683,124	59.5%	100,000	411,559		1,201,688	1,194,684	66.2%		706,303	699,134		1,229,852	1,222,683
2024		694,506	7,635	686,871	59.5%	101,000	412,360		1,207,865	1,200,231	66.2%		710,783	702,969		1,236,174	1,228,360
2025		699,212	8,296	690,916	59.5%	102,000	413,170		1,214,382	1,206,086	66.2%		715,599	707,108		1,242,843	1,234,353
2026		704,247	9,010	695,237	59.5%	103,000	413,992		1,221,239	1,212,228	66.2%		720,752	711,531		1,249,860	1,240,639
2027		709,612	9,742	699,870	59.4%	104,000	414,823		1,228,435	1,218,693	66.2%		726,243	716,272		1,257,226	1,247,255
2028		715,306	10,541	704,765	59.4%	105,000	415,655		1,235,961	1,225,420	66.2%		732,070	721,282		1,264,928	1,254,140
2029		721,329	11,340	709,989	59.4%	106,000	416,487		1,243,816	1,232,476	66.1%		738,235	726,629		1,272,967	1,261,361
2030		727,352	12,139	715,213	59.3%	107,000	417,319		1,251,671	1,239,532	66.0%		744,399	731,975		1,281,006	1,268,583
2031		733,375	12,938	720,437	59.2%	108,000	418,151		1,259,527	1,246,588	66.0%		750,563	737,322		1,289,046	1,275,804
2032		739,399	13,737	725,662	59.2%	109,000	418,983		1,267,382	1,253,645	65.9%		756,728	742,669		1,297,085	1,283,026
2033		745,422	14,536	730,886	59.1%	110,000	419,815		1,275,237	1,260,701	65.9%		762,892	748,016		1,305,124	1,290,248
2034		751,445	15,335	736,110	59.0%	111,000	420,647		1,283,092	1,267,757	65.8%		769,057	753,362		1,313,163	1,297,469

ANNUAL GROWTH RATES

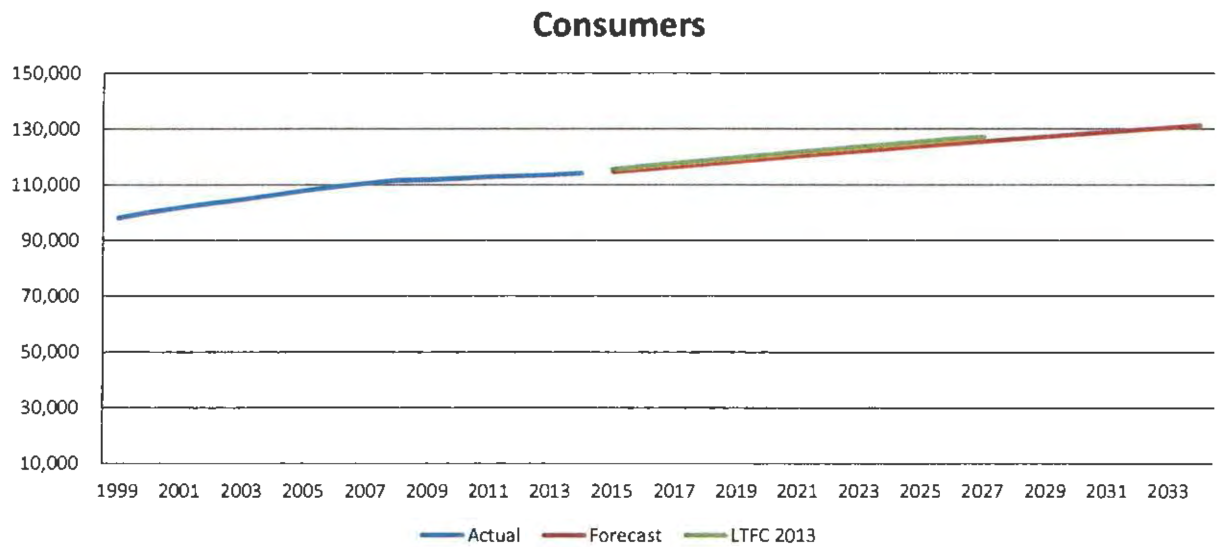
1999-2004	-0.5%					0.9%		-0.3%				-0.7%			-0.5%		
2004-2009	3.4%	3.2%				-0.2%		2.9%	2.7%			3.4%	3.1%		2.9%	2.6%	
2009-2014	2.2%	-0.2%				1.4%		2.1%	-0.3%			2.3%	0.0%		2.3%	-0.1%	
2014-2019		1.2%		1.0%		-1.2%			5.6%	5.5%			1.3%	1.2%		5.8%	5.7%
2019-2024		0.5%	10.0%	0.5%		1.0%	17.8%		4.8%	4.8%			0.5%	0.5%		4.8%	4.8%
2024-2029		0.8%	8.2%	0.7%		1.0%	0.2%		0.6%	0.5%			0.8%	0.7%		0.6%	0.5%
2029-2034		0.8%	6.2%	0.7%		0.9%	0.2%		0.6%	0.6%			0.8%	0.7%		0.6%	0.6%
2014-2034		0.8%		0.7%		0.4%			2.9%	2.8%			0.9%	0.8%		2.9%	2.9%

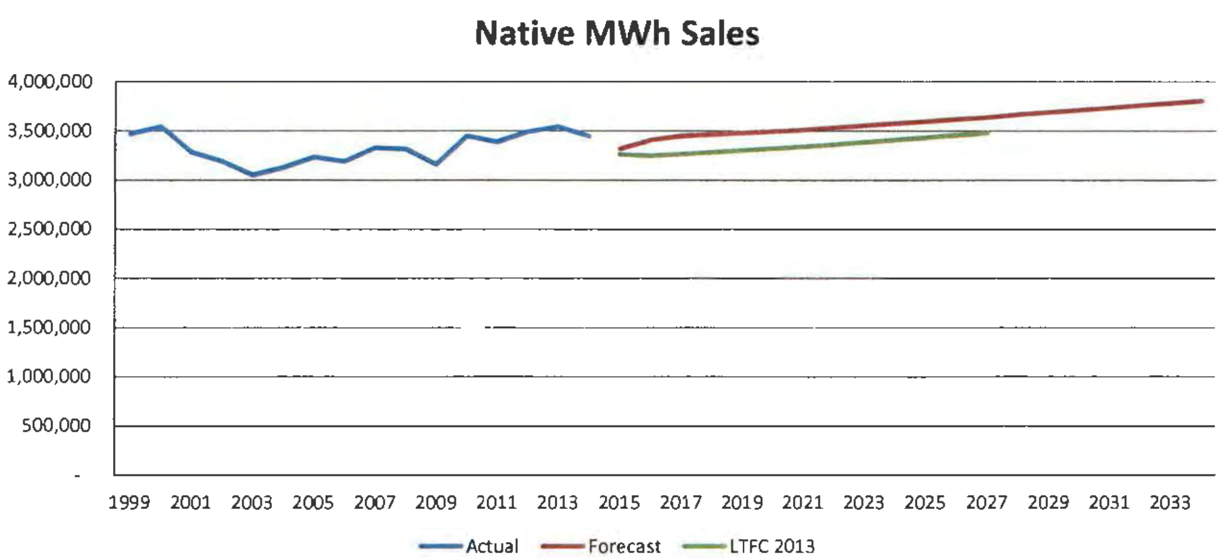
NCP represents the highest 1-hour peak demand recorded during the summer and winter seasons
Winter season is November of the prior year through April of the reported year
Total system peak includes native, HMP&L, and non-member load

BIG RIVERS ELECTRIC CORPORATION

2015 LONG-TERM LOAD FORECAST - BASE CASE FORECAST

SYSTEM REQUIREMENTS - ADJUSTED FOR DSM

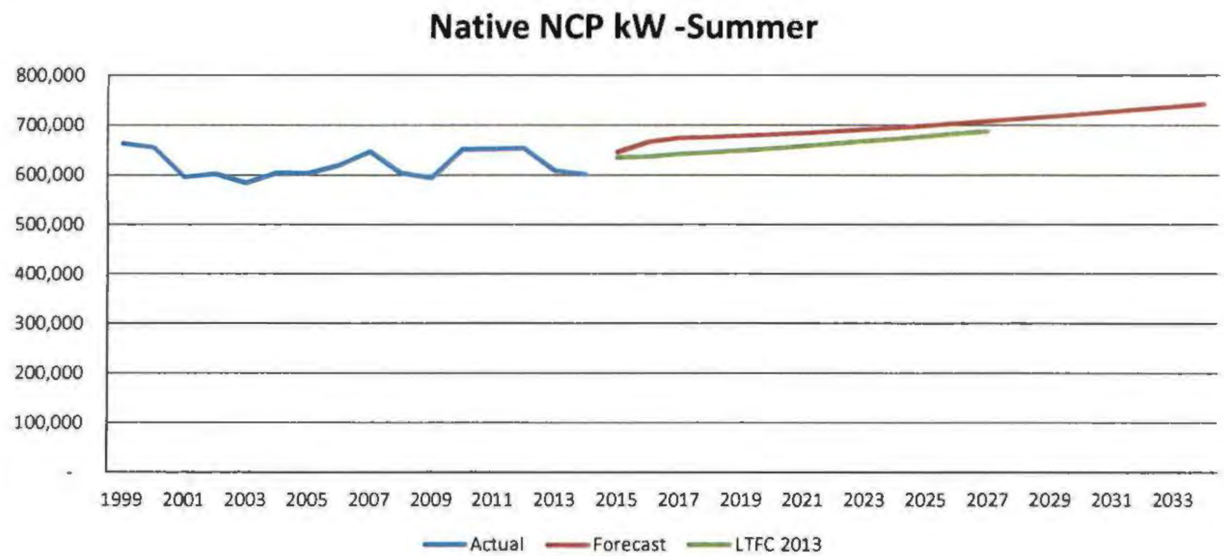


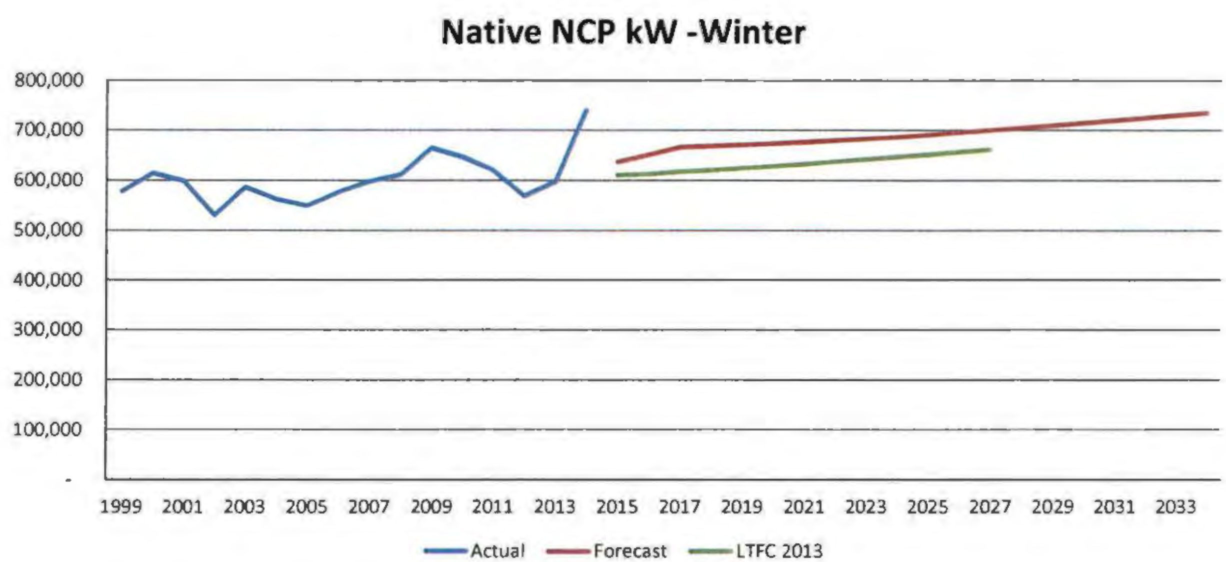


BIG RIVERS ELECTRIC CORPORATION

2015 LONG-TERM LOAD FORECAST - BASE CASE FORECAST

SYSTEM REQUIREMENTS - ADJUSTED FOR DSM





BIG RIVERS ELECTRIC CORPORATION

2015 LONG-TERM LOAD FORECAST - BASE CASE FORECAST

TOTAL SYSTEM SALES TO MEMBERS - NO DSM ADJUSTMENT

Year	Consumers	Percent Growth	Actual Mbr. Sales (MWh)	Normal Mbr. Sales (MWh)	Percent Growth	Distr. Line Loss	Actual Sales (MWh)	Normal Sales (MWh)	Percent Growth
1999	98,170		3,354,913	3,360,125		3.2%	3,466,380	3,471,020	
2000	100,272	2.1%	3,419,939	3,379,802	0.6%	3.4%	3,540,923	3,498,602	0.8%
2001	101,989	1.7%	3,192,415	3,247,382	-3.9%	3.3%	3,301,563	3,357,014	-4.0%
2002	103,482	1.5%	3,120,298	3,090,232	-4.8%	3.5%	3,233,105	3,199,595	-4.7%
2003	104,764	1.2%	3,004,389	3,064,453	-0.8%	3.5%	3,112,481	3,172,912	-0.8%
2004	106,414	1.6%	3,027,344	3,062,721	-0.1%	3.4%	3,134,981	3,170,576	-0.1%
2005	107,883	1.4%	3,131,950	3,118,503	1.8%	3.4%	3,243,103	3,227,681	1.8%
2006	109,329	1.3%	3,090,437	3,164,424	1.5%	3.3%	3,196,272	3,271,644	1.4%
2007	110,585	1.1%	3,219,155	3,173,861	0.3%	3.4%	3,331,224	3,283,482	0.4%
2008	111,693	1.0%	3,204,376	3,224,757	1.6%	3.5%	3,321,469	3,340,617	1.7%
2009	111,923	0.2%	3,092,391	3,230,026	0.2%	3.6%	3,207,143	3,345,993	0.2%
2010	112,391	0.4%	3,317,423	3,245,497	0.5%	3.6%	3,442,678	3,365,636	0.6%
2011	112,888	0.4%	3,279,929	3,312,538	2.1%	3.2%	3,387,368	3,419,334	1.6%
2012	113,252	0.3%	3,367,558	3,438,395	3.8%	3.5%	3,488,817	3,558,817	4.1%
2013	113,553	0.3%	3,438,437	3,475,152	1.1%	2.9%	3,541,242	3,576,724	0.5%
2014	114,210	0.6%	3,330,195	3,303,556	-4.9%	3.4%	3,445,639	3,416,209	-4.5%
2015	114,864	0.6%		3,214,200	-2.7%	3.5%		3,329,072	-2.6%
2016	115,694	0.7%		3,314,616	3.1%	3.3%		3,429,139	3.0%
2017	116,511	0.7%		3,360,401	1.4%	3.3%		3,474,953	1.3%
2018	117,529	0.9%		3,382,399	0.7%	3.3%		3,498,215	0.7%
2019	118,538	0.9%		3,403,643	0.6%	3.3%		3,520,547	0.6%
2020	119,523	0.8%		3,419,599	0.5%	3.3%		3,537,288	0.5%
2021	120,465	0.8%		3,440,161	0.6%	3.3%		3,558,925	0.6%
2022	121,386	0.8%		3,466,731	0.8%	3.3%		3,586,858	0.8%
2023	122,313	0.8%		3,495,213	0.8%	3.4%		3,616,801	0.8%
2024	123,206	0.7%		3,520,543	0.7%	3.4%		3,643,399	0.7%
2025	124,067	0.7%		3,546,155	0.7%	3.4%		3,670,351	0.7%
2026	124,910	0.7%		3,573,217	0.8%	3.4%		3,698,802	0.8%
2027	125,712	0.6%		3,598,034	0.7%	3.4%		3,724,887	0.7%
2028	126,511	0.6%		3,631,262	0.9%	3.4%		3,759,795	0.9%
2029	127,313	0.6%		3,659,968	0.8%	3.4%		3,790,001	0.8%
2030	128,115	0.6%		3,689,190	0.8%	3.4%		3,820,723	0.8%
2031	128,917	0.6%		3,718,411	0.8%	3.5%		3,851,445	0.8%
2032	129,719	0.6%		3,748,148	0.8%	3.5%		3,882,682	0.8%
2033	130,521	0.6%		3,776,854	0.8%	3.5%		3,912,889	0.8%
2034	131,324	0.6%		3,806,076	0.8%	3.5%		3,943,611	0.8%

ANNUAL GROWTH RATES

1999-2004	1.6%		-2.0%	-1.8%			-2.0%	-1.8%	
2004-2009	1.0%		0.4%	1.1%			0.5%	1.1%	
2009-2014	0.4%		1.5%	0.5%			1.4%	0.4%	
2014-2019	0.7%			0.6%				0.6%	
2019-2024	0.8%			0.7%				0.7%	
2019-2029	0.7%			0.8%				0.8%	
2024-2034	0.6%			0.8%				0.8%	
2014-2034	0.7%			0.7%				0.7%	

BIG RIVERS ELECTRIC CORPORATION

2015 LONG-TERM LOAD FORECAST - BASE CASE FORECAST

TOTAL SYSTEM SALES TO MEMBERS - NO DSM ADJUSTMENT

Year	Summer Actual NCP (kW)	Summer Normal NCP (kW)	Percent Growth	Load Factor	Winter Native NCP (kW)	Winter Normal NCP (kW)	Percent Growth	Load Factor
1999	663,890			59.6%	577,320			68.5%
2000	655,248	665,330	-1.3%	61.7%	614,496	626,702	6.4%	65.8%
2001	596,310	637,285	-9.0%	63.2%	598,797	582,446	-2.6%	62.9%
2002	602,623	610,846	1.1%	61.2%	530,467	564,796	-11.4%	69.6%
2003	583,906	587,666	-3.1%	60.8%	585,549	559,149	10.4%	60.7%
2004	604,155	641,432	3.5%	59.2%	562,082	550,700	-4.0%	63.7%
2005	603,783	607,926	-0.1%	61.3%	548,765	565,400	-2.4%	67.5%
2006	619,258	638,279	2.6%	58.9%	576,534	608,047	5.1%	63.3%
2007	647,502	616,033	4.6%	58.7%	597,267	596,590	3.6%	63.7%
2008	604,334	613,863	-6.7%	62.7%	611,454	625,449	2.4%	62.0%
2009	594,126	607,076	-1.7%	61.6%	664,788	643,585	8.7%	55.1%
2010	651,634	617,337	9.7%	60.3%	646,750	651,364	-2.7%	60.8%
2011	652,127	635,368	0.1%	59.3%	620,588	594,196	-4.0%	62.3%
2012	654,218	622,159	0.3%	60.9%	569,006	625,199	-8.3%	70.0%
2013	608,899	625,912	-6.9%	66.4%	596,831	589,426	4.9%	67.7%
2014	601,935	636,118	-1.1%	65.3%	740,203	637,849	24.0%	53.1%
2015		649,159	2.1%	58.5%		639,390	0.2%	59.4%
2016		669,945	3.2%	58.4%		654,597	2.4%	59.8%
2017		678,867	1.3%	58.4%		670,612	2.4%	59.2%
2018		681,541	0.4%	58.6%		673,185	0.4%	59.3%
2019		684,436	0.4%	58.7%		675,915	0.4%	59.5%
2020		687,660	0.5%	58.7%		678,975	0.5%	59.5%
2021		691,213	0.5%	58.8%		682,363	0.5%	59.5%
2022		695,096	0.6%	58.9%		686,082	0.5%	59.7%
2023		699,308	0.6%	59.0%		690,129	0.6%	59.8%
2024		703,849	0.6%	59.1%		694,506	0.6%	59.9%
2025		708,720	0.7%	59.1%		699,212	0.7%	59.9%
2026		713,920	0.7%	59.1%		704,247	0.7%	60.0%
2027		719,449	0.8%	59.1%		709,612	0.8%	59.9%
2028		725,308	0.8%	59.2%		715,306	0.8%	60.0%
2029		731,496	0.9%	59.1%		721,329	0.8%	60.0%
2030		737,684	0.8%	59.1%		727,352	0.8%	60.0%
2031		743,872	0.8%	59.1%		733,375	0.8%	60.0%
2032		750,060	0.8%	59.1%		739,399	0.8%	59.9%
2033		756,248	0.8%	59.1%		745,422	0.8%	59.9%
2034		762,436	0.8%	59.0%		751,445	0.8%	59.9%

ANNUAL GROWTH RATES				
1999-2004	-1.9%		-0.5%	
2004-2009	-0.3%		3.4%	
2009-2014	0.3%		2.2%	
2014-2019		1.5%		1.2%
2019-2024		0.6%		0.5%
2019-2029		0.8%		0.8%
2024-2034		0.8%		0.8%
2014-2034		0.9%		0.8%

NCP represents the highest 1-hour peak demand recorded during the summer and winter seasons
Summer season is May to October. Winter season is November of the prior year through April of the reported year.

BIG RIVERS ELECTRIC CORPORATION

2015 LONG-TERM LOAD FORECAST - BASE CASE FORECAST

RURAL SYSTEM REQUIREMENTS - ADJUSTED FOR DSM

Year	Actual Sales (MWh)	Projected Sales (MWh)	DSM Sales (MWh)	DSM Adj. Sales (MWh)	Percent Growth	Line Loss	DSM Adj. Purchases (MWh)	Normalized (MWh)	Percent Growth
1999	1,810,326					5.8%	1,921,792	1,878,683	
2000	1,880,555				3.9%	6.0%	2,001,539	1,905,521	1.4%
2001	1,891,730				0.6%	5.5%	2,000,877	2,005,688	5.3%
2002	2,002,034				5.8%	5.3%	2,114,841	2,033,135	1.4%
2003	1,981,586				-1.0%	5.2%	2,089,678	2,106,254	3.6%
2004	2,025,554				2.2%	5.0%	2,133,190	2,122,615	0.8%
2005	2,150,864				6.2%	4.9%	2,262,017	2,195,757	3.4%
2006	2,126,746				-1.1%	4.7%	2,232,581	2,258,048	2.8%
2007	2,292,340				7.8%	4.8%	2,407,449	2,307,012	2.2%
2008	2,282,771				-0.4%	4.4%	2,387,974	2,352,719	2.0%
2009	2,124,010				-7.0%	5.1%	2,238,762	2,325,872	-1.1%
2010	2,355,166				10.9%	5.0%	2,480,421	2,345,996	0.9%
2011	2,263,573				-3.9%	4.5%	2,371,106	2,352,481	0.3%
2012	2,200,119				-2.8%	5.2%	2,321,478	2,336,110	-0.7%
2013	2,271,660				3.3%	4.3%	2,374,920	2,359,410	1.0%
2014	2,300,120	2,239,312	-	2,239,312	1.3%	4.8%	2,415,564	2,330,615	-1.2%
2015		2,251,389	10,311	2,241,078	-2.6%	4.9%		2,355,425	-2.5%
2016		2,244,386	15,823	2,228,562	-0.6%	4.9%		2,342,274	-0.6%
2017		2,245,296	21,518	2,223,779	-0.2%	4.9%		2,337,217	-0.2%
2018		2,270,141	27,389	2,242,752	0.9%	4.9%		2,357,144	0.9%
2019		2,291,385	33,158	2,258,226	0.7%	4.9%		2,373,402	0.7%
2020		2,306,824	39,034	2,267,791	0.4%	4.9%		2,383,442	0.4%
2021		2,327,902	43,111	2,284,790	0.7%	4.9%		2,401,302	0.7%
2022		2,354,472	48,343	2,306,129	0.9%	4.9%		2,423,730	0.9%
2023		2,382,954	53,686	2,329,268	1.0%	4.9%		2,448,050	1.0%
2024		2,407,769	59,192	2,348,577	0.8%	4.9%		2,468,340	0.8%
2025		2,433,896	65,078	2,368,818	0.9%	4.9%		2,489,615	0.9%
2026		2,460,959	71,506	2,389,452	0.9%	4.9%		2,511,303	0.9%
2027		2,485,776	78,443	2,407,333	0.7%	4.9%		2,530,093	0.7%
2028		2,518,488	86,065	2,432,423	1.0%	4.9%		2,556,470	1.0%
2029		2,547,709	93,687	2,454,022	0.9%	4.9%		2,579,177	0.9%
2030		2,576,931	101,309	2,475,622	0.9%	4.9%		2,601,884	0.9%
2031		2,606,152	108,931	2,497,221	0.9%	4.9%		2,624,591	0.9%
2032		2,635,374	116,554	2,518,820	0.9%	4.9%		2,647,298	0.9%
2033		2,664,596	124,176	2,540,420	0.9%	4.9%		2,670,005	0.9%
2034		2,693,817	131,798	2,562,019	0.9%	4.9%		2,692,712	0.9%

ANNUAL GROWTH RATES

	Actual Sales	Projected Sales	DSM Adj. Sales	DSM Adj. Purchases	Normalized
1999-2004	2.3%			2.1%	2.5%
2004-2009	1.0%			1.0%	1.8%
2009-2014	1.6%			1.5%	0.0%
2014-2019		0.5%	-0.4%		0.4%
2019-2024		1.0%	0.8%		0.8%
2019-2029		1.1%	0.9%		0.9%
2024-2034		1.1%	0.9%		0.9%
2014-2034		0.9%	0.7%		0.7%

BIG RIVERS ELECTRIC CORPORATION

2015 LONG-TERM LOAD FORECAST - BASE CASE FORECAST

RURAL SYSTEM REQUIREMENTS - ADJUSTED FOR DSM

Year	Summer Actual NCP (kW)	Summer Normal NCP (kW)	DSM Impact (kW)	DSM Adj. NCP (kW)	Winter Actual NCP (kW)	Winter Normal NCP (kW)	DSM Impact (kW)	DSM Adj. NCP (kW)
1999	466,954				389,245			
2000	455,792	465,874			378,524	390,730		
2001	441,183	482,158			423,149	406,797		
2002	461,561	469,783			380,606	414,934		
2003	458,050	461,810			460,626	434,226		
2004	472,169	509,445			430,124	418,741		
2005	497,997	502,140			444,494	461,129		
2006	501,463	520,484			439,167	470,680		
2007	532,264	500,796			489,272	488,594		
2008	497,743	507,272			511,901	525,896		
2009	496,641	509,591			560,598	539,396		
2010	539,955	505,659			507,388	512,001		
2011	532,240	515,481			532,501	506,109		
2012	541,865	509,807			456,468	512,662		
2013	493,751	510,764			484,077	476,672		
2014	481,155	515,338	-	515,338	616,023	513,669	-	513,669
2015		532,166	1,747	530,419		523,760	1,530	522,230
2016		534,073	2,653	531,420		527,347	2,333	525,014
2017		536,309	3,567	532,742		529,419	3,150	526,269
2018		538,875	4,494	534,381		531,819	3,978	527,841
2019		541,769	5,355	536,414		534,550	4,750	529,799
2020		544,994	6,224	538,770		537,609	5,535	532,074
2021		548,547	6,677	541,870		540,998	5,666	535,331
2022		552,430	7,414	545,015		544,716	6,330	538,386
2023		556,642	8,159	548,483		548,763	7,005	541,758
2024		561,183	8,938	552,245		553,140	7,635	545,505
2025		566,054	9,777	556,277		557,846	8,296	549,550
2026		571,254	10,700	560,554		562,881	9,010	553,871
2027		576,783	11,687	565,096		568,246	9,742	558,504
2028		582,642	12,781	569,861		573,940	10,541	563,399
2029		588,830	13,875	574,955		579,963	11,340	568,623
2030		595,018	14,968	580,049		585,987	12,139	573,848
2031		601,206	16,062	585,144		592,010	12,938	579,072
2032		607,393	17,155	590,238		598,033	13,737	584,296
2033		613,581	18,249	595,332		604,056	14,536	589,520
2034		619,769	19,343	600,427		610,080	15,335	594,745

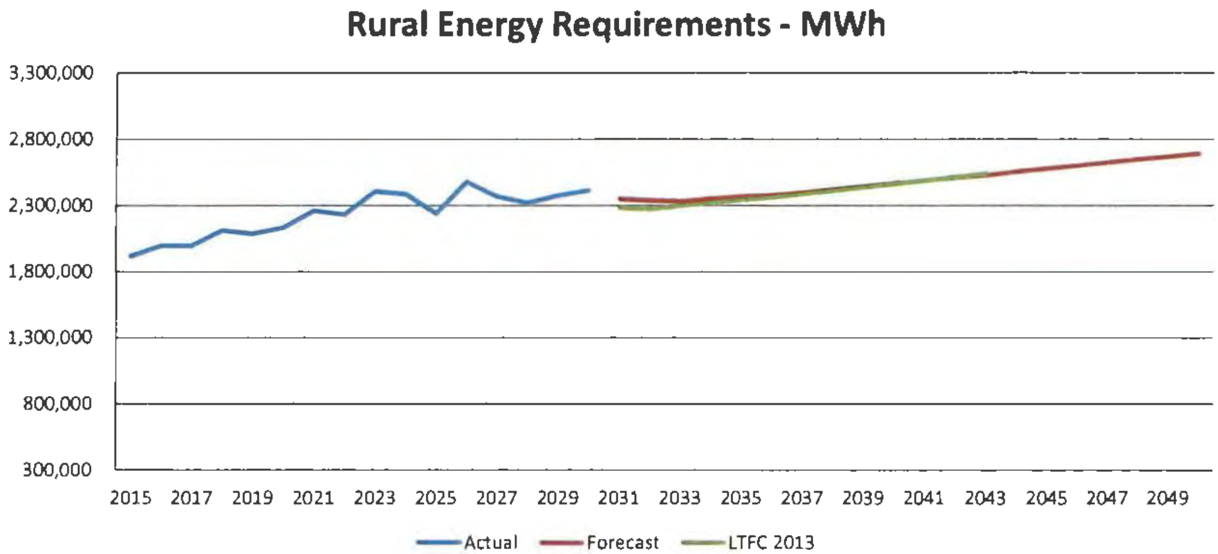
ANNUAL GROWTH RATES								
1999-2004	0.2%				2.0%			
2004-2009	1.0%				5.4%			
2009-2014	-0.6%				1.9%			
2014-2019		1.0%		0.8%		0.7%		0.6%
2019-2024		0.7%		0.6%		0.7%		0.6%
2019-2029		1.0%		0.8%		1.0%		0.8%
2024-2034		1.0%		0.9%		1.0%		0.9%
2014-2034		0.9%		0.8%		0.9%		0.7%

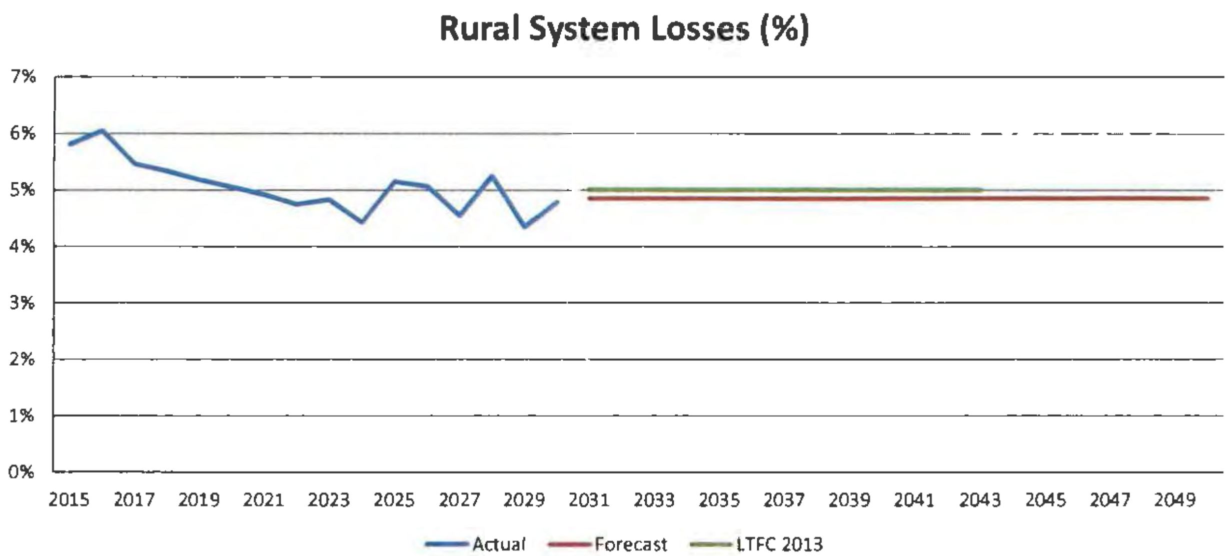
NCP values represent the highest 1-hour peak at the rural system level in each season
Summer season is May to October. Winter season is November of the prior year through April of the reported year.

BIG RIVERS ELECTRIC CORPORATION

2015 LONG-TERM LOAD FORECAST - BASE CASE FORECAST

RURAL SYSTEM REQUIREMENTS - ADJUSTED FOR DSM

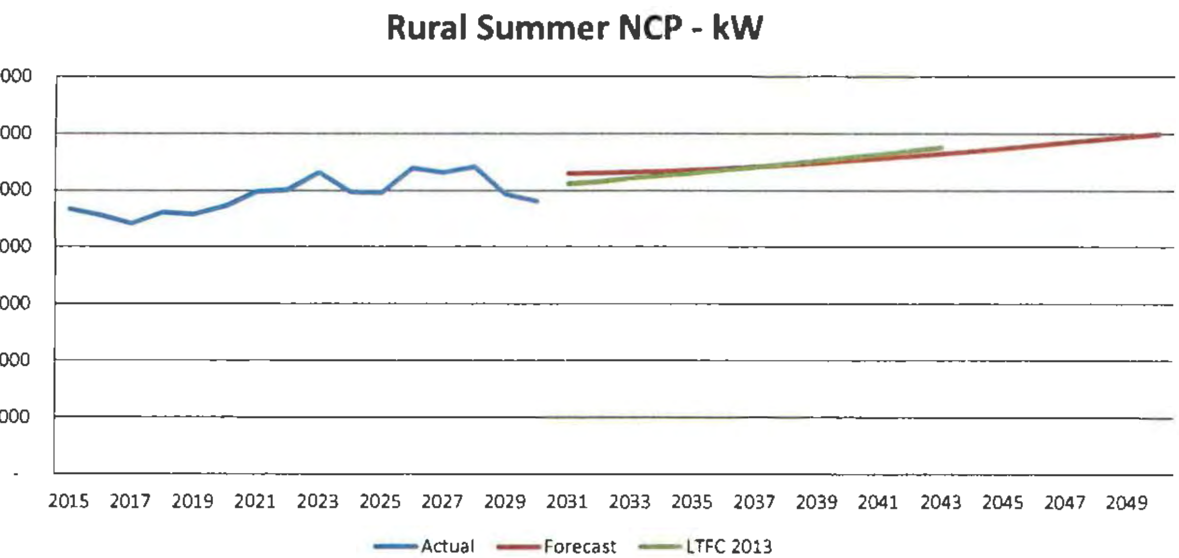


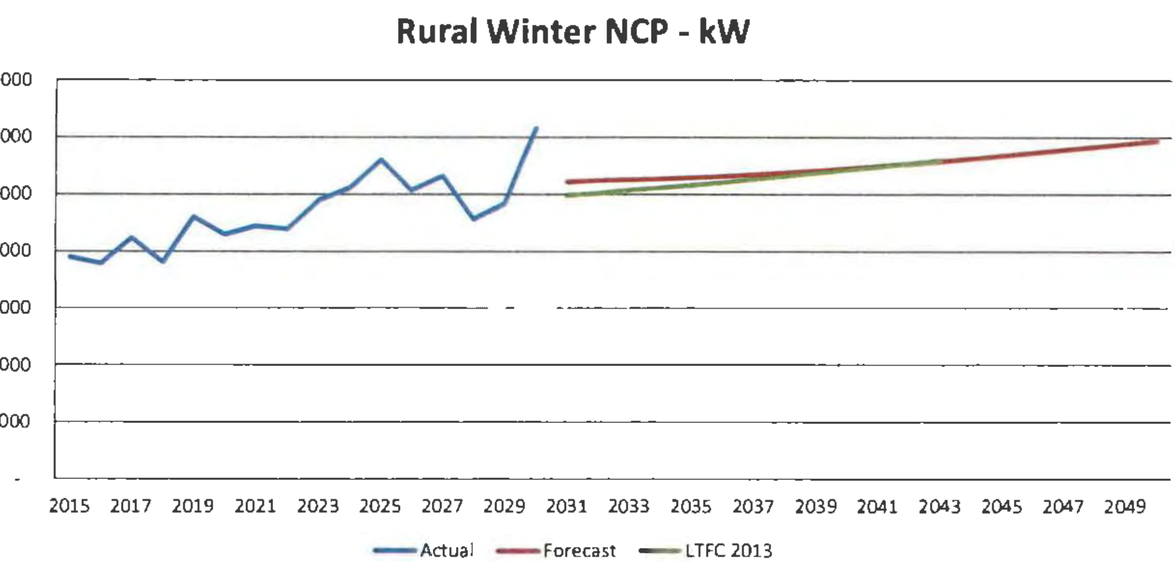


BIG RIVERS ELECTRIC CORPORATION

2015 LONG-TERM LOAD FORECAST - BASE CASE FORECAST

RURAL SYSTEM REQUIREMENTS - ADJUSTED FOR DSM





BIG RIVERS ELECTRIC CORPORATION

2015 LONG-TERM LOAD FORECAST - BASE CASE FORECAST

RESIDENTIAL CLASSIFICATION

Year	Consumers	Consumer Growth	Percent Growth	Actual Sales (MWh)	Normal Sales (MWh)	Percent Growth	Actual Average Use (kWh/Cust/Mo)	Normal Average Use (kWh/Cust/Mo)	Percent Growth
1999	88,092			1,215,474	1,264,625		1,150	1,196	
2000	89,860	1,768	2.0%	1,264,194	1,264,292	0.0%	1,172	1,172	-2.0%
2001	91,276	1,416	1.6%	1,246,139	1,272,751	0.7%	1,138	1,162	-0.9%
2002	92,355	1,079	1.2%	1,371,067	1,333,438	4.8%	1,237	1,203	3.5%
2003	93,405	1,050	1.1%	1,340,451	1,381,531	3.6%	1,196	1,233	2.4%
2004	94,768	1,363	1.5%	1,362,667	1,406,577	1.8%	1,198	1,237	0.3%
2005	94,877	109	0.1%	1,452,182	1,451,236	3.2%	1,275	1,275	3.1%
2006	95,028	151	0.2%	1,415,359	1,463,678	0.9%	1,241	1,284	0.7%
2007	95,993	965	1.0%	1,534,506	1,502,774	2.7%	1,332	1,305	1.6%
2008	96,886	893	0.9%	1,529,478	1,517,852	1.0%	1,316	1,306	0.1%
2009	97,084	198	0.2%	1,426,775	1,458,294	-3.9%	1,225	1,252	-4.1%
2010	97,467	383	0.4%	1,611,212	1,526,991	4.7%	1,378	1,306	4.3%
2011	97,750	283	0.3%	1,530,090	1,529,904	0.2%	1,304	1,304	-0.1%
2012	97,675	(74)	-0.1%	1,465,749	1,480,285	-3.2%	1,251	1,263	-3.2%
2013	97,588	(87)	-0.1%	1,495,894	1,478,411	-0.1%	1,277	1,262	0.0%
2014	97,667	79	0.1%	1,517,068	1,467,145	-0.8%	1,294	1,252	-0.8%
2015	98,114	447	0.5%		1,470,062	0.2%		1,249	-0.3%
2016	98,561	447	0.5%		1,457,938	-0.8%		1,233	-1.3%
2017	99,007	447	0.5%		1,447,437	-0.7%		1,218	-1.2%
2018	99,692	685	0.7%		1,461,984	1.0%		1,222	0.3%
2019	100,456	763	0.8%		1,475,491	0.9%		1,224	0.2%
2020	101,209	754	0.8%		1,483,603	0.5%		1,222	-0.2%
2021	101,931	722	0.7%		1,497,662	0.9%		1,224	0.2%
2022	102,635	703	0.7%		1,517,257	1.3%		1,232	0.6%
2023	103,341	706	0.7%		1,538,630	1.4%		1,241	0.7%
2024	104,027	686	0.7%		1,556,728	1.2%		1,247	0.5%
2025	104,693	666	0.6%		1,576,452	1.3%		1,255	0.6%
2026	105,349	656	0.6%		1,597,333	1.3%		1,264	0.7%
2027	105,978	629	0.6%		1,616,338	1.2%		1,271	0.6%
2028	106,605	627	0.6%		1,643,253	1.7%		1,285	1.1%
2029	107,235	630	0.6%		1,666,646	1.4%		1,295	0.8%
2030	107,866	630	0.6%		1,690,039	1.4%		1,306	0.8%
2031	108,496	630	0.6%		1,713,432	1.4%		1,316	0.8%
2032	109,126	630	0.6%		1,736,825	1.4%		1,326	0.8%
2033	109,757	630	0.6%		1,760,218	1.3%		1,336	0.8%
2034	110,387	630	0.6%		1,783,611	1.3%		1,346	0.8%

ANNUAL GROWTH RATES

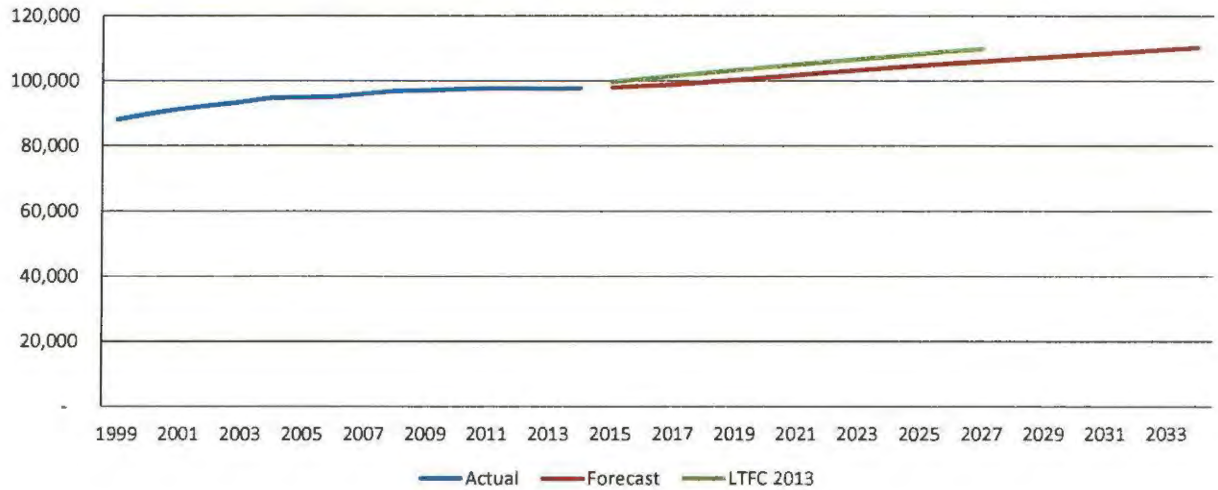
1999-2004	1.5%	1,335	2.3%	2.2%	0.8%	0.7%	
2004-2009	0.5%	463	0.9%	0.7%	0.4%	0.2%	
2009-2014	0.1%	117	1.2%	0.1%	1.1%	0.0%	
2014-2019	0.6%	558		0.1%		-0.4%	
2019-2024	0.7%	714		1.1%		0.4%	
2019-2029	0.6%	642		1.4%		0.8%	
2024-2034	0.6%	630		1.4%		0.8%	
2014-2034	0.6%	636		1.0%		0.4%	

BIG RIVERS ELECTRIC CORPORATION

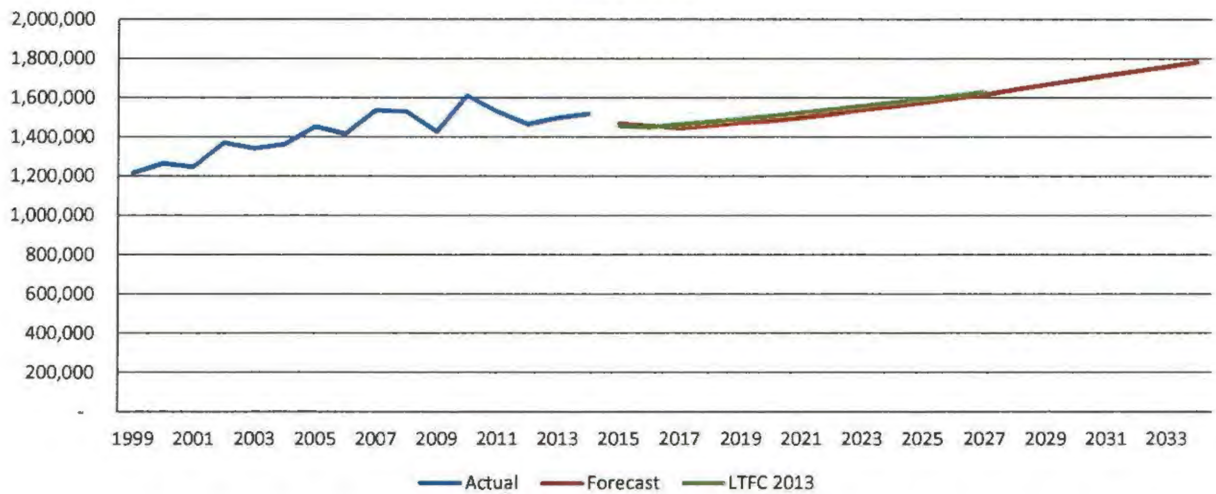
2015 LONG-TERM LOAD FORECAST - BASE CASE FORECAST

RESIDENTIAL CLASSIFICATION

Consumers



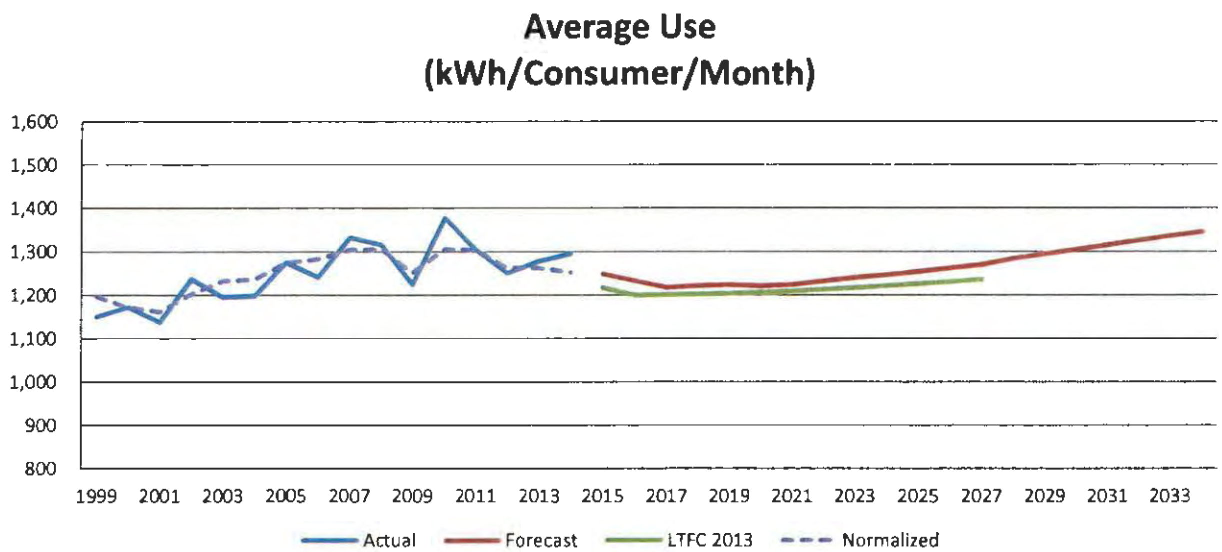
MWh Sales



BIG RIVERS ELECTRIC CORPORATION

2015 LONG-TERM LOAD FORECAST - BASE CASE FORECAST

RESIDENTIAL CLASSIFICATION



BIG RIVERS ELECTRIC CORPORATION

2015 LONG-TERM LOAD FORECAST - BASE CASE FORECAST

SMALL COMMERCIAL CLASSIFICATION

Year	Consumers	Consumer Growth	Percent Growth	Actual Sales (MWh)	Normal Sales (MWh)	Percent Growth	Actual Average Use (kWh/Cust/Mo)	Normal Average Use (kWh/Cust/Mo)	Percent Growth
1999	9,864			478,067			4,039		
2000	10,190	326	3.3%	509,568			4,167		
2001	10,487	297	2.9%	528,560			4,200		
2002	10,899	412	3.9%	507,563			3,881		
2003	11,163	264	2.4%	509,312			3,802		
2004	11,518	355	3.2%	521,300			3,772		
2005	12,876	1,358	11.8%	553,496			3,582		
2006	14,168	1,291	10.0%	568,398	581,519		3,343	3,420	
2007	14,458	290	2.0%	608,391	594,961	2.3%	3,507	3,429	0.3%
2008	14,672	214	1.5%	602,535	600,097	0.9%	3,422	3,408	-0.6%
2009	14,725	53	0.4%	569,297	579,549	-3.4%	3,222	3,280	-3.8%
2010	14,808	82	0.6%	618,684	594,230	2.5%	3,482	3,344	2.0%
2011	14,999	192	1.3%	599,542	597,655	0.6%	3,331	3,320	-0.7%
2012	15,435	435	2.9%	595,342	594,448	-0.5%	3,214	3,209	-3.3%
2013	15,982	547	3.5%	615,002	611,247	2.8%	3,207	3,187	-0.7%
2014	16,394	412	2.6%	624,488	613,604	0.4%	3,174	3,119	-2.1%
2015	16,604	210	1.3%		622,642	1.5%		3,125	0.2%
2016	16,989	384	2.3%		634,930	2.0%		3,114	-0.3%
2017	17,360	371	2.2%		646,338	1.8%		3,103	-0.4%
2018	17,693	333	1.9%		656,633	1.6%		3,093	-0.3%
2019	17,940	247	1.4%		664,366	1.2%		3,086	-0.2%
2020	18,171	231	1.3%		671,691	1.1%		3,080	-0.2%
2021	18,391	220	1.2%		678,707	1.0%		3,075	-0.2%
2022	18,608	217	1.2%		685,679	1.0%		3,071	-0.2%
2023	18,829	221	1.2%		692,785	1.0%		3,066	-0.1%
2024	19,036	207	1.1%		699,499	1.0%		3,062	-0.1%
2025	19,231	195	1.0%		705,899	0.9%		3,059	-0.1%
2026	19,418	187	1.0%		712,077	0.9%		3,056	-0.1%
2027	19,591	173	0.9%		717,886	0.8%		3,054	-0.1%
2028	19,763	172	0.9%		723,680	0.8%		3,052	-0.1%
2029	19,934	172	0.9%		729,506	0.8%		3,050	-0.1%
2030	20,106	172	0.9%		735,331	0.8%		3,048	-0.1%
2031	20,278	172	0.9%		741,157	0.8%		3,046	-0.1%
2032	20,450	172	0.8%		746,983	0.8%		3,044	-0.1%
2033	20,622	172	0.8%		752,808	0.8%		3,042	-0.1%
2034	20,793	172	0.8%		758,634	0.8%		3,040	-0.1%

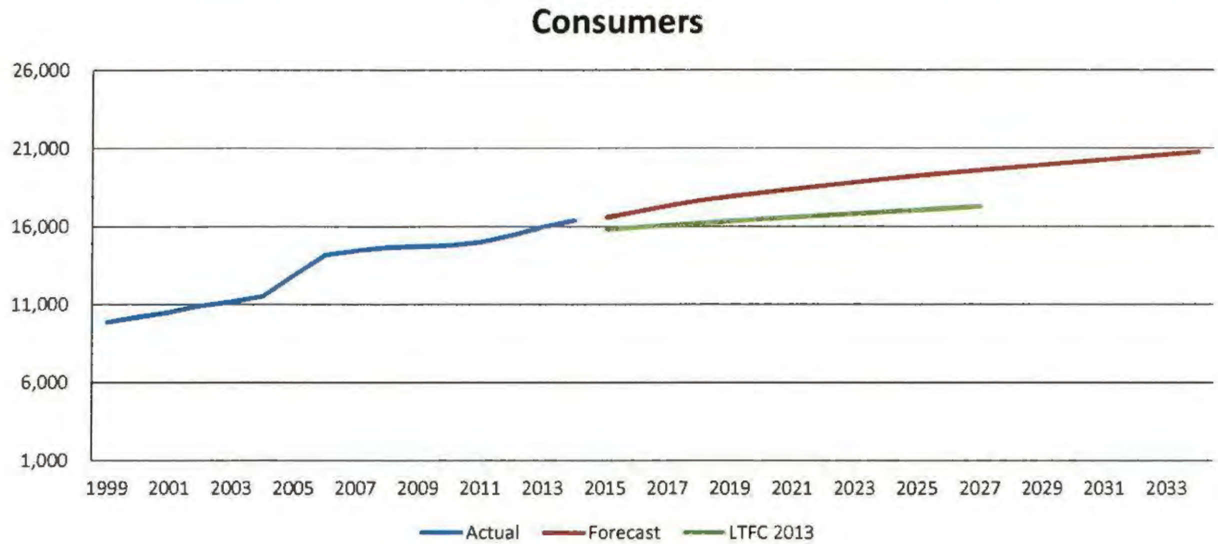
ANNUAL GROWTH RATES

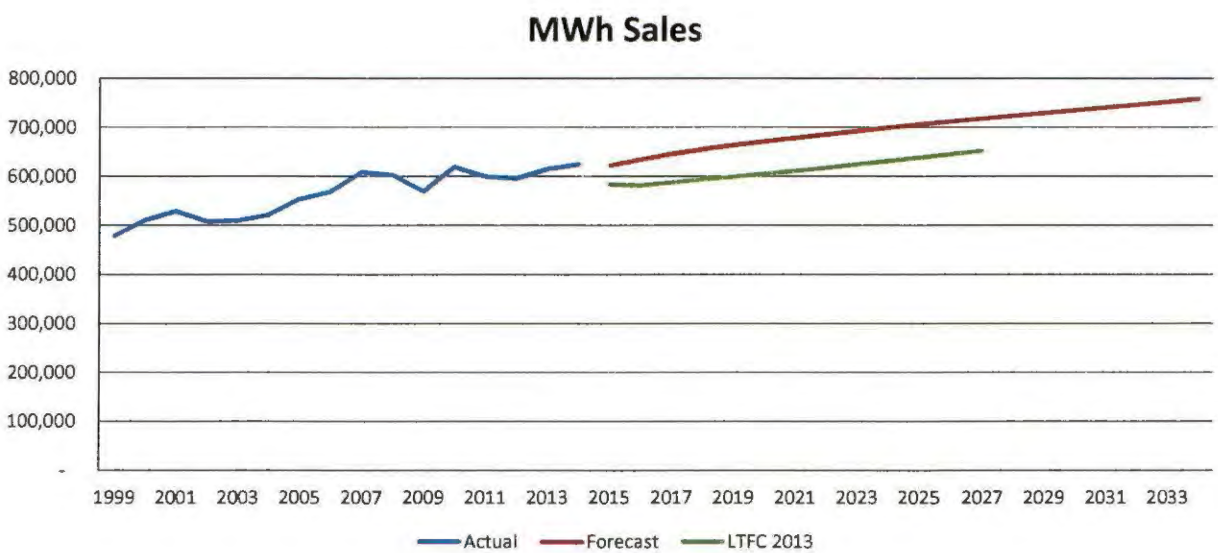
1999-2004	3.1%	331	1.7%		-1.4%	
2004-2009	5.0%	641	1.8%		-3.1%	
2009-2014	2.2%	334	1.9%	1.1%	-0.3%	-1.0%
2014-2019	1.8%	309		1.6%		-0.2%
2019-2024	1.2%	219		1.0%		-0.2%
2019-2029	0.9%	180		0.8%		-0.1%
2024-2034	0.8%	172		0.8%		-0.1%
2014-2034	1.2%	220		1.1%		-0.1%

BIG RIVERS ELECTRIC CORPORATION

2015 LONG-TERM LOAD FORECAST - BASE CASE FORECAST

SMALL COMMERCIAL CLASSIFICATION





BIG RIVERS ELECTRIC CORPORATION

2015 LONG-TERM LOAD FORECAST - BASE CASE FORECAST

LARGE COMMERCIAL CLASSIFICATION

Year	Consumers	Consumer Growth	Percent Growth	Sales (MWh)	Percent Growth	Average Use (kWh/Cust/Mo)	Percent Growth
1999	36			1,658,114		3,874,097	
2000	37	1	3.5%	1,642,917	-0.9%	3,708,615	-4.3%
2001	34	(3)	-8.8%	1,414,538	-13.9%	3,501,331	-5.6%
2002	35	2	5.0%	1,238,353	-12.5%	2,920,644	-16.6%
2003	38	3	7.1%	1,151,279	-7.0%	2,535,856	-13.2%
2004	39	1	3.5%	1,140,217	-1.0%	2,425,995	-4.3%
2005	37	(2)	-5.1%	1,123,081	-1.5%	2,518,119	3.8%
2006	36	(1)	-2.0%	1,103,512	-1.7%	2,525,199	0.3%
2007	37	1	2.3%	1,071,969	-2.9%	2,398,142	-5.0%
2008	39	1	3.8%	1,080,619	0.8%	2,328,919	-2.9%
2009	38	(1)	-1.9%	1,092,667	1.1%	2,401,466	3.1%
2010	39	1	2.4%	1,083,734	-0.8%	2,325,609	-3.2%
2011	43	4	9.7%	1,146,619	5.8%	2,243,874	-3.5%
2012	44	1	2.2%	1,302,573	13.6%	2,495,350	11.2%
2013	52	8	19.0%	1,323,552	1.6%	2,131,323	-14.6%
2014	51	(1)	-1.1%	1,185,042	-10.5%	1,930,035	-9.4%
2015	49	(2)	-4.1%	1,117,726	-5.7%	1,897,667	-1.7%
2016	48	(1)	-2.0%	1,217,976	9.0%	2,110,876	11.2%
2017	47	(1)	-2.1%	1,262,850	3.7%	2,235,133	5.9%
2018	46	(1)	-2.1%	1,260,004	-0.2%	2,278,488	1.9%
2019	46	0	0.0%	1,260,004	0.0%	2,278,488	0.0%
2020	46	0	0.0%	1,260,519	0.0%	2,279,420	0.0%
2021	46	0	0.0%	1,260,004	0.0%	2,278,488	0.0%
2022	46	0	0.0%	1,260,004	0.0%	2,278,488	0.0%
2023	46	0	0.0%	1,260,004	0.0%	2,278,488	0.0%
2024	46	0	0.0%	1,260,519	0.0%	2,279,420	0.0%
2025	46	0	0.0%	1,260,004	0.0%	2,278,488	0.0%
2026	46	0	0.0%	1,260,004	0.0%	2,278,488	0.0%
2027	46	0	0.0%	1,260,004	0.0%	2,278,488	0.0%
2028	46	0	0.0%	1,260,519	0.0%	2,279,420	0.0%
2029	46	0	0.0%	1,260,004	0.0%	2,278,488	0.0%
2030	46	0	0.0%	1,260,004	0.0%	2,278,488	0.0%
2031	46	0	0.0%	1,260,004	0.0%	2,278,488	0.0%
2032	46	0	0.0%	1,260,519	0.0%	2,279,420	0.0%
2033	46	0	0.0%	1,260,004	0.0%	2,278,488	0.0%
2034	46	0	0.0%	1,260,004	0.0%	2,278,488	0.0%

ANNUAL GROWTH RATES

1999-2004	1.9%	1	-7.2%	-8.9%
2004-2009	-0.6%	(0)	-0.8%	-0.2%
2009-2014	6.2%	3	1.6%	-4.3%
2014-2019	-2.1%	(1)	1.2%	3.4%
2019-2024	0.0%	-	0.0%	0.0%
2019-2029	0.0%	-	0.0%	0.0%
2024-2034	0.0%	-	0.0%	0.0%
2014-2034	-0.5%	(0)	0.3%	0.8%

BIG RIVERS ELECTRIC CORPORATION

2015 LONG-TERM LOAD FORECAST - BASE CASE FORECAST

RURAL LARGE COMMERCIAL CLASSIFICATION

Year	Consumers	Consumer Growth	Percent Growth	Sales (MWh)	Percent Growth	Average Use (kWh/Cust/Mo)	Percent Growth
1999	19			113,526		506,814	
2000	18	(1)	-4.0%	103,533	-8.8%	481,548	-5.0%
2001	13	(5)	-29.3%	113,852	10.0%	749,025	55.5%
2002	14	2	13.2%	120,089	5.5%	698,194	-6.8%
2003	19	5	31.4%	128,476	7.0%	568,476	-18.6%
2004	21	2	12.4%	138,427	7.7%	544,987	-4.1%
2005	21	0	0.0%	141,995	2.6%	559,036	2.6%
2006	17	(4)	-17.7%	139,821	-1.5%	669,001	19.7%
2007	19	2	10.5%	145,200	3.8%	628,572	-6.0%
2008	21	1	7.4%	147,038	1.3%	592,896	-5.7%
2009	20	(1)	-3.6%	124,286	-15.5%	520,024	-12.3%
2010	21	1	4.6%	121,477	-2.3%	485,907	-6.6%
2011	23	2	8.4%	130,264	7.2%	480,678	-1.1%
2012	24	1	4.1%	135,134	3.7%	479,199	-0.3%
2013	31	7	30.9%	157,230	16.4%	426,097	-11.1%
2014	30	(1)	-1.9%	154,966	-1.4%	428,084	0.5%
2015	29	(1)	-3.6%	154,915	0.0%	443,883	3.7%
2016	28	(1)	-3.4%	147,745	-4.6%	438,412	-1.2%
2017	27	(1)	-3.6%	147,745	0.0%	454,600	3.7%
2018	27	0	0.0%	147,745	0.0%	454,600	0.0%
2019	27	0	0.0%	147,745	0.0%	454,600	0.0%
2020	27	0	0.0%	147,745	0.0%	454,600	0.0%
2021	27	0	0.0%	147,745	0.0%	454,600	0.0%
2022	27	0	0.0%	147,745	0.0%	454,600	0.0%
2023	27	0	0.0%	147,745	0.0%	454,600	0.0%
2024	27	0	0.0%	147,745	0.0%	454,600	0.0%
2025	27	0	0.0%	147,745	0.0%	454,600	0.0%
2026	27	0	0.0%	147,745	0.0%	454,600	0.0%
2027	27	0	0.0%	147,745	0.0%	454,600	0.0%
2028	27	0	0.0%	147,745	0.0%	454,600	0.0%
2029	27	0	0.0%	147,745	0.0%	454,600	0.0%
2030	27	0	0.0%	147,745	0.0%	454,600	0.0%
2031	27	0	0.0%	147,745	0.0%	454,600	0.0%
2032	27	0	0.0%	147,745	0.0%	454,600	0.0%
2033	27	0	0.0%	147,745	0.0%	454,600	0.0%
2034	27	0	0.0%	147,745	0.0%	454,600	0.0%

ANNUAL GROWTH RATES				
1999-2004	2.5%	1	4.0%	1.5%
2004-2009	-1.2%	(0)	-2.1%	-0.9%
2009-2014	8.7%	2	4.5%	-3.8%
2014-2019	-2.1%	(1)	-0.9%	1.2%
2019-2024	0.0%	-	0.0%	0.0%
2019-2029	0.0%	-	0.0%	0.0%
2024-2034	0.0%	-	0.0%	0.0%
2014-2034	-0.5%	(0)	-0.2%	0.3%

BIG RIVERS ELECTRIC CORPORATION

2015 LONG-TERM LOAD FORECAST - BASE CASE FORECAST

DIRECT SERVE LARGE COMMERCIAL CLASSIFICATION

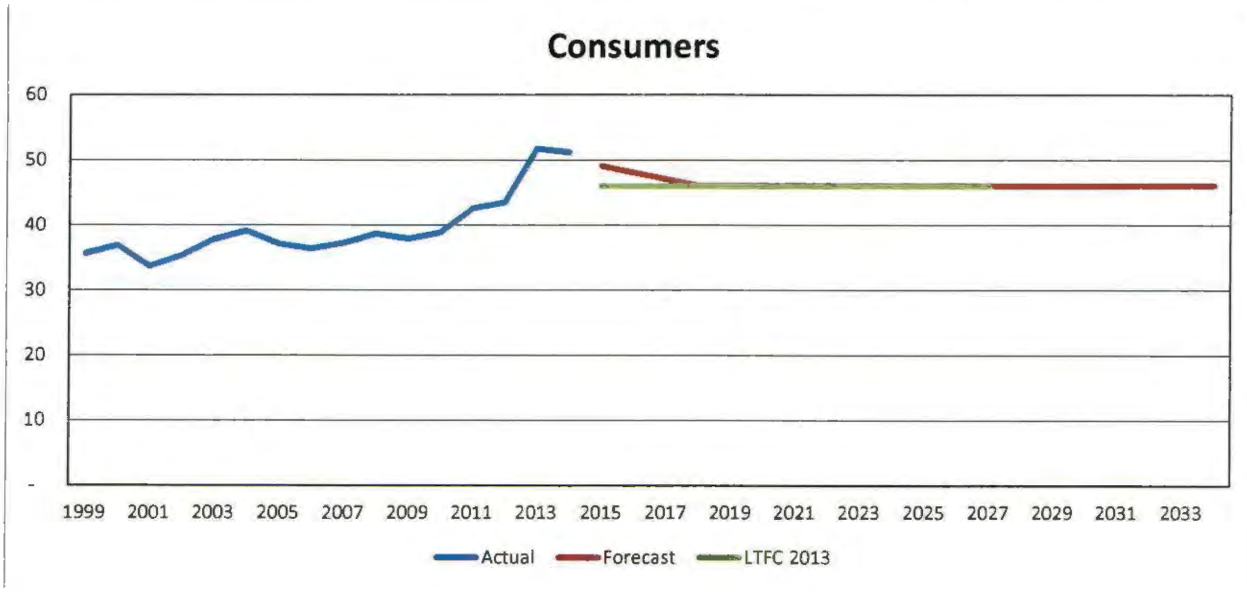
Year	Consumers	Consumer Growth	Percent Growth	Sales (MWh)	Percent Growth	Average Use (kWh/Cust/Mo)	Percent Growth
1999	17			1,544,587		7,571,506	
2000	19	2	11.8%	1,539,384	-0.3%	6,751,684	-10.8%
2001	21	2	10.5%	1,300,686	-15.5%	5,161,452	-23.6%
2002	21	0	0.0%	1,118,264	-14.0%	4,437,555	-14.0%
2003	19	(2)	-9.5%	1,022,803	-8.5%	4,485,979	1.1%
2004	18	(1)	-5.3%	1,001,791	-2.1%	4,637,919	3.4%
2005	16	(2)	-11.1%	981,086	-2.1%	5,109,824	10.2%
2006	19	3	18.8%	963,691	-1.8%	4,226,714	-17.3%
2007	18	(1)	-5.3%	926,769	-3.8%	4,290,599	1.5%
2008	18	0	0.0%	933,580	0.7%	4,322,131	0.7%
2009	18	0	0.0%	968,381	3.7%	4,483,246	3.7%
2010	18	0	0.0%	962,257	-0.6%	4,454,894	-0.6%
2011	20	2	11.1%	1,016,356	5.6%	4,234,816	-4.9%
2012	20	0	0.0%	1,167,439	14.9%	4,864,328	14.9%
2013	21	1	5.0%	1,166,322	-0.1%	4,628,261	-4.9%
2014	21	0	0.0%	1,030,075	-11.7%	4,087,600	-11.7%
2015	20	(1)	-4.8%	962,811	-6.5%	4,011,712	-1.9%
2016	20	0	0.0%	1,070,231	11.2%	4,459,294	11.2%
2017	20	0	0.0%	1,115,105	4.2%	4,646,272	4.2%
2018	19	(1)	-5.0%	1,112,259	-0.3%	4,878,328	5.0%
2019	19	0	0.0%	1,112,259	0.0%	4,878,328	0.0%
2020	19	0	0.0%	1,112,774	0.0%	4,880,589	0.0%
2021	19	0	0.0%	1,112,259	0.0%	4,878,328	0.0%
2022	19	0	0.0%	1,112,259	0.0%	4,878,328	0.0%
2023	19	0	0.0%	1,112,259	0.0%	4,878,328	0.0%
2024	19	0	0.0%	1,112,774	0.0%	4,880,589	0.0%
2025	19	0	0.0%	1,112,259	0.0%	4,878,328	0.0%
2026	19	0	0.0%	1,112,259	0.0%	4,878,328	0.0%
2027	19	0	0.0%	1,112,259	0.0%	4,878,328	0.0%
2028	19	0	0.0%	1,112,774	0.0%	4,880,589	0.0%
2029	19	0	0.0%	1,112,259	0.0%	4,878,328	0.0%
2030	19	0	0.0%	1,112,259	0.0%	4,878,328	0.0%
2031	19	0	0.0%	1,112,259	0.0%	4,878,328	0.0%
2032	19	0	0.0%	1,112,774	0.0%	4,880,589	0.0%
2033	19	0	0.0%	1,112,259	0.0%	4,878,328	0.0%
2034	19	0	0.0%	1,112,259	0.0%	4,878,328	0.0%

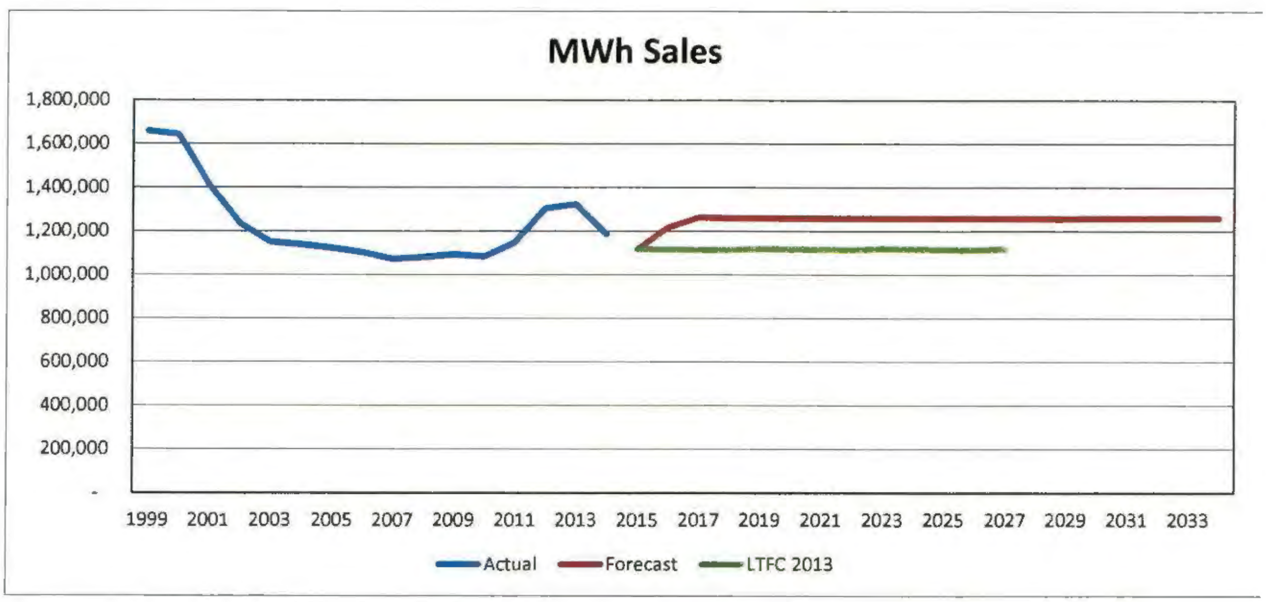
ANNUAL GROWTH RATES				
1999-2004	1.1%	0	-8.3%	-9.3%
2004-2009	0.0%	-	-0.7%	-0.7%
2009-2014	3.1%	1	1.2%	-1.8%
2014-2019	-2.0%	(0)	1.5%	3.6%
2019-2024	0.0%	-	0.0%	0.0%
2019-2029	0.0%	-	0.0%	0.0%
2024-2034	0.0%	-	0.0%	0.0%
2014-2034	-0.5%	(0)	0.4%	0.9%

BIG RIVERS ELECTRIC CORPORATION

2015 LONG-TERM LOAD FORECAST - BASE CASE FORECAST

LARGE COMMERCIAL CLASSIFICATION





BIG RIVERS ELECTRIC CORPORATION

2015 LONG-TERM LOAD FORECAST - BASE CASE FORECAST

IRRIGATION CLASSIFICATION

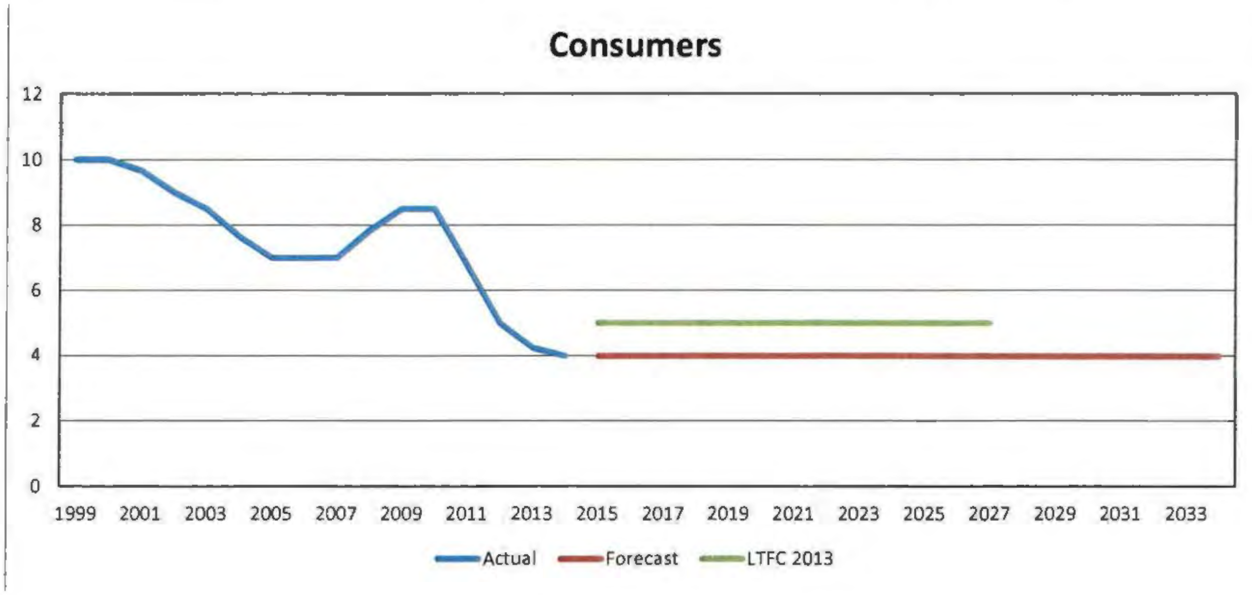
Year	Consumers	Consumer Growth	Percent Growth	Sales (MWh)	Percent Growth	Average Use (kWh/Cust/Mo)	Percent Growth
1999	10			121		1,008	
2000	10	0	0.0%	70	-42.0%	585	-42.0%
2001	10	(0)	-3.3%	75	6.5%	644	10.2%
2002	9	(1)	-6.9%	38	-49.1%	352	-45.4%
2003	9	(1)	-5.6%	113	196.9%	1,106	214.4%
2004	8	(1)	-9.8%	164	45.1%	1,780	60.9%
2005	7	(1)	-8.7%	114	-30.4%	1,356	-23.8%
2006	7	0	0.0%	65	-43.2%	770	-43.2%
2007	7	0	0.0%	1,068	1551.4%	12,715	1551.4%
2008	8	1	11.9%	432	-59.6%	4,594	-63.9%
2009	9	1	8.5%	406	-5.9%	3,984	-13.3%
2010	9	0	0.0%	356	-12.4%	3,491	-12.4%
2011	7	(2)	-20.6%	269	-24.5%	3,321	-4.9%
2012	5	(2)	-25.9%	440	63.7%	7,338	121.0%
2013	4	(1)	-15.0%	48	-89.2%	933	-87.3%
2014	4	(0)	-5.9%	136	186.9%	2,843	204.8%
2015	4	0	0.0%	298	118.6%	6,213	118.6%
2016	4	0	0.0%	298	0.0%	6,213	0.0%
2017	4	0	0.0%	298	0.0%	6,213	0.0%
2018	4	0	0.0%	298	0.0%	6,213	0.0%
2019	4	0	0.0%	298	0.0%	6,213	0.0%
2020	4	0	0.0%	298	0.0%	6,213	0.0%
2021	4	0	0.0%	298	0.0%	6,213	0.0%
2022	4	0	0.0%	298	0.0%	6,213	0.0%
2023	4	0	0.0%	298	0.0%	6,213	0.0%
2024	4	0	0.0%	298	0.0%	6,213	0.0%
2025	4	0	0.0%	298	0.0%	6,213	0.0%
2026	4	0	0.0%	298	0.0%	6,213	0.0%
2027	4	0	0.0%	298	0.0%	6,213	0.0%
2028	4	0	0.0%	298	0.0%	6,213	0.0%
2029	4	0	0.0%	298	0.0%	6,213	0.0%
2030	4	0	0.0%	298	0.0%	6,213	0.0%
2031	4	0	0.0%	298	0.0%	6,213	0.0%
2032	4	0	0.0%	298	0.0%	6,213	0.0%
2033	4	0	0.0%	298	0.0%	6,213	0.0%
2034	4	0	0.0%	298	0.0%	6,213	0.0%

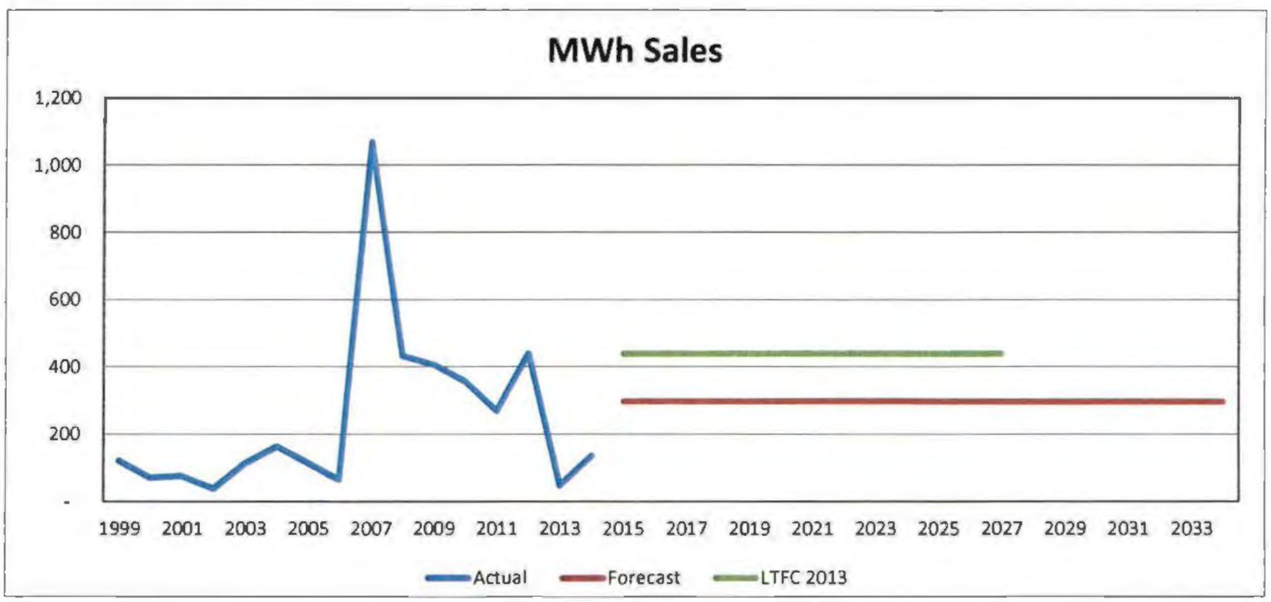
ANNUAL GROWTH RATES				
1999-2004	-5.2%	(0)	6.2%	12.0%
2004-2009	2.1%	0	19.9%	17.5%
2009-2014	-14.0%	(1)	-19.6%	-6.5%
2014-2019	0.0%	-	16.9%	16.9%
2019-2024	0.0%	-	0.0%	0.0%
2019-2029	0.0%	-	0.0%	0.0%
2024-2034	0.0%	-	0.0%	0.0%
2014-2034	0.0%	-	4.0%	4.0%

BIG RIVERS ELECTRIC CORPORATION

2015 LONG-TERM LOAD FORECAST - BASE CASE FORECAST

IRRIGATION CLASSIFICATION





BIG RIVERS ELECTRIC CORPORATION

2015 LONG-TERM LOAD FORECAST - BASE CASE FORECAST

STREET LIGHTING CLASSIFICATION

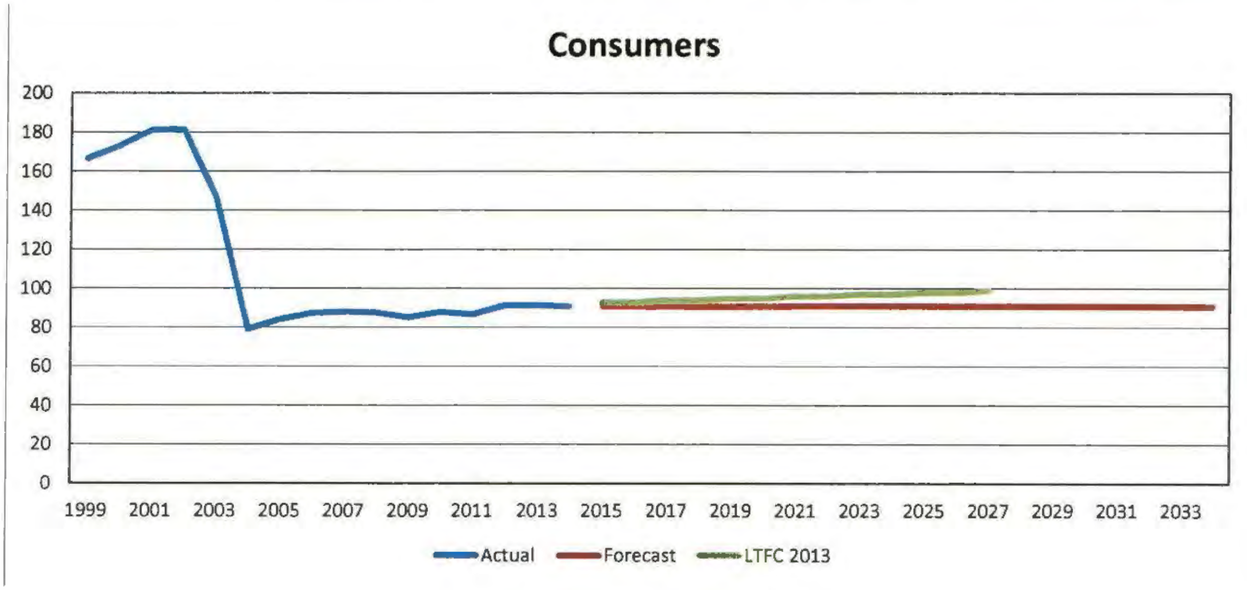
Year	Consumers	Consumer Growth	Percent Growth	Sales (MWh)	Percent Growth	Average Use (kWh/Cust/Mo)	Percent Growth
1999	167			3,138		1,571	
2000	173	7	3.9%	3,191	1.7%	1,537	-2.1%
2001	181	8	4.8%	3,104	-2.7%	1,427	-7.2%
2002	182	0	0.1%	3,277	5.6%	1,505	5.4%
2003	147	(34)	-18.9%	3,235	-1.3%	1,831	21.7%
2004	79	(68)	-46.3%	2,997	-7.3%	3,158	72.5%
2005	84	5	6.4%	3,077	2.7%	3,047	-3.5%
2006	87	3	3.8%	3,104	0.9%	2,962	-2.8%
2007	88	1	0.8%	3,175	2.3%	3,007	1.5%
2008	88	(0)	-0.5%	3,287	3.5%	3,128	4.0%
2009	85	(2)	-2.8%	3,246	-1.2%	3,177	1.6%
2010	88	3	3.3%	3,438	5.9%	3,256	2.5%
2011	87	(1)	-1.3%	3,409	-0.8%	3,272	0.5%
2012	92	5	5.4%	3,454	1.3%	3,146	-3.9%
2013	91	(0)	-0.1%	3,486	0.9%	3,178	1.0%
2014	91	(0)	-0.5%	3,461	-0.7%	3,169	-0.3%
2015	91	0	0.0%	3,472	0.3%	3,179	0.3%
2016	91	0	0.0%	3,475	0.1%	3,182	0.1%
2017	91	0	0.0%	3,478	0.1%	3,185	0.1%
2018	91	0	0.0%	3,481	0.1%	3,188	0.1%
2019	91	0	0.0%	3,484	0.1%	3,190	0.1%
2020	91	0	0.0%	3,487	0.1%	3,193	0.1%
2021	91	0	0.0%	3,490	0.1%	3,196	0.1%
2022	91	0	0.0%	3,493	0.1%	3,199	0.1%
2023	91	0	0.0%	3,496	0.1%	3,201	0.1%
2024	91	0	0.0%	3,499	0.1%	3,204	0.1%
2025	91	0	0.0%	3,502	0.1%	3,207	0.1%
2026	91	0	0.0%	3,505	0.1%	3,210	0.1%
2027	91	0	0.0%	3,508	0.1%	3,213	0.1%
2028	91	0	0.0%	3,511	0.1%	3,215	0.1%
2029	91	0	0.0%	3,514	0.1%	3,218	0.1%
2030	91	0	0.0%	3,517	0.1%	3,221	0.1%
2031	91	0	0.0%	3,520	0.1%	3,224	0.1%
2032	91	0	0.0%	3,523	0.1%	3,226	0.1%
2033	91	0	0.0%	3,526	0.1%	3,229	0.1%
2034	91	0	0.0%	3,529	0.1%	3,232	0.1%

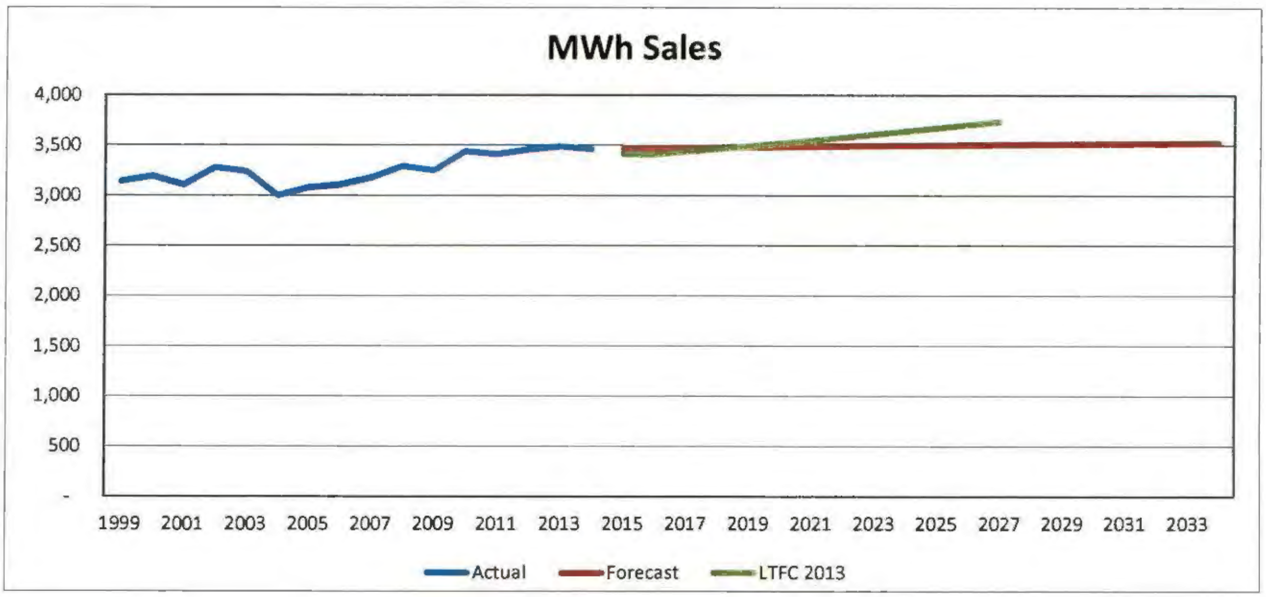
ANNUAL GROWTH RATES				
1999-2004	-13.8%	(17)	-0.9%	15.0%
2004-2009	1.5%	1	1.6%	0.1%
2009-2014	1.3%	1	1.3%	0.0%
2014-2019	0.0%	-	0.1%	0.1%
2019-2024	0.0%	-	0.1%	0.1%
2019-2029	0.0%	-	0.1%	0.1%
2024-2034	0.0%	-	0.1%	0.1%
2014-2034	0.0%	-	0.1%	0.1%

BIG RIVERS ELECTRIC CORPORATION

2015 LONG-TERM LOAD FORECAST - BASE CASE FORECAST

STREET LIGHTING CLASSIFICATION





Appendix B – Forecast Scenario Tables & Graphs

BIG RIVERS ELECTRIC CORPORATION

2015 LONG-TERM LOAD FORECAST - RANGE FORECASTS

NATIVE SYSTEM REQUIREMENTS

Year	Base Case (MWh)	Weather Adjusted (MWh)	ECONOMIC SCENARIOS Optimistic (MWh)	ECONOMIC SCENARIOS Pessimistic (MWh)	WEATHER SCENARIOS Extreme (MWh)	WEATHER SCENARIOS Mild (MWh)
1999	3,468,661	3,474,050				
2000	3,540,719	3,499,164				
2001	3,284,432	3,340,982				
2002	3,191,176	3,160,427				
2003	3,052,582	3,113,609				
2004	3,129,980	3,166,556				
2005	3,233,245	3,219,363				
2006	3,188,986	3,265,332				
2007	3,325,859	3,279,063				
2008	3,313,571	3,334,646				
2009	3,159,286	3,299,898				
2010	3,445,715	3,371,007				
2011	3,385,501	3,419,160				
2012	3,488,924	3,562,315				
2013	3,540,787	3,578,596				
2014	3,444,252	3,416,701				
2015		3,318,236	3,533,155	3,123,152	3,463,145	3,170,384
2016		3,412,505	3,663,522	3,191,060	3,557,028	3,265,693
2017		3,452,322	3,739,188	3,207,925	3,596,020	3,306,237
2018		3,469,403	3,780,186	3,211,936	3,614,306	3,322,307
2019		3,485,661	3,821,015	3,216,429	3,630,685	3,337,359
2020		3,496,216	3,852,820	3,218,643	3,642,977	3,346,438
2021		3,513,561	3,889,874	3,223,847	3,661,537	3,362,832
2022		3,535,988	3,932,829	3,236,145	3,685,031	3,383,364
2023		3,560,308	3,977,676	3,250,722	3,710,991	3,406,212
2024		3,581,114	4,020,722	3,259,875	3,732,592	3,425,748
2025		3,601,873	4,062,636	3,271,618	3,754,961	3,444,571
2026		3,623,562	4,106,260	3,284,746	3,777,711	3,464,778
2027		3,642,351	4,147,744	3,295,637	3,798,186	3,482,437
2028		3,669,244	4,194,808	3,316,947	3,826,503	3,507,318
2029		3,691,436	4,240,800	3,331,796	3,850,411	3,527,621
2030		3,714,143	4,287,336	3,347,134	3,874,835	3,548,439
2031		3,736,850	4,333,875	3,362,471	3,899,258	3,569,257
2032		3,760,072	4,380,957	3,378,299	3,924,197	3,590,590
2033		3,782,264	4,426,964	3,393,143	3,948,105	3,610,893
2034		3,804,971	4,473,515	3,408,478	3,972,529	3,631,711

ANNUAL GROWTH RATES						
1999-2004	-2.0%	-1.8%				
2004-2009	0.2%	0.8%				
2009-2014	1.7%	0.7%				
2014-2019		0.4%	2.3%	-1.2%	1.2%	-0.5%
2019-2024		0.5%	1.0%	0.3%	0.6%	0.5%
2024-2029		0.6%	1.1%	0.4%	0.6%	0.6%
2029-2034		0.6%	1.1%	0.5%	0.6%	0.6%
2014-2034		0.5%	1.4%	0.0%	0.8%	0.3%

BIG RIVERS ELECTRIC CORPORATION

2015 LONG-TERM LOAD FORECAST - RANGE FORECASTS

NATIVE SYSTEM NCP DEMAND - SUMMER

	Base	Weather	ECONOMIC SCENARIOS		WEATHER SCENARIOS	
	Case	Adjusted	Optimistic	Pessimistic	Extreme	Mild
Year	(kW)	(MWh)	(kW)	(kW)	(kW)	(kW)
1999	663,890					
2000	655,248	665,330				
2001	596,310	637,285				
2002	602,623	610,846				
2003	583,906	587,666				
2004	604,155	641,432				
2005	603,783	607,926				
2006	619,258	638,279				
2007	647,502	616,033				
2008	604,334	613,863				
2009	594,126	607,076				
2010	651,634	617,337				
2011	652,127	635,368				
2012	654,218	622,159				
2013	608,899	625,912				
2014	601,935	636,118				
2015		647,412	690,133	609,225	691,960	595,943
2016		667,293	717,395	624,007	708,441	615,377
2017		675,299	733,407	627,031	714,370	623,036
2018		677,047	740,405	625,974	718,025	624,878
2019		679,080	747,898	625,451	720,858	626,858
2020		681,436	755,135	625,891	722,561	628,977
2021		684,536	762,635	626,294	726,029	631,857
2022		687,682	770,206	627,319	730,433	634,865
2023		691,149	778,054	628,777	735,330	638,171
2024		694,912	786,741	629,985	739,597	641,638
2025		698,943	795,457	632,049	744,035	645,344
2026		703,220	804,605	634,455	748,633	649,259
2027		707,762	814,345	637,172	752,869	653,333
2028		712,527	823,457	640,817	758,426	657,737
2029		717,621	833,939	644,247	763,498	662,338
2030		722,716	844,421	647,678	768,570	666,940
2031		727,810	854,904	651,108	773,642	671,542
2032		732,904	865,388	654,537	778,714	676,143
2033		737,999	875,871	657,967	783,785	680,745
2034		743,093	886,356	661,397	788,857	685,347

ANNUAL GROWTH RATES						
1999-2004	-1.9%					
2004-2009	-0.3%					
2009-2014	0.3%					
2014-2019		1.3%	3.3%	-0.3%	2.5%	-0.3%
2019-2024		0.5%	1.0%	0.1%	0.5%	0.5%
2024-2029		0.6%	1.2%	0.4%	0.6%	0.6%
2029-2034		0.7%	1.2%	0.5%	0.7%	0.7%
2014-2034		0.8%	1.7%	0.2%	1.1%	0.4%

BIG RIVERS ELECTRIC CORPORATION

2015 LONG-TERM LOAD FORECAST - RANGE FORECASTS

NATIVE SYSTEM NCP DEMAND - WINTER

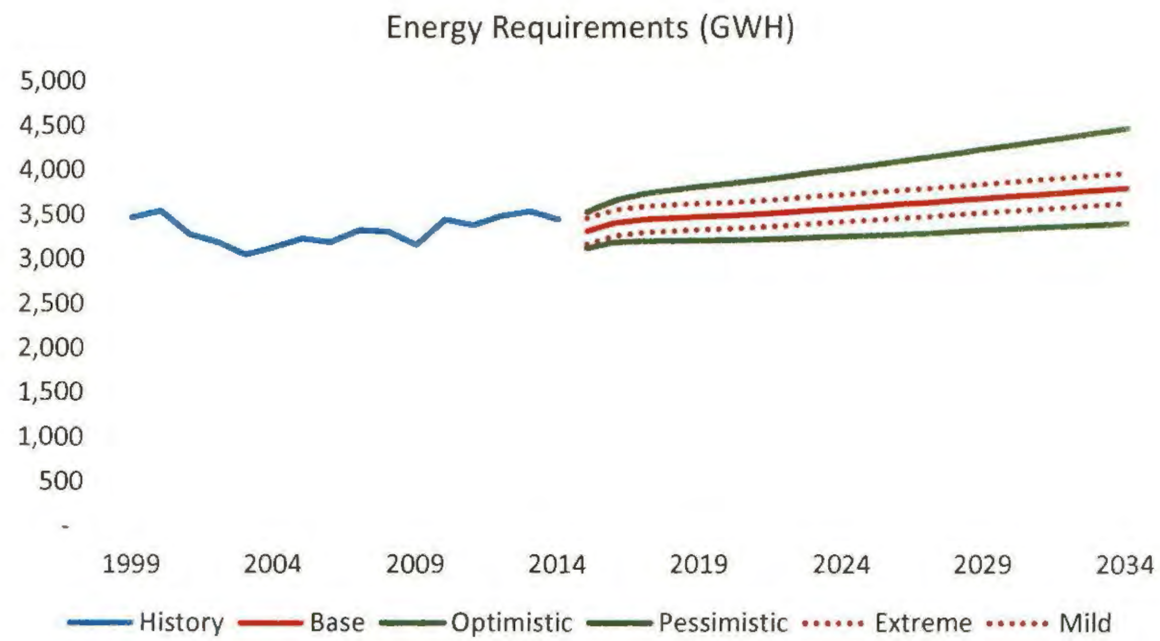
Year	Base Case (kW)	Weather Adjusted (MWh)	ECONOMIC SCENARIOS Optimistic (kW)	ECONOMIC SCENARIOS Pessimistic (kW)	WEATHER SCENARIOS Extreme (kW)	WEATHER SCENARIOS Mild (kW)
1999	577,320					
2000	614,496	626,702				
2001	598,797	582,446				
2002	530,467	564,796				
2003	585,549	559,149				
2004	562,082	550,700				
2005	548,765	565,400				
2006	576,534	608,047				
2007	597,267	596,590				
2008	611,454	625,449				
2009	664,788	643,585				
2010	646,750	651,364				
2011	620,588	594,196				
2012	569,006	625,199				
2013	596,831	589,426				
2014	740,203	637,849				
2015		637,860	679,998	600,185	745,533	551,630
2016		652,264	701,823	609,440	758,314	564,781
2017		667,463	724,925	619,720	771,618	579,438
2018		669,207	731,850	618,697	775,402	581,323
2019		671,165	739,195	618,135	778,254	583,188
2020		673,439	746,285	618,523	780,001	585,080
2021		676,697	753,914	619,098	783,582	587,898
2022		679,752	761,333	620,062	788,078	590,714
2023		683,124	769,025	621,455	793,105	593,808
2024		686,871	777,641	622,675	797,539	597,039
2025		690,916	786,323	624,770	802,163	600,508
2026		695,237	795,472	627,232	806,966	604,182
2027		699,870	805,267	630,045	811,412	607,987
2028		704,765	814,494	633,811	817,200	612,204
2029		709,989	825,081	637,368	822,534	616,539
2030		715,213	835,671	640,924	827,868	620,875
2031		720,437	846,265	644,479	833,202	625,211
2032		725,662	856,862	648,034	838,536	629,546
2033		730,886	867,462	651,587	843,870	633,882
2034		736,110	878,065	655,140	849,204	638,218

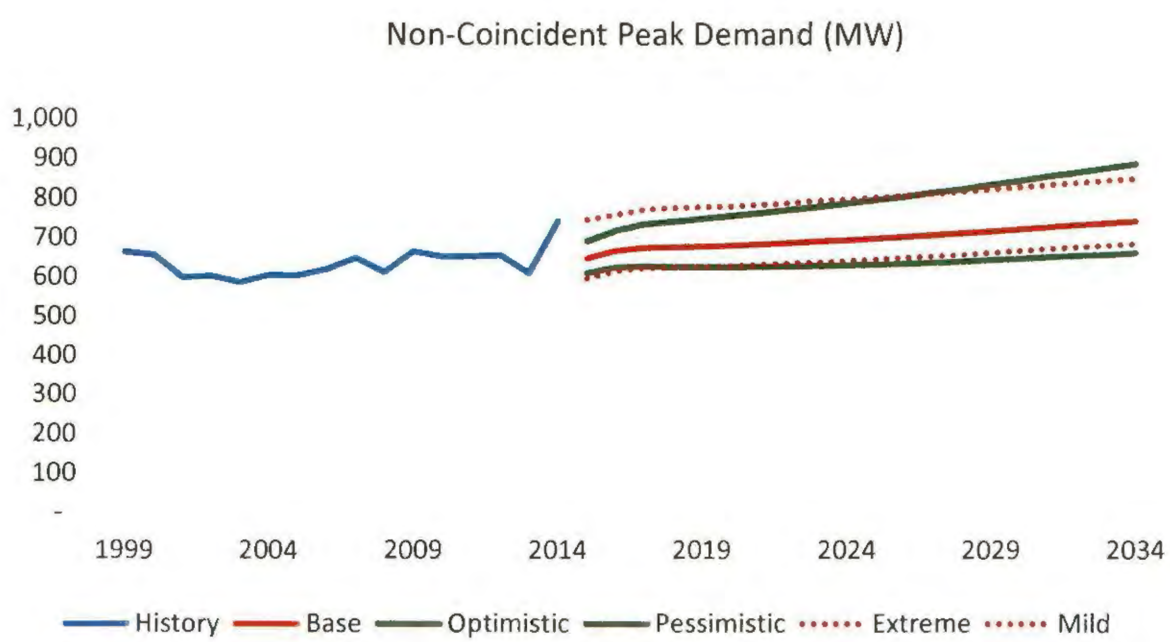
ANNUAL GROWTH RATES						
1999-2004	-0.5%					
2004-2009	3.4%					
2009-2014	2.2%					
2014-2019		1.0%	3.0%	-0.6%	4.1%	-1.8%
2019-2024		0.5%	1.0%	0.1%	0.5%	0.5%
2024-2029		0.7%	1.2%	0.5%	0.6%	0.6%
2029-2034		0.7%	1.3%	0.6%	0.6%	0.7%
2014-2034		0.7%	1.6%	0.1%	1.4%	0.0%

BIG RIVERS ELECTRIC CORPORATION

2015 LONG-TERM LOAD FORECAST - RANGE FORECASTS

NATIVE SYSTEM REQUIREMENTS





BIG RIVERS ELECTRIC CORPORATION

2015 LONG-TERM LOAD FORECAST - RANGE FORECASTS

RURAL SYSTEM REQUIREMENTS

Year	Base Case (MWh)	Weather Adjusted (MWh)	ECONOMIC SCENARIOS Optimistic (MWh)	ECONOMIC SCENARIOS Pessimistic (MWh)	WEATHER SCENARIOS Extreme (MWh)	WEATHER SCENARIOS Mild (MWh)
1999	1,921,792	1,878,683				
2000	2,001,539	1,905,521				
2001	2,000,877	2,005,688				
2002	2,114,841	2,033,135				
2003	2,089,678	2,106,254				
2004	2,133,190	2,122,615				
2005	2,262,017	2,195,757				
2006	2,232,581	2,258,048				
2007	2,407,449	2,307,012				
2008	2,387,974	2,352,719				
2009	2,238,762	2,325,872				
2010	2,480,421	2,345,996				
2011	2,371,106	2,352,481				
2012	2,321,478	2,336,110				
2013	2,374,920	2,359,410				
2014	2,415,564	2,330,615				
2015		2,355,425	2,522,929	2,208,050	2,500,334	2,207,573
2016		2,342,274	2,541,067	2,173,528	2,486,798	2,195,463
2017		2,337,217	2,570,210	2,147,392	2,480,915	2,191,131
2018		2,357,144	2,614,560	2,153,916	2,502,047	2,210,048
2019		2,373,402	2,655,765	2,158,238	2,518,426	2,225,101
2020		2,383,442	2,687,358	2,159,839	2,530,202	2,233,664
2021		2,401,302	2,725,241	2,165,360	2,549,278	2,250,574
2022		2,423,730	2,768,487	2,177,526	2,572,772	2,271,105
2023		2,448,050	2,813,617	2,191,980	2,598,732	2,293,954
2024		2,468,340	2,856,438	2,200,487	2,619,818	2,312,974
2025		2,489,615	2,899,184	2,212,607	2,642,702	2,332,313
2026		2,511,303	2,943,108	2,225,632	2,665,452	2,352,520
2027		2,530,093	2,984,907	2,236,429	2,685,927	2,370,178
2028		2,556,470	3,031,686	2,257,200	2,713,729	2,394,544
2029		2,579,177	3,078,534	2,272,460	2,738,152	2,415,362
2030		2,601,884	3,125,382	2,287,719	2,762,576	2,436,180
2031		2,624,591	3,172,230	2,302,979	2,786,999	2,456,998
2032		2,647,298	3,219,078	2,318,238	2,811,423	2,477,816
2033		2,670,005	3,265,927	2,333,497	2,835,846	2,498,634
2034		2,692,712	3,312,775	2,348,757	2,860,270	2,519,452

ANNUAL GROWTH RATES						
1999-2004	2.1%	2.5%				
2004-2009	1.0%	1.8%				
2009-2014	1.5%	0.0%				
2014-2019		0.4%	2.6%	-1.5%	1.6%	-0.9%
2019-2024		0.8%	1.5%	0.4%	0.8%	0.8%
2024-2029		0.9%	1.5%	0.6%	0.9%	0.9%
2029-2034		0.9%	1.5%	0.7%	0.9%	0.8%
2014-2034		0.7%	1.8%	0.0%	1.0%	0.4%

BIG RIVERS ELECTRIC CORPORATION

2015 LONG-TERM LOAD FORECAST - RANGE FORECASTS

RURAL SYSTEM CP DEMAND - SUMMER

Year	Base Case (MWh)	Weather Adjusted (MWh)	ECONOMIC SCENARIOS Optimistic (kW)	Pessimistic (kW)	WEATHER SCENARIOS Extreme (kW)	Mild (kW)
1999	466,954					
2000	455,792					
2001	441,183					
2002	461,561					
2003	458,050					
2004	472,169					
2005	497,997					
2006	501,463					
2007	532,264					
2008	497,743					
2009	496,641					
2010	539,955					
2011	532,240					
2012	541,865					
2013	493,751					
2014	481,155	515,338				
2015		530,419	568,139	497,231	574,967	478,949
2016		531,420	576,523	493,135	572,568	479,504
2017		532,742	585,850	489,473	571,812	480,478
2018		534,381	592,739	488,308	575,358	482,212
2019		536,414	600,231	487,785	578,192	484,192
2020		538,770	607,469	488,225	579,895	486,311
2021		541,870	614,968	488,628	583,363	489,191
2022		545,015	622,540	489,652	587,767	492,198
2023		548,483	630,388	491,111	592,663	495,505
2024		552,245	639,075	492,318	596,930	498,972
2025		556,277	647,791	494,383	601,369	502,678
2026		560,554	656,939	496,789	605,967	506,593
2027		565,096	666,679	499,506	610,202	510,667
2028		569,861	675,791	503,151	615,760	515,071
2029		574,955	686,273	506,581	620,831	519,672
2030		580,049	696,755	510,011	625,903	524,274
2031		585,144	707,238	513,441	630,975	528,876
2032		590,238	717,721	516,871	636,047	533,477
2033		595,332	728,205	520,301	641,119	538,079
2034		600,427	738,690	523,731	646,191	542,681

ANNUAL GROWTH RATES						
1999-2004	0.2%					
2004-2009	1.0%					
2009-2014	-0.6%					
2014-2019		0.8%	3.1%	-1.1%	2.3%	-1.2%
2019-2024		0.6%	1.3%	0.2%	0.6%	0.6%
2024-2029		0.8%	1.4%	0.6%	0.8%	0.8%
2029-2034		0.9%	1.5%	0.7%	0.8%	0.9%
2014-2034		0.8%	1.8%	0.1%	1.1%	0.3%

BIG RIVERS ELECTRIC CORPORATION

2015 LONG-TERM LOAD FORECAST - RANGE FORECASTS

RURAL SYSTEM CP DEMAND - WINTER

Year	Base Case (MWh)	Weather Adjusted (MWh)	ECONOMIC SCENARIOS Optimistic (kW)	ECONOMIC SCENARIOS Pessimistic (kW)	WEATHER SCENARIOS Extreme (kW)	WEATHER SCENARIOS Mild (kW)
1999	389,245					
2000	378,524					
2001	423,149					
2002	380,606					
2003	460,626					
2004	430,124					
2005	444,494					
2006	439,167					
2007	489,272					
2008	511,901					
2009	560,598					
2010	507,388					
2011	532,501					
2012	456,468					
2013	484,077					
2014	616,023	513,669				
2015		522,230	559,368	489,555	629,903	436,000
2016		525,014	569,573	487,190	631,064	437,531
2017		526,269	578,732	483,526	630,425	438,244
2018		527,841	585,485	482,332	634,036	439,957
2019		529,799	592,829	481,770	636,888	441,822
2020		532,074	599,919	482,157	638,635	443,714
2021		535,331	607,548	482,732	642,216	446,532
2022		538,386	614,967	483,696	646,712	449,348
2023		541,758	622,659	485,090	651,740	452,442
2024		545,505	631,275	486,310	656,173	455,674
2025		549,550	639,957	488,404	660,797	459,143
2026		553,871	649,106	490,866	665,600	462,817
2027		558,504	658,902	493,679	670,047	466,621
2028		563,399	668,128	497,445	675,834	470,838
2029		568,623	678,715	501,002	681,168	475,174
2030		573,848	689,306	504,558	686,502	479,509
2031		579,072	699,899	508,113	691,836	483,845
2032		584,296	710,496	511,668	697,171	488,181
2033		589,520	721,096	515,222	702,505	492,517
2034		594,745	731,699	518,775	707,839	496,852

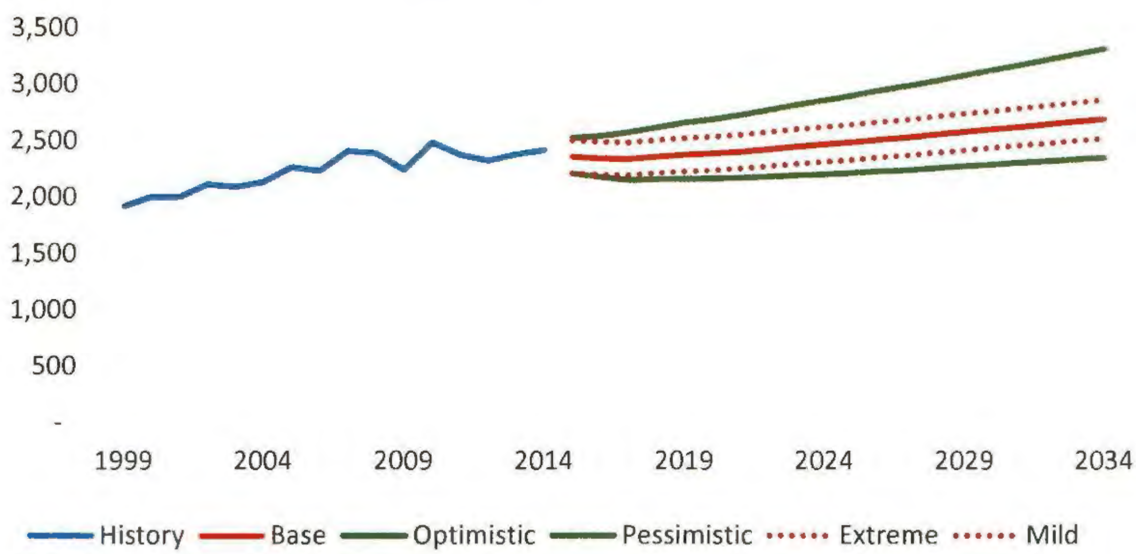
ANNUAL GROWTH RATES						
1999-2004	2.0%					
2004-2009	5.4%					
2009-2014	1.9%					
2014-2019		0.6%	2.9%	-1.3%	4.4%	-3.0%
2019-2024		0.6%	1.3%	0.2%	0.6%	0.6%
2024-2029		0.8%	1.5%	0.6%	0.8%	0.8%
2029-2034		0.9%	1.5%	0.7%	0.8%	0.9%
2014-2034		0.7%	1.8%	0.0%	1.6%	-0.2%

BIG RIVERS ELECTRIC CORPORATION

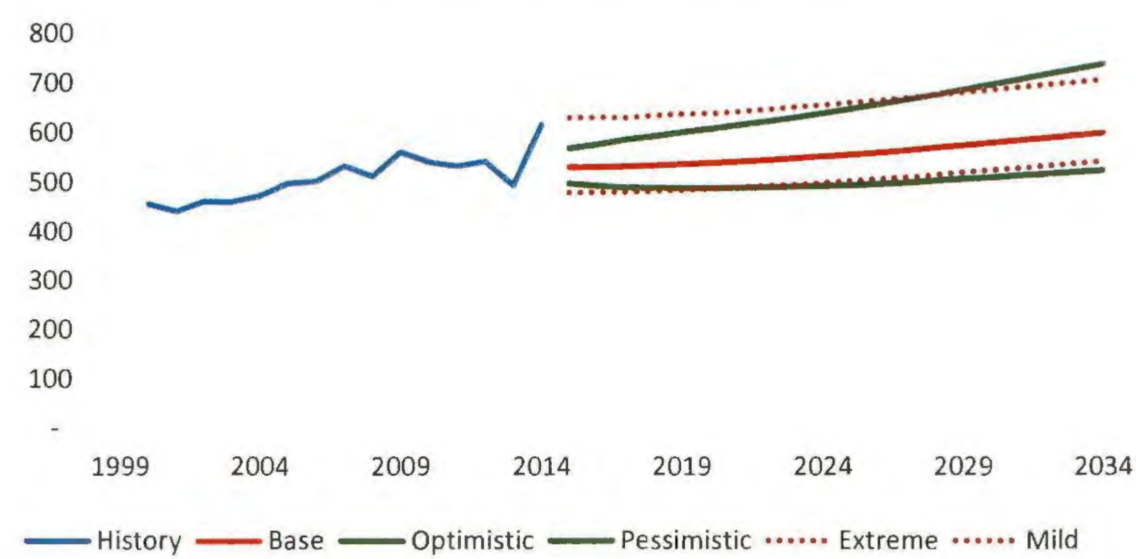
2015 LONG-TERM LOAD FORECAST - RANGE FORECASTS

RURAL SYSTEM REQUIREMENTS

Energy Requirements (GWH)



Non-Coincident Peak Demand (MW)



BIG RIVERS ELECTRIC CORPORATION

2015 LONG-TERM LOAD FORECAST - RANGE FORECASTS

RESIDENTIAL ENERGY SALES

Year	Base Case (MWh)	Weather Normalized (MWh)	ECONOMIC SCENARIOS Optimistic (MWh)	ECONOMIC SCENARIOS Pessimistic (MWh)	WEATHER SCENARIOS Extreme (MWh)	WEATHER SCENARIOS Mild (MWh)
1999	1,215,474	1,264,625				
2000	1,264,194	1,264,292				
2001	1,246,139	1,272,751				
2002	1,371,067	1,333,438				
2003	1,340,451	1,381,531				
2004	1,362,667	1,406,577				
2005	1,452,182	1,451,236				
2006	1,415,359	1,463,678				
2007	1,534,506	1,502,774				
2008	1,529,478	1,517,852				
2009	1,426,775	1,458,294				
2010	1,611,212	1,526,991				
2011	1,530,090	1,529,904				
2012	1,465,749	1,480,285				
2013	1,495,894	1,478,411				
2014	1,517,068	1,467,145				
2015		1,470,062	1,520,758	1,419,005	1,574,131	1,361,951
2016		1,457,938	1,525,835	1,389,743	1,560,894	1,351,544
2017		1,447,437	1,534,030	1,363,236	1,548,912	1,342,410
2018		1,461,984	1,558,554	1,367,995	1,563,988	1,356,597
2019		1,475,491	1,584,354	1,371,164	1,577,172	1,369,387
2020		1,483,603	1,601,752	1,371,764	1,586,522	1,376,496
2021		1,497,662	1,625,679	1,376,113	1,601,343	1,390,037
2022		1,517,257	1,654,819	1,386,729	1,621,559	1,408,213
2023		1,538,630	1,685,566	1,399,449	1,644,089	1,428,582
2024		1,556,728	1,714,802	1,406,559	1,662,566	1,445,842
2025		1,576,452	1,744,522	1,417,124	1,683,464	1,464,075
2026		1,597,333	1,775,761	1,428,556	1,705,010	1,483,885
2027		1,616,338	1,805,630	1,437,910	1,725,298	1,502,129
2028		1,643,253	1,840,289	1,456,703	1,753,245	1,527,449
2029		1,666,646	1,874,996	1,470,204	1,777,944	1,549,366
2030		1,690,039	1,909,704	1,483,705	1,802,643	1,571,284
2031		1,713,432	1,944,411	1,497,206	1,827,341	1,593,202
2032		1,736,825	1,979,118	1,510,706	1,852,040	1,615,119
2033		1,760,218	2,013,825	1,524,207	1,876,739	1,637,037
2034		1,783,611	2,048,532	1,537,708	1,901,438	1,658,955

ANNUAL GROWTH RATES						
1999-2004	2.3%	2.2%				
2004-2009	0.9%	0.7%				
2009-2014	1.2%	0.1%				
2014-2019		0.1%	1.5%	-1.3%	1.5%	-1.4%
2019-2024		1.1%	1.6%	0.5%	1.1%	1.1%
2024-2029		1.4%	1.8%	0.9%	1.4%	1.4%
2029-2034		1.4%	1.8%	0.9%	1.4%	1.4%
2014-2034		1.0%	1.7%	0.2%	1.3%	0.6%

BIG RIVERS ELECTRIC CORPORATION

2015 LONG-TERM LOAD FORECAST - RANGE FORECASTS

SMALL COMMERCIAL ENERGY SALES

			ECONOMIC SCENARIOS		WEATHER SCENARIOS	
Year	Base Case (MWh)	Weather Normalized (MWh)	Optimistic (MWh)	Pessimistic (MWh)	Extreme (MWh)	Mild (MWh)
1999	478,067					
2000	509,568					
2001	528,560					
2002	507,563					
2003	509,312					
2004	521,300					
2005	553,496					
2006	568,398	581,519				
2007	608,391	594,961				
2008	602,535	600,097				
2009	569,297	579,549				
2010	618,684	594,230				
2011	599,542	597,655				
2012	595,342	594,448				
2013	615,002	611,247				
2014	624,488	613,604				
2015		622,642	689,791	554,383	656,178	590,347
2016		634,930	710,569	556,530	669,212	601,908
2017		646,338	730,130	558,192	681,318	612,638
2018		656,633	747,815	559,651	692,231	622,331
2019		664,366	761,223	560,595	700,404	629,635
2020		671,691	773,894	561,527	708,143	636,556
2021		678,707	786,016	562,434	715,553	643,185
2022		685,679	798,020	563,389	722,919	649,772
2023		692,785	810,209	564,418	730,428	656,482
2024		699,499	821,716	565,402	737,521	662,826
2025		705,899	832,664	566,366	744,278	668,875
2026		712,077	843,213	567,322	750,801	674,715
2027		717,886	853,114	568,240	756,932	680,208
2028		723,680	862,953	569,202	763,048	685,684
2029		729,506	872,810	570,212	769,201	691,188
2030		735,331	882,668	571,222	775,353	696,692
2031		741,157	892,525	572,232	781,506	702,196
2032		746,983	902,382	573,242	787,659	707,700
2033		752,808	912,239	574,252	793,811	713,204
2034		758,634	922,097	575,262	799,964	718,708

ANNUAL GROWTH RATES						
1999-2004	1.7%					
2004-2009	1.8%					
2009-2014	1.9%	1.1%				
2014-2019		1.6%	4.4%	-1.8%	2.7%	0.5%
2019-2024		1.0%	1.5%	0.2%	1.0%	1.0%
2024-2029		0.8%	1.2%	0.2%	0.8%	0.8%
2029-2034		0.8%	1.1%	0.2%	0.8%	0.8%
2014-2034		1.1%	2.1%	-0.3%	1.3%	0.8%

BIG RIVERS ELECTRIC CORPORATION

2015 LONG-TERM LOAD FORECAST - RANGE FORECASTS

LARGE COMMERCIAL ENERGY SALES

Year	Base Case (MWh)	ECONOMIC SCENARIOS Optimistic (MWh)	Pessimistic (MWh)	WEATHER SCENARIOS Extreme (MWh)	Mild (MWh)
1999	1,658,114				
2000	1,642,917				
2001	1,414,538				
2002	1,238,353				
2003	1,151,279				
2004	1,140,217				
2005	1,123,081				
2006	1,103,512				
2007	1,071,969				
2008	1,080,619				
2009	1,092,667				
2010	1,083,734				
2011	1,146,619				
2012	1,302,573				
2013	1,323,552				
2014	1,185,042				
2015	1,117,726	1,196,849	1,038,602	1,117,726	1,117,726
2016	1,217,976	1,301,036	1,134,915	1,217,976	1,217,976
2017	1,262,850	1,348,155	1,177,546	1,262,850	1,262,850
2018	1,260,004	1,345,166	1,174,842	1,260,004	1,260,004
2019	1,260,004	1,345,166	1,174,842	1,260,004	1,260,004
2020	1,260,519	1,345,707	1,175,332	1,260,519	1,260,519
2021	1,260,004	1,345,166	1,174,842	1,260,004	1,260,004
2022	1,260,004	1,345,166	1,174,842	1,260,004	1,260,004
2023	1,260,004	1,345,166	1,174,842	1,260,004	1,260,004
2024	1,260,519	1,345,707	1,175,332	1,260,519	1,260,519
2025	1,260,004	1,345,166	1,174,842	1,260,004	1,260,004
2026	1,260,004	1,345,166	1,174,842	1,260,004	1,260,004
2027	1,260,004	1,345,166	1,174,842	1,260,004	1,260,004
2028	1,260,519	1,345,707	1,175,332	1,260,519	1,260,519
2029	1,260,004	1,345,166	1,174,842	1,260,004	1,260,004
2030	1,260,004	1,345,166	1,174,842	1,260,004	1,260,004
2031	1,260,004	1,345,166	1,174,842	1,260,004	1,260,004
2032	1,260,519	1,345,707	1,175,332	1,260,519	1,260,519
2033	1,260,004	1,345,166	1,174,842	1,260,004	1,260,004
2034	1,260,004	1,345,166	1,174,842	1,260,004	1,260,004

ANNUAL GROWTH RATES					
1999-2004	-7.2%				
2004-2009	-0.8%				
2009-2014	1.6%				
2014-2019		2.6%	-0.2%	1.2%	1.2%
2019-2024		0.0%	0.0%	0.0%	0.0%
2024-2029		0.0%	0.0%	0.0%	0.0%
2029-2034		0.0%	0.0%	0.0%	0.0%
2014-2034		0.6%	0.0%	0.3%	0.3%

BIG RIVERS ELECTRIC CORPORATION

2015 LONG-TERM LOAD FORECAST - RANGE FORECASTS

LARGE COMMERCIAL ENERGY SALES - RURAL

Year	Base Case (MWh)	ECONOMIC SCENARIOS Optimistic (MWh)	ECONOMIC SCENARIOS Pessimistic (MWh)	WEATHER SCENARIOS Extreme (MWh)	WEATHER SCENARIOS Mild (MWh)
1999	113,526				
2000	103,533				
2001	113,852				
2002	120,089				
2003	128,476				
2004	138,427				
2005	141,995				
2006	139,821				
2007	145,200				
2008	147,038				
2009	124,286				
2010	121,477				
2011	130,264				
2012	135,134				
2013	157,230				
2014	154,966				
2015	154,915	185,898	123,932	154,915	154,915
2016	147,745	177,294	118,196	147,745	147,745
2017	147,745	177,294	118,196	147,745	147,745
2018	147,745	177,294	118,196	147,745	147,745
2019	147,745	177,294	118,196	147,745	147,745
2020	147,745	177,294	118,196	147,745	147,745
2021	147,745	177,294	118,196	147,745	147,745
2022	147,745	177,294	118,196	147,745	147,745
2023	147,745	177,294	118,196	147,745	147,745
2024	147,745	177,294	118,196	147,745	147,745
2025	147,745	177,294	118,196	147,745	147,745
2026	147,745	177,294	118,196	147,745	147,745
2027	147,745	177,294	118,196	147,745	147,745
2028	147,745	177,294	118,196	147,745	147,745
2029	147,745	177,294	118,196	147,745	147,745
2030	147,745	177,294	118,196	147,745	147,745
2031	147,745	177,294	118,196	147,745	147,745
2032	147,745	177,294	118,196	147,745	147,745
2033	147,745	177,294	118,196	147,745	147,745
2034	147,745	177,294	118,196	147,745	147,745

ANNUAL GROWTH RATES					
1999-2004	4.0%				
2004-2009	-2.1%				
2009-2014	4.5%				
2014-2019		2.7%	-5.3%	-0.9%	-0.9%
2019-2024		0.0%	0.0%	0.0%	0.0%
2024-2029		0.0%	0.0%	0.0%	0.0%
2029-2034		0.0%	0.0%	0.0%	0.0%
2014-2034		0.7%	-1.3%	-0.2%	-0.2%

BIG RIVERS ELECTRIC CORPORATION

2015 LONG-TERM LOAD FORECAST - RANGE FORECASTS

LARGE COMMERCIAL ENERGY SALES - DIRECT SERVE

Year	Base Case (MWh)	ECONOMIC SCENARIOS Optimistic (MWh)	Pessimistic (MWh)	WEATHER SCENARIOS Extreme (MWh)	Mild (MWh)
1999	1,544,587				
2000	1,539,384				
2001	1,300,686				
2002	1,118,264				
2003	1,022,803				
2004	1,001,791				
2005	981,086				
2006	963,691				
2007	926,769				
2008	933,580				
2009	968,381				
2010	962,257				
2011	1,016,356				
2012	1,167,439				
2013	1,166,322				
2014	1,030,075				
2015	962,811	1,010,951	914,670	962,811	962,811
2016	1,070,231	1,123,742	1,016,719	1,070,231	1,070,231
2017	1,115,105	1,170,861	1,059,350	1,115,105	1,115,105
2018	1,112,259	1,167,872	1,056,646	1,112,259	1,112,259
2019	1,112,259	1,167,872	1,056,646	1,112,259	1,112,259
2020	1,112,774	1,168,413	1,057,136	1,112,774	1,112,774
2021	1,112,259	1,167,872	1,056,646	1,112,259	1,112,259
2022	1,112,259	1,167,872	1,056,646	1,112,259	1,112,259
2023	1,112,259	1,167,872	1,056,646	1,112,259	1,112,259
2024	1,112,774	1,168,413	1,057,136	1,112,774	1,112,774
2025	1,112,259	1,167,872	1,056,646	1,112,259	1,112,259
2026	1,112,259	1,167,872	1,056,646	1,112,259	1,112,259
2027	1,112,259	1,167,872	1,056,646	1,112,259	1,112,259
2028	1,112,774	1,168,413	1,057,136	1,112,774	1,112,774
2029	1,112,259	1,167,872	1,056,646	1,112,259	1,112,259
2030	1,112,259	1,167,872	1,056,646	1,112,259	1,112,259
2031	1,112,259	1,167,872	1,056,646	1,112,259	1,112,259
2032	1,112,774	1,168,413	1,057,136	1,112,774	1,112,774
2033	1,112,259	1,167,872	1,056,646	1,112,259	1,112,259
2034	1,112,259	1,167,872	1,056,646	1,112,259	1,112,259

ANNUAL GROWTH RATES					
1999-2004	-8.3%				
2004-2009	-0.7%				
2009-2014	1.2%				
2014-2019		2.5%	0.5%	1.5%	1.5%
2019-2024		0.0%	0.0%	0.0%	0.0%
2024-2029		0.0%	0.0%	0.0%	0.0%
2029-2034		0.0%	0.0%	0.0%	0.0%
2014-2034		0.6%	0.1%	0.4%	0.4%

BIG RIVERS ELECTRIC CORPORATION

2015 LONG-TERM LOAD FORECAST - RANGE FORECASTS

STREET LIGHTING ENERGY SALES

	Base	ECONOMIC SCENARIOS		WEATHER SCENARIOS	
Year	Case (MWh)	Optimistic (MWh)	Pessimistic (MWh)	Extreme (MWh)	Mild (MWh)
1999	3,138				
2000	3,191				
2001	3,104				
2002	3,277				
2003	3,235				
2004	2,997				
2005	3,077				
2006	3,104				
2007	3,175				
2008	3,287				
2009	3,246				
2010	3,438				
2011	3,409				
2012	3,454				
2013	3,486				
2014	3,461				
2015	3,472	3,645	3,298	3,472	3,472
2016	3,475	3,649	3,301	3,475	3,475
2017	3,478	3,652	3,304	3,478	3,478
2018	3,481	3,655	3,307	3,481	3,481
2019	3,484	3,658	3,310	3,484	3,484
2020	3,487	3,661	3,313	3,487	3,487
2021	3,490	3,664	3,315	3,490	3,490
2022	3,493	3,668	3,318	3,493	3,493
2023	3,496	3,671	3,321	3,496	3,496
2024	3,499	3,674	3,324	3,499	3,499
2025	3,502	3,677	3,327	3,502	3,502
2026	3,505	3,680	3,330	3,505	3,505
2027	3,508	3,684	3,333	3,508	3,508
2028	3,511	3,687	3,336	3,511	3,511
2029	3,514	3,690	3,338	3,514	3,514
2030	3,517	3,693	3,341	3,517	3,517
2031	3,520	3,696	3,344	3,520	3,520
2032	3,523	3,699	3,347	3,523	3,523
2033	3,526	3,703	3,350	3,526	3,526
2034	3,529	3,706	3,353	3,529	3,529

ANNUAL GROWTH RATES					
1999-2004	-0.9%				
2004-2009	1.6%				
2009-2014	1.3%				
2014-2019		1.1%	-0.9%	0.1%	0.1%
2019-2024		0.1%	0.1%	0.1%	0.1%
2024-2029		0.1%	0.1%	0.1%	0.1%
2029-2034		0.1%	0.1%	0.1%	0.1%
2014-2034		0.3%	-0.2%	0.1%	0.1%

BIG RIVERS ELECTRIC CORPORATION

2015 LONG-TERM LOAD FORECAST - RANGE FORECASTS

IRRIGATION ENERGY SALES

Year	Base Case (MWh)	ECONOMIC SCENARIOS Optimistic (MWh)	ECONOMIC SCENARIOS Pessimistic (MWh)	WEATHER SCENARIOS Extreme (MWh)	WEATHER SCENARIOS Mild (MWh)
1999	121				
2000	70				
2001	75				
2002	38				
2003	113				
2004	164				
2005	114				
2006	65				
2007	1,068				
2008	432				
2009	406				
2010	356				
2011	269				
2012	440				
2013	48				
2014	136				
2015	298	358	239	567	30
2016	298	358	239	567	30
2017	298	358	239	567	30
2018	298	358	239	567	30
2019	298	358	239	567	30
2020	298	358	239	567	30
2021	298	358	239	567	30
2022	298	358	239	567	30
2023	298	358	239	567	30
2024	298	358	239	567	30
2025	298	358	239	567	30
2026	298	358	239	567	30
2027	298	358	239	567	30
2028	298	358	239	567	30
2029	298	358	239	567	30
2030	298	358	239	567	30
2031	298	358	239	567	30
2032	298	358	239	567	30
2033	298	358	239	567	30
2034	298	358	239	567	30

ANNUAL GROWTH RATES					
1999-2004	6.2%				
2004-2009	19.9%				
2009-2014	-19.6%				
2014-2019		21.3%	11.8%	32.9%	-26.2%
2019-2024		0.0%	0.0%	0.0%	0.0%
2024-2029		0.0%	0.0%	0.0%	0.0%
2029-2034		0.0%	0.0%	0.0%	0.0%
2014-2034		4.9%	2.8%	7.4%	-7.3%

Appendix C – Forecast Model Specifications

Meade County Rural Electric Cooperative Corporation
Residential Customers
Short Term Model

Variable	Coefficient	StdErr	T-Stat	P-Value	Definition
CONST	21885.404	163.513	133.845	0.00%	Constant term
ModelData.Trend1	11.614	0.431	26.939	0.00%	

Model Statistics	
Iterations	1
Adjusted Observations	84
Deg. of Freedom for Error	82
R-Squared	0.898
Adjusted R-Squared	0.897
AIC	9.148
BIC	9.206
F-Statistic	725.71
Prob (F-Statistic)	0.0000
Log-Likelihood	-501.41
Model Sum of Squares	6,661,170.33
Sum of Squared Errors	752,663.91
Mean Squared Error	9,178.83
Std. Error of Regression	95.81
Mean Abs. Dev. (MAD)	81.32
Mean Abs. % Err. (MAPE)	0.31%
Durbin-Watson Statistic	0.224
Durbin-H Statistic	#NA
Ljung-Box Statistic	397.82
Prob (Ljung-Box)	0.0000
Skewness	0.170
Kurtosis	1.955
Jarque-Bera	4.223
Prob (Jarque-Bera)	0.1210

Meade County Rural Electric Cooperative Corporation
Residential Customers
Long Term Model

Variable	Coefficient	StdErr	T-Stat	P-Value	Definition
CONST	81,312.69	117,754.6	0.691	49.02%	Constant term
ModelData.HH	396.395	97.765	4.055	0.01%	
AR(1)	1.000	0.000623843	1602.4	0.00%	

Model Statistics	
Iterations	30
Adjusted Observations	419
Deg. of Freedom for Error	416
R-Squared	1.000
Adjusted R-Squared	1.000
AIC	7.521
BIC	7.550
F-Statistic	2,060,988.83
Prob (F-Statistic)	0.0000
Log-Likelihood	-2,167.24
Model Sum of Squares	7,558,891,910.18
Sum of Squared Errors	762,861.74
Mean Squared Error	1,833.80
Std. Error of Regression	42.82
Mean Abs. Dev. (MAD)	31.16
Mean Abs. % Err. (MAPE)	0.16%
Durbin-Watson Statistic	1.884
Durbin-H Statistic	#NA
Ljung-Box Statistic	176.28
Prob (Ljung-Box)	0.0000
Skewness	-0.759
Kurtosis	10.159
Jarque-Bera	934.969
Prob (Jarque-Bera)	0.0000

Meade County Rural Electric Cooperative Corporation
Small Commercial Customers
Short Term Model

Variable	Coefficient	StdErr	T-Stat	P-Value	Definition
CONST	979.674	45.833	21.375	0.00%	Constant term
ModelData.Trend1	3.073	0.145	21.139	0.00%	

Model Statistics	
Iterations	1
Adjusted Observations	144
Deg. of Freedom for Error	142
R-Squared	0.759
Adjusted R-Squared	0.757
AIC	8.582
BIC	8.623
F-Statistic	446.85
Prob (F-Statistic)	0.0000
Log-Likelihood	-820.20
Model Sum of Squares	2,350,129.44
Sum of Squared Errors	746,824.72
Mean Squared Error	5,259.33
Std. Error of Regression	72.52
Mean Abs. Dev. (MAD)	64.12
Mean Abs. % Err. (MAPE)	3.44%
Durbin-Watson Statistic	0.020
Durbin-H Statistic	#NA
Ljung-Box Statistic	1198.63
Prob (Ljung-Box)	0.0000
Skewness	-0.451
Kurtosis	1.831
Jarque-Bera	13.086
Prob (Jarque-Bera)	0.0014

Meade County Rural Electric Cooperative Corporation
Small Commercial Customers
Long Term Model

Variable	Coefficient	StdErr	T-Stat	P-Value	Definition
CONST	1.78	2.21	0.806	42.10%	Constant term
ModelData.Emp	1.620	1.165	1.390	16.53%	
Scom_Con_LT.LagDep(1)	0.994	0.004287334	231.873	0.00%	

Model Statistics	
Iterations	1
Adjusted Observations	383
Deg. of Freedom for Error	380
R-Squared	0.999
Adjusted R-Squared	0.999
AIC	4.237
BIC	4.268
F-Statistic	301,833.36
Prob (F-Statistic)	0.0000
Log-Likelihood	-1,351.79
Model Sum of Squares	41,437,844.99
Sum of Squared Errors	26,084.56
Mean Squared Error	68.64
Std. Error of Regression	8.29
Mean Abs. Dev. (MAD)	5.92
Mean Abs. % Err. (MAPE)	0.38%
Durbin-Watson Statistic	1.775
Durbin-H Statistic	2.207722066
Ljung-Box Statistic	48.00
Prob (Ljung-Box)	0.0025
Skewness	1.124
Kurtosis	8.865
Jarque-Bera	629.606
Prob (Jarque-Bera)	0.0000

Meade County Rural Electric Cooperative Corporation
Residential kWh Use per Customer per Month

Variable	Coefficient	StdErr	T-Stat	P-Value	Definition
ModelData.BASE	2,008.05	92.44	21.724	0.00%	
ModelData.COOL	134.139	21.923	6.119	0.00%	
ModelData.HEAT	292.858	15.937	18.376	0.00%	
Binary.January	143.568	36.229	3.963	0.01%	
Binary.February	193.083	33.011	5.849	0.00%	
Binary.April	88.946	30.962	2.873	0.46%	
Binary.June	81.436	50.433	1.615	10.81%	
Binary.July	146.668	62.515	2.346	2.00%	
Binary.August	189.116	60.320	3.135	0.20%	
Binary.September	232.749	36.993	6.292	0.00%	

Model Statistics	
Iterations	1
Adjusted Observations	192
Deg. of Freedom for Error	182
R-Squared	0.836
Adjusted R-Squared	0.827
AIC	9.428
BIC	9.597
F-Statistic	#NA
Prob (F-Statistic)	#NA
Log-Likelihood	-1,167.50
Model Sum of Squares	10,923,572.92
Sum of Squared Errors	2,150,217.62
Mean Squared Error	11,814.38
Std. Error of Regression	108.69
Mean Abs. Dev. (MAD)	80.82
Mean Abs. % Err. (MAPE)	7.56%
Durbin-Watson Statistic	1.973
Durbin-H Statistic	#NA
Ljung-Box Statistic	165.78
Prob (Ljung-Box)	0.0000
Skewness	0.114
Kurtosis	3.388
Jarque-Bera	1.624
Prob (Jarque-Bera)	0.4440

Meade County Rural Electric Cooperative Corporation
Small Commercial kWh Use per Customer per Month

Variable	Coefficient	StdErr	T-Stat	P-Value	Definition
CONST	3,755.22	202.67	18.529	0.00%	Constant term
MonthlyModel.WTHDDSC	0.089	0.205	0.435	66.41%	
MonthlyModel.WTCDDSC	1.914	0.383	4.996	0.00%	
Binary.February	52.379	101.514	0.516	60.64%	
Binary.March	-330.779	123.416	-2.680	0.79%	
Binary.April	-299.239	171.146	-1.748	8.18%	
Binary.May	-474.747	204.928	-2.317	2.14%	
Binary.June	-421.135	238.629	-1.765	7.90%	
Binary.July	-338.346	261.475	-1.294	19.70%	
Binary.August	-42.328	260.262	-0.163	87.09%	
Binary.September	274.241	217.414	1.261	20.85%	
Binary.October	-120.395	175.035	-0.688	49.23%	
Binary.November	-162.494	126.968	-1.280	20.19%	
Binary.December	-151.228	96.366	-1.569	11.80%	

Model Statistics	
Iterations	1
Adjusted Observations	240
Deg. of Freedom for Error	226
R-Squared	0.609
Adjusted R-Squared	0.586
AIC	11.449
BIC	11.652
F-Statistic	27.06
Prob (F-Statistic)	0.0000
Log-Likelihood	-1,700.44
Model Sum of Squares	31,193,321.64
Sum of Squared Errors	20,036,494.78
Mean Squared Error	88,657.06
Std. Error of Regression	297.75
Mean Abs. Dev. (MAD)	231.84
Mean Abs. % Err. (MAPE)	6.00%
Durbin-Watson Statistic	0.828
Durbin-H Statistic	#NA
Ljung-Box Statistic	890.22
Prob (Ljung-Box)	0.0000
Skewness	0.117
Kurtosis	2.904
Jarque-Bera	0.641
Prob (Jarque-Bera)	0.7259

Meade County Rural Electric Cooperative Corporation
Rural System Peak Demand

Variable	Coefficient	StdErr	T-Stat	P-Value	Definition
CONST	(60,975.90)	8,822.61	-6.911	0.00%	Constant term
ModelData.EGY_TREND	2.501	0.183	13.668	0.00%	
MonthlyModel.PeakHDD	1315.667	99.096	13.277	0.00%	
MonthlyModel.PeakCDD	1142.209	162.857	7.014	0.00%	
Binary.February	-1873.493	1706.913	-1.098	27.39%	
Binary.March	-4892.751	2327.581	-2.102	3.70%	
Binary.April	-6761.750	3198.746	-2.114	3.59%	
Binary.May	10360.102	7092.717	1.461	14.59%	
Binary.June	19831.138	7561.999	2.622	0.95%	
Binary.July	21889.949	7777.866	2.814	0.54%	
Binary.August	22557.118	7815.759	2.886	0.44%	
Binary.September	16841.176	7496.204	2.247	2.59%	
Binary.October	10249.155	6760.655	1.516	13.13%	
Binary.November	-5384.140	2498.827	-2.155	3.25%	
Binary.December	-3140.937	1699.319	-1.848	6.62%	
AR(1)	0.351	0.068	5.184	0.00%	

Model Statistics	
Iterations	8
Adjusted Observations	192
Deg. of Freedom for Error	176
R-Squared	0.910
Adjusted R-Squared	0.902
AIC	17.260
BIC	17.531
F-Statistic	118.75
Prob (F-Statistic)	0.0000
Log-Likelihood	-1,913.37
Model Sum of Squares	51,517,956,365
Sum of Squared Errors	5,090,226,036.09
Mean Squared Error	28,921,738.84
Std. Error of Regression	5,377.89
Mean Abs. Dev. (MAD)	4,110.56
Mean Abs. % Err. (MAPE)	5.05%
Durbin-Watson Statistic	2.083
Durbin-H Statistic	#NA
Ljung-Box Statistic	78.65
Prob (Ljung-Box)	0.0000
Skewness	0.044
Kurtosis	3.268
Jarque-Bera	0.635
Prob (Jarque-Bera)	0.7279

Jackson Purchase Energy Corporation
Residential Customers
Short Term Model

Variable	Coefficient	StdErr	T-Stat	P-Value	Definition
CONST	19866.993	131.010	151.645	0.00%	Constant term
ModelData.Trend1	17.338	0.416	41.720	0.00%	

Model Statistics	
Iterations	1
Adjusted Observations	144
Deg. of Freedom for Error	142
R-Squared	0.925
Adjusted R-Squared	0.924
AIC	10.682
BIC	10.723
F-Statistic	1,740.53
Prob (F-Statistic)	0.0000
Log-Likelihood	-971.44
Model Sum of Squares	74,793,008.44
Sum of Squared Errors	6,101,930.50
Mean Squared Error	42,971.34
Std. Error of Regression	207.30
Mean Abs. Dev. (MAD)	170.83
Mean Abs. % Err. (MAPE)	0.68%
Durbin-Watson Statistic	0.030
Durbin-H Statistic	#NA
Ljung-Box Statistic	1061.98
Prob (Ljung-Box)	0.0000
Skewness	-0.773
Kurtosis	2.562
Jarque-Bera	15.478
Prob (Jarque-Bera)	0.0004

Jackson Purchase Energy Corporation
Residential Customers
Long Term Model

Variable	Coefficient	StdErr	T-Stat	P-Value	Definition
CONST	(12,912,366.53)	6,079,134,332.6	-0.002	99.83%	Constant term
ModelData.HH	278.514	119.234	2.336	2.00%	
AR(1)	1.000	0.000667986	1497.04	0.00%	

Model Statistics	
Iterations	99
Adjusted Observations	419
Deg. of Freedom for Error	416
R-Squared	1.000
Adjusted R-Squared	1.000
AIC	7.132
BIC	7.161
F-Statistic	1,881,218.03
Prob (F-Statistic)	0.0000
Log-Likelihood	-2,085.64
Model Sum of Squares	4,673,582,233.41
Sum of Squared Errors	516,742.39
Mean Squared Error	1,242.17
Std. Error of Regression	35.24
Mean Abs. Dev. (MAD)	27.51
Mean Abs. % Err. (MAPE)	0.13%
Durbin-Watson Statistic	1.627
Durbin-H Statistic	#NA
Ljung-Box Statistic	298.03
Prob (Ljung-Box)	0.0000
Skewness	-0.188
Kurtosis	3.494
Jarque-Bera	6.740
Prob (Jarque-Bera)	0.0344

Jackson Purchase Energy Corporation
Small Commercial Customers
Short Term Model

Variable	Coefficient	StdErr	T-Stat	P-Value	Definition
CONST	624.883	31.535	19.816	0.00%	Constant term
ModelData.Trend1	6.824	0.100	68.222	0.00%	

Model Statistics	
Iterations	1
Adjusted Observations	144
Deg. of Freedom for Error	142
R-Squared	0.970
Adjusted R-Squared	0.970
AIC	7.834
BIC	7.875
F-Statistic	4,654.24
Prob (F-Statistic)	0.0000
Log-Likelihood	-766.35
Model Sum of Squares	11,587,693.30
Sum of Squared Errors	353,538.53
Mean Squared Error	2,489.71
Std. Error of Regression	49.90
Mean Abs. Dev. (MAD)	41.00
Mean Abs. % Err. (MAPE)	1.46%
Durbin-Watson Statistic	0.136
Durbin-H Statistic	#NA
Ljung-Box Statistic	1025.03
Prob (Ljung-Box)	0.0000
Skewness	-0.193
Kurtosis	2.469
Jarque-Bera	2.589
Prob (Jarque-Bera)	0.2740

Jackson Purchase Energy Corporation
Small Commercial Customers
Long Term Model

Variable	Coefficient	StdErr	T-Stat	P-Value	Definition
CONST	(3.72)	5.48	-0.678	49.79%	Constant term
ModelData.Emp	0.284	0.228	1.246	21.36%	
Scom_Con_LT.LagDep(1)	0.999	0.002346417	425.685	0.00%	

Model Statistics	
Iterations	1
Adjusted Observations	383
Deg. of Freedom for Error	380
R-Squared	1.000
Adjusted R-Squared	0.999
AIC	5.230
BIC	5.261
F-Statistic	381,036.65
Prob (F-Statistic)	0.0000
Log-Likelihood	-1,541.93
Model Sum of Squares	141,194,495.80
Sum of Squared Errors	70,405.18
Mean Squared Error	185.28
Std. Error of Regression	13.61
Mean Abs. Dev. (MAD)	9.57
Mean Abs. % Err. (MAPE)	0.46%
Durbin-Watson Statistic	2.162
Durbin-H Statistic	-1.587177806
Ljung-Box Statistic	22.76
Prob (Ljung-Box)	0.5342
Skewness	-0.266
Kurtosis	5.888
Jarque-Bera	137.623
Prob (Jarque-Bera)	0.0000

Jackson Purchase Energy Corporation
Residential kWh Use per Customer per Month

Variable	Coefficient	StdErr	T-Stat	P-Value	Definition
CONST	221.68	122.28	1.813	7.15%	Constant term
ModelData.BASE	1283.752	430.742	2.980	0.33%	
ModelData.COOL	298.699	24.674	12.106	0.00%	
ModelData.HEAT	355.922	13.406	26.550	0.00%	
Binary.February	-131.302	35.831	-3.664	0.03%	
Binary.June	155.346	55.520	2.798	0.57%	
Binary.July	181.041	68.317	2.650	0.87%	
Binary.August	142.635	65.871	2.165	3.16%	
Binary.September	107.408	40.222	2.670	0.83%	

Model Statistics	
Iterations	1
Adjusted Observations	192
Deg. of Freedom for Error	183
R-Squared	0.864
Adjusted R-Squared	0.858
AIC	9.635
BIC	9.788
F-Statistic	145.45
Prob (F-Statistic)	0.0000
Log-Likelihood	-1,188.44
Model Sum of Squares	17,003,641.26
Sum of Squared Errors	2,674,208.69
Mean Squared Error	14,613.16
Std. Error of Regression	120.88
Mean Abs. Dev. (MAD)	90.21
Mean Abs. % Err. (MAPE)	7.54%
Durbin-Watson Statistic	2.418
Durbin-H Statistic	#NA
Ljung-Box Statistic	50.20
Prob (Ljung-Box)	0.0013
Skewness	0.198
Kurtosis	3.788
Jarque-Bera	6.224
Prob (Jarque-Bera)	0.0445

Jackson Purchase Energy Corporation
Small Commercial kWh Use per Customer per Month

Variable	Coefficient	StdErr	T-Stat	P-Value	Definition
CONST	2,049.87	449.26	4.563	0.00%	Constant term
MonthlyModel.WTHDD5C	1.930	0.378	5.101	0.00%	
MonthlyModel.WTCDD5C	3.652	0.739	4.941	0.00%	
SCOM_USE.LagDep(1)	0.289	0.058	4.971	0.00%	
Binary.February	-389.308	179.818	-2.165	3.14%	
Binary.March	183.781	220.840	0.832	40.62%	
Binary.April	565.871	304.811	1.856	6.47%	
Binary.May	1068.401	370.756	2.882	0.43%	
Binary.June	1000.468	434.719	2.301	2.23%	
Binary.July	761.629	474.677	1.605	11.00%	
Binary.August	594.121	467.288	1.271	20.49%	
Binary.September	448.993	389.629	1.152	25.04%	
Binary.October	509.201	307.765	1.655	9.94%	
Binary.November	313.662	219.588	1.428	15.46%	
Binary.December	157.665	169.792	0.929	35.41%	

Model Statistics	
Iterations	1
Adjusted Observations	240
Deg. of Freedom for Error	225
R-Squared	0.597
Adjusted R-Squared	0.572
AIC	12.580
BIC	12.797
F-Statistic	23.81
Prob (F-Statistic)	0.0000
Log-Likelihood	-1,835.12
Model Sum of Squares	91,206,355.09
Sum of Squared Errors	61,555,110.89
Mean Squared Error	273,578.27
Std. Error of Regression	523.05
Mean Abs. Dev. (MAD)	349.92
Mean Abs. % Err. (MAPE)	6.75%
Durbin-Watson Statistic	2.033
Durbin-H Statistic	-0.591627603
Ljung-Box Statistic	96.36
Prob (Ljung-Box)	0.0000
Skewness	0.812
Kurtosis	5.109
Jarque-Bera	70.868
Prob (Jarque-Bera)	0.0000

Jackson Purchase Energy Corporation
Rural System Peak Demand

Variable	Coefficient	StdErr	T-Stat	P-Value	Definition
CONST	(57,297.82)	12,532.31	-4.572	0.00%	Constant term
ModelData.EGY_TREND	2.208	0.202	10.928	0.00%	
MonthlyModel.PeakHDD	1113.825	109.964	10.129	0.00%	
MonthlyModel.PeakCDD	1960.393	200.431	9.781	0.00%	
Binary.February	-4986.870	1999.367	-2.494	1.35%	
Binary.March	-8557.989	2572.666	-3.327	0.11%	
Binary.April	-9112.394	3419.207	-2.665	0.84%	
Binary.May	3315.824	8167.481	0.406	68.53%	
Binary.June	15258.628	8888.677	1.717	8.78%	
Binary.July	20566.933	9090.724	2.262	2.49%	
Binary.August	21096.388	9166.969	2.301	2.25%	
Binary.September	9830.338	8631.689	1.139	25.63%	
Binary.October	-9291.108	7764.258	-1.197	23.31%	
Binary.November	-9623.892	2644.073	-3.640	0.04%	
Binary.December	-4016.379	1983.470	-2.025	4.44%	
AR(1)	0.289	0.072	3.998	0.01%	

Model Statistics	
Iterations	8
Adjusted Observations	192
Deg. of Freedom for Error	176
R-Squared	0.921
Adjusted R-Squared	0.914
AIC	17.580
BIC	17.851
F-Statistic	136.99
Prob (F-Statistic)	0.0000
Log-Likelihood	-1,944.08
Model Sum of Squares	81,829,693,164
Sum of Squared Errors	7,008,837,033.32
Mean Squared Error	39,822,937.69
Std. Error of Regression	6,310.54
Mean Abs. Dev. (MAD)	4,792.04
Mean Abs. % Err. (MAPE)	4.25%
Durbin-Watson Statistic	2.024
Durbin-H Statistic	#NA
Ljung-Box Statistic	33.68
Prob (Ljung-Box)	0.0905
Skewness	0.279
Kurtosis	3.134
Jarque-Bera	2.628

Kenergy Corporation
Residential Customers
Short Term Model

Variable	Coefficient	StdErr	T-Stat	P-Value	Definition
CONST	42226.641	311.549	135.538	0.00%	Constant term
ModelData.Trend1	8.272	0.988	8.371	0.00%	

Model Statistics	
Iterations	1
Adjusted Observations	144
Deg. of Freedom for Error	142
R-Squared	0.330
Adjusted R-Squared	0.326
AIC	12.415
BIC	12.456
F-Statistic	70.07
Prob (F-Statistic)	0.0000
Log-Likelihood	-1,096.18
Model Sum of Squares	17,027,283.03
Sum of Squared Errors	34,507,189.46
Mean Squared Error	243,008.38
Std. Error of Regression	492.96
Mean Abs. Dev. (MAD)	347.75
Mean Abs. % Err. (MAPE)	0.78%
Durbin-Watson Statistic	0.112
Durbin-H Statistic	#NA
Ljung-Box Statistic	605.57
Prob (Ljung-Box)	0.0000
Skewness	0.895
Kurtosis	3.752
Jarque-Bera	22.606
Prob (Jarque-Bera)	0.0000

Kenergy Corporation
Residential Customers
Long Term Model

Variable	Coefficient	StdErr	T-Stat	P-Value	Definition
CONST	25,947.61	21,199.0	1.224	22.16%	Constant term
ModelData.HH	221.619	178.012	1.245	21.38%	
AR(1)	0.997	0.001	666.884	0.00%	

Model Statistics	
Iterations	11
Adjusted Observations	419
Deg. of Freedom for Error	416
R-Squared	0.999
Adjusted R-Squared	0.999
AIC	9.344
BIC	9.373
F-Statistic	406,850.09
Prob (F-Statistic)	0.0000
Log-Likelihood	-2,549.05
Model Sum of Squares	9,231,976,203.52
Sum of Squared Errors	4,719,800.00
Mean Squared Error	11,345.67
Std. Error of Regression	106.52
Mean Abs. Dev. (MAD)	48.33
Mean Abs. % Err. (MAPE)	0.12%
Durbin-Watson Statistic	1.538
Durbin-H Statistic	#NA
Ljung-Box Statistic	77.99
Prob (Ljung-Box)	0.0000
Skewness	-11.798
Kurtosis	198.122
Jarque-Bera	674407.010
Prob (Jarque-Bera)	0.0000

Kenergy Corporation
Small Commercial Customers
Short Term Model

Variable	Coefficient	StdErr	T-Stat	P-Value	Definition
CONST	4963.729	168.083	29.531	0.00%	Constant term
ModelData.Trend1	13.128	0.443	29.623	0.00%	

Model Statistics	
Iterations	1
Adjusted Observations	84
Deg. of Freedom for Error	82
R-Squared	0.915
Adjusted R-Squared	0.913
AIC	9.203
BIC	9.261
F-Statistic	877.53
Prob (F-Statistic)	0.0000
Log-Likelihood	-503.73
Model Sum of Squares	8,511,233.18
Sum of Squared Errors	795,327.14
Mean Squared Error	9,699.11
Std. Error of Regression	98.48
Mean Abs. Dev. (MAD)	83.70
Mean Abs. % Err. (MAPE)	0.85%
Durbin-Watson Statistic	0.066
Durbin-H Statistic	#NA
Ljung-Box Statistic	441.16
Prob (Ljung-Box)	0.0000
Skewness	0.191
Kurtosis	1.806
Jarque-Bera	5.499
Prob (Jarque-Bera)	0.0640

Kenergy Corporation
Small Commercial Customers
Long Term Model

Variable	Coefficient	StdErr	T-Stat	P-Value	Definition
CONST	(22,034.21)	2,348.98	-9.380	0.00%	Constant term
ModelData.Emp	33.640	6.915	4.865	0.00%	
Res_Con_LT.Predicted	0.622	0.044	14.087	0.00%	
MA(1)	0.820	0.069	11.863	0.00%	

Model Statistics	
Iterations	16
Adjusted Observations	84
Deg. of Freedom for Error	80
R-Squared	0.903
Adjusted R-Squared	0.900
AIC	8.583
BIC	8.699
F-Statistic	249.60
Prob (F-Statistic)	0.0000
Log-Likelihood	-475.67
Model Sum of Squares	3,816,198.49
Sum of Squared Errors	407,719.07
Mean Squared Error	5,096.49
Std. Error of Regression	71.39
Mean Abs. Dev. (MAD)	51.66
Mean Abs. % Err. (MAPE)	0.53%
Durbin-Watson Statistic	0.692
Durbin-H Statistic	#NA
Ljung-Box Statistic	189.41
Prob (Ljung-Box)	0.0000
Skewness	0.782
Kurtosis	3.482
Jarque-Bera	9.373
Prob (Jarque-Bera)	0.0092

Kenergy Corporation
Residential kWh Use per Customer per Month

Variable	Coefficient	StdErr	T-Stat	P-Value	Definition
ModelData.BASE	2,969.93	51.11	58.105	0.00%	
ModelData.COOL	182.479	8.437	21.630	0.00%	
ModelData.HEAT	275.658	9.196	29.975	0.00%	
Binary.January	69.510	23.382	2.973	0.33%	
Binary.February	115.317	21.365	5.397	0.00%	
Binary.July	134.078	25.705	5.216	0.00%	
Binary.August	248.025	25.099	9.882	0.00%	
Binary.September	203.474	19.486	10.442	0.00%	
Binary.November	-162.232	19.114	-8.488	0.00%	
MonthlyModel.Jan2001	-302.321	78.384	-3.857	0.02%	
MonthlyModel.Feb2001	-303.940	78.321	-3.881	0.01%	

Model Statistics	
Iterations	1
Adjusted Observations	240
Deg. of Freedom for Error	229
R-Squared	0.914
Adjusted R-Squared	0.910
AIC	8.715
BIC	8.874
F-Statistic	#NA
Prob (F-Statistic)	#NA
Log-Likelihood	-1,375.33
Model Sum of Squares	14,152,640.94
Sum of Squared Errors	1,334,243.70
Mean Squared Error	5,826.39
Std. Error of Regression	76.33
Mean Abs. Dev. (MAD)	55.82
Mean Abs. % Err. (MAPE)	4.37%
Durbin-Watson Statistic	1.268
Durbin-H Statistic	#NA
Ljung-Box Statistic	105.17
Prob (Ljung-Box)	0.0000
Skewness	0.475
Kurtosis	4.574
Jarque-Bera	33.813
Prob (Jarque-Bera)	0.0000

Kenergy Corporation
Small Commercial kWh Use per Customer per Month

Variable	Coefficient	StdErr	T-Stat	P-Value	Definition
CONST	1,553.02	166.06	9.352	0.00%	Constant term
MonthlyModel.WTHDDSC	1.432	0.170	8.406	0.00%	
MonthlyModel.WTCDDSC	3.270	0.319	10.246	0.00%	
Binary.February	-347.555	71.550	-4.858	0.00%	
Binary.March	-145.149	99.122	-1.464	14.64%	
Binary.April	-112.680	136.771	-0.824	41.21%	
Binary.May	322.564	162.590	1.984	5.02%	
Binary.June	594.725	190.162	3.127	0.24%	
Binary.July	463.697	200.195	2.316	2.27%	
Binary.August	283.158	200.304	1.414	16.08%	
Binary.September	270.204	171.275	1.578	11.80%	
Binary.October	368.032	134.973	2.727	0.76%	
Binary.November	542.469	94.665	5.730	0.00%	
Binary.December	513.545	71.761	7.156	0.00%	

Model Statistics	
Iterations	1
Adjusted Observations	108
Deg. of Freedom for Error	94
R-Squared	0.927
Adjusted R-Squared	0.917
AIC	10.070
BIC	10.418
F-Statistic	91.77
Prob (F-Statistic)	0.0000
Log-Likelihood	-683.02
Model Sum of Squares	24,983,377.80
Sum of Squared Errors	1,968,539.88
Mean Squared Error	20,941.91
Std. Error of Regression	144.71
Mean Abs. Dev. (MAD)	103.12
Mean Abs. % Err. (MAPE)	3.97%
Durbin-Watson Statistic	1.099
Durbin-H Statistic	#NA
Ljung-Box Statistic	54.85
Prob (Ljung-Box)	0.0003
Skewness	-0.905
Kurtosis	4.091
Jarque-Bera	20.092
Prob (Jarque-Bera)	0.0000

Kenergy Corporation
Rural System Peak Demand

Variable	Coefficient	StdErr	T-Stat	P-Value	Definition
CONST	(139,008.77)	9,531.19	-14.585	0.00%	Constant term
ModelData.EGY_TREND	2.266	0.093	24.257	0.00%	
MonthlyModel.PeakHDD	2504.324	93.498	26.785	0.00%	
MonthlyModel.PeakCDD	5150.214	170.606	30.188	0.00%	
MonthlyModel.Oct2009	16735.066	13708.116	1.221	22.32%	
MonthlyModel.Oct2010	-63987.355	13589.576	-4.709	0.00%	
AR(1)	0.262	0.059	4.420	0.00%	

Model Statistics	
Iterations	8
Adjusted Observations	276
Deg. of Freedom for Error	269
R-Squared	0.892
Adjusted R-Squared	0.889
AIC	19.109
BIC	19.201
F-Statistic	369.72
Prob (F-Statistic)	0.0000
Log-Likelihood	-3,021.62
Model Sum of Squares	430,477,139,406
Sum of Squared Errors	52,200,323,619.04
Mean Squared Error	194,053,247.65
Std. Error of Regression	13,930.30
Mean Abs. Dev. (MAD)	10,798.91
Mean Abs. % Err. (MAPE)	5.87%
Durbin-Watson Statistic	1.956
Durbin-H Statistic	#NA
Ljung-Box Statistic	92.73
Prob (Ljung-Box)	0.0000
Skewness	-0.275
Kurtosis	3.154
Jarque-Bera	3.751
Prob (Jarque-Bera)	0.1533

Appendix D – Glossary

Glossary

Big Rivers	Big Rivers Electric Corporation
C&I	Commercial and Industrial
CHP	Combined Heat and Power
Commission	Kentucky Public Service Commission
DOE	U. S. Department of Energy
DSM	Demand-Side Management
EE	Energy Efficiency
EF	Efficiency Factor
EIA	Energy Information Administration
EPA	Environmental Protection Agency
GDP	Gross Domestic Product
GDS	GDS Associates, Inc.
GWH	Gigawatt hours
HMP&L	Henderson Municipal Power & Light
HSPF	Heating Seasonal Performance Factor
IRP	Integrated Resource Plan
JPEC	Jackson Purchase Energy Corporation
Kenergy	Kenergy Corp.
KW	Kilowatt
kWh	Kilowatt hours
LIC	Large Industrial Customer Tariff
MCRECC	Meade County Rural Electric Cooperative Corporation
MDA	MDA EarthSat Weather data provider
Members	Collectively: MCRECC, Kenergy, JPEC
MISO	Midcontinent Independent System Operator, Inc.
MW	Megawatt
MWH	Megawatt hours
NERC	North American Electric Reliability Council
NCP	Non-coincident peak
RCUST	Rural system customers
RUS	Rural Utilities Services
RUSE	Rural system energy use per customer
SAE	Statistically Adjusted End-Use
SEER	Seasonal Energy Efficiency Ratio
SEPA	Southeastern Power Administration
The 2010 IRP	Case No. 2010-00443

BIG RIVERS ELECTRIC CORPORATION

Energy Efficiency and Demand Response Potential

FINAL REPORT

September 2017

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1 EXECUTIVE SUMMARY

1.1 BACKGROUND

Big Rivers Electric Corporation ("Big Rivers" or "the Company") commissioned GDS Associates ("GDS") to conduct a study of the potential for electric energy efficiency and demand response programs to reduce electric consumption and peak demand throughout Big Rivers Members' service territories. Improving energy efficiency and lowering electric demand in homes, businesses, and industries can be a cost-effective way to address the challenges of increasing energy costs and the increasing demand for energy. Consequently, demand-side management ("DSM") potential studies are important and helpful tools for identifying those DSM measures that are the most cost-effective which have the most electricity savings potential. The results of this study provide a roadmap for the development of detailed program plans for cost effective DSM measures.

This report presents results from the evaluation of opportunities for energy efficiency programs in the Big Rivers Members' service territories. Estimates of technical potential, economic potential, and achievable potential are provided for the ten-year period spanning 2017-2026 for the residential and commercial/industrial ("C&I"), or nonresidential) sectors. Results from two program potential scenarios are also presented to estimate the portion of the achievable potential that could be achieved given specific funding levels for existing Big Rivers DSM programs.

All results were developed using customized residential and C&I sector-level potential assessment Excel models and Company-specific cost effectiveness criteria including the most recent Big Rivers avoided energy and capacity cost projections for electricity. The results of this study provide detailed information on energy efficiency measures that are cost-effective and have potential kWh and kW savings. The data referenced in this report were the best available at the time this analysis was developed. As building and appliance codes and energy efficiency standards change, and as energy prices fluctuate, additional opportunities for energy efficiency may occur while current practices may become outdated. Actual energy and demand savings will depend upon the level and degree of voluntary member system participation in DSM programs.

1.2 STUDY SCOPE

This study examines the potential to reduce electric consumption and peak demand through the implementation of DSM technologies and practices in residential, commercial, and industrial facilities. The study assessed energy efficiency potential and demand response throughout Big Rivers Members' service territories over ten years, from 2017 through 2026.

The study had five primary objectives:

- Develop databases of energy efficiency and demand response measures in the residential and nonresidential sectors. The measure database reflects current industry knowledge of energy efficiency and demand response measures, accounts for known codes and standards, and aligns with the market and demographics of Big Rivers Members' customers.
- Evaluate the electric DSM technical potential savings in Big Rivers Members' territories;
- Calculate the Total Resource Cost ("TRC") test and Utility Cost Test ("UCT") benefit-cost ratios for potential electric energy efficiency measures; determine the electric energy efficiency economic potential savings (using the TRC test) for Big Rivers Members;

- Evaluate the potential for achievable savings through DSM programs over a ten-year horizon (2017-2026);
- Estimate the potential savings over a ten-year period from the delivery of a portfolio of energy efficiency programs based on a specific funding level. The portfolio of energy efficiency programs has been analyzed based on two funding scenarios: a $1 million incentive budget and a $2 million incentive budget.

1.3 TYPES OF POTENTIAL ESTIMATED

The scope of this study distinguishes three types of energy efficiency potential: (1) technical, (2) economic, and (3) achievable.

- **Technical Potential** is the theoretical maximum amount of energy use that could be displaced by efficiency, disregarding all non-engineering constraints such as cost-effectiveness and the willingness of end users to adopt the efficiency measures. Technical potential is constrained only by factors such as technical feasibility and applicability of measures. Under technical potential, GDS assumed that 100% of new construction and burnout measures are adopted as those opportunities become available, while retrofit and early retirement opportunities are replaced incrementally (10% per year) until 100% of homes (residential) and square footage stock (nonresidential) are converted to the efficient measures over 10 years.
- **Economic Potential** refers to the subset of the technical potential that is economically cost-effective as compared to conventional supply-side energy resources. Economic potential follows the same adoption rates as technical potential. Like technical potential, the economic scenario ignores market barriers to ensuring actual implementation of efficiency. Finally, economic potential only considers the costs of efficiency measures themselves, ignoring any programmatic costs (e.g., marketing, analysis, administration) that would be necessary to capture them.[1]
- **Achievable Potential** is the amount of energy use that efficiency can realistically be expected to displace, assuming the most aggressive program scenario possible (e.g., providing end users with payments for the entire incremental cost of more efficient equipment). Achievable potential considers real-world barriers to encouraging end users to adopt efficiency measures, the non-measure costs of delivering programs (for administration, marketing, tracking systems, and monitoring and evaluation), and the capability of programs and administrators to boost program activity over time.[2]
- **Program Potential** is the amount of potential that can be achieved given specific funding levels and program designs.

1.4 ENERGY EFFICIENCY POTENTIAL

Figure 1-1 provides the technical, economic, achievable and program potential (two funding scenarios) across all sectors in the Big Rivers service territory. The economic potential is approximately 25% of forecasted sales by 2026. The program potential at the $1 million incentive scenario is approximately 2% of forecasted sales by 2026. Chapters 3 and 4 provide sector level details. Chapter 6 provides program potential details.

[1] National Action Plan for Energy Efficiency, "Guide for Conducting Energy Efficiency Potential Studies" (November 2007), page 2-4.
[2] National Action Plan for Energy Efficiency, "Guide for Conducting Energy Efficiency Potential Studies" (Nov. 2007), page 2-4.

Figure 1-1// Electric Efficiency Potential Savings Summary

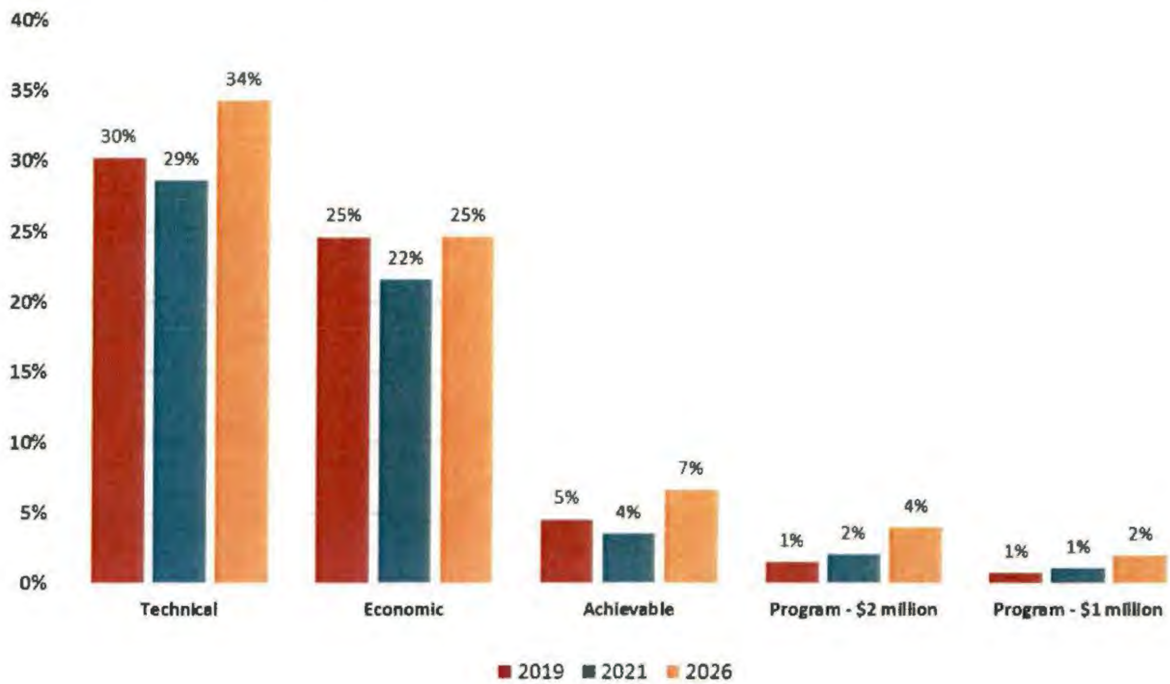


Table 1-1 provides the 10-yr energy, summer demand, and winter demand potential.

Table 1-1// Summary Results for Energy and Demand

Potential	MWh	Summer MW	Winter MW
Technical	1,174,792	224.3	128.0
Economic	845,682	164.4	110.5
Achievable	228,863	41.6	36.1
Program - $2 million	136,582	20.6	16.2
Program - $1 million	68,339	10.5	8.5

Table 1-2 shows the net present value benefits, costs and benefit-cost ratios for the two Program Potential scenarios examined in this study. The overall cost-effectiveness ratios have decreased since the last study, but still indicate that the program potential scenarios are cost-effective overall. There are several reasons for decreased cost-effectiveness including reduced opportunity for low cost lighting savings due to changing market conditions and the effect of standards. The avoided capacity costs used to value demand savings also decreased since the last study.

Table 1-2// Program Potential Cost-Effectiveness (TRC Test)

Potential	NPV Benefits	NPV Costs	NPV Savings (Benefits - Costs)	TRC Test Ratio
Program - $2 million	$126.3	$83.0	$43.3	1.5
Program - $1 million	$62.6	$43.8	$18.8	1.4

2 ANALYSIS APPROACH

This section describes the overall methodology that was utilized to develop the energy efficiency potential study for Big Rivers. The main objective of this energy efficiency potential study is to quantify the electric energy efficiency savings potential in the Big Rivers Member's territories. This report provides estimates of the potential kWh and kW electric savings for each level (technical, economic, achievable and program potential) of energy efficiency potential. This document describes the general steps and methods that were used at each stage of the analytical process necessary to produce the various estimates of energy efficiency potential.

Energy efficiency potential studies involve several analytical steps to produce estimates of each type of energy efficiency potential. This study utilizes benefit/cost screening tools for the residential and nonresidential sectors to assess the cost effectiveness of energy efficiency measures. These cost effectiveness screening tools are Excel-based models that integrate technology-specific impacts and costs, customer characteristics, utility avoided cost forecasts and other valuation modeling parameters such as discount and inflation rates. Excel was used as the modeling platform to provide transparency to the estimation process and allow for simple customization based on Big Rivers' unique characteristics and the availability of specific model input data. This section describes major analytical steps and provides an overview of how the potential savings are calculated. Specific differences in methodology from one sector to another are also discussed in this section.

2.1 OVERVIEW OF APPROACH

GDS used a bottom-up approach to estimate energy efficiency potential in the residential sector. Bottom-up approaches begin with characterizing the eligible equipment stock, estimating savings and screening for cost-effectiveness first at the measure level, then summing savings at the end-use and service area levels. In the commercial and industrial sectors, GDS utilized the bottom-up modeling approach to first estimate measure-level savings and costs as well as cost-effectiveness, and then applied cost-effective measure savings to all applicable shares of energy load. Further details of the market research and modeling techniques utilized in this assessment are provided in the following sections.

2.2 MEASURE ANALYSIS

2.2.1 Measure List Development

Energy efficiency measure lists were based on the analysis team's existing knowledge and current databases of electric end-use technologies and energy efficiency measures, and were supplemented as necessary to include measures currently offered by Big Rivers' Members. The study scope was restricted to measures and practices that are currently commercially available. These are measures that are of most immediate interest to energy efficiency program planners.

In addition, this study focused on measures that could be relatively easily substituted for or applied to existing technologies on a retrofit or replace-on-burnout basis. Replace-on-burnout applies to equipment replacements that are made normally in the market when a piece of equipment is at the end of its useful life. A retrofit measure is eligible to be replaced at any time in the life of the equipment or building. Replace-on-burnout measures are generally characterized by incremental measure costs and savings (e.g. the costs and savings of a high-efficiency versus standard efficiency air-source heat pump); whereas retrofit measures are generally characterized by full costs and savings (e.g. the full costs and savings associated with retrofitting ceiling insulation into an existing attic.).

2.2.2 Number of Measures Evaluated

In total, GDS analyzed 433 measure types. This included 354 types of measures in the residential sector as detailed in Section 3, and 79 types in the nonresidential sector as described in Section 4 of this report. Many measures required multiple permutations for different applications, such as different building types, efficiency levels, and replacement options.

2.2.3 Measure Characterization

A significant amount of data is needed to estimate the electric and savings potential for individual energy efficiency measures or programs across the residential and nonresidential customer sectors in the Big Rivers territory. To this extent, considerable effort was expended to identify, review, and document all available data sources. This review allowed development of reasonable assumptions regarding measure lives; installed incremental and full costs (where appropriate); and electric energy and demand savings for each measure included in the final lists of measures in this study.

Measure Savings: GDS utilized the Illinois TRM[3] to inform calculations supporting estimates of annual measure savings as a percentage of base equipment usage. GDS selected the Illinois TRM for this study as a primary data source because it is comprehensive, current, and from a state in close proximity to Kentucky. For custom measures and measures not included in the Illinois TRM, GDS estimated savings from a variety of sources, including:

- Mid-Atlantic TRM, Minnesota TRM, Michigan Energy Measures Database (MEMD) and other existing deemed savings databases
- Building energy simulation software (BEopt) and engineering analyses
- Known changes in federal codes and standards
- Secondary sources such as the American Council for an Energy-Efficient Economy (ACEEE), Department of Energy (DOE), Energy Information Administration (EIA), ENERGY STAR©, and other technical potential studies

Measure Costs: Measure costs represent either incremental or full costs. These costs typically include the incremental cost of measure installation, when appropriate based on the measure definition. For purposes of this study, nominal measure costs held constant over time. GDS obtained measure cost estimates primarily from the Illinois TRM. GDS used the following data sources to supplement the Illinois TRM:

- TRMs in other states
- Secondary sources such as the ACEEE, ENERGY STAR, National Renewable Energy Lab (NREL), California Database for Energy Efficient Resources (DEER) database, Northeast Energy Efficiency Partnership (NEEP) Incremental Cost Study, and other technical potential studies
- Retail store pricing (such as websites of Home Depot, Lowe's, and Grainger) and industry experts
- Program evaluation and market assessment reports completed for utilities in other states

Measure Life: Measure life represents the number of years that energy using equipment is expected to operate. GDS obtained measure life estimates from the Illinois TRM, and used the following data sources for measures not in the Illinois TRM:

[3] Illinois TRM

- TRMs in other states
- Manufacturer data
- Savings calculators and life-cycle cost analyses
- Other consultant research or technical reports

Baseline and Efficient Technology Saturations: To assess the potential electric energy efficiency savings available, estimates of the current saturation of baseline equipment and energy efficiency measures are necessary. The residential sector relied mainly on 2017 appliance surveys conducted by the Big Rivers Member Cooperatives. This survey was completed on behalf of the Member's by Bellomy Research, Inc. The survey collected data from residential customers regarding the presence of energy consuming appliances and devices, as well as the efficiency level of this equipment. This information helped GDS create an updated profile of the electric energy consumption and efficiency characteristics of residential customers, which in turn helped to create updated estimates of potential among residential customers. The commercial sector utilized regional specific data available from the Commercial Buildings Energy Consumption Survey ("CBECS") conducted by the EIA.

2.2.4 Treatment of Codes and Standards

Although this analysis does not attempt to predict how energy codes and standards will change over time, the analysis does account for the impacts of several known improvements to federal codes and standards. Although not exhaustive, key adjustments include:

- The baseline efficiency for air source heat pumps (ASHP) improved to 14 SEER/8.2 HSPF[4] in 2015. As the existing stock of ASHPs is estimated to turn over and allowing for a sell-through period, the baseline efficiency was assumed to be the new federal standard, beginning in 2018.
- In 2015, the DOE made amended standards effective for residential water heaters that required updated energy factors (EF) depending on the type of water heater and the rated storage volume. For electric storage water heaters with a volume greater than 55 gallons, the standards effectively require heat pumps for electric storage products. For storage tank water heaters with a volume of 55 gallons or less, the new standard (EF=0.948) becomes essentially the equivalent of today's efficient storage tank water heaters.
- In March 2015, the DOE amended the standards for residential clothes washers. The new standards require the Integrated Modified Energy Factor (MEF) (ft^3/kWh/cycle) to meet certain thresholds based on the machine configurations. The ENERGY STAR specifications for residential clothes washers is amended to increase the efficiency of units that can earn the ENERGY STAR label. Version 7.0 of the ENERGY STAR specification went into effect in March 2015. These amended federal and ENERGY STAR standards have been factored into the study.
- In line with the phase-in of 2005 EPAct regulations, the baseline efficiency for general service linear fluorescent lamps was moved from the T12 light bulb to a T8 light bulb effective June 1, 2016.

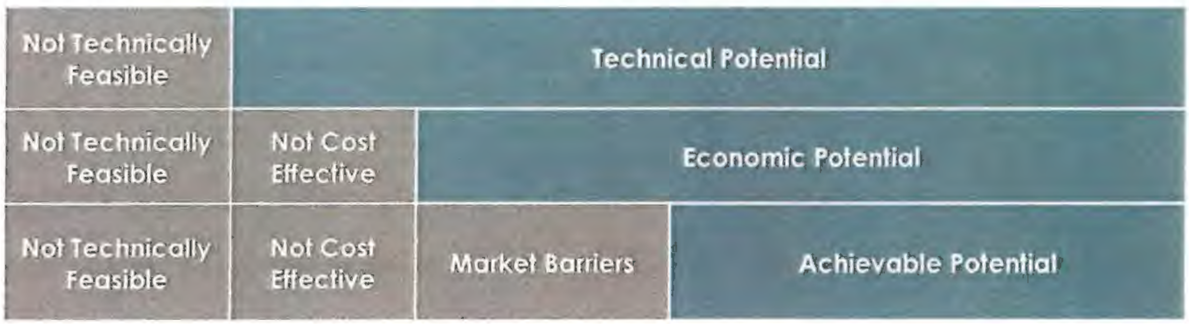
2.3 POTENTIAL SAVINGS OVERVIEW

Potential studies often distinguish between several types of energy efficiency potential: technical, economic, achievable, and program. However, because there are often important definitional issues between studies, it is important to understand the definition and scope of each potential estimate as it applies to this analysis.

[4] SEER: Seasonal Energy Efficiency Ratio; HSPF: Heating Seasonal Performance Factor.

The first two types of potential, technical and economic, provide a theoretical upper bound for energy savings from energy efficiency measures. Still, even the best-designed portfolio of programs is unlikely to capture 100% of the technical or economic potential. Therefore, achievable potential attempts to estimate what savings may realistically be achieved through market interventions, when it can be captured, and how much it would cost to do so. Figure 2-1 illustrates the types of energy efficiency potential considered in this analysis.[5]

Figure 2-1 // Type of Energy Efficiency Potential[6]



2.4 TECHNICAL POTENTIAL

Technical potential is the theoretical maximum amount of energy use that could be displaced by efficiency, disregarding all non-engineering constraints such as cost-effectiveness and the willingness of end users to adopt the efficiency measures. Technical potential is only constrained by factors such as technical feasibility and applicability of measures. Under technical potential, GDS assumed that 100% of new construction and market opportunity measures are adopted as those opportunities become available (e.g., as new buildings are constructed they immediately adopt efficiency measures, or as existing measures reach the end of their useful life). For retrofit measures, implementation was assumed to be resource constrained and that it was not possible to install all retrofit measures all at once. Retrofit opportunities were assumed to be replaced incrementally until 100% of stock were converted to the efficient measure over a period of no more than 10 years.

2.4.1 Core Equation for the Residential Sector

The core equation used in the residential sector energy efficiency technical potential analysis for each individual efficiency measure is shown in Equation 2-1 below.

Equation 2-1 // Core Equation for Residential Sector Technical Potential

[5] The figure does not show program potential. For this study program potential is unique because it does not require a measure to be cost-effective. The measures in program potential align with those currently offered by Big Rivers. For this reason, program potential in this study is appropriate for understanding what can be achieved in the short-term, given existing funding levels and program design; and achievable potential provides a better indication of what could be achieved in the long-term, if program design considerations more fully account for cost-effective measures, and assuming future funding could be less restricted than it is at present.

[6] Reproduced from "Guide to Resource Planning with Energy Efficiency." November 2007. US Environmental Protection Agency (EPA). Figure 2-1.

Where:

Base Case Equipment End-Use Intensity = the electricity used per customer per year by each base-case technology in each market segment. In other words, the base case equipment end-use intensity is the consumption of the electrical energy using equipment that the efficient technology replaces or affects.

Saturation Share = the fraction of the end-use electrical energy that is applicable for the efficient technology in each market segment. For example, for residential water heating, the saturation share would be the fraction of all residential electric customers that have electric water heating in their household.

Remaining Factor = the fraction of equipment that is not considered to already be energy efficient. To extend the example above, the fraction of electric water heaters that is not already energy efficient.[7]

Applicability Factor = the fraction of the applicable units that is technically feasible for conversion to the most efficient available technology from an engineering perspective (e.g., it may not be possible to install LEDs in all light sockets in a home because the LEDs may not fit in every socket).[8]

Savings Factor = the percentage reduction in electricity consumption resulting from the application of the efficient technology.

2.4.2 Core Equation for the Nonresidential Sector

The core equation utilized in the nonresidential sector technical potential analysis for each individual efficiency measure is shown in Equation 2-2 below.

Equation 2-2// Core Equation for Nonresidential Sector Technical Potential

Where:

Total End Use MWh Sales by Building Type = the forecasted MWh sales for a given building type (e.g., office buildings).

Base Case Factor = the fraction of the equipment electrical energy that is applicable for the efficient technology in each market segment. For example, for room air conditioners, the saturation share would be the fraction of all space cooling kWh in each market segment that is associated with room air conditioner equipment.

[7] For purposes of this study, the remaining factor for most market opportunity measures, and select retrofit measures, was 100%. This assumes that all measures, regardless of current efficiency, are eligible to revert to the code baseline at the time of replacement. This is uniquely different from the prior market potential study which removed installed measures that were already energy efficient from the analysis pool. GDS made this change to its methodology to recognize that some customers would choose an inefficient alternative without an incentive, even after having previously purchased an efficient alternative in the past.

[8] In instances where there are two (or more) competing technologies for the same electrical end use, such as heat pump water heaters, water heater efficiency measures, high-efficiency electric storage water heaters and solar water heating systems, an applicability factor aids in determining the proportion of the available population assigned to each measure. In estimating the technical potential, measures with the most savings are given priority for installation. For all other types of potential, both total savings and cost-effectiveness were considered as factors in determining the assumed installation priority.

Applicability Factor = the fraction of the equipment or practice that is technically feasible for conversion to the efficient technology from an engineering perspective (e.g., it may not be possible to install variable frequency drives ("VFD")s on all motors in each market segment).

Remaining Factor = the fraction of equipment that is not considered to already be energy efficient. For example, the fraction of electric water heaters that is not already energy efficient.

Savings Factor = the percentage reduction in electricity consumption resulting from the application of the efficient technology.

2.5 ECONOMIC POTENTIAL

Economic potential refers to the subset of the technical potential that is economically cost-effective, based on screening with the Total Resource Cost (TRC) test, as compared to conventional supply-side energy resources. All measures that were not found to be cost-effective were excluded from further analysis in the economic and achievable potential. GDS then readjusted and applied allocation factors to the remaining measures that were cost-effective.

The TRC test, which measures the regional net benefits, is the most common test used to evaluate energy efficiency and is the appropriate test from a regulatory perspective.[9] The previous study in 2014 also used the TRC test. The TRC Test measures the net costs of an energy efficiency 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. The benefits include the avoided electric supply costs, the reduction in transmission, distribution, generation, and capacity costs (valued at marginal cost for the period when there is an electric load reduction), and savings of other resources such as fossil fuels and water. The costs are the program costs paid both by the utility and the participants. All equipment costs (including: installation, operation and maintenance, cost of removal, and administration costs) are included in this test. Results are typically expressed as either net benefits or a benefit-to-cost ratio.

Other tests that are used in evaluating energy efficiency throughout the U.S. include:

The Utility Cost Test ("UCT"): or Program Administrator's Test, considers only the avoided energy costs as benefits and counts only expenditures incurred by the utility;

The Participant Cost Test ("PCT"): uses retail energy rates and incentives received to value the benefits of energy savings and count only costs paid directly by participants;

The Rate Impact Measure Test ("RIM") Test: uses the same benefits and costs as the utility test, but also counts the lost sales revenue as a cost;

The Societal Cost Test ("SCT"): uses the same costs as the TRC test, but includes societal benefits such as avoided participant costs for hypothesized change in medical expenses due to healthier surroundings.

The use of UCT is becoming increasingly more common in measuring utility program performance.[10] The UCT can help improve the seeming cost-effectiveness of programs, if incentives are set to a low enough level that measures which fail the TRC can still pass the UCT. The PCT is also an important measure of how

[9] ACEEE, 2014. A Brief Review of Benefit-Cost Testing for Energy Efficiency Programs: Current Status and Some Key Issues http://nasuca.org/nwp/wp-content/uploads/2014/01/Dr.-Kushler.pdf
[10] Cadmus, 2012. Whose Perspective? The Impact of the Utility Cost Test http://www.cadmusgroup.com/wp-content/uploads/2012/11/TRC_UCT-Paper_12DEC11.pdf

likely a measure is to be installed by participants. Measures with higher PCT ratios have a greater likelihood of eliciting participation. This study relies on the TRC test as stated, but the potential models used in the study have also calculated the UCT and PCT, as well as the SCT and RIM test, benefit-cost ratios. The UCT and PCT especially are useful in designing programs and associated measures. In some cases, measures which do not pass the TRC test can still be important part of program offerings if either or both the UCT and PCT are cost-effective.

2.6 ACHIEVABLE POTENTIAL

Achievable potential is the amount of energy that can realistically be saved given various market barriers. Achievable potential considers real-world barriers to encouraging end users to adopt efficiency measures; the non-measure costs of delivering programs (for administration, marketing, analysis, and EM&V); and the capability of programs and administrators to boost program activity over time. Barriers include financial, customer awareness and willingness to participate in programs, technical constraints, and other barriers the "program intervention" is modeled to overcome. Additional considerations include political and/or regulatory constraints. The potential study evaluated one achievable potential scenario. In this scenario, we estimated achievable potential assuming Big Rivers pays 35% incentives (as a percent of incremental measure costs).

GDS assessed achievable potential on a measure-by-measure basis. In addition to accounting for the natural replacement cycle of equipment in the achievable potential scenario, GDS estimated measure specific adoption rates that reflect the presence of possible market barriers and associated difficulties in achieving the 100% market adoption assumed in the technical and economic scenarios.

3 RESIDENTIAL ENERGY EFFICIENCY POTENTIAL

This chapter provides the potential results for technical, economic, and achievable potential for the residential sector. The chapter provides a list of the measures included in the study, and identifies leading end uses and measures within the potential. Cumulative ten-year total estimates are provided as well as annual achievable savings estimates. Program potential is discussed in Chapter 0.

3.1 MEASURES EXAMINED

There were 354 total electric energy efficiency measures included in the analysis. Table 3-1 provides a list of the measures included for each end use in the residential model. The list of measures was developed based on a review of the Illinois TRM, the current Big Rivers program offerings, the 2014 residential potential study measure list. Measure data includes incremental costs, electric energy and demand savings, natural gas savings, and measure life.

Table 3-1// Residential Energy Efficiency Measures In Study

End-Use	Measure Name
Refrigeration	Energy Star Compliant Top-Mount Refrigerator
Refrigeration	CEE Tier 2 Compliant Top-Mount Refrigerator
Refrigeration	Energy Star Compliant Side-by-Side Refrigerator
Refrigeration	CEE Tier 2 Compliant Side-by-Side Refrigerator
Refrigeration	Energy Star Compliant Chest Freezer
Refrigeration	Energy Star Compliant Upright Freezer (Manual Def.)
Refrigeration	Second Refrigerator Turn In
Refrigeration	Second Freezer Turn In
Clothes Washer/Dryer	Energy Star Clothes Washer (w/ Elec. WH & Elec. Dryer)
Clothes Washer/Dryer	Energy Star Most Efficient Clothes Washer (w/ Elec. WH & Elec. Dryer)
Clothes Washer/Dryer	Energy Star Clothes Washer (w/ NG WH & Elec. Dryer)
Clothes Washer/Dryer	Energy Star Most Efficient Clothes Washer (w/ NG WH & Elec. Dryer)
Clothes Washer/Dryer	ENERGY STAR Clothes Dryer
Dishwasher	Energy Star Dishwasher (Electric Water Heating)
Dishwasher	Energy Star Dishwasher (Non-Electric WH)
Misc. Plug Load	Energy Star Dehumidifier
Misc. Plug Load	Energy Star Room Air Cleaner
Consumer Electronics	Efficient Televisions
Consumer Electronics	Energy Star Desktop Computer
Consumer Electronics	Energy Star Computer Monitor
Consumer Electronics	Energy Star Laptop Computer
Consumer Electronics	Tier 1 Power Strip
Consumer Electronics	Tier 2 Power Strip
Lighting	Standard CFL
Lighting	Standard LED
Lighting	Specialty CFL
Lighting	Specialty LED

Table 3-1 // Residential Energy Efficiency Measures in Study (*continued*)

End Use	Measure Name
Lighting	Reflector CFL
Lighting	Reflector LED
Lighting	Energy Star Torchiere
Lighting	LED Nightlight
Lighting	Exterior CFL Fixture
Lighting	Exterior LED Fixture
Water Heating	Low Flow Faucet Aerators
Water Heating	Low Flow Showerhead
Water Heating	Thermostatic Restriction Valve
Water Heating	Water Heater Blanket
Water Heating	Water Heater Pipe Wrap
Water Heating	Heat Pump Water Heater (resistance heat)
Water Heating	Heat Pump Water Heater (ASHP heat)
Water Heating	Solar Water Heating
HVAC Shell	Insulation - Ceiling (R-0 to R-38) - (Elec AC & Gas Heat)
HVAC Shell	Insulation - Ceiling (R-11 to R-49) - (Elec AC & Gas Heat)
HVAC Shell	Insulation - Ceiling (R-19 to R-49) - (Elec AC & Gas Heat)
HVAC Shell	Insulation - Floor (R-0 to R-19) - (Elec AC & Gas Heat)
HVAC Shell	Insulation - Floor (R-11 to R-30) - (Elec AC & Gas Heat)
HVAC Shell	Energy Star Windows - (Elec AC & Gas Heat)
HVAC Shell	Air Sealing - (Elec AC & Gas Heat)
HVAC Shell	Duct Sealing - (Elec AC & Gas Heat)
HVAC Shell	Radiant Barriers - (Elec AC & Gas Heat)
HVAC Shell	Insulation - Ceiling (R-0 to R-38) - (Elec HP)
HVAC Shell	Insulation - Ceiling (R-11 to R-49) - (Elec HP)
HVAC Shell	Insulation - Ceiling (R-19 to R-49) - (Elec HP)
HVAC Shell	Insulation - Floor (R-0 to R-19) - (Elec HP)
HVAC Shell	Insulation - Floor (R-11 to R-30) - (Elec HP)
HVAC Shell	Energy Star Windows - (Elec HP)
HVAC Shell	Air Sealing - (Elec HP)
HVAC Shell	Duct Sealing - (Elec HP)
HVAC Shell	Radiant Barriers - (Elec HP)
HVAC Shell	Insulation - Ceiling (R-0 to R-38) - (Elec Furnace / AC)
HVAC Shell	Insulation - Ceiling (R-11 to R-49) - (Elec Furnace / AC)
HVAC Shell	Insulation - Ceiling (R-19 to R-49) - (Elec Furnace / AC)
HVAC Shell	Insulation - Floor (R-0 to R-19) - (Elec Furnace / AC)
HVAC Shell	Insulation - Floor (R-11 to R-30) - (Elec Furnace / AC)
HVAC Shell	Energy Star Windows - (Elec Furnace / AC)

Table 3-1 // Residential Energy Efficiency Measures in Study (*continued*)

End Use	Measure Name
HVAC Shell	Air Sealing - (Elec Furnace / AC)
HVAC Shell	Duct Sealing - (Elec Furnace / AC)
HVAC Shell	Radiant Barriers - (Elec Furnace / AC)
HVAC Equipment	HVAC Tune-Up (Central AC)
HVAC Equipment	High Efficiency Central AC - 16 SEER
HVAC Equipment	High Efficiency Central AC - 17 SEER
HVAC Equipment	High Efficiency Central AC - 18 SEER
HVAC Equipment	High Efficiency Central AC - 19 SEER
HVAC Equipment	High Efficiency Central AC - 20 SEER
HVAC Equipment	Ductless mini-split AC
HVAC Equipment	HVAC Tune-Up (Heat Pump)
HVAC Equipment	High Efficiency Heat Pump (HP Upgrade) - 16 SEER/9.0 HSPF
HVAC Equipment	High Efficiency Heat Pump (HP Upgrade) - 17 SEER/9.5 HSPF
HVAC Equipment	High Efficiency Heat Pump (HP Upgrade) - 18 SEER/10 HSPF
HVAC Equipment	Ground Source Heat Pump (HP Upgrade)
HVAC Equipment	Dual Fuel Heat Pump Upgrade (Replacing New ASHP)
HVAC Equipment	Ductless mini-split HP (replacing ASHP)
HVAC Equipment	Heat Pump (Replacing Electric Furnace) - 16 SEER/9.0 HSPF
HVAC Equipment	Heat Pump (Replacing Electric Furnace) - 17 SEER/9.5 HSPF
HVAC Equipment	Heat Pump (Replacing Electric Furnace) - 18 SEER/10 HSPF
HVAC Equipment	Dual Fuel Heat Pump (Replacing Electric Furnace)
HVAC Equipment	Ductless mini-split HP (replacing furnace)
HVAC Equipment	Energy Star Room A/C
HVAC Equipment	Room Air Conditioner Recycling
HVAC Equipment	ECM Furnace Fan
HVAC Equipment	Programmable Thermostat - Gas/AC - Tier 1
HVAC Equipment	Smart Thermostat - Gas Heat / AC - Tier 2
HVAC Equipment	Peak Period Thermostat - Gas Heat / AC - Tier 3
HVAC Equipment	Programmable Thermostat - ASHP - Tier 1
HVAC Equipment	Smart Thermostat - ASHP - Tier 2
HVAC Equipment	Peak Period Thermostat - ASHP - Tier 3
HVAC Equipment	Programmable Thermostat - Elec Furnace/AC - Tier 1
HVAC Equipment	Smart Thermostat - Elec Furnace/AC - Tier 2
HVAC Equipment	Peak Period Thermostat - Elec Furnace/AC - Tier 3
Behavioral	In Home Energy Display Monitor - Gas/CAC
Behavioral	Home Energy Reports - Gas/CAC
Behavioral	In Home Energy Display Monitor - ASHP
Behavioral	Home Energy Reports - ASHP

Table 3-1 // Residential Energy Efficiency Measures in Study
(continued)

End Use	Measure Name
Behavioral	In Home Energy Display Monitor - Elec Furn/CAC
Behavioral	Home Energy Reports - Elec Furn/CAC
Pool/Spa	Two Speed Pool Pumps
Pool/Spa	Variable Speed Pool Pumps
Cross-Cutting	Multi-Family Homes Efficiency Kit
New Construction	Touchstone Home - 15% more efficient (w/AC only) - New Single-family home
New Construction	Touchstone Home - 30% more efficient (w/AC only) - New Single-family home
New Construction	Touchstone Home - 15% more efficient (w/Elec. HP) - New Single-family home
New Construction	Touchstone Home - 30% more efficient (w/Elec. HP) - New Single-family home
New Construction	Touchstone Home - 15% more efficient (w/AC only) - New manufactured home
New Construction	Touchstone Home - 30% more efficient (w/AC only) - New manufactured home
New Construction	Touchstone Home - 15% more efficient (w/Elec. HP) - New manufactured home
New Construction	Touchstone Home - 30% more efficient (w/Elec. HP) - New manufactured home

Section 3.2 provides the results. There are summaries of each type of potential, including the breakdown of potential by end-use and market segment. There are annual savings details for the achievable potential and measure level details for technical, economic and achievable potential.

3.2 RESULTS

Figure 3-1 provides the technical, economic, and achievable results for the 3-yr, 5-yr, and 10-yr timeframes. The 3-yr technical potential is 20.6% of forecasted sales, and the economic potential is 14.8% of forecasted sales, indicating that a majority of technical potential is cost-effective. The 3-yr achievable potential is 7.9%. Achievable potential drops to 4.1% in 2021 because of lighting savings being negated by the effects of the Energy Independence and Security Act "EISA" lighting standards.[11] Achievable potential then increases to 7.6% over the ten-year timeframe.

[11] https://www.energystar.gov/ia/products/lighting/cfls/downloads/EISA_Backgrounder_FINAL_4-11_EPA.pdf

Figure 3-1 // Residential Electric Energy (MWh) Cumulative Annual Potential (as a % of Residential Sales)

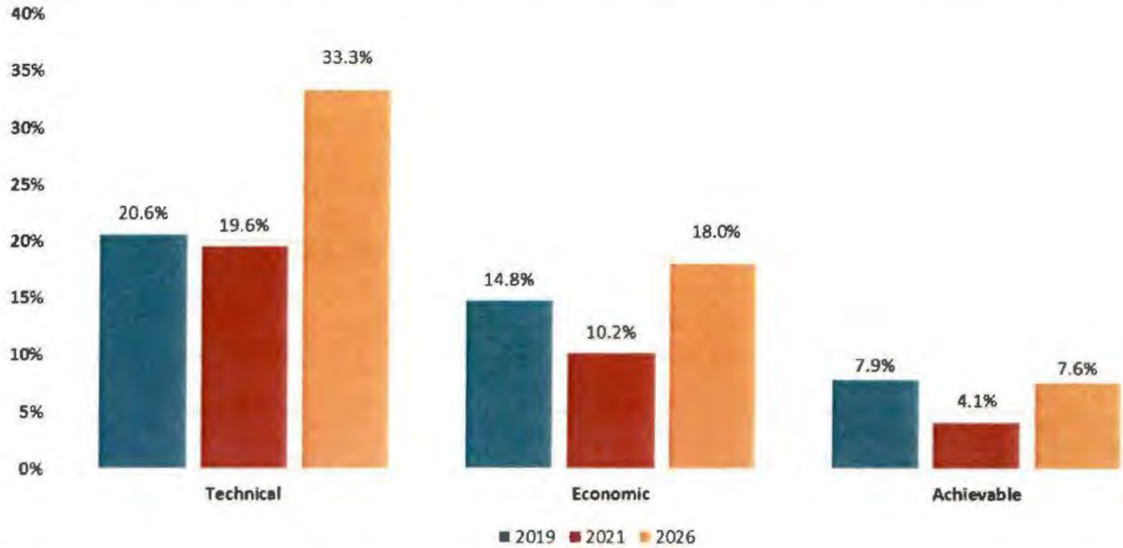


Table 3-2 provides 1-, 2-, 3-, 5-, and 10-yr estimates of cumulative annual technical, economic, and achievable potential for energy, summer peak demand, and winter peak demand. The technical potential is nearly 500,000 MWh by 2026, and the achievable potential rises to more than 113,000 MWh by 2026. Summer peak demand achievable potential is 18 MW by 2026.

Table 3-2 // Residential Energy Potential Summary

	2017	2018	2019	2021	2026
Annual Energy (MWh)					
Technical	105,754	204,229	299,458	284,935	497,474
Economic	77,509	146,165	214,511	148,357	269,138
Achievable	40,182	74,763	114,218	60,217	113,554
Summer Peak Demand (MW)					
Technical	17.5	33.2	48.1	55.3	97.4
Economic	11.4	20.6	29.7	25.7	46.1
Achievable	6.0	10.2	14.9	10.0	17.8
Winter Peak Demand (MW)					
Technical	14.7	28.2	41.0	4414	75.3
Economic	12.1	22.8	33.5	25.7	61.3
Achievable	5.9	10.8	16.5	10.0	26.4

3.2.1 Technical Potential

Table 3-3 provides 1-, 2-, 3-, 5-, and 10-yr cumulative annual technical potential estimates for energy by end use for Big Rivers. Lighting is the leading end use in the first three years, and as the impacts of EISA fully take effect lighting potential disappears. The HVAC Equipment, HVAC Shell, and water heating end uses become the leading end uses by 2026.

Table 3-3 // Residential Electric Energy (Cumulative Annual MWh) Technical Potential by End-Use

End Use	2017	2018	2019	2021	2026
Refrigeration	3,489	6,983	10,477	17,465	29,893
Clothes Washer /Dryer	1,959	3,930	5,903	9,844	19,561
Dishwasher	209	420	631	1,052	2,092
Misc. Plug Load	586	1,175	1,764	2,942	5,541
Consumer Electronics	7,299	14,621	21,944	36,193	48,923
Lighting	40,330	80,757	121,191	0	0
Water Heating	9,919	19,734	29,395	48,228	91,960
HVAC Shell	10,968	21,169	30,759	47,985	81,630
HVAC Equipment	18,484	36,933	52,874	84,424	153,400
Behavioral	7,585	8,457	9,329	11,397	15,670
Pool/Spa	2,198	4,406	6,615	11,030	21,956
Cross-Cutting	26	52	78	131	258
New Construction	2,702	5,592	8,496	14,245	26,589
Total	**105,754**	**204,229**	**299,458**	**284,935**	**497,474**

Table 3-4 provides 1-, 2-, 3-, 5-, and 10-yr cumulative annual technical potential estimates for summer demand by end use for Big Rivers. Lighting is the leading end use in the first three years, and as the impacts of EISA fully take effect lighting potential disappears. The HVAC Equipment, HVAC Shell, and water heating end uses become the leading end uses by 2026.

Table 3-4 // Residential Electric Energy (Cumulative Annual MW) Technical Potential by End-Use

End Use	2017	2018	2019	2021	2026
Refrigeration	0.5	0.9	1.4	2.3	3.9
Clothes Washer /Dryer	0.3	0.5	0.8	1.3	2.6
Dishwasher	0.0	0.0	0.1	0.1	0.2
Misc. Plug Load	0.1	0.2	0.3	0.5	0.9
Consumer Electronics	1.0	2.0	3.0	4.9	6.8
Lighting	4.4	8.8	13.2	0.0	0.0
Water Heating	0.7	1.3	1.9	3.1	5.7
HVAC Shell	3.4	6.5	9.5	14.8	25.2
HVAC Equipment	3.8	7.5	10.8	17.1	31.6
Behavioral	1.8	2.0	2.1	2.6	3.4
Pool/Spa	1.5	2.9	4.4	7.3	14.5
Cross-Cutting	0.0	0.0	0.0	0.0	0.0
New Construction	0.3	0.5	0.8	1.3	2.5
Total	**17.5**	**33.2**	**48.1**	**55.3**	**97.4**

3.2.2 Economic Potential

Table 3-5 provides 1-, 2-, 3-, 5-, and 10-yr cumulative annual economic potential estimates for energy by end use for Big Rivers. Lighting is the leading end use in the first three years, and as the impacts of EISA fully take effect lighting potential disappears. The HVAC Equipment and HVAC Shell end uses become the leading end uses by 2026.

Table 3-5// Residential Electric Energy (Cumulative Annual MWh) Economic Potential by End-Use

End Use	2017	2018	2019	2021	2026
Refrigeration	2,491	4,982	7,473	12,455	19,929
Clothes Washer /Dryer	1,389	2,787	4,185	6,979	13,869
Dishwasher	138	277	415	693	1,377
Misc. Plug Load	334	670	1,006	1,678	3,027
Consumer Electronics	1,465	2,934	4,404	7,342	10,451
Lighting	40,330	80,757	121,191	0	0
Water Heating	2,090	4,206	6,324	10,553	20,835
HVAC Shell	7,038	13,789	20,254	32,336	57,701
HVAC Equipment	10,951	21,876	32,765	54,352	107,356
Behavioral	8,875	9,044	9,215	9,826	10,561
Pool/Spa	2,198	4,406	6,615	11,030	21,956
Cross-Cutting	0	0	0	0	0
New Construction	211	436	663	1,112	2,075
Total	**77,509**	**146,165**	**214,511**	**148,357**	**269,138**

Table 3-6 provides 1-, 2-, 3-, 5-, and 10-yr cumulative annual technical potential estimates for summer demand by end use for Big Rivers. Lighting is the leading end use in the first three years, and as the impacts of EISA fully take effect lighting potential disappears. The HVAC Equipment and HVAC Shell end uses become the leading end uses by 2026.

Table 3-6// Residential Electric Energy (Cumulative Annual MW) Economic Potential by End-Use

End Use	2017	2018	2019	2021	2026
Refrigeration	0.3	0.6	0.9	1.5	2.4
Clothes Washer /Dryer	0.2	0.4	0.5	0.9	1.8
Dishwasher	0.0	0.0	0.0	0.1	0.1
Misc. Plug Load	0.0	0.1	0.1	0.2	0.3
Consumer Electronics	0.2	0.3	0.5	0.8	1.2
Lighting	4.4	8.8	13.2	0.0	0.0
Water Heating	0.3	0.6	0.9	1.5	3.0
HVAC Shell	1.5	3.0	4.4	7.0	12.5
HVAC Equipment	0.8	1.6	2.5	4.0	7.7
Behavioral	2.2	2.3	2.3	2.3	2.4
Pool/Spa	1.5	2.9	4.4	7.3	14.5
Cross-Cutting	0.0	0.0	0.0	0.0	0.0
New Construction	0.0	0.0	0.1	0.1	0.2
Total	**11.4**	**20.6**	**29.7**	**25.7**	**46.1**

3.2.3 Achievable Potential

Achievable potential is the amount of energy that can realistically be saved given various market barriers. Achievable potential considers real-world barriers to encouraging end users to adopt efficiency measures; the non-measure costs of delivering programs (for administration, marketing, analysis, and EM&V); and the capability of programs and administrators to boost program activity over time. Therefore, achievable potential is an estimate of how much economic potential can be achieved by program administrators

Table 3-7 provides 1-, 2-, 3-, 5-, and 10-yr cumulative annual technical potential estimates for summer demand by end use for Big Rivers. Lighting is the leading end use in the first three years, and as the impacts of EISA fully take effect lighting potential disappears. The HVAC Equipment, HVAC Shell, refrigeration, behavioral, and water heating end uses become the top 5 end uses by 2026.

Table 3-7 // Residential Electric Energy (Cumulative Annual MWh) Achievable Potential by End-Use

End Use	2017	2018	2019	2021	2026
Refrigeration	2,111	4,221	6,332	10,553	16,885
Clothes Washer /Dryer	447	989	1,690	3,300	7,338
Dishwasher	61	126	197	347	721
Misc. Plug Load	82	189	340	700	1,539
Consumer Electronics	262	637	1,205	2,597	5,037
Lighting	23,641	49,175	77,880	0	0
Water Heating	950	1,913	2,877	4,800	9,476
HVAC Shell	2,546	5,075	7,569	12,432	23,934
HVAC Equipment	1,145	3,010	6,119	13,943	33,826
Behavioral	8,662	8,806	8,939	9,438	10,137
Pool/Spa	195	453	815	1,678	3,857
Cross-Cutting	0	0	0	0	0
New Construction	82	169	256	430	802
Total	**40,182**	**74,763**	**114,218**	**60,217**	**113,554**

Figure 3-2 provides a graphical representation of the 1-, 2-, 3-, 10-, and 20-yr cumulative annual achievable potential results by end use. At this point in time, GDS expects the lighting potential to essentially approach zero in the residential sector after 2020 because of the EISA backstop provision and the effect of the DOE Final Rules on General Service Lamps.[12] This may be a conservative assumption, and it will be worth re-visiting in three years to determine if significant sell through of inefficient bulbs continues, or if standards and legislation change.

[12] https://energy.gov/eere/buildings/downloads/two-gsl-final-rules

Figure 3-2// Residential Electric Energy (Cumulative Annual GWh) Achievable Potential by End-Use

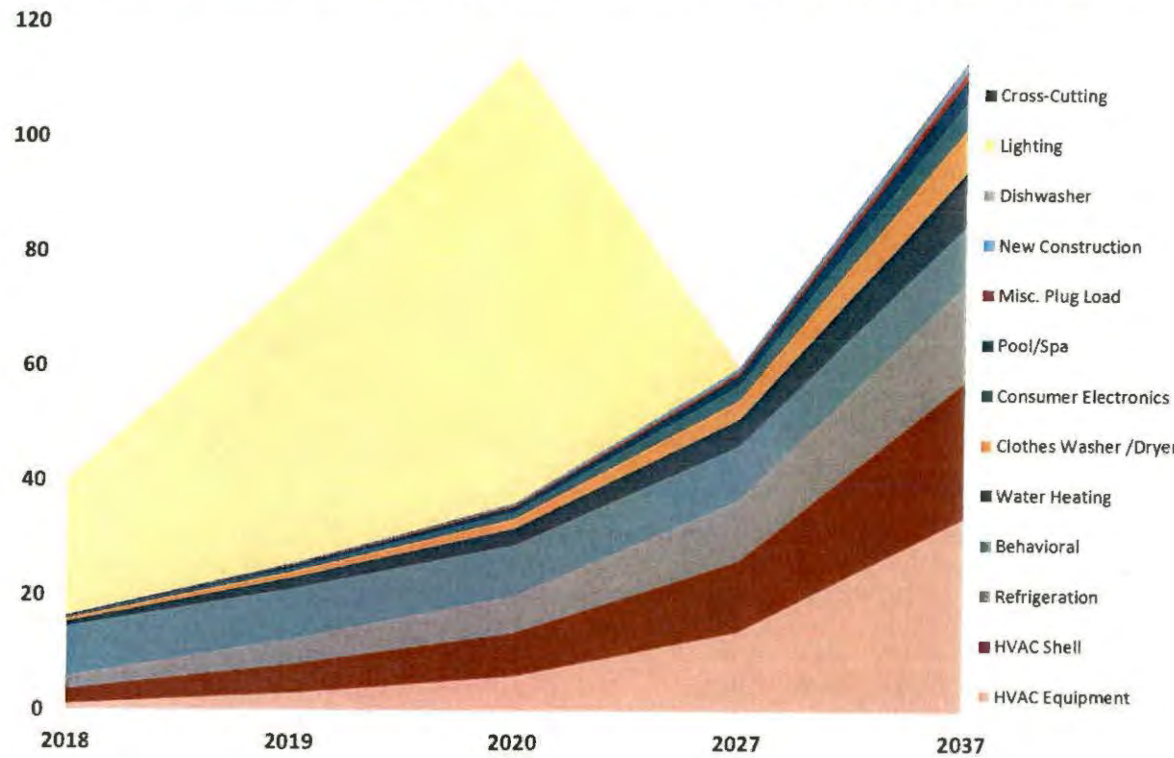
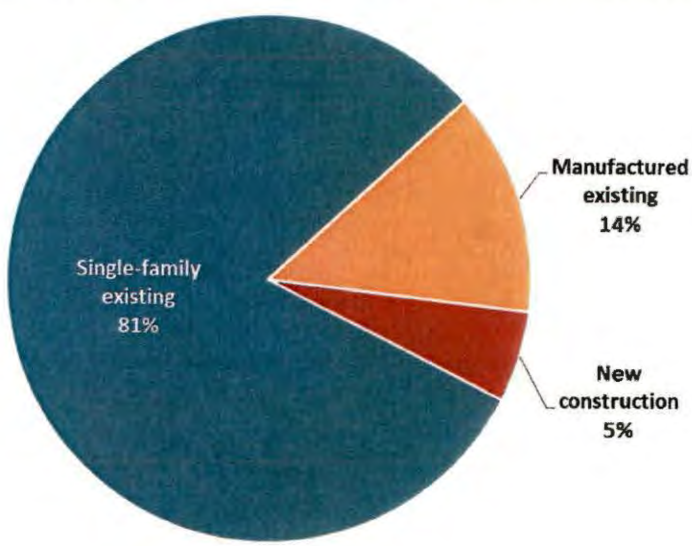


Figure 3-3 illustrates a market segmentation of the achievable potential in the residential sector by 2026. The leading market segment is single-family existing homes at 81% of total savings. Manufactured homes account for 14% of savings. The single-family and manufactured savings proportions are in close alignment with the Big Rivers footprint – 81% of homes are single-family homes, and 16% are manufactured homes. New construction accounts for 5% of savings.

Figure 3-3// 2026 Residential Electric Energy (Cumulative Annual) Achievable Potential by Market Segment



3.2.4 Annual Savings Detail

Table 3-8 and Table 3-9 provide cumulative annual and incremental annual savings data for each year of the study. The tables show energy, summer demand, and winter demand savings.

Table 3-8// Residential Electric Cumulative Annual Achievable Potential – Energy and Demand, by Year

Year	MWh	Summer MW	Winter MW
2017	40,182	6.0	5.9
2018	74,763	10.2	10.8
2019	114,218	14.9	16.5
2020	156,592	20.0	22.5
2021	60,217	10.1	13.6
2022	72,043	11.8	16.3
2023	83,826	13.5	18.9
2024	95,341	15.2	21.6
2025	104,622	16.6	24.0
2026	113,554	18.0	26.4

Table 3-9// Residential Electric Incremental Annual Achievable Potential – Energy and Demand, by Year

Year	MWh	Summer MW	Winter MW
2017	40,182	6.0	5.9
2018	43,253	6.4	6.3
2019	48,292	6.9	7.0
2020	51,370	7.3	7.4
2021	21,310	4.0	4.2
2022	21,393	4.0	4.1
2023	21,511	4.0	4.1
2024	21,663	4.0	4.1
2025	21,815	4.1	4.2
2026	22,065	4.1	4.8

3.2.5 Measure Level Detail

Table 3-10 below presents the measure-level technical, economic, and achievable MWh savings, sorted by end-use. Measures with significant remaining potential either possess significant per unit savings opportunities or are applicable to a large number homes in the Big Rivers territory. For example, high efficiency heat pumps and ceiling insulation represent two of the leading measures in the economic potential. Measures with zero economic and achievable potential were not found to be cost effective.

Table 3-10 // Residential Technical, Economic, Achievable Savings Potential (MWh), by Measure (2026)

Measure Name	Technical	Economic	Achievable
ENERGY STAR / CEE Tier 2 Refrigerator	7,247	0	0
Energy Star Compliant Freezer	2,717	0	0
Second Refrigerator Turn In	14,141	14,141	12,024
Second Freezer Turn In	5,787	5,787	4,861
Energy Star Clothes Washer	13,869	13,869	7,338
ENERGY STAR Clothes Dryer	5,691	0	0
Energy Star Dishwasher	2,092	1,377	721
Energy Star Dehumidifier	2,513	0	0
Energy Star Room Air Cleaner	3,027	3,027	1,539
Efficient Televisions	12,382	0	0
Energy Star Desktop Computer	319	0	0
Energy Star Computer Monitor	768	0	0
Energy Star Laptop Computer	587	0	0
Tier 1 Power Strip	10,451	10,451	5,037
Tier 2 Power Strip	24,416	0	0
Standard CFL	0	0	0
Standard LED	0	0	0
Specialty CFL	0	0	0
Specialty LED	0	0	0
Reflector CFL	0	0	0
Reflector LED	0	0	0
Energy Star Torchiere	0	0	0
LED Nightlight	0	0	0
Exterior CFL Fixture	0	0	0
Exterior LED Fixture	0	0	0
Low Flow Faucet Aerators	1,810	3,444	1,568
Low Flow Showerhead	4,327	7,995	3,641
Thermostatic Restriction Valve	3,614	6,450	2,937
Water Heater Blanket	898	0	0
Water Heater Pipe Wrap	1,643	2,946	1,331
Heat Pump Water Heater	61,797	0	0
Solar Water Heating	17,872	0	0
Ceiling Insulation	27,432	23,638	9,614
Floor Insulation	843	848	556
Energy Star Windows	26,747	15,869	5,758

Table 3-10 Residential Technical, Economic, Achievable Savings Potential (MWh), by Measure (2026) (*continued*)

Measure Name	Technical	Economic	Achievable
Air Sealing	11,361	5,973	2,780
Duct Sealing	11,092	11,372	5,228
Radiant Barriers	4,155	0	0
HVAC Tune-Up (Central AC)	3,798	0	0
High Efficiency Central AC	30,739	0	0
Ductless mini-split AC	11,754	0	0
HVAC Tune-Up (Heat Pump)	4,785	0	0
High Efficiency Heat Pump	52,296	37,043	7,574
Ground Source Heat Pump	1,149	0	0
Dual Fuel Heat Pump Upgrade	16,427	48,021	19,224
Ductless mini-split HP	14,000	14,048	3,827
Energy Star Room A/C	376	0	0
Room Air Conditioner Recycling	294	296	107
ECM Furnace Fan	4,043	4,112	1,565
Programmable Thermostat	0	1,458	759
Smart Thermostat	13,739	484	178
Peak Period Thermostat	0	1,894	591
In Home Energy Display Monitor	7,508	0	0
Home Energy Reports	8,162	10,561	10,137
Two Speed Pool Pumps	0	0	0
Variable Speed Pool Pumps	21,956	21,956	3,857
Multi-Family Homes Efficiency Kit	258	0	0
Touchstone Home New Single-family home	22,438	0	0
Touchstone Home - New manufactured home	4,150	2,075	802
Total	**497,474**	**269,138**	**113,554**

4 NONRESIDENTIAL ENERGY EFFICIENCY POTENTIAL

This chapter provides the potential results for technical, economic, and achievable potential for the nonresidential sector. The chapter provides a list of the measures included in the study, and identifies leading end uses and measures within the potential. Cumulative ten-year total estimates are provided as well as annual achievable savings estimates. Program potential is discussed in Chapter 0.

4.1 MEASURES EXAMINED

There were 79 total electric energy efficiency measures included in the analysis. Table 4-1 provides a list of the measures included for each end use in the residential model. The list of measures was developed based on a review of the Illinois TRM, the current Big Rivers program offerings, the 2014 residential potential study measure list. Measure data includes incremental costs, electric energy and demand savings, natural gas savings, and measure life.

Table 4-1 // Nonresidential Energy Efficiency Measures in Study

End-Use	Measure Name
Lighting	Lighting Controls
Lighting	T5, and HPT8 Fluorescent Fixtures bulbs
Lighting	CFL Fixtures and Screw-in Bulbs
Lighting	LED High Bay, Low Bay, Screw-in Bulbs and Exit Signs
Lighting	LED Outdoor Lighting
Space Cooling	Air Cooled Chiller
Space Cooling	DX Packaged AC
Space Cooling	Split AC
Space Cooling	Packaged Terminal AC (PTAC)
Space Cooling	Tune-Up
Space Heating	Packaged Terminal Heat Pump (PTHP)
Motors	Variable Frequency Drives
Water Heating	High Efficiency Storage Water Heater
Water Heating	Water Heater Tank Insulation
Water Heating	On Demand (Tankless) Water Heater
Water Heating	Pre-Rinse Low Flow Sprayer
Water Heating	Heat Pump Water Heater
Cooking	Efficient Cooking Equipment

Table 4-1 // Nonresidential Energy Efficiency Measures in Study (*continued*)

End-Use	Measure Name
Refrigeration	Refrigerators, Freezers, Ice Machines
Refrigeration	Anti-sweat Controls, Door Heater Controls, Zero Energy Doors
Refrigeration	Fan Controls
Refrigeration	Evaporator Coil Defrost Control
Refrigeration	Brushless DC Motors (ECM) for freezers and coolers
Refrigeration	LED Case lighting
Refrigeration	Display Case Covers
Refrigeration	Vending Misers
Refrigeration	Tune-ups
Other	Fix Compressed Air Leaks
Other	Engineered Nozzles for Blow-off Valves
Other	Watt Sensors for Office Electronics

Sections 4.2 provides the results. There are summaries of each type of potential, including the breakdown of potential by end-use and market segment. There are annual savings details for the achievable potential and measure level details for technical, economic and achievable potential.

4.2 RESULTS

Figure 4-1 provides the technical, economic, and achievable results for the 3-yr, 5-yr, and 10-yr timeframes. The 3-yr technical potential is 37.7% of forecasted sales, and the economic potential is 32.3% of forecasted sales, indicating that most technical potential is cost-effective. The 3-yr achievable potential is 1.9%. Achievable potential grows to 6.0% over a ten-year timeframe.

Figure 4-1 // Nonresidential Electric Energy (MWh) Cumulative Annual Potential (as a % of Nonresidential Sales)

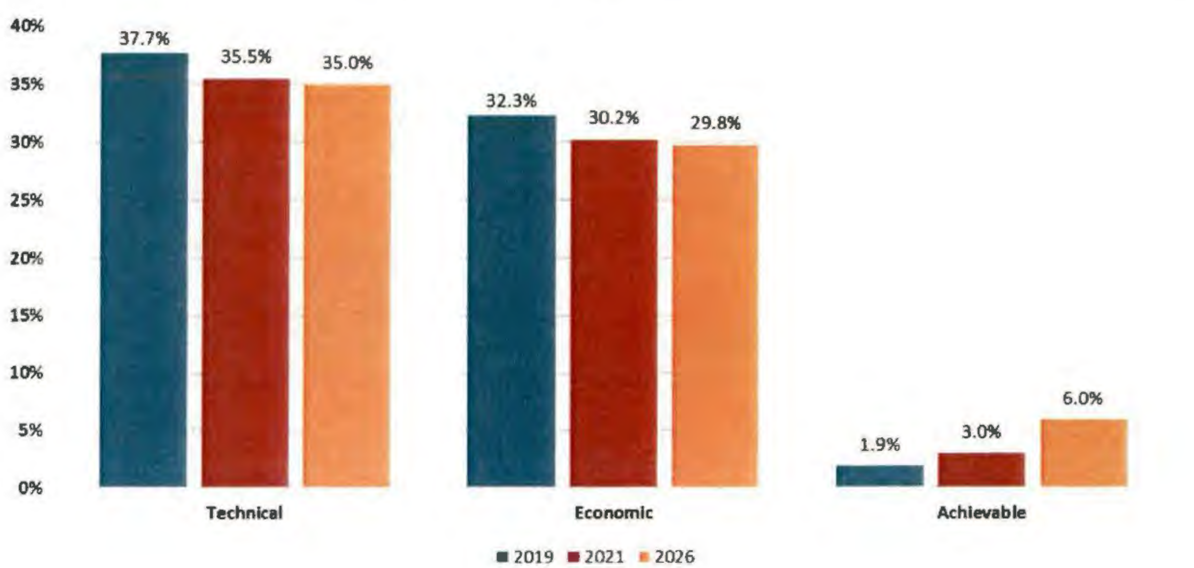


Table 4-2 provides 1-, 2-, 3-, 5-, and 10-yr estimates of cumulative annual technical, economic, and achievable potential for energy, summer peak demand, and winter peak demand. The technical potential is nearly 700,000 MWh by 2026, and the achievable potential rises to more than 115,000 MWh by 2026. Summer peak demand achievable potential is nearly 24 MW by 2026.

Table 4-2 // Nonresidential Energy Potential Summary

	2017	2018	2019	2021	2026
Annual Energy (MWh)					
Technical	700,075	700,075	700,075	677,318	677,318
Economic	599,301	599,301	599,301	576,544	576,544
Achievable	11,986	23,972	35,958	57,654	115,309
Summer Peak Demand (MW)					
Technical	130.4	130.4	130.4	126.6	126.6
Economic	121.8	121.8	121.8	118.0	118.0
Achievable	2.4	4.9	7.3	11.8	23.6
Winter Peak Demand (MW)					
Technical	54.8	54.8	54.8	52.4	52.4
Economic	51.3	51.3	51.3	48.8	48.8
Achievable	1.0	2.1	3.1	4.9	9.8

4.2.1 Technical Potential

Table 4-3 provides 1-, 2-, 3-, 5-, and 10-yr cumulative annual technical potential estimates for energy by end use for Big Rivers. Refrigeration is the leading end use, followed by lighting, space cooling and ventilation.

Table 4-3 // Nonresidential Electric Energy (Cumulative Annual MWh) Technical Potential by End-Use

End Use	2017	2018	2019	2021	2026
Lighting	183,215	183,215	183,215	160,458	160,458
Space cooling	90,102	90,102	90,102	90,102	90,102
Space Heating	741	741	741	741	741
Ventilation	89,904	89,904	89,904	89,904	89,904
Motors (Non-Ventilation)	44,477	44,477	44,477	44,477	44,477
Water Heating	218	218	218	218	218
Cooking	2,841	2,841	2,841	2,841	2,841
Refrigeration	215,555	215,555	215,555	215,555	215,555
Office Equipment	51,638	51,638	51,638	51,638	51,638
Compressed Air	21,383	21,383	21,383	21,383	21,383
Total	**700,075**	**700,075**	**700,075**	**677,318**	**677,318**

Table 4-4 provides 1-, 2-, 3-, 5-, and 10-yr cumulative annual technical potential estimates for summer demand by end use for Big Rivers. Refrigeration is the leading end use, followed by space cooling and lighting.

Table 4-4// Nonresidential Electric Energy (Cumulative Annual MW) Technical Potential by End-Use

End Use	2017	2018	2019	2021	2026
Lighting	25.9	25.9	25.9	22.0	22.0
Space cooling	43.7	43.7	43.7	43.7	43.7
Space Heating	0.0	0.0	0.0	0.0	0.0
Ventilation	8.2	8.2	8.2	8.2	8.2
Motors (Non-Ventilation)	1.7	1.7	1.7	1.7	1.7
Water Heating	0.0	0.0	0.0	0.0	0.0
Cooking	0.8	0.8	0.8	0.8	0.8
Refrigeration	44.3	44.3	44.3	44.3	44.3
Office Equipment	0.0	0.0	0.0	0.0	0.0
Compressed Air	5.8	5.8	5.8	5.8	5.8
Total	**130.4**	**130.4**	**130.4**	**126.6**	**126.6**

4.2.2 Economic Potential

Table 4-5 provides 1-, 2-, 3-, 5-, and 10-yr cumulative annual technical potential estimates for energy by end use for Big Rivers. Refrigeration is the leading end use, followed by lighting, space cooling and ventilation.

Table 4-5// Nonresidential Electric Energy (Cumulative Annual MWh) Economic Potential by End-Use

End Use	2017	2018	2019	2021	2026
Lighting	156,125	156,125	156,125	133,368	133,368
Space cooling	88,190	88,190	88,190	88,190	88,190
Space Heating	741	741	741	741	741
Ventilation	86,977	86,977	86,977	86,977	86,977
Motors (Non-Ventilation)	42,897	42,897	42,897	42,897	42,897
Water Heating	218	218	218	218	218
Cooking	2,744	2,744	2,744	2,744	2,744
Refrigeration	206,617	206,617	206,617	206,617	206,617
Office Equipment	0	0	0	0	0
Compressed Air	14,791	14,791	14,791	14,791	14,791
Total	**599,301**	**599,301**	**599,301**	**576,544**	**576,544**

Table 4-6 provides 1-, 2-, 3-, 5-, and 10-yr cumulative annual economic potential estimates for summer demand by end use for Big Rivers. Refrigeration is the leading end use, followed by space cooling and lighting.

Table 4-6 // Nonresidential Electric Energy (Cumulative Annual MW) Economic Potential by End-Use

End Use	2017	2018	2019	2021	2026
Lighting	22.4	22.4	22.4	18.6	18.6
Space cooling	42.5	42.5	42.5	42.5	42.5
Space Heating	0.0	0.0	0.0	0.0	0.0
Ventilation	7.9	7.9	7.9	7.9	7.9
Motors (Non-Ventilation)	1.7	1.7	1.7	1.7	1.7
Water Heating	0.0	0.0	0.0	0.0	0.0
Cooking	0.8	0.8	0.8	0.8	0.8
Refrigeration	42.8	42.8	42.8	42.8	42.8
Office Equipment	0.0	0.0	0.0	0.0	0.0
Compressed Air	3.8	3.8	3.8	3.8	3.8
Total	**121.8**	**121.8**	**121.8**	**118.0**	**118.0**

4.2.3 Achievable Potential

Achievable potential is the amount of energy that can realistically be saved given various market barriers. Achievable potential considers real-world barriers to encouraging end users to adopt efficiency measures; the non-measure costs of delivering programs (for administration, marketing, analysis, and EM&V); and the capability of programs and administrators to boost program activity over time. Therefore, achievable potential is an estimate of how much economic potential can be achieved by program administrators.

Table 4-7 provides 1-, 2-, 3-, 5-, and 10-yr cumulative annual achievable potential estimates for energy by end use for Big Rivers. Refrigeration is the leading end use, followed by lighting, space cooling and ventilation.

Table 4-7 // Nonresidential Electric Energy (Cumulative Annual MWh) Achievable Potential by End-Use

End Use	2017	2018	2019	2021	2026
Lighting	3,122	6,245	9,367	13,337	26,674
Space cooling	1,764	3,528	5,291	8,819	17,638
Space Heating	15	30	44	74	148
Ventilation	1,740	3,479	5,219	8,698	17,395
Motors (Non-Ventilation)	858	1,716	2,574	4,290	8,579
Water Heating	4	9	13	22	44
Cooking	55	110	165	274	549
Refrigeration	4,132	8,265	12,397	20,662	41,323
Office Equipment	0	0	0	0	0
Compressed Air	296	592	887	1,479	2,958
Total	**11,986**	**23,972**	**35,958**	**57,654**	**115,309**

Figure 4-2 provides a graphical representation of the 1-, 2-, 3-, 10-, and 20-yr cumulative annual achievable potential results by end use.

Figure 4-2 // Nonresidential Electric Energy (Cumulative Annual GWh) Achievable Potential by End-Use

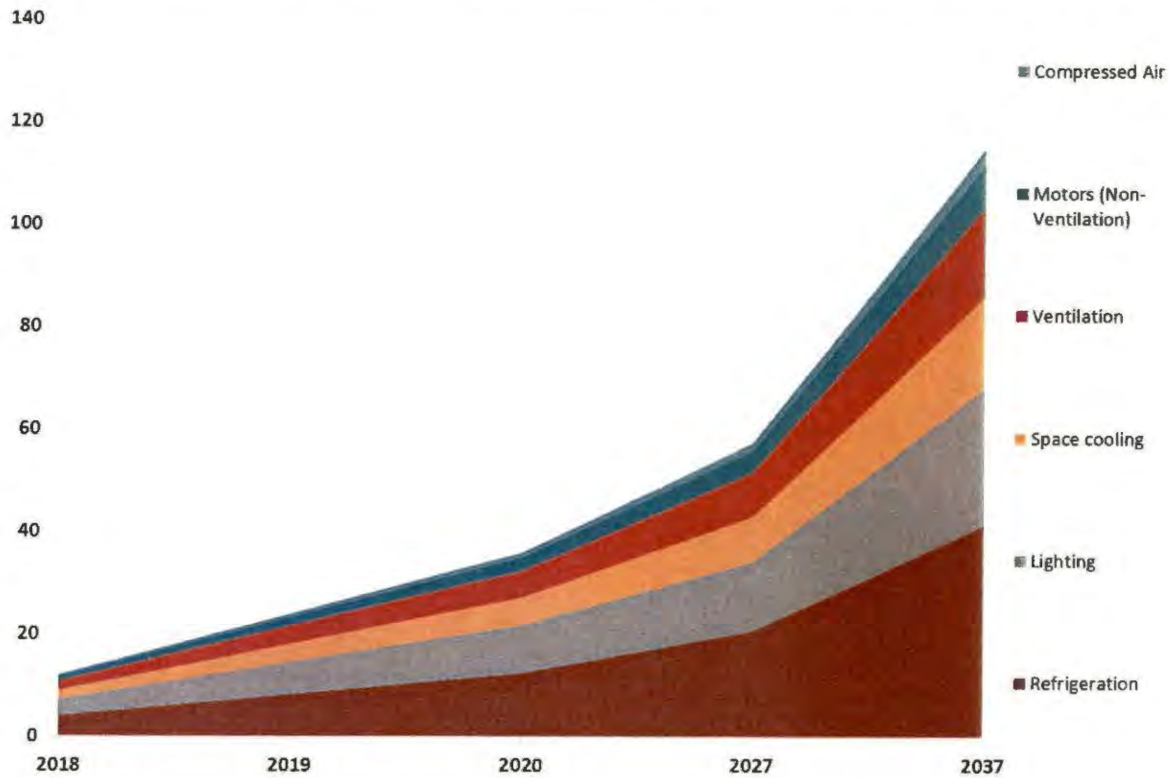
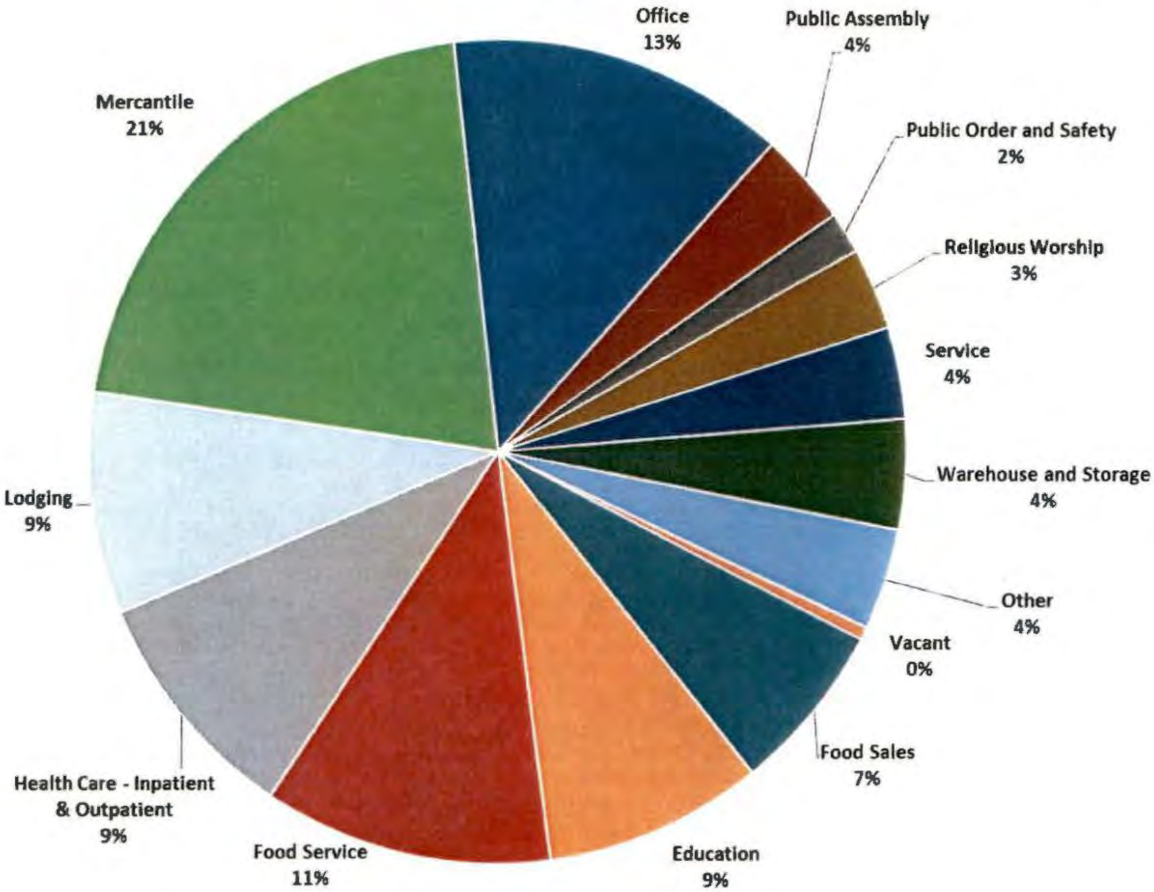


Figure 4-3 illustrates a market segmentation of the achievable potential in the nonresidential sector by 2026. The leading market segment is mercantile (21%), followed by offices (13%), food service (11%), education (9%), lodging (9%), and health care (9%). The savings by market segment align closely with consumption by market segment, as no market segment shares of savings differ by more than 3% from the respective consumption shares (e.g. food sales consumption is estimated to be 4% of consumption, and food sales savings are 7% of total saving).

Figure 4-3 // 2026 Nonresidential Electric Energy (Cumulative Annual) Achievable Potential by Market Segment



4.2.4 Annual Savings Detail

Table 4-88 and Table 4-9 provide cumulative annual and incremental annual savings data for each year of the study. The tables show energy, summer demand, and winter demand savings.

Table 4-8 // Nonresidential Electric Cumulative Annual Achievable Potential – Energy and Demand, by Year

Year	MWh	Summer MW	Winter MW
2017	23,972	4.87	2.05
2018	35,958	7.31	3.08
2019	47,944	9.75	4.10
2020	57,654	11.80	4.88
2021	69,185	14.16	5.86
2022	80,716	16.52	6.84
2023	92,247	18.88	7.82
2024	103,778	21.24	8.79
2025	115,309	23.60	9.77
2026	23,972	4.87	2.05

Table 4-9 // Nonresidential Electric Incremental Annual Achievable Potential – Energy and Demand, by Year

Year	MWh	Summer MW	Winter MW
2017	11,986	2.44	1.03
2018	12,355	2.53	1.04
2019	12,723	2.62	1.06
2020	13,547	2.79	1.13
2021	13,006	2.73	1.05
2022	13,618	2.82	1.07
2023	13,987	2.91	1.09
2024	14,356	3.00	1.11
2025	15,169	3.14	1.16
2026	15,591	3.24	1.18

4.2.5 Measure Level Detail

Table 4-10 below presents the measure-level technical, economic, and achievable MWh savings, sorted by end-use. Measures with significant remaining potential either possess significant per unit savings opportunities or are applicable to a large number nonresidential customers in the Big Rivers territory.

Table 4-10 // Nonresidential Technical, Economic, Achievable Savings Potential (MWh), by Measure (2026)

Measure Name	Technical	Economic	Achievable
Lighting	107,161	88,974	17,119
Lighting Controls	29,473	20,571	3,958
Sunset Lighting	23,419	23,419	4,506
Exterior Lighting	23,162	23,162	4,456
Air Conditioning	60,628	58,716	11,297
Chiller	29,474	29,474	5,671
PTHP Heating	741	741	143
Ventilation Fan Controls	89,904	86,977	16,735
Motor Controls	44,477	42,897	8,254
Water Heating	218	218	42
Cooking	2,841	2,744	528
Freezers	18,554	18,554	3,570
Refrigerators	37,690	37,690	7,252
Refrigeration Tune-up	14,678	7,846	1,510
Refrigeration door measures	30,985	28,879	5,557
Vending Miser	12,153	12,153	2,338
Refrigeration motor measures	97,154	97,154	18,693
Ice Machine	2,682	2,682	516
Refrigeration LED lighting retrofit	1,660	1,660	319
Watt Sensors on Office Electronics	51,638	0	0
Compressed Air Leaks	17,180	10,588	2,037
Engineered Nozzles	4,203	4,203	809
Total	**700,075**	**599,301**	**115,309**

5 DEMAND RESPONSE ANALYSIS

In an August 2006 report by staff to the FERC, a definition of "demand response" ("DR") was adopted by the Commission. This definition was used earlier by the U.S. Department of Energy ("DOE") in its February 2006 report to Congress:

> *Changes in electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized.*[13]

In their August 2006 report FERC staff noted that demand response is an active response to prices or incentive payments. The changes in electricity use are designed to be short-term in nature, centered on critical hours when demand or market prices are high, or when reserve margins are low. This is contrasted to energy efficiency programs that are focused on longer-term responses or reduction in consumption through the investment in energy efficient equipment or change in behavior.

5.1 TYPES OF DEMAND RESPONSE

There are generally two major types of demand response programs: incentive-based programs and time-based programs. Incentive-based programs generally involve the utility paying an incentive to a retail customer to reduce peak demand or allow for direct control of end use appliances. Such programs include direct load control, interruptible programs, demand buy-back, and emergency demand response. Time-based programs include a suite of rate alternatives known as dynamic pricing. These programs have rates that incentivize customers to reduce loads during certain times of the day and year (critical peaking hours). Time-based programs include time-of-use, critical peak pricing, and real time pricing rates.

For incentive-based programs, generally the goal is for the load reduction to act as a resource, i.e., the demand reduction occurs via dispatch by the system operator. With this treatment, the demand reduction capability can be included in the resource portfolio. The resources can be dispatched for several reasons including peak load, low reserves, high energy costs, and transmission line loading.

The goal with price-based incentives is to provide a price signal that is reflective of current market conditions and the demand reductions occur as a voluntary response to the price signal. Generally, these types of responses are embedded in the load forecast, and not explicitly modeled. While it is often a concern that the load response is not as "firm" as with incentive-based programs, the response can become more predictable based on weather, foreknowledge of prices, and experience.

5.2 GENERAL BENEFITS OF DEMAND RESPONSE

Customer responses under demand response programs can either reduce or shift consumption during high cost periods. While all the programs evaluated within this project result in reducing the load requirements of the system during certain peak periods, there are two distinct load impacts that can result.

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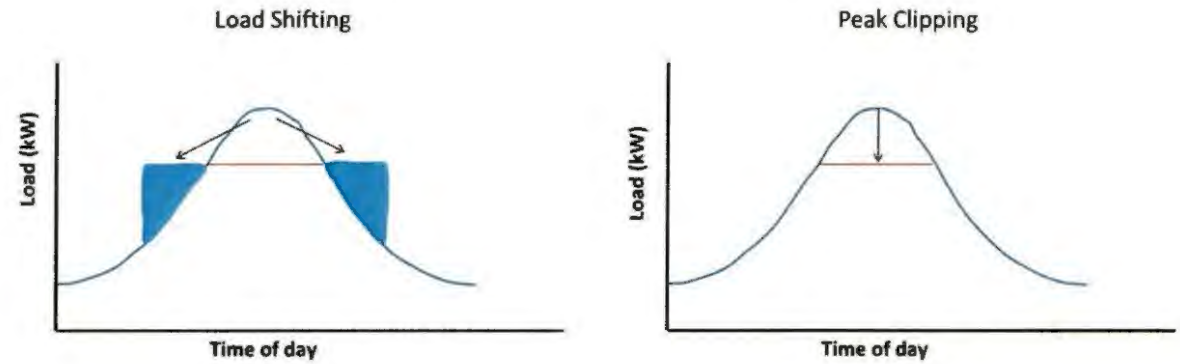
[13] U.S. Department of Energy, Benefits of Demand Response in Electricity Markets and Recommendations for Achieving Them: A Report to the United States Congress Pursuant to Section 1252 of the Energy Policy Act of 2005, February 2006 (February 2006 DOE EPAct Report), http://energy.gov/sites/prod/files/oeprod/DocumentsandMedia/DOE_Benefits_of_Demand_Response_in_Electricity_Markets_and_Recommendations_for_Achieving_Them_Report_to_Congress.pdf

- "Load Shifting" – Projects that move energy consumption from one time to another (usually during a single day).
- "Peak Clipping" – Projects that reduce energy demand at certain critical times, with no recovery of the energy at a later time.

Figure 5-1 below provides a graphical representation of these two types of load impacts.

Figure 5-1 // Load Shifting and Peak Clipping Program



Demand response can provide the benefit of serving as a substitute for peaking generation resources. In addition, it can reduce the need for expansion in distribution investment. Demand response also has the potential to reduce energy supply costs and, in general, electricity price volatility. Finally, demand response can also serve as supplemental (non-spinning) operating reserves.

5.3 ENHANCEMENTS OF RESPONSE WITH TECHNOLOGY

Automated technology enhances the responsiveness of a facility participating in a demand response program by enabling the customer to achieve a higher percentage of its load reduction potential. Studies conducted by the Rocky Mountain Institute[14] indicate that technology appears to be an important driver in reducing load, especially the most critical peaks for consumers within a rate class that have the highest levels of consumption. Automated technology can help produce consistent load reductions across the cooling season. For example, large commercial and industrial customers show the greatest price elasticity with their ability and willingness to respond to incentives, but without automation the response is uneven, with the load reductions coming from backup generation, shifting operations, or manually shutting off loads in a less organized manner.

Automated metering infrastructure ("AMI") technology can combine load management capabilities with alternative retail rate structures, in addition to providing the benefits of improved meter reading, outage management and power quality, as well as reducing theft. AMI can provide the first step in having the necessary technology in place to support demand response efforts. As an example, with AMI, time-based rates can be offered without the additional cost of interval metering, normally a barrier in the implementation of Time-Of-Use ("TOU") rates. Additionally, with AMI, load control can be initiated via power line carrier technology with load control operations coinciding with on-peak or critical peak price periods achieving a greater load impact than if a manual response was required by the customer.

[14] "Demand Response: An Introduction", Rocky Mountain Institute, April 30, 2006, http://www.ceeforum.org/content/demand-response-introduction-overview-programs-technologies-and-lessons-learned

5.4 CURRENT DEMAND RESPONSE PROGRAMS

Big Rivers does not currently operate any direct control programs and does not provide electric service to any retail or wholesale customers under an interruptible or curtailable contract or tariff. Big Rivers offers a Voluntary Curtailment Rider, which provides a means for potentially reducing system peak demand during peak periods. In the last fourteen years, there have been four curtailments affecting two commercial customers. The maximum estimated load reduction due to the two voluntary curtailment customers is 20-25 MW. Table 5-1 shows the years in which curtailments have occurred and the load reduction in MW associated with these events.

Table 5-1 // 2003-2016 Voluntary Industrial Curtailment Results

Year	Number of Curtailments	Load Reduction (MW)
2003	0	n/a
2004	0	n/a
2005	0	n/a
2006	0	n/a
2007	0	n/a
2008	1	20
2009	3	1 to 25
2010	0	n/a
2011	0	n/a
2012	0	n/a
2013	0	n/a
2014	0	n/a
2015	0	n/a
2016	0	n/a

5.5 MISO DEMAND RESPONSE

MISO allows for demand response participation in the market through various means, including participation as a load modifying resource ("LMR"), as demand response resource ("DRR") and as emergency demand response ("EDR"). Participation in such programs requires meeting various operational, registration, and credit requirements. For DRR and LMR, the payments received are based on how the resource is used (e.g. energy, reserves, and/or capacity) and includes energy costs via the Locational Marginal Price ("LMP"), Marginal Clearing Price, Auction Clearing Price, and possibly make-whole payments. EDR payment is based on LMP or production costs (shut-down costs of production unit plus a curtailment energy offer that is made). By using MISO market prices as the proxy for demand response resources, Big Rivers is appropriately assessing the value of DR in the MISO market.

5.6 DEMAND RESPONSE PROGRAMS EVALUATED

A list of potential DR programs representing the most common and most likely to be cost-effective were evaluated in this screening analysis. Big Rivers focused the analysis on the most common types of programs that a utility might use in starting a demand response initiative. If more of these programs passed the screening, the list of potential programs for screening would have been expanded. Programs not included initially, but that could have been considered if further analysis was warranted include, but are not limited to: dual fuel heat pumps, electric thermal storage ("ETS") heating units for residences, ETS cooling units for commercial buildings, direct control of swimming pool pumps, and direct control of agricultural applications such as irrigators and grain dryers.

A total of fifteen programs were evaluated, with a mix of both residential and commercial incentive-based and price-based programs. Consistent with the energy efficiency evaluation, DR programs are primarily evaluated based on the TRC test, but UCT and PCT were also calculated. Table 5-2 provides the results of the evaluations.

Table 5-2// Demand Response Programs Evaluated Results

Sector	Program	Basis	Peak Effect	Direct Control	Summer kW Savings per Unit	Winter kW Savings per Unit
Residential	Air Conditioner - 33% Cycling	Incentive	Peak Shift	Yes	0.8	0.0
	Air Conditioner - 50% Cycling	Incentive	Peak Shift	Yes	1.1	0.0
	Water Heater - 40/50 Gallon	Incentive	Peak Shift	Yes	0.4	0.6
	Time-of-Use (TOU) Rate	Price	Peak Shift	No	0.2	0.1
	Critical Peak Pricing (CPP) Rate	Price	Peak Shift	No	1.0	0.5
	Smart Thermostat w/ CPP Rate	Incentive / Price	Peak Shift	Yes	1.4	0.5
Commercial	Distributed Generation	Incentive	Peak Clip	Yes	350.0	350.0
	Lighting - Small Application	Incentive	Peak Clip	Yes	2.1	2.1
	Lighting - Large Application	Incentive	Peak Clip	Yes	20.6	20.5
	Energy Management System (EMS)	Incentive	Peak Shift	No	11.9	11.9
	Time-of-Use (TOU) Rate	Price	Peak Shift	No	0.1	0.1
	Critical Peak Pricing (CPP) Rate	Price	Peak Shift	No	0.6	0.6
Industrial	Distributed Generation	Incentive	Peak Clip	Yes	1,000.0	1,000.0
	Energy Management System (EMS)	Incentive	Peak Shift	No	149.6	149.6
	Interruptible Rate	Price	Peak Clip	No	1,000.0	1,000.0

5.7 DEMAND RESPONSE COST-EFFECTIVENESS

Due to the low value currently associated with avoided production and transmission capacity, most of the DR programs evaluated are not cost effective under the TRC test. Table 5-3 below presents the 10-year net present value benefits and costs for a single unit and shows the benefit/cost ratios for the TRC test. The methodology employed in calculating these effectiveness tests is consistent with the methodology employed in evaluating energy efficiency as described earlier in this report. Further details on inputs into the analysis including load, benefit, and cost assumptions are described below.

Table 5-3 // Cost-Effectiveness Screening Results per DR Measure Installed

Program		NPV Benefits	NPV Costs	TRC Ratio
Residential	Air Conditioner - 33% Cycling	$236	$737	0.32
	Air Conditioner - 50% Cycling	$351	$830	0.42
	Water Heater - 40/50 Gallon	$375	$868	0.43
	Time-of-Use (TOU) Rate	$108	$291	0.37
	Critical Peak Pricing (CPP) Rate	$452	$713	0.63
	Smart Thermostat w/ CPP Rate	$549	$981	0.56
Commercial	Distributed Generation	$225,304	$192,779	1.17
	Lighting - Small Application	$1,338	$1,947	0.69
	Lighting - Large Application	$13,236	$13,936	0.95
	Energy Management System (EMS)	$6,507	$14,339	0.45
	Time-of-Use (TOU) Rate	$93	$989	0.09
	Critical Peak Pricing (CPP) Rate	$417	$1,094	0.38
Industrial	Distributed Generation	$437,719	$615,074	0.71
	Energy Management System (EMS)	$55,366	$236,806	0.23
	Interruptible Rate	$362,513	$246,393	1.47

5.8 KEY ASSUMPTIONS AND INPUTS

The demand response analysis is consistent with the energy efficiency analysis in many respects. The same screening model is used to calculate the evaluation metrics for the TRC Test. Key input system data such as the load forecast, loss factors, reserve margins, transmission and distribution avoided costs, and discount factors are also consistent between the Energy Efficiency and Demand Response analyses. This section details the assumptions that are specific to demand response programs.

Load Impacts

One of the critical assumptions for screening demand response programs is the amount of load reduction possible at the time of the system peak. Secondary research sources including white papers, state Technical Reference Manuals, and data submitted to regulatory agencies and GDS' experience with other cooperatives were used to develop load impact assumptions for Big Rivers. Specifics on a DR program basis are provided below.

Air Conditioners: For air conditioners, the study used load impact estimates from potential studies for utilities in four other states. The load estimates were weather-adjusted by developing a linear regression relationship between normal cooling degree days and the load impact. The regression model and cooling degree days for Big Rivers were used to estimate air conditioner impacts in Kentucky. These were then checked for reasonableness with measurement and verification study results in the secondary literature. The impacts for the proxy utilities in other states were developed using system specific data including weather, size of home, and estimation techniques suggested by the Air Conditioning Contractors of America ("ACCA").[15]

[15] "Manual S – Residential Equipment Selection." ACCA.

Water Heaters: Water heaters are estimated in a manner like air conditioners, averaging load impacts seen in other GDS studies. However, water heaters are not as weather-sensitive and the estimates are very stable from region to region.

Residential and Commercial Rate Programs: There are three residential rate programs that build upon each other: Time of Use ("TOU"), Critical Peak Pricing ("CPP") interactive metering (manual control by consumer), and CPP smart thermostat (control by utility).

TOU rates have fixed prices for defined time periods. The CPP rates would have fixed prices for off-peak hours and defined on-peak periods. In addition, there are higher (critical) prices during select high energy cost hours. For this study, the top 100 energy cost hours are assumed for the CPP rate. For the CPP manual program, the residential user has a programmable thermostat and can choose to respond to prices, but there is no control from the utility. With the smart thermostat program, the utility can control the air conditioner and, therefore, achieve load impacts consistent with an AC control program plus additional benefits associated with customer response to prices. Figure 5-2 demonstrates theoretical time-based rates for a summer day.

Figure 5-2 // Example of Time-Based Rates on a Summer Day

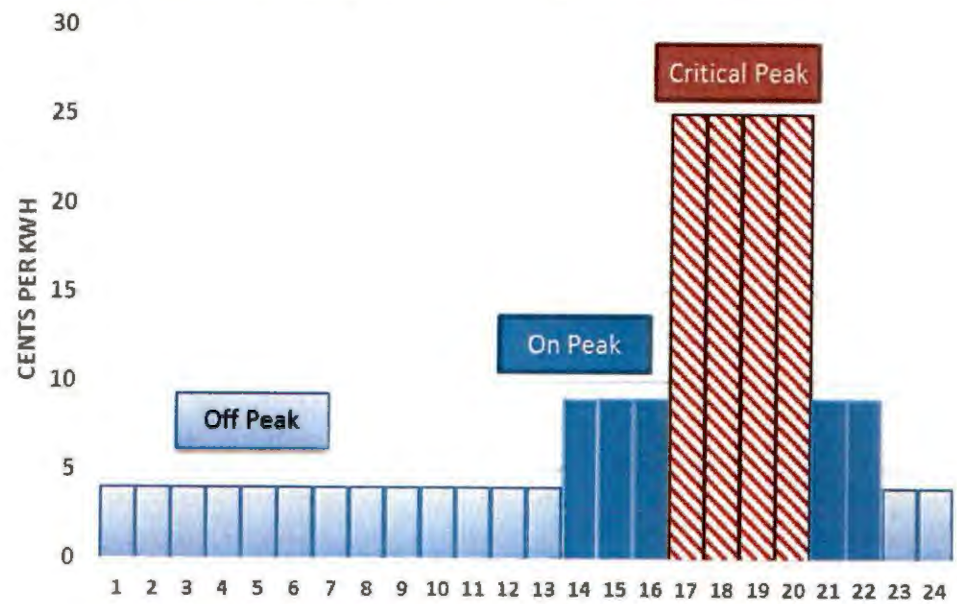
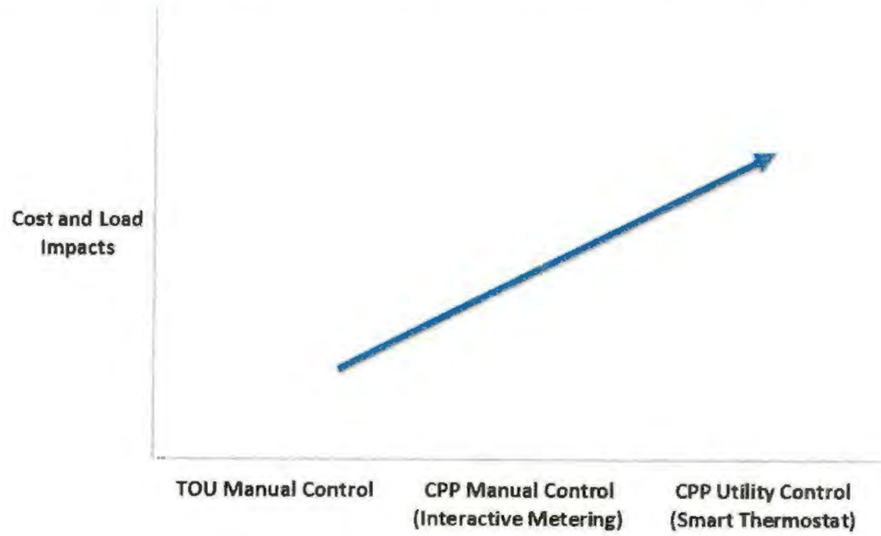


Figure 5-3 demonstrates the relationship between program costs and load impacts for the three rates. The TOU rate with manual control[16] has the lowest equipment and administrative costs but also provides the least demand response since it is based on voluntary response. The CPP rate with manual control provides a stronger price signal and therefore gets a slightly better energy and demand benefit, but costs are also higher than the TOU rate because of the need for equipment to send price signals during critical peak pricing hours. Finally, the addition of a smart thermostat that allows the utility to control air conditioning is the costliest alternative, but also provides the highest demand impact.

[16] Manual control means that the utility has no ability to control the thermostat, so any changes to the thermostat must be made by the homeowner by manually changing the temperature setting. Therefore, a manual control rate program requires voluntary response to price signals.

Figure 5-3 Illustration of the Build-Up Nature of the Time Based Residential Rates



TOU and CPP impacts are estimated based on a macro-analysis performed by the Brattle Group, examining measured load impacts for several utilities throughout the country.[17] The industrial interruptible rate is simply an assumption that the retail consumer can somehow curtail 1 MW of load during interruption notices. These curtailments could be achieved through shutting down processes or moving shifts or by other means.

Distributed Generation: It is assumed that a commercial application would equal 350 kW and an industrial application would equal 1,000 kW.

Commercial Lighting Control Large Application: Load impacts for commercial lighting were estimated using commercial load profiles developed by GDS for other energy efficiency and demand response analyses. The load profiles include estimated internal lighting wattage per square foot for various building types. A report by Peter Morante of the Lighting Research Center indicates that control switches can be installed in buildings to interrupt 25% of the lighting load (*e.g.* dimming some areas, or shutting off every third hallway light).[18] The commercial lighting program was broken into small and large commercial applications, and the average load impact for each group was used for the benefit/cost analysis. It is assumed that the control strategy would mirror the standard capacity water heater program, resulting in 100 hours of control each year. The commercial energy lighting results in energy losses as indicated in the Table 5-4 below.

[17] *Rethinking Prices*. Faruqui, Ahmad, Ryan Hledik, and Sanem Sergici. *Public Utilities Fortnightly*. January 2010. Pp. 30-39, http://www.fortnightly.com/fortnightly/2010/01/rethinking-prices?page=0%2C0.

[18] "Making Lighting Responsive to Demand Response." Peter Morante, Lighting Research Center. Rensselaer Polytechnic Institute, http://www.ieadsm.org/Files/Tasks/Task%2013%20-%20Demand%20Response%20Resources/Peak%20Load%20Management%20Alliance%20-%20May%202005/Peter%20MoranteLRC.pdf

Table 5-4 // Commercial Lighting Control Load Impacts

Type	Square Footage	Watts per Sq. Ft.	Total Watts	25% kW Reduction
Small Commercial				
Office	6,600	1.33	8,778	2.19
Retail Store	6,400	0.87	5,568	1.39
Restaurant	5,250	0.92	4,830	1.21
School	16,000	0.88	14,080	3.52
Group Average	**8,563**	**0.97**	**8,306**	**2.08**
Large Commercial				
Office	90,000	0.87	78,300	19.58
Retail Store	79,000	0.87	68,730	17.18
Hospital	155,800	0.64	99,712	24.93
Group Average	**108,267**	**0.76**	**82,247**	**20.56**

Energy Management Systems: Energy Management Systems ("EMS") can take on many forms, but the basic approach is that multiple end-uses are controlled on-site through an integrated system to achieve combined demand reductions. Typically, these systems include built-in logic to monitor loads and initiate control measures when needed. Extensive research indicates that such systems are very site-specific, thus, characterizing a "general" EMS set-up is difficult. However, a pilot study of small commercial applications was conducted by Southern California Edison in 2006[19] using a product developed and sold by Dencor, Inc. (www.dencor.com). The system included control of rooftop air conditioners, walk-in coolers, walk-in freezers, reach-in coolers, ice makers, and electric water heaters. The pilot included retail stores, restaurants, beverage stores, offices, and small groceries, with loads ranging from 15 kW to 150 kW. The Dencor systems include the ability of the utility to monitor the system through the internet, dial-up, or GPS technology. The pilot program demonstrated an average 11.9 kW reduction for a customer with an average base load of 54.3 kW, a 22% reduction.

Both small commercial and larger industrial EMS were included in the benefit/cost analysis. For small commercial, this study uses the 11.9 kW impact from the Southern California Edison pilot study and assumed the same control strategy as a large capacity water heater program. With the significant upfront costs associated with an EMS, a customer is very likely willing to control for many more hours per year than a standard residential air conditioner or water heater strategy. For industrial applications, it is assumed the load is 1,000 kW and that 15% demand reductions can be achieved. Energy is assumed to be shifted and not lost due to control through the EMS.

Benefits

The benefits of avoided peaking demand and transmission demand are consistent with the energy efficiency analysis. Development of the avoided costs is detailed in Section 5.9 of the report. Avoided production demand is based on market price of capacity and growing into the value of a peaking unit. There is no benefit assumed for avoided transmission or distribution demand. For peak shifting programs, there is an avoided energy benefit associated with serving the load during the recovery periods that tend to have lower energy production costs. The benefit is the difference between the energy cost during peaking and recovery hours. For this study, the on- and off-peak avoided energy costs are used to

[19] "Demand Response Enabling Technologies For Small-Medium Businesses." Lockheed Martin Aspen, April 12, 2006. http://sites.energetics.com/madri/pdfs/LMADRT_060506.pdf

estimate the benefit of shifting energy. For peak clipping programs in which energy is not recovered, the avoided energy cost is the on-peak energy charge.

Costs

The costs included in the Total Resource Cost Test benefit/cost analysis generally include equipment installation and carrying costs, program administration and marketing costs, and costs associated with delivery of the communication or price signal to the affected device or consumer. For direct control programs in which the participant incurs no cost, incentives are also included as program costs. Costs may be incurred by the G&T, Member Cooperative, or retail consumer. The TRC test does not include lost electric revenues that may arise from programs that reduce energy consumption.

Incentives

Incentives for demand response programs take on many forms and levels. For instance, some cooperatives can get participation for a water heater control program with little or no incentive, simply by appealing to the "cooperative spirit". Incentives include a one-time payment, monthly fixed payments, rate incentives, and contributions to equipment cost. For programs in which the participant has some share in equipment cost, incentives by the utility to offset that cost are excluded from the TRC test. However, in a program such as air conditioner control in which the participant has no monetary cost, incentives paid by the utility to the participant are included as a representation of the economic value the customer places on their potential displacement of comfort during control events. The levels of incentive assumed in the Big Rivers screening analysis are shown in Table 5-5 below, with the magnitude of the incentive being representative of what other utilities with programs often pay. Some are assumed to be monthly payments (e.g., $4 per month for water heaters) and others, such as distributed generation, are rate incentives ($6.50 per kW-month demand credit). However, the ultimate form of the incentive is not as important as the magnitude for purposes of a screening analysis.

Table 5-5 // Incentive Amounts for TRC Test

Program		TRC Annual Incentive	Nature
Residential	Air Conditioner - 33% Cycling	$36	Recurring
	Air Conditioner - 50% Cycling	$48	Recurring
	Water Heater - 40/50 Gallon	$48	Recurring
	Time-of-Use (TOU) Rate	$0	
	Critical Peak Pricing (CPP) Rate	$0	
	Smart Thermostat w/ CPP Rate	$0	
Commercial	Distributed Generation	$0	
	Lighting - Small Application	$500	One-Time
	Lighting - Large Application	$1,000	One-Time
	Energy Management System (EMS)	$0	
	Time-of-Use (TOU) Rate	$0	
	Critical Peak Pricing (CPP) Rate	$0	
Industrial	Distributed Generation	$0	
	Energy Management System (EMS)	$0	
	Interruptible Rate	$31,455	Recurring

Carrying Costs for Capital Equipment

Two different carrying cost factors are used to expense capital items in the analysis. The first factor is when the utility will own and operate the equipment (direct control programs) and includes interest, depreciation at 10 years, operations and maintenance, and margins on the interest expense. Margins are a blended average of a G&T Times Interest Earned Ratio ("TIER") of 1.1 (25% weight) and a distribution cooperative TIER of 1.5 (75% weight). The TIER represent typical target TIER levels for G&T's and cooperatives. The weights represent the expectation that distribution cooperatives typically bear a greater share of capital costs in a DR program. If Big Rivers initiated a DR program, actual cost sharing would be part of the program design. The second factor is when a commercial account owns the equipment. That factor includes interest, depreciation over 15 years, and operations and maintenance. Table 5-6 below lists the carrying cost assumptions based by ownership type.

Table 5-6 // Carrying Cost Factors

Item	Utility Ownership	Commercial Ownership
Interest	4.50%	5.50%
Depreciation	10.00%	6.67%
O&M	3.00%	3.00%
Insurance & Taxes	0.00%	0.00%
Margins on Interest	1.80%	0.00%
Total Carrying Cost	**19.30%**	**15.17%**

Capital Costs of Equipment

Capital costs for DR equipment were based on current costs for residential control switches and on the assumed capital costs from Big Rivers' 2014 DSM Potential Study but escalated at 2.5% per year for four years to reflect current costs.

Administrative, Marketing, and Operating Costs

Other program costs were estimated using current estimates for central communication equipment and software and for G&T and Member Cooperative staffs to dedicate to the DR programs. Finally, marketing costs for each Member Cooperative were included. These costs were then levelized and divided into a number of DR participants that represents achieving 5% of rural peak demand reduction after 10 years of a program. This level of penetration has been proven to be reasonably achievable for a utility starting a program and with persistent marketing and program support over ten years. The average program costs per DR program participant per year $17.29.

5.9 CONCLUSIONS AND RECOMMENDATIONS FOR DEMAND RESPONSE

With Big Rivers and the region in and around MISO being long on capacity, the value of demand response programs is presently low, even lower than in the 2014 DSM Potential Study. Furthermore, there are no benefits associated with avoided transmission facilities (an assumption consistent with the 2014 DSM Potential Study). Therefore, it is not surprising that most of the DR programs analyzed do not pass the TRC test. The following programs did pass the TRC test.

Commercial Distributed Generation: This program passes the TRC test, but only by a small margin. The benefit cost ratio is 1.17. If there are any C&I accounts that already have distributed generation for back-up or other purposes, then Big Rivers' member cooperative could conceivably consider approach such customers about use of the generators for peak shaving. However, EPA rules may prohibit or limit such programs. Furthermore, many customers that own generation for emergency purposes may be hesitant to participate in a demand response program or allow a utility to have control of their resource.

Interruptible Rate: This program is highly beneficial with very little cost. That is because the assumption is that the industrial customer is able to curtail 1 MW without additional equipment. An interruptible program looks highly beneficial in many DR studies even with low avoided cost benefits. Obviously, the challenge to the utility is finding candidates that meet these stringent criteria that would be willing to either change shifts or operations in order to reduce their power bills.

Recommendation

At this time, based on the study conclusions Big Rivers has elected to not pursue a formal demand response program. Most of the typical DR programs analyzed in this screening are not cost-effective at this time and those that are cost effective are either complicated to implement or are only marginally cost effective. Big Rivers would be better served by using its DSM budgets pursuing higher value energy efficiency programs, which do also provide peak demand reductions although overall energy reductions are the target objective. When and if capacity tightens in the region, the value of capacity should increase, approaching the avoided cost of a peaking unit. At that time, demand response programs could become cost effective. Big Rivers should therefore continue to monitor the cost effectiveness of DR. Based on GDS recommendations in this study, Big Rivers will:

- Not pursue a full-scale demand response program at this time.
- Continue to monitor opportunities for demand response, looking for reduction in costs or increases in the value of avoided peaking generation.
- Monitor the opportunity of new technologies that may provide peak demand reduction benefits at a lower cost than current programs evaluated.[20]
- Encourage the Member Cooperatives to consider whether any existing large commercial or industrial accounts would be benefitted by an interruptible rate arrangement. If so, determine whether there is a desire on the part of the Members to offer an interruptible rate arrangement.

[20] For example, several utilities have begun to investigate pilot battery storage programs tied to residential customers that own solar generation. Such programs, however, would be cost prohibitive in Big Rivers' case given very low avoided cost benefits as batteries are currently costly pieces of equipment. Therefore, this new DR approach has not been formally evaluated as part of the 2017 DSM Potential Study.

6 ENERGY EFFICIENCY PROGRAMS AND PROGRAM POTENTIAL SUMMARY

This section of the report provides a summary of the program potential and a breakdown of costs and savings associated with each program. This section is the most relevant for the IRP as it transforms the results of the energy efficiency and demand response potential study analysis into realistic estimates of program potential than can be achieved by Big Rivers. These estimates are realistic because they take into consideration budget constraints, which limit the portion of achievable potential (that is free of cost constraints), that can actually be achieved by Big Rivers.

6.1 OVERVIEW OF PROGRAMS

The analysis included 10 programs in the Big Rivers service territory: 6 in the residential sector and 4 in the commercial/industrial sector. Table 6-1 below provides a listing of each program, by sector.

Table 6-1 // List of Programs Evaluated in the Study

Sector	Program Name
Residential	Residential Lighting Program
Residential	Residential Efficient Appliances Program
Residential	Residential HVAC Program
Residential	Residential HVAC Tune-Up Program
Residential	Residential New Construction Program
Residential	A 'la Carte Individual Prescriptive Program
Commercial/Industrial	C&I Prescriptive Lighting Program
Commercial/Industrial	C&I Prescriptive HVAC Program
Commercial/Industrial	C&I General Program
Commercial/Industrial	Outdoor Lighting LED

6.2 RESULTS

The analysis considered program potential at two different funding scenarios: a $2 million incentive scenario and a $1 million incentive scenario. In each case, the residential sector was allocated 50% of the incentive budget, and the nonresidential sector was also allocated 50% of the incentive budget.

Figure 6-1 provides the program potential for the 3-yr, 5-yr, and 10-yr program potential for each funding scenario. The $2 million funding scenario program potential is 1.5% of forecast sales over the 3-yr timeframe, and rises to 4.0% across the 10-yr timeframe. The $1 million funding scenario program potential is 0.8% of forecast sales over the 3-yr timeframe, and rises to 2.0% across the 10-yr timeframe.

Figure 6-1 // Electric Energy (MWh) Cumulative Annual Program Potential (as a % of System Sales)

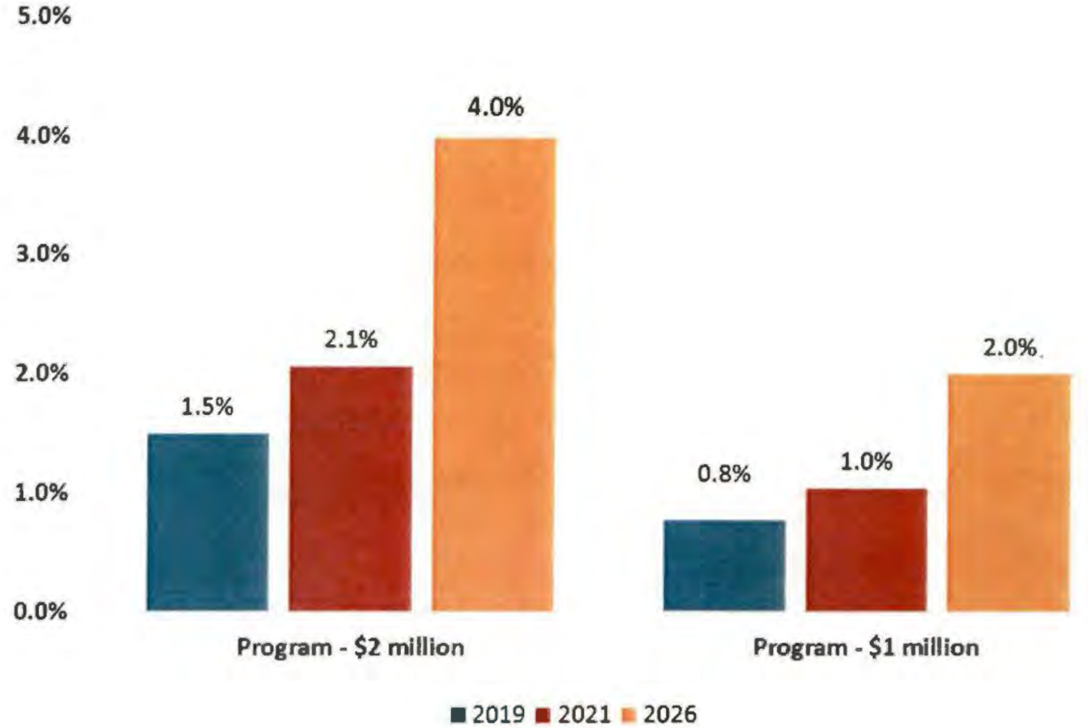


Table 6-2 provides 1-, 2-, 3-, 5-, and 10-yr estimates of cumulative annual program potential for energy, summer peak demand, and winter peak demand. The $2 million program potential is nearly 50,000 MWh by 2019, and the $1 million program potential is approximately half that amount at just over 25,000 MWh Summer peak demand program potential is 7.4 MW and 3.8 MW for the respective $2 million and $1 million program potential scenarios.

Table 6-2 // Program Potential Summary

	2017	2018	2019	2021	2026
Annual Energy (MWh)					
Program - $2 million	16,286	32,996	49,434	69,138	136,582
Program - $1 million	8,443	17,102	25,262	34,964	68,339
Summer Peak Demand (MW)					
Program - $2 million	2.5	5.0	7.4	10.5	20.6
Program - $1 million	1.3	2.6	3.8	5.4	10.5
Winter Peak Demand (MW)					
Program - $2 million	1.8	3.7	5.5	8.0	16.2
Program - $1 million	1.0	1.9	2.8	4.2	8.5

Table 6-3 provides a summary of the program potential for the $2 million incentive scenario. The C&I Prescriptive Lighting program provides the most potential energy savings over the next three years, followed by the Outdoor Lighting LED program and the Residential Lighting Program.

Table 6-3// $2 Million Scenario – Savings by Program (MWh)

Program Name	2017	2018	2019	2021	2026
Residential Lighting Program	1,062	2,496	4,366	0	0
Residential Efficient Appliances Program	698	1,340	1,921	2,805	4,162
Residential HVAC Program	597	1,313	2,135	4,720	11,237
Residential HVAC Tune-Up Program	738	1,476	1,475	1,473	1,467
Residential New Construction Program	339	678	1,017	2,033	4,575
A 'la Carte Individual Prescriptive Program	920	1,835	2,741	5,417	11,786
C&I Prescriptive Lighting Program	8,111	16,221	24,332	33,637	65,420
C&I Prescriptive HVAC Program	1,122	2,245	3,367	5,612	11,224
C&I General Program	398	790	1,177	1,937	3,701
Outdoor Lighting LED	2,301	4,602	6,903	11,505	23,010
Total	**16,286**	**32,996**	**49,434**	**69,138**	**136,582**

Table 6-4 provides a summary of the program potential for the $1 million incentive scenario. The C&I Prescriptive Lighting program provides the most potential energy savings over the next three years, followed by the Outdoor Lighting LED program and the Residential Lighting Program.

Table 6-4// $1 Million Scenario – Savings by Program (MWh)

Program Name	2017	2018	2019	2021	2026
Residential Lighting Program	531	1,248	2,183	0	0
Residential Efficient Appliances Program	279	536	769	1,210	1,973
Residential HVAC Program	299	657	1,068	1,929	4,100
Residential HVAC Tune-Up Program	738	1,476	1,475	1,473	1,467
Residential New Construction Program	169	339	508	847	1,695
A 'la Carte Individual Prescriptive Program	460	918	1,370	3,160	7,426
C&I Prescriptive Lighting Program	4,055	8,111	12,166	16,818	32,710
C&I Prescriptive HVAC Program	561	1,122	1,684	2,806	5,612
C&I General Program	199	395	589	968	1,851
Outdoor Lighting LED	1,151	2,301	3,452	5,753	11,505
Total	**8,443**	**17,102**	**25,262**	**34,964**	**68,339**

Table 6-5 provides a breakdown of the program incentive budgets in the $2 million funding scenario for the 1-, 2-, and 3-yr timeframes. Table 6-6 provides a breakdown of the program budgets in the $2 million funding scenario for the 1-, 2-, and 3-yr timeframes. The C&I Prescriptive Program, Outdoor Lighting LED program and Residential Lighting Programs have the largest incentive budgets in the $2 million incentive scenario. These three programs have the largest incentive budgets in the $1 million scenario as well, along with the Residential Lighting Program, which has a $100,000 budget in this scenario. The incentive budgets are held constant each year within each respective scenario.

Table 6-5 // $2 Million Scenario – Program Incentive Budgets

Program Name	2017	2018	2019
Residential Lighting Program	$200,000	$200,000	$200,000
Residential Efficient Appliances Program	$250,000	$250,000	$250,000
Residential HVAC Program	$150,000	$150,000	$150,000
Residential HVAC Tune-Up Program	$50,000	$50,000	$50,000
Residential New Construction Program	$150,000	$150,000	$150,000
A 'la Carte Individual Prescriptive Program	$200,000	$200,000	$200,000
C&I Prescriptive Lighting Program	$450,000	$450,000	$450,000
C&I Prescriptive HVAC Program	$100,000	$100,000	$100,000
C&I General Program	$50,000	$50,000	$50,000
Outdoor Lighting LED	$400,000	$400,000	$400,000
Total	**$2,000,000**	**$2,000,000**	**$2,000,000**

Table 6-6 // $1 Million Scenario – Program Incentive Budgets

Program Name	2017	2018	2019
Residential Lighting Program	$100,000	$100,000	$100,000
Residential Efficient Appliances Program	$100,000	$100,000	$100,000
Residential HVAC Program	$75,000	$75,000	$75,000
Residential HVAC Tune-Up Program	$50,000	$50,000	$50,000
Residential New Construction Program	$75,000	$75,000	$75,000
A 'la Carte Individual Prescriptive Program	$100,000	$100,000	$100,000
C&I Prescriptive Lighting Program	$225,000	$225,000	$225,000
C&I Prescriptive HVAC Program	$50,000	$50,000	$50,000
C&I General Program	$25,000	$25,000	$25,000
Outdoor Lighting LED	$200,000	$200,000	$200,000
Total	**$1,000,000**	**$1,000,000**	**$1,000,000**

Table 6-7 provides a summary of the cost-effectiveness of each program in the $2 million funding scenario. The overall TRC ratio is 1.5, indicated the portfolio would be cost-effective across all 10 programs. Several of the residential program are not cost-effective on their own. This indicates that the measure mix currently offered by Big Rivers for these programs may need be reviewed to determine if more cost-effective options are available.

Table 6-7 // $2 Million Scenario – Program Cost-Effectiveness (TRC Test)

Program Name	NPV Benefits	NPV Costs	NPV Savings (Benefits - Costs)	TRC Test Ratio
Residential Lighting Program	$0.5	$0.7	-$0.2	0.7
Residential Efficient Appliances Program	$3.1	$3.8	-$0.6	0.8
Residential HVAC Program	$13.1	$9.4	$3.7	1.4
Residential HVAC Tune-Up Program	$1.1	$4.3	-$3.2	0.3
Residential New Construction Program	$4.3	$6.9	-$2.7	0.6
A 'la Carte Individual Prescriptive Program	$11.2	$18.6	-$7.5	0.6
C&I Prescriptive Lighting Program	$45.8	$17.6	$28.2	2.6
C&I Prescriptive HVAC Program	$11.3	$3.9	$7.3	2.9
C&I General Program	$2.6	$2.0	$0.6	1.3
Outdoor Lighting LED	$33.3	$15.7	$17.6	2.1
Total	**$126.3**	**$83.0**	**$43.3**	**1.5**

Table 6-8 provides a summary of the cost-effectiveness of each program in the $1 million funding scenario. The overall TRC ratio is 1.4, indicated the portfolio would be cost-effective across all 10 programs.

Table 6-8 // $1 Million Scenario – Program Cost-Effectiveness (TRC Test)

Program Name	NPV Benefits	NPV Costs	NPV Savings (Benefits - Costs)	TRC Test Ratio
Residential Lighting Program	$0.3	$0.4	-$0.1	0.7
Residential Efficient Appliances Program	$1.5	$1.8	-$0.3	0.8
Residential HVAC Program	$4.7	$3.4	$1.3	1.4
Residential HVAC Tune-Up Program	$1.1	$4.3	-$3.2	0.3
Residential New Construction Program	$1.5	$2.5	-$1.0	0.6
A 'la Carte Individual Prescriptive Program	$7.0	$11.8	-$4.8	0.6
C&I Prescriptive Lighting Program	$22.9	$8.8	$14.1	2.6
C&I Prescriptive HVAC Program	$5.6	$2.0	$3.7	2.9
C&I General Program	$1.3	$1.0	$0.3	1.3
Outdoor Lighting LED	$16.7	$7.8	$8.8	2.1
Total	**$62.6**	**$43.8**	**$18.8**	**1.4**

6.3 PROGRAM DESCRIPTIONS

Big Rivers currently offers 10 programs to its Members. Six of these are residential programs, and four are C&I programs. These programs were the basis for the program potential assessment according to the $2 million and $1 million incentive funding scenarios. Below are descriptions of each of these 10 programs.

GDS recommends that Big Rivers continuously review the results of these programs each year to determine if the existing programs can be improved and determine if there are opportunities to revise these programs or add new programs to its portfolio. Alternatively, we also recommend that Big Rivers determine if factors such as low participation or low cost-effectiveness indicate that some programs are no longer preferred, and should be cancelled.

6.3.1 Residential Lighting Program

Big Rivers offers a residential lighting replacement program to its Members. This program promotes use of LED bulbs by providing free bulbs at annual meetings and during Cooperative Month in October. LED bulbs are increasing in cost-effectiveness due to rapidly dropping retail prices and are expected to gain a dominant market share in the next few years.

6.3.2 Residential Efficient Appliances Program

Big Rivers offers two residential efficient appliances programs to its Members. The programs promote installation of efficient clothes washers and refrigerators and the removal and recycling of older inefficient refrigerators. For this 2017 DSM Study, GDS combined efficient clothes washers, efficient refrigerators and refrigerator recycling measures into a consolidated Residential Efficient Appliances program.

6.3.3 Residential HVAC Program

Big Rivers offers a residential HVAC replacement program to its Members. This program promotes increased consideration and use of high-efficiency HVAC systems among the retail member-consumers of the Member-Owners by providing financial incentives to a Member-Owner's retail member-consumers to upgrade their HVAC systems.

6.3.4 Residential Weatherization Program

Big Rivers currently offers three residential weatherization programs to its Members. These programs promote the implementation of weatherization measures among the retail member-consumers of the Member-Owner by providing reimbursement to Member-Owner members who undertake weatherization improvements of their homes.

6.3.5 Residential New Construction Program

Big Rivers offers a residential new construction program to its Members. This program provides incentives to homeowners and builders to use energy efficient building standards.

6.3.6 Residential HVAC Tune-Up Program

Big Rivers offers a residential HVAC tune-up program to its Members. This program promotes the initiation of annual maintenance on heating and air conditioning equipment among the retail member-consumers of the Member-Owners by providing reimbursement to Member Cooperative retail members that have their heating and cooling systems professionally cleaned and serviced.

6.3.7 Commercial and Industrial Prescriptive Lighting Program

Big Rivers offers a prescriptive lighting replacement program to its Members' commercial and industrial members. This program provides an incentive to commercial and industrial retail member-consumers for whom service is taken under Big Rivers' Rural Delivery Service Tariff to upgrade poorly designed and low efficiency lighting systems.

6.3.8 Commercial and Industrial Prescriptive HVAC Program

Big Rivers offers a prescriptive HVAC program to its Members' commercial and industrial member-consumers. This program provides an incentive to commercial and industrial retail member-consumers to upgrade inefficient HVAC equipment and to maintain and tune-up their existing equipment.

6.3.9 Commercial and Industrial Prescriptive General Program

Big Rivers offers a general program to its Members' commercial and industrial member-consumers. This program provides an incentive to retail commercial and industrial retail member-consumers served under the Big Rivers' Rural Delivery Service Tariff to upgrade all aspects of cost-effective energy efficiency achievable in individual facilities.

6.3.10 Commercial and Industrial Outdoor Lighting Program

Big Rivers offers an incentive to the Members' commercial and industrial member-consumers who install high efficiency LED outdoor lighting. Outdoor lighting technology is in the process of a major technological upgrade with the use of LED lamps capable of surviving the harsh environment of an outdoor fixture. Products are being introduced continuously into the market for evaluation and the Members' commercial and industrial member-consumers are in the process of converting to the longer life technologies. Successful deployment of this technology will eventually mean a substantial reduction in the cost of outdoor lighting through lower energy use and longer life.

Appendix A – List of Key Data Sources

APPENDIX A: LIST OF KEY DATA SOURCES

This appendix provides a list of key data sources used in the development of the measure assumptions.

- ACEEE Summer Study, 2008
- Arkansas TRM (Version 5.0)
- BEopt: Building Energy Optimization software
- California Public Utilities Commission, 2010-2012 WO 017 Ex Ante Measure Cost Study Final Report (DEER database)
- Duke Energy Carolinas 2015 Residential Neighborhoods Program Final Evaluation Report
- EIA - Technology Forecast Updates – Residential and Commercial Building Technologies – Reference Case
- Energy Efficiency Emerging Technologies
- Illinois TRM (Version 6.0)
- Indiana TRM (Version 1.0) ***No hyperlink available - embedded document***

Indiana TRM
Version 1-10-2013.p

- LED Incremental Cost Study Overall Final Report, February 2016
- Michigan Energy Measures Database (MEMD)
- Mid-Atlantic Technical Reference Manual V6, Dated May 2016
- Minnesota TRM (Version 2.0)
- Northeast Energy Efficiency Partnerships, Incremental Cost Study
- National Residential Efficiency Measures Database
- 2016 PA TRM
- Vermont TRM ***No hyperlink available - embedded document***

TRM User Manual
No. 2016-92d.pdf

Appendix B – Residential Measure Detail

APPENDIX B: RESIDENTIAL MEASURE DETAIL

Big Rivers Electric Corporation
2017 DSM Potentital Study
Appendix B - Residential Measure Detail

Measure #	End-Use	Measure Name	Home Type	Income Type	Replacement Type	Base Annual Electric	% Electric Savings	Per Unit Elec Savings	Per Unit Summer NCP kW	Per Unit Winter NCP kW
1001	Refrigeration	Energy Star Compliant Top-Mount Refrigerator	SF	All	MO	441.7	10%	44.3	0.007	0.007
1002	Refrigeration	CEE Tier 2 Compliant Top-Mount Refrigerator	SF	All	MO	441.7	25%	110.5	0.017	0.017
1003	Refrigeration	Energy Star Compliant Side-by-Side Refrigerator	SF	All	MO	517.1	10%	51.7	0.008	0.008
1004	Refrigeration	CEE Tier 2 Compliant Side-by-Side Refrigerator	SF	All	MO	517.1	25%	129.3	0.019	0.019
1005	Refrigeration	Energy Star Compliant Chest Freezer	SF	All	MO	311.4	10%	31.2	0.005	0.008
1006	Refrigeration	Energy Star Compliant Upright Freezer (Manual Def.)	SF	All	MO	349.2	10%	35.0	0.006	0.006
1007	Refrigeration	Second Refrigerator Turn In	SF	All	Recycle	900.9	100%	900.9	0.111	0.111
1008	Refrigeration	Second Freezer Turn In	SF	All	Recycle	806.0	100%	806.0	0.095	0.095
1009	Refrigeration	Energy Star Compliant Top-Mount Refrigerator	MH	All	MO	441.7	10%	44.3	0.007	0.007
1010	Refrigeration	CEE Tier 2 Compliant Top-Mount Refrigerator	MH	All	MO	441.7	25%	110.5	0.017	0.017
1011	Refrigeration	Energy Star Compliant Side-by-Side Refrigerator	MH	All	MO	517.1	10%	51.7	0.008	0.008
1012	Refrigeration	CEE Tier 2 Compliant Side-by-Side Refrigerator	MH	All	MO	517.1	25%	129.3	0.019	0.019
1013	Refrigeration	Energy Star Compliant Chest Freezer	MH	All	MO	311.4	10%	31.2	0.005	0.005
1014	Refrigeration	Energy Star Compliant Upright Freezer (Manual Def.)	MH	All	MO	349.2	10%	35.0	0.006	0.006
1015	Refrigeration	Second Refrigerator Turn In	MH	All	Recycle	900.9	100%	900.9	0.111	0.111
1016	Refrigeration	Second Freezer Turn In	MH	All	Recycle	806.0	100%	806.0	0.095	0.095
1017	Refrigeration	Energy Star Compliant Top-Mount Refrigerator	SF	All	NC	441.7	10%	44.3	0.007	0.007
1018	Refrigeration	CEE Tier 2 Compliant Top-Mount Refrigerator	SF	All	NC	441.7	25%	110.5	0.017	0.017
1019	Refrigeration	Energy Star Compliant Side-by-Side Refrigerator	SF	All	NC	517.1	10%	51.7	0.008	0.008
1020	Refrigeration	CEE Tier 2 Compliant Side-by-Side Refrigerator	SF	All	NC	517.1	25%	129.3	0.019	0.019
1021	Refrigeration	Energy Star Compliant Chest Freezer	SF	All	NC	311.4	10%	31.2	0.005	0.005
1022	Refrigeration	Energy Star Compliant Upright Freezer (Manual Def.)	SF	All	NC	349.2	10%	35.0	0.006	0.006
1023	Refrigeration	Energy Star Compliant Top-Mount Refrigerator	MH	All	NC	441.7	10%	44.3	0.007	0.007
1024	Refrigeration	CEE Tier 2 Compliant Top-Mount Refrigerator	MH	All	NC	441.7	25%	110.5	0.017	0.017
1025	Refrigeration	Energy Star Compliant Side-by-Side Refrigerator	MH	All	NC	517.1	10%	51.7	0.008	0.008

Big Rivers Electric Corporation
2017 DSM Potentital Study
Appendix B - Residential Measure Detail

Measure #	End-Use	Measure Name	Home Type	Income Type	Replacement Type	Per unit NG Saving	Per Unit Water Savings	RC EUL	EE EUL	Initial Measure Cost	O&M Benefits
1001	Refrigeration	Energy Star Compliant Top-Mount Refrigerator	SF	All	MO	0.00	0	12.0	12.0	$40.0	$0.0
1002	Refrigeration	CEE Tier 2 Compliant Top-Mount Refrigerator	SF	All	MO	0.00	0	12.0	12.0	$140.0	$0.0
1003	Refrigeration	Energy Star Compliant Side-by-Side Refrigerator	SF	All	MO	0.00	0	12.0	12.0	$40.0	$0.0
1004	Refrigeration	CEE Tier 2 Compliant Side-by-Side Refrigerator	SF	All	MO	0.00	0	12.0	12.0	$140.0	$0.0
1005	Refrigeration	Energy Star Compliant Chest Freezer	SF	All	MO	0.00	0	11.0	11.0	$35.0	$0.0
1006	Refrigeration	Energy Star Compliant Upright Freezer (Manual Def.)	SF	All	MO	0.00	0	11.0	11.0	$35.0	$0.0
1007	Refrigeration	Second Refrigerator Turn In	SF	All	Recycle	0.00	0	8.0	8.0	$170.0	$0.0
1008	Refrigeration	Second Freezer Turn In	SF	All	Recycle	0.00	0	8.0	8.0	$170.0	$0.0
1009	Refrigeration	Energy Star Compliant Top-Mount Refrigerator	MH	All	MO	0.00	0	12.0	12.0	$40.0	$0.0
1010	Refrigeration	CEE Tier 2 Compliant Top-Mount Refrigerator	MH	All	MO	0.00	0	12.0	12.0	$140.0	$0.0
1011	Refrigeration	Energy Star Compliant Side-by-Side Refrigerator	MH	All	MO	0.00	0	12.0	12.0	$40.0	$0.0
1012	Refrigeration	CEE Tier 2 Compliant Side-by-Side Refrigerator	MH	All	MO	0.00	0	12.0	12.0	$140.0	$0.0
1013	Refrigeration	Energy Star Compliant Chest Freezer	MH	All	MO	0.00	0	11.0	11.0	$35.0	$0.0
1014	Refrigeration	Energy Star Compliant Upright Freezer (Manual Def.)	MH	All	MO	0.00	0	11.0	11.0	$35.0	$0.0
1015	Refrigeration	Second Refrigerator Turn In	MH	All	Recycle	0.00	0	8.0	8.0	$170.0	$0.0
1016	Refrigeration	Second Freezer Turn In	MH	All	Recycle	0.00	0	8.0	8.0	$170.0	$0.0
1017	Refrigeration	Energy Star Compliant Top-Mount Refrigerator	SF	All	NC	0.00	0	12.0	12.0	$40.0	$0.0
1018	Refrigeration	CEE Tier 2 Compliant Top-Mount Refrigerator	SF	All	NC	0.00	0	12.0	12.0	$140.0	$0.0
1019	Refrigeration	Energy Star Compliant Side-by-Side Refrigerator	SF	All	NC	0.00	0	12.0	12.0	$40.0	$0.0
1020	Refrigeration	CEE Tier 2 Compliant Side-by-Side Refrigerator	SF	All	NC	0.00	0	12.0	12.0	$140.0	$0.0
1021	Refrigeration	Energy Star Compliant Chest Freezer	SF	All	NC	0.00	0	11.0	11.0	$35.0	$0.0
1022	Refrigeration	Energy Star Compliant Upright Freezer (Manual Def.)	SF	All	NC	0.00	0	11.0	11.0	$35.0	$0.0
1023	Refrigeration	Energy Star Compliant Top-Mount Refrigerator	MH	All	NC	0.00	0	12.0	12.0	$40.0	$0.0
1024	Refrigeration	CEE Tier 2 Compliant Top-Mount Refrigerator	MH	All	NC	0.00	0	12.0	12.0	$140.0	$0.0
1025	Refrigeration	Energy Star Compliant Side-by-Side Refrigerator	MH	All	NC	0.00	0	12.0	12.0	$40.0	$0.0

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Measure #	End-Use	Measure Name	Home Type	Income Type	Replacement Type	Base Annual Electric	% Electric Savings	Per Unit Elec Savings	Per Unit Summer NCP kW	Per Unit Winter NCP kW
1026	Refrigeration	CEE Tier 2 Compliant Side-by-Side Refrigerator	MH	All	NC	517.1	25%	129.3	0.019	0.019
1027	Refrigeration	Energy Star Compliant Chest Freezer	MH	All	NC	311.4	10%	31.2	0.005	0.005
1028	Refrigeration	Energy Star Compliant Upright Freezer (Manual Def.)	MH	All	NC	349.2	10%	35.0	0.006	0.006
2001	Clothes Washer/Dryer	Energy Star Clothes Washer (w/ Elec. WH & Elec. Dryer)	SF	All	MO	613.1	27%	162.7	0.552	0.552
2002	Clothes Washer/Dryer	Energy Star Most Efficient Clothes Washer (w/ Elec. WH & Elec. Dryer)	SF	All	MO	613.1	39%	242.1	0.821	0.821
2003	Clothes Washer/Dryer	Energy Star Clothes Washer (w/ NG WH & Elec. Dryer)	SF	All	MO	421.8	18%	77.0	0.261	0.261
2004	Clothes Washer/Dryer	Energy Star Most Efficient Clothes Washer (w/ NG WH & Elec. Dryer)	SF	All	MO	421.8	21%	88.2	0.299	0.299
2005	Clothes Washer/Dryer	ENERGY STAR Clothes Dryer	SF	All	MO	768.9	21%	160.0	0.565	0.565
2006	Clothes Washer/Dryer	Energy Star Clothes Washer (w/ Elec. WH & Elec. Dryer)	MH	All	MO	613.1	27%	162.7	0.552	0.552
2007	Clothes Washer/Dryer	Energy Star Most Efficient Clothes Washer (w/ Elec. WH & Elec. Dryer)	MH	All	MO	613.1	39%	242.1	0.821	0.821
2008	Clothes Washer/Dryer	Energy Star Clothes Washer (w/ NG WH & Elec. Dryer)	MH	All	MO	421.8	18%	77.0	0.261	0.261
2009	Clothes Washer/Dryer	Energy Star Most Efficient Clothes Washer (w/ NG WH & Elec. Dryer)	MH	All	MO	421.8	21%	88.2	0.299	0.299
2010	Clothes Washer/Dryer	ENERGY STAR Clothes Dryer	MH	All	MO	768.9	21%	160.0	0.565	0.565
2011	Clothes Washer/Dryer	Energy Star Clothes Washer (w/ Elec. WH & Elec. Dryer)	SF	All	NC	613.1	27%	162.7	0.552	0.552
2012	Clothes Washer/Dryer	Energy Star Most Efficient Clothes Washer (w/ Elec. WH & Elec. Dryer)	SF	All	NC	613.1	39%	242.1	0.821	0.821
2013	Clothes Washer/Dryer	Energy Star Clothes Washer (w/ NG WH & Elec. Dryer)	SF	All	NC	421.8	18%	77.0	0.261	0.261
2014	Clothes Washer/Dryer	Energy Star Most Efficient Clothes Washer (w/ NG WH & Elec. Dryer)	SF	All	NC	421.8	21%	88.2	0.299	0.299

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Measure #	End-Use	Measure Name	Home Type	Income Type	Replacement Type	Per unit NG Saving	Per Unit Water Savings	RC EUL	EE EUL	Initial Measure Cost	O&M Benefits
1026	Refrigeration	CEE Tier 2 Compliant Side-by-Side Refrigerator	MH	All	NC	0.00	0	12.0	12.0	$140.0	$0.0
1027	Refrigeration	Energy Star Compliant Chest Freezer	MH	All	NC	0.00	0	11.0	11.0	$35.0	$0.0
1028	Refrigeration	Energy Star Compliant Upright Freezer (Manual Def.)	MH	All	NC	0.00	0	11.0	11.0	$35.0	$0.0
2001	Clothes Washer/Dryer	Energy Star Clothes Washer (w/ Elec. WH & Elec. Dryer)	SF	All	MO	0.00	2,024	14.0	14.0	$65.0	$0.0
2002	Clothes Washer/Dryer	Energy Star Most Efficient Clothes Washer (w/ Elec. WH & Elec. Dryer)	SF	All	MO	0.00	2,760	14.0	14.0	$210.0	$0.0
2003	Clothes Washer/Dryer	Energy Star Clothes Washer (w/ NG WH & Elec. Dryer)	SF	All	MO	0.37	2,024	14.0	14.0	$65.0	$0.0
2004	Clothes Washer/Dryer	Energy Star Most Efficient Clothes Washer (w/ NG WH & Elec. Dryer)	SF	All	MO	0.66	2,760	14.0	14.0	$210.0	$0.0
2005	Clothes Washer/Dryer	ENERGY STAR Clothes Dryer	SF	All	MO	0.00	0	14.0	14.0	$152.0	$0.0
2006	Clothes Washer/Dryer	Energy Star Clothes Washer (w/ Elec. WH & Elec. Dryer)	MH	All	MO	0.00	2,024	14.0	14.0	$65.0	$0.0
2007	Clothes Washer/Dryer	Energy Star Most Efficient Clothes Washer (w/ Elec. WH & Elec. Dryer)	MH	All	MO	0.00	2,760	14.0	14.0	$210.0	$0.0
2008	Clothes Washer/Dryer	Energy Star Clothes Washer (w/ NG WH & Elec. Dryer)	MH	All	MO	0.37	2,024	14.0	14.0	$65.0	$0.0
2009	Clothes Washer/Dryer	Energy Star Most Efficient Clothes Washer (w/ NG WH & Elec. Dryer)	MH	All	MO	0.66	2,760	14.0	14.0	$210.0	$0.0
2010	Clothes Washer/Dryer	ENERGY STAR Clothes Dryer	MH	All	MO	0.00	0	14.0	14.0	$152.0	$0.0
2011	Clothes Washer/Dryer	Energy Star Clothes Washer (w/ Elec. WH & Elec. Dryer)	SF	All	NC	0.00	2,024	14.0	14.0	$65.0	$0.0
2012	Clothes Washer/Dryer	Energy Star Most Efficient Clothes Washer (w/ Elec. WH & Elec. Dryer)	SF	All	NC	0.00	2,760	14.0	14.0	$210.0	$0.0
2013	Clothes Washer/Dryer	Energy Star Clothes Washer (w/ NG WH & Elec. Dryer)	SF	All	NC	0.37	2,024	14.0	14.0	$65.0	$0.0
2014	Clothes Washer/Dryer	Energy Star Most Efficient Clothes Washer (w/ NG WH & Elec. Dryer)	SF	All	NC	0.66	2,760	14.0	14.0	$210.0	$0.0

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Measure #	End-Use	Measure Name	Home Type	Income Type	Replacement Type	Base Annual Electric	% Electric Savings	Per Unit Elec Savings	Per Unit Summer NCP kW	Per Unit Winter NCP kW
2015	Clothes Washer/Dryer	ENERGY STAR Clothes Dryer	SF	All	NC	768.9	21%	160.0	0.565	0.565
2016	Clothes Washer/Dryer	Energy Star Clothes Washer (w/ Elec. WH & Elec. Dryer)	MH	All	NC	613.1	27%	162.7	0.552	0.552
2017	Clothes Washer/Dryer	Energy Star Most Efficient Clothes Washer (w/ Elec. WH & Elec. Dryer)	MH	All	NC	613.1	39%	242.1	0.821	0.821
2018	Clothes Washer/Dryer	Energy Star Clothes Washer (w/ NG WH & Elec. Dryer)	MH	All	NC	421.8	18%	77.0	0.261	0.261
2019	Clothes Washer/Dryer	Energy Star Most Efficient Clothes Washer (w/ NG WH & Elec. Dryer)	MH	All	NC	421.8	21%	88.2	0.299	0.299
2020	Clothes Washer/Dryer	ENERGY STAR Clothes Dryer	MH	All	NC	768.9	21%	160.0	0.565	0.565
3001	Dishwasher	Energy Star Dishwasher (Electric Water Heating)	SF	All	MO	307.0	12%	37.0	0.147	0.147
3002	Dishwasher	Energy Star Dishwasher (Non-Electric WH)	SF	All	MO	135.1	12%	16.3	0.065	0.065
3003	Dishwasher	Energy Star Dishwasher (Electric Water Heating)	MH	All	MO	307.0	12%	37.0	0.147	0.147
3004	Dishwasher	Energy Star Dishwasher (Non-Electric WH)	MH	All	MO	135.1	12%	16.3	0.065	0.065
3005	Dishwasher	Energy Star Dishwasher (Electric Water Heating)	SF	All	NC	307.0	12%	37.0	0.147	0.147
3006	Dishwasher	Energy Star Dishwasher (Non-Electric WH)	SF	All	NC	135.1	12%	16.3	0.065	0.065
3007	Dishwasher	Energy Star Dishwasher (Electric Water Heating)	MH	All	NC	307.0	12%	37.0	0.147	0.147
3008	Dishwasher	Energy Star Dishwasher (Non-Electric WH)	MH	All	NC	135.1	12%	16.3	0.065	0.065
4001	Misc. Plug Load	Energy Star Dehumidifer	SF	All	MO	1,071.6	13%	140.7	0.086	0.086
4002	Misc. Plug Load	Energy Star Room Air Cleaner	SF	All	MO	441.0	66%	293.0	0.050	0.050
4003	Misc. Plug Load	Energy Star Dehumidifer	MH	All	MO	1,071.6	13%	140.7	0.086	0.086
4004	Misc. Plug Load	Energy Star Room Air Cleaner	MH	All	MO	441.0	66%	293.0	0.050	0.050
4005	Misc. Plug Load	Energy Star Dehumidifer	SF	All	NC	1,071.6	13%	140.7	0.086	0.086

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Measure #	End-Use	Measure Name	Home Type	Income Type	Replacement Type	Per unit NG Saving	Per Unit Water Savings	RC EUL	EE EUL	Initial Measure Cost	O&M Benefits
2015	Clothes Washer/Dryer	ENERGY STAR Clothes Dryer	SF	All	NC	0.00	0	14.0	14.0	$152.0	$0.0
2016	Clothes Washer/Dryer	Energy Star Clothes Washer (w/ Elec. WH & Elec. Dryer)	MH	All	NC	0.00	2,024	14.0	14.0	$65.0	$0.0
2017	Clothes Washer/Dryer	Energy Star Most Efficient Clothes Washer (w/ Elec. WH & Elec. Dryer)	MH	All	NC	0.00	2,760	14.0	14.0	$210.0	$0.0
2018	Clothes Washer/Dryer	Energy Star Clothes Washer (w/ NG WH & Elec. Dryer)	MH	All	NC	0.37	2,024	14.0	14.0	$65.0	$0.0
2019	Clothes Washer/Dryer	Energy Star Most Efficient Clothes Washer (w/ NG WH & Elec. Dryer)	MH	All	NC	0.66	2,760	14.0	14.0	$210.0	$0.0
2020	Clothes Washer/Dryer	ENERGY STAR Clothes Dryer	MH	All	NC	0.00	0	14.0	14.0	$182.0	$0.0
3001	Dishwasher	Energy Star Dishwasher (Electric Water Heating)	SF	All	MO	0.00	252	13.0	13.0	$50.0	$0.0
3002	Dishwasher	Energy Star Dishwasher (Non-Electric WH)	SF	All	MO	0.09	252	13.0	13.0	$80.0	$0.0
3003	Dishwasher	Energy Star Dishwasher (Electric Water Heating)	MH	All	MO	0.00	252	13.0	13.0	$80.0	$0.0
3004	Dishwasher	Energy Star Dishwasher (Non-Electric WH)	MH	All	MO	0.09	252	13.0	13.0	$80.0	$0.0
3005	Dishwasher	Energy Star Dishwasher (Electric Water Heating)	SF	All	NC	0.00	252	13.0	13.0	$80.0	$0.0
3006	Dishwasher	Energy Star Dishwasher (Non-Electric WH)	SF	All	NC	0.09	252	13.0	13.0	$80.0	$0.0
3007	Dishwasher	Energy Star Dishwasher (Electric Water Heating)	MH	All	NC	0.00	252	13.0	13.0	$50.0	$0.0
3008	Dishwasher	Energy Star Dishwasher (Non-Electric WH)	MH	All	NC	0.09	252	13.0	13.0	$80.0	$0.0
4001	Misc. Plug Load	Energy Star Dehumidifer	SF	All	MO	0.00	0	12.0	12.0	$60.0	$0.0
4002	Misc. Plug Load	Energy Star Room Air Cleaner	SF	All	MO	0.00	0	9.0	9.0	$70.0	$0.0
4003	Misc. Plug Load	Energy Star Dehumidifer	MH	All	MO	0.00	0	12.0	12.0	$60.0	$0.0
4004	Misc. Plug Load	Energy Star Room Air Cleaner	MH	All	MO	0.00	0	9.0	9.0	$70.0	$0.0
4005	Misc. Plug Load	Energy Star Dehumidifer	SF	All	NC	0.00	0	12.0	12.0	$60.0	$0.0

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Measure #	End-Use	Measure Name	Home Type	Income Type	Replacement Type	Base Annual Electric	% Electric Savings	Per Unit Elec Savings	Per Unit Summer NCP kW	Per Unit Winter NCP kW
4006	Misc. Plug Load	Energy Star Room Air Cleaner	SF	All	NC	441.0	66%	293.0	0.060	0.060
4007	Misc. Plug Load	Energy Star Dehumidifer	MH	All	NC	1,071.6	13%	140.7	0.086	0.086
4008	Misc. Plug Load	Energy Star Room Air Cleaner	MH	All	NC	441.0	66%	293.0	0.060	0.060
5001	Consumer Electronics	Efficient Televisions	SF	All	MO	240.0	25%	60.0	0.032	0.032
5002	Consumer Electronics	Energy Star Desktop Computer	SF	All	MO	48.4	12%	5.9	0.000	0.000
5003	Consumer Electronics	Energy Star Computer Monitor	SF	All	MO	56.8	25%	14.2	0.001	0.001
5004	Consumer Electronics	Energy Star Laptop Computer	SF	All	MO	30.7	25%	7.7	0.001	0.001
5005	Consumer Electronics	Tier 1 Power Strip	SF	All	MO	603.8	13%	80.0	0.011	0.011
5006	Consumer Electronics	Tier 2 Power Strip	SF	All	MO	432.0	55%	238.0	0.054	0.054
5007	Consumer Electronics	Efficient Televisions	MH	All	MO	240.0	25%	60.0	0.032	0.032
5008	Consumer Electronics	Energy Star Desktop Computer	MH	All	MO	48.4	12%	5.9	0.000	0.000
5009	Consumer Electronics	Energy Star Computer Monitor	MH	All	MO	56.8	25%	14.2	0.001	0.001
5010	Consumer Electronics	Energy Star Laptop Computer	MH	All	MO	30.7	25%	7.7	0.001	0.001
5011	Consumer Electronics	Tier 1 Power Strip	MH	All	MO	603.8	13%	80.0	0.011	0.011
5012	Consumer Electronics	Tier 2 Power Strip	MH	All	MO	432.0	55%	238.0	0.054	0.054
5013	Consumer Electronics	Efficient Televisions	SF	All	NC	240.0	25%	60.0	0.032	0.032
5014	Consumer Electronics	Energy Star Desktop Computer	SF	All	NC	48.4	12%	5.9	0.000	0.000
5018	Consumer Electronics	Energy Star Computer Monitor	SF	All	NC	56.8	25%	14.2	0.001	0.001

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Measure #	End-Use	Measure Name	Home Type	Income Type	Replacement Type	Per unit NG Saving	Per Unit Water Savings	RC EUL	EE EUL	Initial Measure Cost	O&M Benefits
4006	Misc. Plug Load	Energy Star Room Air Cleaner	SF	All	NC	0.00	0	9.0	9.0	$70.0	$0.0
4007	Misc. Plug Load	Energy Star Dehumidifer	MH	All	NC	0.00	0	12.0	12.0	$60.0	$0.0
4008	Misc. Plug Load	Energy Star Room Air Cleaner	MH	All	NC	0.00	0	9.0	9.0	$70.0	$0.0
5001	Consumer Electronics	Efficient Televisions	SF	All	MO	0.00	0	6.0	6.0	$14.3	$0.0
5002	Consumer Electronics	Energy Star Desktop Computer	SF	All	MO	0.00	0	4.0	4.0	$20.0	$0.0
5003	Consumer Electronics	Energy Star Computer Monitor	SF	All	MO	0.00	0	4.0	4.0	$2.6	$0.0
5004	Consumer Electronics	Energy Star Laptop Computer	SF	All	MO	0.00	0	4.0	4.0	$2.6	$0.0
5005	Consumer Electronics	Tier 1 Power Strip	SF	All	MO	0.00	0	7.0	7.0	$10.0	$0.0
5006	Consumer Electronics	Tier 2 Power Strip	SF	All	MO	0.00	0	7.0	7.0	$70.0	$0.0
5007	Consumer Electronics	Efficient Televisions	MH	All	MO	0.00	0	6.0	6.0	$14.3	$0.0
5008	Consumer Electronics	Energy Star Desktop Computer	MH	All	MO	0.00	0	4.0	4.0	$20.0	$0.0
5009	Consumer Electronics	Energy Star Computer Monitor	MH	All	MO	0.00	0	4.0	4.0	$2.6	$0.0
5010	Consumer Electronics	Energy Star Laptop Computer	MH	All	MO	0.00	0	4.0	4.0	$2.6	$0.0
5011	Consumer Electronics	Tier 1 Power Strip	MH	All	MO	0.00	0	7.0	7.0	$10.0	$0.0
5012	Consumer Electronics	Tier 2 Power Strip	MH	All	MO	0.00	0	7.0	7.0	$70.0	$0.0
5013	Consumer Electronics	Efficient Televisions	SF	All	NC	0.00	0	6.0	6.0	$14.3	$0.0
5014	Consumer Electronics	Energy Star Desktop Computer	SF	All	NC	0.00	0	4.0	4.0	$20.0	$0.0
5015	Consumer Electronics	Energy Star Computer Monitor	SF	All	NC	0.00	0	4.0	4.0	$2.6	$0.0

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Measure #	End-Use	Measure Name	Home Type	Income Type	Replacement Type	Base Annual Electric	% Electric Savings	Per Unit Elec Savings	Per Unit Summer NCP kW	Per Unit Winter NCP kW
5016	Consumer Electronics	Energy Star Laptop Computer	SF	All	NC	30.7	25%	7.7	0.001	0.001
5017	Consumer Electronics	Tier 1 Power Strip	*SF*	All	NC	603.5	13%	80.0	0.011	0.011
5018	Consumer Electronics	Tier 2 Power Strip	*SF*	All	NC	432.0	55%	238.0	0.054	0.054
5019	Consumer Electronics	Efficient Televisions	MH	All	NC	240.0	25%	60.0	0.032	0.032
5020	Consumer Electronics	Energy Star Desktop Computer	MH	All	NC	48.4	12%	5.9	0.000	0.000
5021	Consumer Electronics	Energy Star Computer Monitor	MH	All	NC	56.8	25%	14.2	0.001	0.001
5022	Consumer Electronics	Energy Star Laptop Computer	MH	All	NC	30.7	25%	7.7	0.001	0.001
5023	Consumer Electronics	Tier 1 Power Strip	MH	All	NC	603.5	13%	80.0	0.011	0.011
5024	Consumer Electronics	Tier 2 Power Strip	MH	All	NC	432.0	55%	238.0	0.054	0.054
6001	Lighting	Standard CFL	SF	All	MO	40.2	65%	26.1	0.035	0.035
6002	Lighting	Standard LED	SF	All	MO	40.2	71%	28.3	0.038	0.038
6003	Lighting	Specialty CFL	SF	All	MO	55.6	75%	41.7	0.056	0.056
6004	Lighting	Specialty LED	SF	All	MO	55.5	79%	43.8	0.059	0.059
6005	Lighting	Reflector CFL	SF	All	MO	52.8	74%	39.0	0.052	0.052
6006	Lighting	Reflector LED	SF	All	MO	57.8	82%	47.3	0.064	0.064
6007	Lighting	Energy Star Torchiere	SF	All	MO	173.4	67%	116.6	0.149	0.149
6008	Lighting	LED Nightlight	SF	All	MO	25.6	86%	21.9	0.006	0.006
6009	Lighting	Exterior CFL Fixture	SF	All	MO	208.6	67%	140.7	0.057	0.057
6010	Lighting	Exterior LED Fixture	SF	All	MO	208.6	72%	151.1	0.061	0.061
6011	Lighting	Standard CFL	*MH*	All	MO	40.2	65%	26.1	0.035	0.035
6012	Lighting	Standard LED	*MH*	All	MO	40.2	71%	28.3	0.038	0.038
6013	Lighting	Specialty CFL	MH	All	MO	55.6	75%	41.7	0.056	0.056
6014	Lighting	Specialty LED	MH	All	MO	55.5	79%	43.8	0.059	0.059
6015	Lighting	Reflector CFL	MH	All	MO	52.8	74%	39.0	0.052	0.052
5016	Lighting	Reflector LED	MH	All	MO	57.8	82%	47.3	0.064	0.064

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Measure #	End-Use	Measure Name	Home Type	Income Type	Replacement Type	Per unit NG Saving	Per Unit Water Savings	RC EUL	EE EUL	Initial Measure Cost	O&M Benefits
5016	Consumer Electronics	Energy Star Laptop Computer	SF	All	NC	0.00	0	4.0	4.0	$2.6	$0.0
5017	Consumer Electronics	Tier 1 Power Strip	*SF*	All	NC	0.00	0	7.0	7.0	$10.0	$0.0
5018	Consumer Electronics	Tier 2 Power Strip	*SF*	All	NC	0.00	0	7.0	7.0	$70.0	$0.0
5019	Consumer Electronics	Efficient Televisions	MH	All	NC	0.00	0	6.0	6.0	$14.3	$0.0
5020	Consumer Electronics	Energy Star Desktop Computer	MH	All	NC	0.00	0	4.0	4.0	$20.0	$0.0
5021	Consumer Electronics	Energy Star Computer Monitor	MH	All	NC	0.00	0	4.0	4.0	$2.6	$0.0
5022	Consumer Electronics	Energy Star Laptop Computer	MH	All	NC	0.00	0	4.0	4.0	$2.6	$0.0
5023	Consumer Electronics	Tier 1 Power Strip	MH	All	NC	0.00	0	7.0	7.0	$10.0	$0.0
5024	Consumer Electronics	Tier 2 Power Strip	MH	All	NC	0.00	0	7.0	7.0	$70.0	$0.0
6001	Lighting	Standard CFL	SF	All	MO	-0.03	0	2.0	7.0	$0.8	$1.3
6002	Lighting	Standard LED	SF	All	MO	-0.04	0	2.0	15.0	$5.3	$4.1
6003	Lighting	Specialty CFL	SF	All	MO	-0.05	0	2.0	7.0	$2.3	$3.6
6004	Lighting	Specialty LED	SF	All	MO	-0.06	0	2.0	15.0	$9.4	$6.8
6005	Lighting	Reflector CFL	SF	All	MO	-0.05	0	2.0	7.0	$2.4	$7.8
6006	Lighting	Reflector LED	SF	All	MO	-0.06	0	2.0	15.0	$7.2	$13.3
6007	Lighting	Energy Star Torchiere	SF	All	MO	-0.17	0	2.0	8.0	$5.0	$0.0
6008	Lighting	LED Nightlight	SF	All	MO	0.00	0	2.0	12.0	$5.0	$0.0
6009	Lighting	Exterior CFL Fixture	SF	All	MO	0.00	0	2.0	20.0	$32.0	$0.0
6010	Lighting	Exterior LED Fixture	SF	All	MO	0.00	0	2.0	20.0	$59.6	$0.0
6011	Lighting	Standard CFL	*MH*	All	MO	-0.03	0	2.0	7.0	$0.8	$1.3
6012	Lighting	Standard LED	*MH*	All	MO	-0.04	0	2.0	15.0	$5.3	$4.1
6013	Lighting	Specialty CFL	MH	All	MO	-0.05	0	2.0	7.0	$2.3	$3.6
6014	Lighting	Specialty LED	MH	All	MO	-0.06	0	2.0	15.0	$9.4	$6.8
6015	Lighting	Reflector CFL	MH	All	MO	-0.05	0	2.0	7.0	$2.4	$7.8
6016	Lighting	Reflector LED	MH	All	MO	-0.06	0	2.0	15.0	$7.2	$13.3

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Measure #	End-Use	Measure Name	Home Type	Income Type	Replacement Type	Base Annual Electric	% Electric Savings	Per Unit Elec Savings	Per Unit Summer NCP kW	Per Unit Winter NCP kW
6017	Lighting	Energy Star Torchiere	MH	All	MO	173.4	67%	115.6	0.149	0.149
6018	Lighting	LED Nightlight	MH	All	MO	25.6	86%	21.9	0.006	0.006
6019	Lighting	Exterior CFL Fixture	MH	All	MO	208.6	67%	140.7	0.057	0.057
6020	Lighting	Exterior LED Fixture	MH	All	MO	208.6	72%	151.1	0.061	0.061
6021	Lighting	Standard CFL	SF	All	NC	40.2	65%	26.1	0.035	0.035
6022	Lighting	Standard LED	SF	All	NC	40.2	71%	28.3	0.038	0.038
6023	Lighting	Specialty CFL	*SF*	All	NC	55.6	75%	41.7	0.056	0.056
6024	Lighting	Specialty LED	*SF*	All	NC	55.5	79%	43.8	0.059	0.059
6025	Lighting	Reflector CFL	*SF*	All	NC	52.8	74%	39.0	0.052	0.052
6026	Lighting	Reflector LED	*SF*	All	NC	57.8	82%	47.3	0.064	0.064
6027	Lighting	Energy Star Torchiere	*SF*	All	NC	173.4	67%	115.6	0.149	0.149
6028	Lighting	LED Nightlight	*SF*	All	NC	25.6	86%	21.9	0.006	0.006
6029	Lighting	Exterior CFL Fixture	*SF*	All	NC	208.6	67%	140.7	0.057	0.057
6030	Lighting	Exterior LED Fixture	*SF*	All	NC	208.6	72%	151.1	0.061	0.061
6031	Lighting	Standard CFL	*MH*	All	NC	40.2	65%	26.1	0.035	0.035
6032	Lighting	Standard LED	*MH*	All	NC	40.2	71%	28.3	0.038	0.038
6033	Lighting	Specialty CFL	*MH*	All	NC	55.6	75%	41.7	0.056	0.056
6034	Lighting	Specialty LED	*MH*	All	NC	55.5	79%	43.8	0.059	0.059
6035	Lighting	Reflector CFL	*MH*	All	NC	52.8	74%	39.0	0.052	0.052
6036	Lighting	Reflector LED	*MH*	All	NC	57.8	82%	47.3	0.064	0.064
6037	Lighting	Energy Star Torchiere	*MH*	All	NC	173.4	67%	115.6	0.149	0.149
6038	Lighting	LED Nightlight	*MH*	All	NC	25.6	86%	21.9	0.006	0.006
6039	Lighting	Exterior CFL Fixture	*MH*	All	NC	208.6	67%	140.7	0.057	0.057
6040	Lighting	Exterior LED Fixture	*MH*	All	NC	208.6	72%	151.1	0.061	0.061
7001	Water Heating	Low Flow Faucet Aerators	*SF*	All	Retrofit	3,018.6	2%	68.6	1.320	1.320
7002	Water Heating	Low Flow Showerhead	*SF*	All	Retrofit	3,018.6	11%	328.0	1.086	1.086
7003	Water Heating	Thermostatic Restriction Valve	*SF*	All	Retrofit	3,018.6	3%	85.4	0.196	0.027
7004	Water Heating	Water Heater Blanket	*SF*	All	Retrofit	3,018.6	5%	156.6	0.018	0.018
7005	Water Heating	Water Heater Pipe Wrap	*SF*	All	Retrofit	3,018.6	3%	77.1	0.009	0.009
7006	Water Heating	Heat Pump Water Heater (Resistance Heat)	*SF*	All	MO	3,018.6	49%	1,477.3	0.583	0.583
7007	Water Heating	Heat Pump Water Heater (ASHP heat)	*SF*	All	MO	3,018.6	54%	1,640.0	0.647	0.647
7008	Water Heating	Solar Water Heating	*SF*	All	MO	3,018.6	68%	2,059.0	1.047	1.047

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Measure #	End-Use	Measure Name	Home Type	Income Type	Replacement Type	Per unit NG Saving	Per Unit Water Savings	RC EUL	EE EUL	Initial Measure Cost	O&M Benefits
6017	Lighting	Energy Star Torchiere	MH	All	MO	-0.17	0	2.0	8.0	$5.0	$0.0
6018	Lighting	LED Nightlight	MH	All	MO	0.00	0	2.0	12.0	$5.0	$0.0
6019	Lighting	Exterior CFL Fixture	MH	All	MO	0.00	0	2.0	20.0	$32.0	$0.0
6020	Lighting	Exterior LED Fixture	MH	All	MO	0.00	0	2.0	20.0	$59.6	$0.0
6021	Lighting	Standard CFL	SF	All	NC	-0.03	0	2.0	7.0	$0.8	$1.3
6022	Lighting	Standard LED	SF	All	NC	-0.04	0	2.0	15.0	$5.3	$4.1
6023	Lighting	Specialty CFL	*SF*	All	NC	-0.05	0	2.0	7.0	$2.3	$3.6
6024	Lighting	Specialty LED	*SF*	All	NC	-0.06	0	2.0	15.0	$9.4	$6.8
6025	Lighting	Reflector CFL	*SF*	All	NC	-0.05	0	2.0	7.0	$2.4	$7.8
6026	Lighting	Reflector LED	*SF*	All	NC	-0.06	0	2.0	15.0	$7.2	$13.3
6027	Lighting	Energy Star Torchiere	*SF*	All	NC	-0.17	0	2.0	8.0	$5.0	$0.0
6028	Lighting	LED Nightlight	*SF*	All	NC	0.00	0	2.0	12.0	$5.0	$0.0
6029	Lighting	Exterior CFL Fixture	*SF*	All	NC	0.00	0	2.0	20.0	$32.0	$0.0
6030	Lighting	Exterior LED Fixture	*SF*	All	NC	0.00	0	2.0	20.0	$59.6	$0.0
6031	Lighting	Standard CFL	*MH*	All	NC	-0.03	0	2.0	7.0	$0.8	$1.3
6032	Lighting	Standard LED	*MH*	All	NC	-0.04	0	2.0	15.0	$5.3	$4.1
6033	Lighting	Specialty CFL	*MH*	All	NC	-0.05	0	2.0	7.0	$2.3	$3.6
6034	Lighting	Specialty LED	*MH*	All	NC	-0.06	0	2.0	15.0	$9.4	$6.8
6035	Lighting	Reflector CFL	*MH*	All	NC	-0.05	0	2.0	7.0	$2.4	$7.8
6036	Lighting	Reflector LED	*MH*	All	NC	-0.06	0	2.0	15.0	$7.2	$13.3
6037	Lighting	Energy Star Torchiere	*MH*	All	NC	-0.17	0	2.0	8.0	$5.0	$0.0
6038	Lighting	LED Nightlight	*MH*	All	NC	0.00	0	2.0	12.0	$5.0	$0.0
6039	Lighting	Exterior CFL Fixture	*MH*	All	NC	0.00	0	2.0	20.0	$32.0	$0.0
6040	Lighting	Exterior LED Fixture	*MH*	All	NC	0.00	0	2.0	20.0	$59.6	$0.0
7001	Water Heating	Low Flow Faucet Aerators	*SF*	All	Retrofit	0.00	747	9.0	9.0	$8.0	$0.0
7002	Water Heating	Low Flow Showerhead	*SF*	All	Retrofit	0.00	2,803	10.0	10.0	$12.0	$0.0
7003	Water Heating	Thermostatic Restriction Valve	*SF*	All	Retrofit	0.00	730	10.0	10.0	$50.0	$0.0
7004	Water Heating	Water Heater Blanket	*SF*	All	Retrofit	0.00	0	5.0	5.0	$35.0	$0.0
7005	Water Heating	Water Heater Pipe Wrap	*SF*	All	Retrofit	0.00	0	15.0	15.0	$9.0	$0.0
7006	Water Heating	Heat Pump Water Heater (Resistance Heat)	*SF*	All	MO	0.00	0	13.0	13.0	$1,134.0	$0.0
7007	Water Heating	Heat Pump Water Heater (ASHP heat)	*SF*	All	MO	0.00	0	13.0	13.0	$1,134.0	$0.0
7008	Water Heating	Solar Water Heating	*SF*	All	MO	0.00	0	13.0	20.0	$4,500.0	$0.0

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Measure #	End-Use	Measure Name	Home Type	Income Type	Replacement Type	Base Annual Electric	% Electric Savings	Per Unit Elec Savings	Per Unit Summer NCP kW	Per Unit Winter NCP kW
7009	Water Heating	Low Flow Faucet Aerators	MH	All	Retrofit	3,018.6	2%	68.6	1.320	1.320
7010	Water Heating	Low Flow Showerhead	MH	All	Retrofit	3,018.6	11%	328.0	1.086	1.086
7011	Water Heating	Thermostatic Restriction Valve	MH	All	Retrofit	3,018.6	3%	85.4	0.196	0.027
7012	Water Heating	Water Heater Blanket	MH	All	Retrofit	3,018.6	6%	186.6	0.018	0.018
7013	Water Heating	Water Heater Pipe Wrap	MH	All	Retrofit	3,018.6	3%	77.1	0.009	0.009
7014	Water Heating	Heat Pump Water Heater (Resistance Heat)	MH	All	MO	3,018.6	49%	1,477.3	0.583	0.583
7015	Water Heating	Heat Pump Water Heater (ASHP heat)	MH	All	MO	3,018.6	54%	1,640.0	0.647	0.647
7016	Water Heating	Low Flow Faucet Aerators	SF	All	NC	3,018.6	2%	68.6	1.320	1.320
7017	Water Heating	Low Flow Showerhead	SF	All	NC	3,018.6	8%	238.3	0.896	0.896
7018	Water Heating	Thermostatic Restriction Valve	SF	All	NC	3,018.6	3%	85.4	0.196	0.027
7019	Water Heating	Water Heater Blanket	SF	All	NC	3,018.6	5%	156.6	0.018	0.018
7020	Water Heating	Water Heater Pipe Wrap	SF	All	NC	3,018.6	3%	77.1	0.009	0.009
7021	Water Heating	Heat Pump Water Heater (ASHP heat)	SF	All	NC	3,018.6	54%	1,640.0	0.647	0.647
7022	Water Heating	Solar Water Heating	SF	All	NC	3,018.6	68%	2,059.0	1.047	1.047
7023	Water Heating	Low Flow Faucet Aerators	MH	All	NC	3,018.6	2%	68.6	1.320	1.320
7024	Water Heating	Low Flow Showerhead	MH	All	NC	3,018.6	8%	238.3	0.896	0.896
7025	Water Heating	Thermostatic Restriction Valve	MH	All	NC	3,018.6	3%	85.4	0.196	0.027
7026	Water Heating	Water Heater Blanket	MH	All	NC	3,018.6	5%	156.6	0.018	0.018
7027	Water Heating	Water Heater Pipe Wrap	MH	All	NC	3,018.6	3%	77.1	0.009	0.009
7028	Water Heating	Heat Pump Water Heater (ASHP heat)	MH	All	NC	3,018.6	54%	1,640.0	0.647	0.647
8001	HVAC Shell	Insulation - Ceiling (R-0 to R-38) - (Elec AC & Gas Heat)	SF	All	Retrofit	5,726.9	42%	2,424.3	3.149	0.465
8002	HVAC Shell	Insulation - Ceiling (R-11 to R-49) - (Elec AC & Gas Heat)	SF	All	Retrofit	3,626.7	10%	361.7	0.630	0.102
8003	HVAC Shell	Insulation - Ceiling (R-19 to R-49) - (Elec AC & Gas Heat)	SF	All	Retrofit	3,455.8	6%	190.9	0.334	0.051
8004	HVAC Shell	Insulation - Floor (R-0 to R-19) - (Elec AC & Gas Heat)	SF	All	Retrofit	3,329.4	-5%	-165.0	-0.092	0.117
8005	HVAC Shell	Insulation - Floor (R-11 to R-30) - (Elec AC & Gas Heat)	SF	All	Retrofit	3,455.8	-2%	-68.1	-0.047	0.033

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Measure #	End-Use	Measure Name	Home Type	Income Type	Replacement Type	Per unit NG Saving	Per Unit Water Savings	RC EUL	EE EUL	Initial Measure Cost	O&M Benefits
7009	Water Heating	Low Flow Faucet Aerators	*MH*	All	Retrofit	0.00	747	9.0	9.0	$8.0	$0.0
7010	Water Heating	Low Flow Showerhead	*MH*	All	Retrofit	0.00	2,803	10.0	10.0	$12.0	$0.0
7011	Water Heating	Thermostatic Restriction Valve	*MH*	All	Retrofit	0.00	730	10.0	10.0	$50.0	$0.0
7012	Water Heating	Water Heater Blanket	*MH*	All	Retrofit	0.00	0	5.0	5.0	$35.0	$0.0
7013	Water Heating	Water Heater Pipe Wrap	*MH*	All	Retrofit	0.00	0	15.0	15.0	$9.0	$0.0
7014	Water Heating	Heat Pump Water Heater (Resistance Heat)	*MH*	All	MO	0.00	0	13.0	13.0	$1,134.0	$0.0
7015	Water Heating	Heat Pump Water Heater (ASHP heat)	MH	All	MO	0.00	0	13.0	13.0	$1,134.0	$0.0
7016	Water Heating	Low Flow Faucet Aerators	SF	All	NC	0.00	747	9.0	9.0	$3.0	$0.0
7017	Water Heating	Low Flow Showerhead	SF	All	NC	0.00	2,036	10.0	10.0	$7.0	$0.0
7018	Water Heating	Thermostatic Restriction Valve	SF	All	NC	0.00	730	10.0	10.0	$50.0	$0.0
7019	Water Heating	Water Heater Blanket	SF	All	NC	0.00	0	5.0	5.0	$35.0	$0.0
7020	Water Heating	Water Heater Pipe Wrap	SF	All	NC	0.00	0	15.0	15.0	$9.0	$0.0
7021	Water Heating	Heat Pump Water Heater (ASHP heat)	SF	All	NC	0.00	0	13.0	13.0	$1,134.0	$0.0
7022	Water Heating	Solar Water Heating	SF	All	NC	0.00	0	13.0	20.0	$4,500.0	$0.0
7023	Water Heating	Low Flow Faucet Aerators	MH	All	NC	0.00	747	9.0	9.0	$3.0	$0.0
7024	Water Heating	Low Flow Showerhead	MH	All	NC	0.00	2,036	10.0	10.0	$7.0	$0.0
7025	Water Heating	Thermostatic Restriction Valve	MH	All	NC	0.00	730	10.0	10.0	$50.0	$0.0
7026	Water Heating	Water Heater Blanket	MH	All	NC	0.00	0	5.0	5.0	$35.0	$0.0
7027	Water Heating	Water Heater Pipe Wrap	MH	All	NC	0.00	0	15.0	15.0	$9.0	$0.0
7028	Water Heating	Heat Pump Water Heater (ASHP heat)	MH	All	NC	0.00	0	13.0	13.0	$1,134.0	$0.0
8001	HVAC Shell	Insulation - Ceiling (R-0 to R-38) - (Elec AC & Gas Heat)	SF	All	Retrofit	44.05	0	25.0	25.0	$3,447.1	$0.0
8002	HVAC Shell	Insulation - Ceiling (R-11 to R-49) - (Elec AC & Gas Heat)	SF	All	Retrofit	11.78	0	25.0	25.0	$3,447.1	$0.0
8003	HVAC Shell	Insulation - Ceiling (R-19 to R-49) - (Elec AC & Gas Heat)	SF	All	Retrofit	6.51	0	25.0	25.0	$3,352.4	$0.0
8004	HVAC Shell	Insulation - Floor (R-0 to R-19) - (Elec AC & Gas Heat)	SF	All	Retrofit	9.73	0	25.0	25.0	$776.5	$0.0
8005	HVAC Shell	Insulation - Floor (R-11 to R-30) - (Elec AC & Gas Heat)	SF	All	Retrofit	3.00	0	25.0	25.0	$776.5	$0.0

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Measure #	End-Use	Measure Name	Home Type	Income Type	Replacement Type	Base Annual Electric	% Electric Savings	Per Unit Elec Savings	Per Unit Summer NCP kW	Per Unit Winter NCP kW
8006	HVAC Shell	Energy Star Windows - (Elec AC & Gas Heat)	SF	All	Retrofit	3,455.8	10%	345.9	0.456	0.018
8007	HVAC Shell	Air Sealing - (Elec AC & Gas Heat)	SF	All	Retrofit	3,455.8	8%	291.0	0.353	0.146
8008	HVAC Shell	Duct Sealing - (Elec AC & Gas Heat)	SF	All	Retrofit	3,455.8	3%	112.1	0.073	0.015
8009	HVAC Shell	Radiant Barriers - (Elec AC & Gas Heat)	SF	All	Retrofit	3,455.8	3%	97.7	0.184	-0.023
8010	HVAC Shell	Insulation - Ceiling (R-0 to R-38) - (Elec HP)	SF	All	Retrofit	13,354.4	49%	6,494.7	2.815	5.722
8011	HVAC Shell	Insulation - Ceiling (R-11 to R-49) - (Elec HP)	SF	All	Retrofit	8,276.0	19%	1,561.9	0.671	1.365
8012	HVAC Shell	Insulation - Ceiling (R-19 to R-49) - (Elec HP)	SF	All	Retrofit	7,471.1	10%	757.0	0.335	0.611
8013	HVAC Shell	Insulation - Floor (R-0 to R-19) - (Elec HP)	SF	All	Retrofit	8,072.6	9%	725.0	-0.084	1.485
8014	HVAC Shell	Insulation - Floor (R-11 to R-30) - (Elec HP)	SF	All	Retrofit	7,471.1	3%	206.6	-0.040	0.425
8015	HVAC Shell	Energy Star Windows - (Elec HP)	SF	All	Retrofit	7,471.1	7%	510.4	0.455	0.264
8016	HVAC Shell	Air Sealing - (Elec HP)	SF	All	Retrofit	7,471.1	10%	751.0	0.188	0.943
8017	HVAC Shell	Duct Sealing - (Elec HP)	SF	All	Retrofit	7,471.1	1%	112.0	0.052	0.074
8018	HVAC Shell	Radiant Barriers - (Elec HP)	SF	All	Retrofit	7,471.1	2%	167.4	0.184	-0.056
8019	HVAC Shell	Insulation - Ceiling (R-0 to R-38) - (Elec Furnace / AC)	SF	All	Retrofit	25,806.4	50%	12,945.4	3.284	10.158
8020	HVAC Shell	Insulation - Ceiling (R-11 to R-49) - (Elec Furnace / AC)	SF	All	Retrofit	15,687.7	57%	8,973.5	0.775	10.562
8021	HVAC Shell	Insulation - Ceiling (R-19 to R-49) - (Elec Furnace / AC)	SF	All	Retrofit	14,235.0	53%	7,520.9	0.474	9.027
8022	HVAC Shell	Insulation - Floor (R-0 to R-19) - (Elec Furnace / AC)	SF	All	Retrofit	16,055.0	14%	2,212.7	-0.092	2.634
8023	HVAC Shell	Insulation - Floor (R-11 to R-30) - (Elec Furnace / AC)	SF	All	Retrofit	14,235.0	5%	664.4	-0.045	0.776
8024	HVAC Shell	Energy Star Windows - (Elec Furnace / AC)	SF	All	Retrofit	14,235.0	5%	756.2	0.457	0.486

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Measure #	End-Use	Measure Name	Home Type	Income Type	Replacement Type	Per unit NG Saving	Per Unit Water Savings	RC EUL	EE EUL	Initial Measure Cost	O&M Benefits
8006	HVAC Shell	Energy Star Windows - (Elec AC & Gas Heat)	SF	All	Retrofit	1.66	0	25.0	25.0	$5,464.8	$0.0
8007	HVAC Shell	Air Sealing - (Elec AC & Gas Heat)	SF	All	Retrofit	12.65	0	15.0	15.0	$776.5	$0.0
8008	HVAC Shell	Duct Sealing - (Elec AC & Gas Heat)	SF	All	Retrofit	2.15	0	20.0	20.0	$408.2	$0.0
8009	HVAC Shell	Radiant Barriers - (Elec AC & Gas Heat)	SF	All	Retrofit	0.73	0	25.0	25.0	$1,269.0	$0.0
8010	HVAC Shell	Insulation - Ceiling (R-0 to R-38) - (Elec HP)	SF	All	Retrofit	0.00	0	25.0	25.0	$3,447.1	$0.0
8011	HVAC Shell	Insulation - Ceiling (R-11 to R-49) - (Elec HP)	SF	All	Retrofit	0.00	0	25.0	25.0	$3,447.1	$0.0
8012	HVAC Shell	Insulation - Ceiling (R-19 to R-49) - (Elec HP)	SF	All	Retrofit	0.00	0	25.0	25.0	$3,352.4	$0.0
8013	HVAC Shell	Insulation - Floor (R-0 to R-19) - (Elec HP)	SF	All	Retrofit	0.00	0	25.0	25.0	$776.5	$0.0
8014	HVAC Shell	Insulation - Floor (R-11 to R-30) - (Elec HP)	SF	All	Retrofit	0.00	0	25.0	25.0	$776.5	$0.0
8015	HVAC Shell	Energy Star Windows - (Elec HP)	SF	All	Retrofit	0.00	0	25.0	25.0	$5,464.8	$0.0
8016	HVAC Shell	Air Sealing - (Elec HP)	SF	All	Retrofit	0.00	0	15.0	15.0	$776.5	$0.0
8017	HVAC Shell	Duct Sealing - (Elec HP)	SF	All	Retrofit	0.00	0	20.0	20.0	$408.2	$0.0
8018	HVAC Shell	Radiant Barriers - (Elec HP)	SF	All	Retrofit	0.00	0	25.0	25.0	$1,269.0	$0.0
8019	HVAC Shell	Insulation - Ceiling (R-0 to R-38) - (Elec Furnace / AC)	SF	All	Retrofit	0.00	0	25.0	25.0	$3,447.1	$0.0
8020	HVAC Shell	Insulation - Ceiling (R-11 to R-49) - (Elec Furnace / AC)	SF	All	Retrofit	0.00	0	25.0	25.0	$3,447.1	$0.0
8021	HVAC Shell	Insulation - Ceiling (R-19 to R-49) - (Elec Furnace / AC)	SF	All	Retrofit	0.00	0	25.0	25.0	$3,352.4	$0.0
8022	HVAC Shell	Insulation - Floor (R-0 to R-19) - (Elec Furnace / AC)	SF	All	Retrofit	0.00	0	25.0	25.0	$776.5	$0.0
8023	HVAC Shell	Insulation - Floor (R-11 to R-30) - (Elec Furnace / AC)	SF	All	Retrofit	0.00	0	25.0	25.0	$776.5	$0.0
8024	HVAC Shell	Energy Star Windows - (Elec Furnace / AC)	SF	All	Retrofit	0.00	0	25.0	25.0	$5,464.8	$0.0

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Measure #	End-Use	Measure Name	Home Type	Income Type	Replacement Type	Base Annual Electric	% Electric Savings	Per Unit Elec Savings	Per Unit Summer NCP kW	Per Unit Winter NCP kW
8025	HVAC Shell	Air Sealing - (Elec Furnace / AC)	SF	All	Retrofit	14,235.0	15%	2,112.9	0.236	2.000
8026	HVAC Shell	Duct Sealing - (Elec Furnace / AC)	SF	All	Retrofit	14,235.0	4%	540.0	0.072	0.396
8027	HVAC Shell	Radiant Barriers - (Elec Furnace / AC)	SF	All	Retrofit	14,235.0	2%	271.8	0.183	-0.045
8028	HVAC Shell	Insulation - Ceiling (R-0 to R-38) - (Elec AC & Gas Heat)	MH	All	Retrofit	3,648.8	31%	1,119.4	1.763	0.211
8029	HVAC Shell	Energy Star Windows - (Elec AC & Gas Heat)	MH	All	Retrofit	2,615.2	6%	154.2	0.137	0.008
8030	HVAC Shell	Air Sealing - (Elec AC & Gas Heat)	MH	All	Retrofit	2,615.2	5%	139.2	0.107	0.056
8031	HVAC Shell	Duct Sealing - (Elec AC & Gas Heat)	MH	All	Retrofit	2,615.2	3%	63.3	-0.016	0.018
8032	HVAC Shell	Insulation - Ceiling (R-0 to R-38) - (Elec HP)	MH	All	Retrofit	9,392.2	43%	4,037.2	1.521	4.544
8033	HVAC Shell	Energy Star Windows - (Elec HP)	MH	All	Retrofit	6,090.4	5%	278.7	0.204	0.269
8034	HVAC Shell	Air Sealing - (Elec HP)	MH	All	Retrofit	6,090.4	8%	494.2	0.060	0.702
8035	HVAC Shell	Duct Sealing - (Elec HP)	MH	All	Retrofit	6,090.4	3%	168.6	-0.011	0.296
8036	HVAC Shell	Insulation - Ceiling (R-0 to R-38) - (Elec Furnace / AC)	MH	All	Retrofit	18,572.6	46%	5,552.1	1.780	7.960
8037	HVAC Shell	Energy Star Windows - (Elec Furnace / AC)	MH	All	Retrofit	11,384.2	0%	47.6	0.148	0.123
8038	HVAC Shell	Air Sealing - (Elec Furnace / AC)	MH	All	Retrofit	11,384.2	9%	1,007.8	0.033	1.061
8039	HVAC Shell	Duct Sealing - (Elec Furnace / AC)	MH	All	Retrofit	11,384.2	4%	404.8	-0.014	0.497
9001	HVAC Equipment	HVAC Tune-Up (Central AC)	SF	All	Retrofit	3,455.8	4%	150.8	0.177	0.000
9002	HVAC Equipment	High Efficiency Central AC - 16 SEER	SF	All	MO	3,245.1	16%	519.8	0.372	0.256
9003	HVAC Equipment	High Efficiency Central AC - 16 SEER	SF	All	ER1	3,455.8	21%	730.5	0.618	0.256
9004	HVAC Equipment	High Efficiency Central AC - 16 SEER	SF	All	ER2	3,245.1	16%	519.8	0.372	0.256
9005	HVAC Equipment	High Efficiency Central AC - 17 SEER	SF	All	MO	3,245.1	22%	728.5	0.653	0.259
9006	HVAC Equipment	High Efficiency Central AC - 17 SEER	SF	All	ER1	3,455.8	27%	939.2	0.908	0.259
9007	HVAC Equipment	High Efficiency Central AC - 17 SEER	SF	All	ER2	3,245.1	22%	728.5	0.653	0.259
9008	HVAC Equipment	High Efficiency Central AC - 18 SEER	SF	All	MO	3,245.1	26%	841.3	0.789	0.259
9009	HVAC Equipment	High Efficiency Central AC - 18 SEER	SF	All	ER1	3,455.8	30%	1,052.1	1.043	0.259
9010	HVAC Equipment	High Efficiency Central AC - 18 SEER	SF	All	ER2	3,245.1	26%	841.3	0.789	0.259
9011	HVAC Equipment	High Efficiency Central AC - 19 SEER	SF	All	MO	3,245.1	29%	942.7	0.912	0.259
9012	HVAC Equipment	High Efficiency Central AC - 19 SEER	SF	All	ER1	3,455.8	33%	1,153.5	1.167	0.259
9013	HVAC Equipment	High Efficiency Central AC - 19 SEER	SF	All	ER2	3,245.1	29%	942.7	0.912	0.259
9014	HVAC Equipment	High Efficiency Central AC - 20 SEER	SF	All	MO	3,245.1	32%	1,043.6	1.038	0.259

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Measure #	End-Use	Measure Name	Home Type	Income Type	Replacement Type	Per unit NG Saving	Per Unit Water Savings	RC EUL	EE EUL	Initial Measure Cost	O&M Benefits
8025	HVAC Shell	Air Sealing - (Elec Furnace / AC)	SF	All	Retrofit	0.00	0	15.0	15.0	$776.5	$0.0
8026	HVAC Shell	Duct Sealing - (Elec Furnace / AC)	SF	All	Retrofit	0.00	0	20.0	20.0	$408.2	$0.0
8027	HVAC Shell	Radiant Barriers - (Elec Furnace / AC)	SF	All	Retrofit	0.00	0	25.0	25.0	$1,269.0	$0.0
8028	HVAC Shell	Insulation - Ceiling (R-0 to R-38) - (Elec AC & Gas Heat)	MH	All	Retrofit	31.42	0	25.0	25.0	$2,446.1	$0.0
8029	HVAC Shell	Energy Star Windows - (Elec AC & Gas Heat)	MH	All	Retrofit	-0.58	0	25.0	25.0	$3,506.6	$0.0
8030	HVAC Shell	Air Sealing - (Elec AC & Gas Heat)	MH	All	Retrofit	6.61	0	15.0	15.0	$551.0	$0.0
8031	HVAC Shell	Duct Sealing - (Elec AC & Gas Heat)	MH	All	Retrofit	1.67	0	20.0	20.0	$289.7	$0.0
8032	HVAC Shell	Insulation - Ceiling (R-0 to R-38) - (Elec HP)	MH	All	Retrofit	0.00	0	25.0	25.0	$2,446.1	$0.0
8033	HVAC Shell	Energy Star Windows - (Elec HP)	MH	All	Retrofit	0.00	0	25.0	25.0	$3,506.6	$0.0
8034	HVAC Shell	Air Sealing - (Elec HP)	MH	All	Retrofit	0.00	0	15.0	15.0	$551.0	$0.0
8035	HVAC Shell	Duct Sealing - (Elec HP)	MH	All	Retrofit	0.00	0	20.0	20.0	$289.7	$0.0
8036	HVAC Shell	Insulation - Ceiling (R-0 to R-38) - (Elec Furnace / AC)	MH	All	Retrofit	0.00	0	25.0	25.0	$2,446.1	$0.0
8037	HVAC Shell	Energy Star Windows - (Elec Furnace / AC)	MH	All	Retrofit	0.00	0	25.0	25.0	$3,506.6	$0.0
8038	HVAC Shell	Air Sealing - (Elec Furnace / AC)	MH	All	Retrofit	0.00	0	15.0	15.0	$551.0	$0.0
8039	HVAC Shell	Duct Sealing - (Elec Furnace / AC)	MH	All	Retrofit	0.00	0	20.0	20.0	$289.7	$0.0
9001	HVAC Equipment	HVAC Tune-Up (Central AC)	SF	All	Retrofit	0.00	0	2.0	2.0	$175.0	$0.0
9002	HVAC Equipment	High Efficiency Central AC - 16 SEER	SF	All	MO	-0.75	0	18.0	18.0	$553.0	$0.0
9003	HVAC Equipment	High Efficiency Central AC - 16 SEER	SF	All	ER1	-0.75	0	18.0	6.0	$2,828.0	$0.0
9004	HVAC Equipment	High Efficiency Central AC - 16 SEER	SF	All	ER2	-0.75	0	18.0	12.0	$0.0	$0.0
9005	HVAC Equipment	High Efficiency Central AC - 17 SEER	SF	All	MO	-0.76	0	18.0	18.0	$829.0	$0.0
9006	HVAC Equipment	High Efficiency Central AC - 17 SEER	SF	All	ER1	-0.76	0	18.0	6.0	$3,104.0	$0.0
9007	HVAC Equipment	High Efficiency Central AC - 17 SEER	SF	All	ER2	-0.76	0	18.0	12.0	$0.0	$0.0
9008	HVAC Equipment	High Efficiency Central AC - 18 SEER	SF	All	MO	-0.76	0	18.0	18.0	$1,106.0	$0.0
9009	HVAC Equipment	High Efficiency Central AC - 18 SEER	SF	All	ER1	-0.76	0	18.0	6.0	$3,381.0	$0.0
9010	HVAC Equipment	High Efficiency Central AC - 18 SEER	SF	All	ER2	-0.76	0	18.0	12.0	$0.0	$0.0
9011	HVAC Equipment	High Efficiency Central AC - 19 SEER	SF	All	MO	-0.76	0	18.0	18.0	$1,382.0	$0.0
9012	HVAC Equipment	High Efficiency Central AC - 19 SEER	SF	All	ER1	-0.76	0	18.0	6.0	$3,657.0	$0.0
9013	HVAC Equipment	High Efficiency Central AC - 19 SEER	SF	All	ER2	-0.76	0	18.0	12.0	$0.0	$0.0
9014	HVAC Equipment	High Efficiency Central AC - 20 SEER	SF	All	MO	-0.76	0	18.0	18.0	$1,658.0	$0.0

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Measure #	End-Use	Measure Name	Home Type	Income Type	Replacement Type	Base Annual Electric	% Electric Savings	Per Unit Elec Savings	Per Unit Summer NCP kW	Per Unit Winter NCP kW
9015	HVAC Equipment	High Efficiency Central AC - 20 SEER	SF	All	ER1	3,455.8	36%	1,254.4	1.294	0.259
9016	HVAC Equipment	High Efficiency Central AC - 20 SEER	SF	All	ER2	3,245.1	32%	1,043.6	1.038	0.259
9017	HVAC Equipment	Ductless mini-split AC	SF	All	MO	3,245.1	43%	1,392.6	0.939	0.000
9018	HVAC Equipment	HVAC Tune-Up (Heat Pump)	SF	All	Retrofit	7,471.1	5%	373.6	0.156	0.330
9019	HVAC Equipment	High Efficiency Heat Pump (HP Upgrade) - 16 SEER/9.0 HSPF	SF	All	MO	6,917.2	9%	613.8	0.584	0.056
9020	HVAC Equipment	High Efficiency Heat Pump (HP Upgrade) - 16 SEER/9.0 HSPF	SF	All	ER1	7,471.1	16%	1,167.8	0.798	0.664
9021	HVAC Equipment	High Efficiency Heat Pump (HP Upgrade) - 16 SEER/9.0 HSPF	SF	All	ER2	6,917.2	9%	613.8	0.584	0.056
9022	HVAC Equipment	High Efficiency Heat Pump (HP Upgrade) - 17 SEER/9.5 HSPF	SF	All	MO	6,917.2	11%	787.6	0.715	0.147
9023	HVAC Equipment	High Efficiency Heat Pump (HP Upgrade) - 17 SEER/9.5 HSPF	SF	All	ER1	7,471.1	18%	1,341.5	0.925	0.751
9024	HVAC Equipment	High Efficiency Heat Pump (HP Upgrade) - 17 SEER/9.5 HSPF	SF	All	ER2	6,917.2	11%	787.6	0.715	0.147
9025	HVAC Equipment	High Efficiency Heat Pump (HP Upgrade) - 18 SEER/10 HSPF	SF	All	MO	6,917.2	17%	1,199.4	0.813	0.746
9026	HVAC Equipment	High Efficiency Heat Pump (HP Upgrade) - 18 SEER/10 HSPF	SF	All	ER1	7,471.1	23%	1,753.3	1.024	1.371
9027	HVAC Equipment	High Efficiency Heat Pump (HP Upgrade) - 18 SEER/10 HSPF	SF	All	ER2	6,917.2	17%	1,199.4	0.813	0.746
9028	HVAC Equipment	Ground Source Heat Pump (HP Upgrade)	SF	All	MO	6,917.2	11%	776.4	0.127	0.956
9029	HVAC Equipment	Ground Source Heat Pump (HP Upgrade)	SF	All	ER1	7,471.1	18%	1,330.3	0.338	1.357
9030	HVAC Equipment	Ground Source Heat Pump (HP Upgrade)	SF	All	ER2	6,917.2	11%	776.4	0.127	0.956
9031	HVAC Equipment	Dual Fuel Heat Pump Upgrade (Replacing New ASHP)	SF	All	MO	7,471.1	41%	3,035.5	0.798	3.028
9032	HVAC Equipment	Ductless mini-split HP (replacing ASHP)	SF	All	MO	6,917.2	28%	1,956.5	0.580	1.194
9033	HVAC Equipment	Heat Pump (Replacing Electric Furnace) - 16 SEER/9.0 HSPF	SF	All	MO	14,235.0	56%	7,931.7	0.950	11.527
9034	HVAC Equipment	Heat Pump (Replacing Electric Furnace) - 16 SEER/9.0 HSPF	SF	All	ER1	14,235.0	56%	7,931.7	0.950	11.527
9035	HVAC Equipment	Heat Pump (Replacing Electric Furnace) - 16 SEER/9.0 HSPF	SF	All	ER2	7,471.1	16%	1,167.8	0.798	0.664

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Measure #	End-Use	Measure Name	Home Type	Income Type	Replacement Type	Per unit NG Saving	Per Unit Water Savings	RC EUL	EE EUL	Initial Measure Cost	O&M Benefits
9015	HVAC Equipment	High Efficiency Central AC - 20 SEER	SF	All	ER1	-0.76	0	18.0	6.0	$3,933.0	$0.0
9016	HVAC Equipment	High Efficiency Central AC - 20 SEER	SF	All	ER2	-0.76	0	18.0	12.0	$0.0	$0.0
9017	HVAC Equipment	Ductless mini-split AC	SF	All	MO	0.00	0	18.0	18.0	$3,913.0	$0.0
9018	HVAC Equipment	HVAC Tune-Up (Heat Pump)	SF	All	Retrofit	0.00	0	2.0	2.0	$175.0	$0.0
9019	HVAC Equipment	High Efficiency Heat Pump (HP Upgrade) - 16 SEER/9.0 HSPF	SF	All	MO	0.00	0	18.0	18.0	$1,097.0	$0.0
9020	HVAC Equipment	High Efficiency Heat Pump (HP Upgrade) - 16 SEER/9.0 HSPF	SF	All	ER1	0.00	0	18.0	6.0	$4,160.0	$0.0
9021	HVAC Equipment	High Efficiency Heat Pump (HP Upgrade) - 16 SEER/9.0 HSPF	SF	All	ER2	0.00	0	18.0	12.0	$0.0	$0.0
9022	HVAC Equipment	High Efficiency Heat Pump (HP Upgrade) - 17 SEER/9.5 HSPF	SF	All	MO	0.00	0	18.0	18.0	$1,645.0	$0.0
9023	HVAC Equipment	High Efficiency Heat Pump (HP Upgrade) - 17 SEER/9.5 HSPF	SF	All	ER1	0.00	0	18.0	6.0	$4,708.0	$0.0
9024	HVAC Equipment	High Efficiency Heat Pump (HP Upgrade) - 17 SEER/9.5 HSPF	SF	All	ER2	0.00	0	18.0	12.0	$0.0	$0.0
9025	HVAC Equipment	High Efficiency Heat Pump (HP Upgrade) - 18 SEER/10 HSPF	SF	All	MO	0.00	0	18.0	18.0	$2,193.0	$0.0
9026	HVAC Equipment	High Efficiency Heat Pump (HP Upgrade) - 18 SEER/10 HSPF	SF	All	ER1	0.00	0	18.0	6.0	$5,256.0	$0.0
9027	HVAC Equipment	High Efficiency Heat Pump (HP Upgrade) - 18 SEER/10 HSPF	SF	All	ER2	0.00	0	18.0	12.0	$0.0	$0.0
9028	HVAC Equipment	Ground Source Heat Pump (HP Upgrade)	SF	All	MO	0.00	0	25.0	25.0	$18,931.0	$0.0
9029	HVAC Equipment	Ground Source Heat Pump (HP Upgrade)	SF	All	ER1	0.00	0	25.0	5.0	$19,661.0	$0.0
9030	HVAC Equipment	Ground Source Heat Pump (HP Upgrade)	SF	All	ER2	0.00	0	25.0	17.0	$0.0	$0.0
9031	HVAC Equipment	Dual Fuel Heat Pump Upgrade (Replacing New ASHP)	SF	All	MO	-22.55	0	18.0	18.0	$1,097.0	$0.0
9032	HVAC Equipment	Ductless mini-split HP (replacing ASHP)	SF	All	MO	0.00	0	18.0	18.0	$3,125.0	$0.0
9033	HVAC Equipment	Heat Pump (Replacing Electric Furnace) - 16 SEER/9.0 HSPF	SF	All	MO	0.00	0	18.0	18.0	$3,470.0	$0.0
9034	HVAC Equipment	Heat Pump (Replacing Electric Furnace) - 16 SEER/9.0 HSPF	SF	All	ER1	0.00	0	18.0	6.0	$4,160.0	$0.0
9035	HVAC Equipment	Heat Pump (Replacing Electric Furnace) - 16 SEER/9.0 HSPF	SF	All	ER2	0.00	0	18.0	12.0	$0.0	$0.0

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Measure #	End-Use	Measure Name	Home Type	Income Type	Replacement Type	Base Annual Electric	% Electric Savings	Per Unit Elec Savings	Per Unit Summer NCP kW	Per Unit Winter NCP kW
9036	HVAC Equipment	Heat Pump (Replacing Electric Furnace) - 17 SEER/9.5 HSPF	SF	All	MO	14,235.0	57%	8,105.5	1.073	11.560
9037	HVAC Equipment	Heat Pump (Replacing Electric Furnace) - 17 SEER/9.5 HSPF	SF	All	ER1	14,235.0	57%	8,105.5	1.073	11.560
9038	HVAC Equipment	Heat Pump (Replacing Electric Furnace) - 17 SEER/9.5 HSPF	SF	All	ER2	7,471.1	18%	1,341.5	0.925	0.751
9039	HVAC Equipment	Heat Pump (Replacing Electric Furnace) - 18 SEER/10 HSPF	SF	All	MO	14,235.0	60%	8,517.3	1.171	12.561
9040	HVAC Equipment	Heat Pump (Replacing Electric Furnace) - 18 SEER/10 HSPF	SF	All	ER1	14,235.0	60%	8,517.3	1.171	12.561
9041	HVAC Equipment	Heat Pump (Replacing Electric Furnace) - 18 SEER/10 HSPF	SF	All	ER2	7,471.1	23%	1,753.3	1.024	1.371
9042	HVAC Equipment	Dual Fuel Heat Pump (Replacing Electric Furnace)	SF	All	MO	14,235.0	69%	9,799.4	0.950	10.862
9043	HVAC Equipment	Ductless mini-split HP (Replacing furnace)	SF	All	MO	14,235.0	65%	9,274.4	0.881	8.758
9044	HVAC Equipment	Energy Star Room A/C	SF	All	MO	288.4	4%	12.6	0.035	0.000
9045	HVAC Equipment	Energy Star Room A/C	SF	All	ER1	408.3	32%	132.5	0.352	0.000
9046	HVAC Equipment	Energy Star Room A/C	SF	All	ER2	288.4	4%	12.6	0.035	0.000
9047	HVAC Equipment	Room Air Conditioner Recycling	SF	All	Recycle	408.3	100%	408.3	1.104	1.104
9048	HVAC Equipment	ECM Furnace Fan	SF	All	Retrofit	3,455.8	15%	514.6	0.000	0.000
9049	HVAC Equipment	Programmable Thermostat - Gas/AC - Tier 1	SF	All	Retrofit	3,455.8	0%	15.8	0.000	0.000
9050	HVAC Equipment	Smart Thermostat - Gas Heat / AC - Tier 2	SF	All	Retrofit	3,455.8	5%	186.6	0.000	0.000
9051	HVAC Equipment	Peak Period Thermostat - Gas Heat / AC - Tier 3	SF	All	Retrofit	3,455.8	9%	307.6	0.000	0.000
9052	HVAC Equipment	Programmable Thermostat - ASHP - Tier 1	SF	All	Retrofit	7,471.1	4%	269.0	0.000	0.000
9053	HVAC Equipment	Smart Thermostat - ASHP - Tier 2	SF	All	Retrofit	7,471.1	5%	403.4	0.000	0.000
9054	HVAC Equipment	Peak Period Thermostat - ASHP - Tier 3	SF	All	Retrofit	7,471.1	9%	664.9	0.000	0.000
9055	HVAC Equipment	Programmable Thermostat - Elec Furnace/AC - Tier 1	SF	All	Retrofit	14,235.0	4%	512.5	0.000	0.000

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Measure #	End-Use	Measure Name	Home Type	Income Type	Replacement Type	Per unit NG Saving	Per Unit Water Savings	RC EUL	EE EUL	Initial Measure Cost	O&M Benefits
9036	HVAC Equipment	Heat Pump (Replacing Electric Furnace) - 17 SEER/9.5 HSPF	SF	All	MO	0.00	0	18.0	18.0	$4,018.0	$0.0
9037	HVAC Equipment	Heat Pump (Replacing Electric Furnace) - 17 SEER/9.5 HSPF	SF	All	ER1	0.00	0	18.0	6.0	$4,708.0	$0.0
9038	HVAC Equipment	Heat Pump (Replacing Electric Furnace) - 17 SEER/9.5 HSPF	SF	All	ER2	0.00	0	18.0	12.0	$0.0	$0.0
9039	HVAC Equipment	Heat Pump (Replacing Electric Furnace) - 18 SEER/10 HSPF	SF	All	MO	0.00	0	18.0	18.0	$4,566.0	$0.0
9040	HVAC Equipment	Heat Pump (Replacing Electric Furnace) - 18 SEER/10 HSPF	SF	All	ER1	0.00	0	18.0	6.0	$5,256.0	$0.0
9041	HVAC Equipment	Heat Pump (Replacing Electric Furnace) - 18 SEER/10 HSPF	SF	All	ER2	0.00	0	18.0	12.0	$0.0	$0.0
9042	HVAC Equipment	Dual Fuel Heat Pump (Replacing Electric Furnace)	SF	All	MO	-22.55	0	18.0	18.0	$4,197.0	$0.0
9043	HVAC Equipment	Ductless mini-split HP (Replacing furnace)	SF	All	MO	0.00	0	18.0	18.0	$4,768.0	$0.0
9044	HVAC Equipment	Energy Star Room A/C	SF	All	MO	0.00	0	12.0	12.0	$40.0	$0.0
9045	HVAC Equipment	Energy Star Room A/C	SF	All	ER1	0.00	0	12.0	4.0	$451.0	$0.0
9046	HVAC Equipment	Energy Star Room A/C	SF	All	ER2	0.00	0	12.0	8.0	$0.0	$0.0
9047	HVAC Equipment	Room Air Conditioner Recycling	SF	All	Recycle	0.00	0	4.0	4.0	$49.0	$0.0
9048	HVAC Equipment	ECM Furnace Fan	SF	All	Retrofit	0.00	0	20.0	20.0	$97.0	$0.0
9049	HVAC Equipment	Programmable Thermostat - Gas/AC - Tier 1	SF	All	Retrofit	2.11	0	10.0	10.0	$130.0	$0.0
9050	HVAC Equipment	Smart Thermostat - Gas Heat / AC - Tier 2	SF	All	Retrofit	3.16	0	10.0	10.0	$210.0	$0.0
9051	HVAC Equipment	Peak Period Thermostat - Gas Heat / AC - Tier 3	SF	All	Retrofit	8.20	0	10.0	10.0	$300.0	$0.0
9052	HVAC Equipment	Programmable Thermostat - ASHP - Tier 1	SF	All	Retrofit	0.00	0	10.0	10.0	$130.0	$0.0
9053	HVAC Equipment	Smart Thermostat - ASHP - Tier 2	SF	All	Retrofit	0.00	0	10.0	10.0	$210.0	$0.0
9054	HVAC Equipment	Peak Period Thermostat - ASHP - Tier 3	SF	All	Retrofit	0.00	0	10.0	10.0	$300.0	$0.0
9055	HVAC Equipment	Programmable Thermostat - Elec Furnace/AC - Tier 1	SF	All	Retrofit	0.00	0	10.0	10.0	$130.0	$0.0

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Measure #	End-Use	Measure Name	Home Type	Income Type	Replacement Type	Base Annual Electric	% Electric Savings	Per Unit Elec Savings	Per Unit Summer NCP kW	Per Unit Winter NCP kW
9056	HVAC Equipment	Smart Thermostat - Elec Furnace/AC - Tier 2	SF	All	Retrofit	14,235.0	5%	768.7	0.000	0.000
9057	HVAC Equipment	Peak Period Thermostat - Elec Furnace/AC - Tier 3	SF	All	Retrofit	14,235.0	9%	1,266.9	0.000	0.000
9058	HVAC Equipment	HVAC Tune-Up (Central AC)	MH	All	Retrofit	2,615.2	4%	114.1	0.139	0.000
9059	HVAC Equipment	High Efficiency Central AC - 16 SEER	MH	All	MO	2,457.2	17%	421.3	0.321	0.186
9060	HVAC Equipment	High Efficiency Central AC - 16 SEER	MH	All	ER1	2,615.2	22%	579.2	0.510	0.185
9061	HVAC Equipment	High Efficiency Central AC - 16 SEER	MH	All	ER2	2,457.2	17%	421.3	0.321	0.186
9062	HVAC Equipment	High Efficiency Central AC - 17 SEER	MH	All	MO	2,457.2	27%	655.3	0.531	0.282
9063	HVAC Equipment	High Efficiency Central AC - 17 SEER	MH	All	ER1	2,615.2	31%	813.3	0.718	0.281
9064	HVAC Equipment	High Efficiency Central AC - 17 SEER	MH	All	ER2	2,457.2	27%	655.3	0.531	0.282
9065	HVAC Equipment	High Efficiency Central AC - 18 SEER	MH	All	MO	2,457.2	30%	734.1	0.624	0.282
9066	HVAC Equipment	High Efficiency Central AC - 18 SEER	MH	All	ER1	2,615.2	34%	892.1	0.811	0.281
9067	HVAC Equipment	High Efficiency Central AC - 18 SEER	MH	All	ER2	2,457.2	30%	734.1	0.624	0.282
9068	HVAC Equipment	High Efficiency Central AC - 19 SEER	MH	All	MO	2,457.2	33%	805.0	0.709	0.282
9069	HVAC Equipment	High Efficiency Central AC - 19 SEER	MH	All	ER1	2,615.2	37%	963.0	0.896	0.281
9070	HVAC Equipment	High Efficiency Central AC - 19 SEER	MH	All	ER2	2,457.2	33%	805.0	0.709	0.282
9071	HVAC Equipment	High Efficiency Central AC - 20 SEER	MH	All	MO	2,457.2	36%	876.0	0.797	0.282
9072	HVAC Equipment	High Efficiency Central AC - 20 SEER	MH	All	ER1	2,615.2	40%	1,033.9	0.985	0.281
9073	HVAC Equipment	High Efficiency Central AC - 20 SEER	MH	All	ER2	2,457.2	36%	876.0	0.797	0.282
9074	HVAC Equipment	Ductless mini-split AC	MH	All	MO	2,457.2	41%	1,010.1	0.704	0.000
9075	HVAC Equipment	HVAC Tune-Up (Heat Pump)	MH	All	Retrofit	6,090.4	5%	304.5	0.129	0.241
9076	HVAC Equipment	High Efficiency Heat Pump (HP Upgrade) - 16 SEER/9.0 HSPF	MH	All	MO	5,625.6	8%	435.8	0.398	0.014
9077	HVAC Equipment	High Efficiency Heat Pump (HP Upgrade) - 16 SEER/9.0 HSPF	MH	All	ER1	11,384.2	54%	6,194.3	0.625	8.799
9078	HVAC Equipment	High Efficiency Heat Pump (HP Upgrade) - 16 SEER/9.0 HSPF	MH	All	ER2	5,625.6	8%	435.5	0.398	0.014
9079	HVAC Equipment	High Efficiency Heat Pump (HP Upgrade) - 17 SEER/9.5 HSPF	MH	All	MO	5,625.6	10%	566.3	0.502	0.086
9080	HVAC Equipment	High Efficiency Heat Pump (HP Upgrade) - 17 SEER/9.8 HSPF	MH	All	ER1	11,384.2	56%	6,324.9	0.730	8.802
9081	HVAC Equipment	High Efficiency Heat Pump (HP Upgrade) - 17 SEER/9.5 HSPF	MH	All	ER2	5,625.6	10%	566.3	0.502	0.086

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9056	HVAC Equipment	Smart Thermostat - Elec Furnace/AC - Tier 2	SF	All	Retrofit	0.00	0	10.0	10.0	$210.0	$0.0
9057	HVAC Equipment	Peak Period Thermostat - Elec Furnace/AC - Tier 3	SF	All	Retrofit	0.00	0	10.0	10.0	$300.0	$0.0
9058	HVAC Equipment	HVAC Tune-Up (Central AC)	MH	All	Retrofit	0.00	0	2.0	2.0	$178.0	$0.0
9059	HVAC Equipment	High Efficiency Central AC - 16 SEER	MH	All	MO	-0.57	0	18.0	18.0	$553.0	$0.0
9060	HVAC Equipment	High Efficiency Central AC - 16 SEER	MH	All	ER1	-0.62	0	18.0	6.0	$2,828.0	$0.0
9061	HVAC Equipment	High Efficiency Central AC - 16 SEER	MH	All	ER2	-0.57	0	18.0	12.0	$0.0	$0.0
9062	HVAC Equipment	High Efficiency Central AC - 17 SEER	MH	All	MO	-1.81	0	18.0	18.0	$829.0	$0.0
9063	HVAC Equipment	High Efficiency Central AC - 17 SEER	MH	All	ER1	-1.86	0	18.0	6.0	$3,104.0	$0.0
9064	HVAC Equipment	High Efficiency Central AC - 17 SEER	MH	All	ER2	-1.81	0	18.0	12.0	$0.0	$0.0
9065	HVAC Equipment	High Efficiency Central AC - 18 SEER	MH	All	MO	-1.81	0	18.0	18.0	$1,106.0	$0.0
9066	HVAC Equipment	High Efficiency Central AC - 18 SEER	MH	All	ER1	-1.86	0	18.0	6.0	$3,381.0	$0.0
9067	HVAC Equipment	High Efficiency Central AC - 18 SEER	MH	All	ER2	-1.81	0	18.0	12.0	$0.0	$0.0
9068	HVAC Equipment	High Efficiency Central AC - 19 SEER	MH	All	MO	-1.81	0	18.0	18.0	$1,382.0	$0.0
9069	HVAC Equipment	High Efficiency Central AC - 19 SEER	MH	All	ER1	-1.86	0	18.0	6.0	$3,657.0	$0.0
9070	HVAC Equipment	High Efficiency Central AC - 19 SEER	MH	All	ER2	-1.81	0	18.0	12.0	$0.0	$0.0
9071	HVAC Equipment	High Efficiency Central AC - 20 SEER	MH	All	MO	-1.81	0	18.0	18.0	$1,658.0	$0.0
9072	HVAC Equipment	High Efficiency Central AC - 20 SEER	MH	All	ER1	-1.86	0	18.0	6.0	$3,933.0	$0.0
9073	HVAC Equipment	High Efficiency Central AC - 20 SEER	MH	All	ER2	-1.81	0	18.0	12.0	$0.0	$0.0
9074	HVAC Equipment	Ductless mini-split AC	MH	All	MO	0.00	0	18.0	18.0	$3,913.0	$0.0
9075	HVAC Equipment	HVAC Tune-Up (Heat Pump)	MH	All	Retrofit	0.00	0	2.0	2.0	$175.0	$0.0
9076	HVAC Equipment	High Efficiency Heat Pump (HP Upgrade) - 16 SEER/9.0 HSPF	MH	All	MO	0.00	0	18.0	18.0	$1,097.0	$0.0
9077	HVAC Equipment	High Efficiency Heat Pump (HP Upgrade) - 16 SEER/9.0 HSPF	MH	All	ER1	0.00	0	18.0	6.0	$4,160.0	$0.0
9078	HVAC Equipment	High Efficiency Heat Pump (HP Upgrade) - 16 SEER/9.0 HSPF	MH	All	ER2	0.00	0	18.0	12.0	$0.0	$0.0
9079	HVAC Equipment	High Efficiency Heat Pump (HP Upgrade) - 17 SEER/9.5 HSPF	MH	All	MO	0.00	0	18.0	18.0	$1,645.0	$0.0
9080	HVAC Equipment	High Efficiency Heat Pump (HP Upgrade) - 17 SEER/9.5 HSPF	MH	All	ER1	0.00	0	18.0	6.0	$4,708.0	$0.0
9081	HVAC Equipment	High Efficiency Heat Pump (HP Upgrade) - 17 SEER/9.5 HSPF	MH	All	ER2	0.00	0	18.0	12.0	$0.0	$0.0

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9082	HVAC Equipment	High Efficiency Heat Pump (HP Upgrade) - 18 SEER/10 HSPF	MH	All	MO	5,625.6	16%	902.8	0.575	0.557
9083	HVAC Equipment	High Efficiency Heat Pump (HP Upgrade) - 18 SEER/10 HSPF	MH	All	ER1	11,384.2	59%	6,661.3	0.802	9.506
9084	HVAC Equipment	High Efficiency Heat Pump (HP Upgrade) - 18 SEER/10 HSPF	MH	All	ER2	5,625.6	16%	902.8	0.575	0.557
9085	HVAC Equipment	Dual Fuel Heat Pump Upgrade (Replacing New ASHP)	MH	All	MO	6,090.4	40%	2,459.4	0.552	2.512

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9082	HVAC Equipment	High Efficiency Heat Pump (HP Upgrade) - 18 SEER/10 HSPF	MH	All	MO	0.00	0	18.0	18.0	$2,193.0	$0.0
9083	HVAC Equipment	High Efficiency Heat Pump (HP Upgrade) - 18 SEER/10 HSPF	MH	All	ER1	0.00	0	18.0	6.0	$5,256.0	$0.0
9084	HVAC Equipment	High Efficiency Heat Pump (HP Upgrade) - 18 SEER/10 HSPF	MH	All	ER2	0.00	0	18.0	12.0	$0.0	$0.0
9085	HVAC Equipment	Dual Fuel Heat Pump Upgrade (Replacing New ASHP)	MH	All	MO	-17.01	0	18.0	18.0	$1,097.0	$0.0

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9086	HVAC Equipment	Ductless mini-split HP (Replacing ASHP)	MH	All	MO	6,090.4	33%	2,009.2	0.635	1.175
9087	HVAC Equipment	Heat Pump (Replacing Electric Furnace) - 16 SEER/9.0 HSPF	MH	All	MO	11,384.2	54%	6,194.3	0.625	8.799
9088	HVAC Equipment	Heat Pump (Replacing Electric Furnace) - 16 SEER/9.0 HSPF	MH	All	ER1	11,384.2	54%	6,194.3	0.625	8.799
9089	HVAC Equipment	Heat Pump (Replacing Electric Furnace) - 16 SEER/9.0 HSPF	MH	All	ER2	6,090.4	15%	900.5	0.552	0.589
9090	HVAC Equipment	Heat Pump (Replacing Electric Furnace) - 17 SEER/9.5 HSPF	MH	All	MO	11,384.2	56%	6,324.9	0.730	8.802
9091	HVAC Equipment	Heat Pump (Replacing Electric Furnace) - 17 SEER/9.5 HSPF	MH	All	ER1	11,384.2	56%	6,324.9	0.730	8.802
9092	HVAC Equipment	Heat Pump (Replacing Electric Furnace) - 17 SEER/9.5 HSPF	MH	All	ER2	6,090.4	17%	1,031.1	0.657	0.627
9093	HVAC Equipment	Heat Pump (Replacing Electric Furnace) - 18 SEER/10 HSPF	MH	All	MO	11,384.2	59%	6,661.3	0.802	9.506
9094	HVAC Equipment	Heat Pump (Replacing Electric Furnace) - 18 SEER/10 HSPF	MH	All	ER1	11,384.2	59%	6,661.3	0.802	9.506
9095	HVAC Equipment	Heat Pump (Replacing Electric Furnace) - 18 SEER/10 HSPF	MH	All	ER2	6,090.4	22%	1,367.5	0.730	1.111
9096	HVAC Equipment	Dual Fuel Heat Pump (Replacing Electric Furnace)	MH	All	MO	11,384.2	68%	7,753.2	0.625	8.540
9097	HVAC Equipment	Ductless mini-split HP (Replacing furnace)	MH	All	MO	11,384.2	64%	7,303.1	0.703	6.335
9098	HVAC Equipment	Energy Star Room A/C	MH	All	MO	288.4	4%	12.6	0.035	0.000
9099	HVAC Equipment	Energy Star Room A/C	MH	All	ER1	408.3	32%	132.5	0.362	0.000
9100	HVAC Equipment	Energy Star Room A/C	MH	All	ER2	288.4	4%	12.6	0.035	0.000
9101	HVAC Equipment	Room Air Conditioner Recycling	MH	All	Recycle	408.3	100%	408.3	1.104	1.104
9102	HVAC Equipment	ECM Furnace Fan	MH	All	Retrofit	2,615.2	20%	514.6	0.000	0.000
9103	HVAC Equipment	Programmable Thermostat - Gas/AC - Tier 1	MH	All	Retrofit	2,615.2	0%	12.0	0.000	0.000
9104	HVAC Equipment	Smart Thermostat - Gas Heat / AC - Tier 2	MH	All	Retrofit	2,615.2	5%	141.2	0.000	0.000
9105	HVAC Equipment	Peak Period Thermostat - Gas Heat / AC - Tier 3	MH	All	Retrofit	2,615.2	9%	232.8	0.000	0.000

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Measure #	End-Use	Measure Name	Home Type	Income Type	Replacement Type	Per unit NG Saving	Per Unit Water Savings	RC EUL	EE EUL	Initial Measure Cost	O&M Benefits
9086	HVAC Equipment	Ductless mini-split HP (Replacing ASHP)	MH	All	MO	0.00	0	18.0	18.0	$3,128.0	$0.0
9087	HVAC Equipment	Heat Pump (Replacing Electric Furnace) - 16 SEER/9.0 HSPF	MH	All	MO	0.00	0	18.0	18.0	$3,470.0	$0.0
9088	HVAC Equipment	Heat Pump (Replacing Electric Furnace) - 16 SEER/9.0 HSPF	MH	All	ER1	0.00	0	18.0	6.0	$4,160.0	$0.0
9089	HVAC Equipment	Heat Pump (Replacing Electric Furnace) - 16 SEER/9.0 HSPF	MH	All	ER2	0.00	0	18.0	12.0	$0.0	$0.0
9090	HVAC Equipment	Heat Pump (Replacing Electric Furnace) - 17 SEER/9.5 HSPF	MH	All	MO	0.00	0	18.0	18.0	$4,018.0	$0.0
9091	HVAC Equipment	Heat Pump (Replacing Electric Furnace) - 17 SEER/9.5 HSPF	MH	All	ER1	0.00	0	18.0	6.0	$4,708.0	$0.0
9092	HVAC Equipment	Heat Pump (Replacing Electric Furnace) - 17 SEER/9.5 HSPF	MH	All	ER2	0.00	0	18.0	12.0	$0.0	$0.0
9093	HVAC Equipment	Heat Pump (Replacing Electric Furnace) - 18 SEER/10 HSPF	MH	All	MO	0.00	0	18.0	18.0	$4,566.0	$0.0
9094	HVAC Equipment	Heat Pump (Replacing Electric Furnace) - 18 SEER/10 HSPF	MH	All	ER1	0.00	0	18.0	6.0	$5,256.0	$0.0
9095	HVAC Equipment	Heat Pump (Replacing Electric Furnace) - 18 SEER/10 HSPF	MH	All	ER2	0.00	0	18.0	12.0	$0.0	$0.0
9096	HVAC Equipment	Dual Fuel Heat Pump (Replacing Electric Furnace)	MH	All	MO	-17.01	0	18.0	18.0	$4,197.0	$0.0
9097	HVAC Equipment	Ductless mini-split HP (Replacing furnace)	MH	All	MO	0.00	0	18.0	18.0	$4,768.0	$0.0
9098	HVAC Equipment	Energy Star Room A/C	MH	All	MO	0.00	0	12.0	12.0	$40.0	$0.0
9099	HVAC Equipment	Energy Star Room A/C	MH	All	ER1	0.00	0	12.0	4.0	$451.0	$0.0
9100	HVAC Equipment	Energy Star Room A/C	MH	All	ER2	0.00	0	12.0	8.0	$0.0	$0.0
9101	HVAC Equipment	Room Air Conditioner Recycling	MH	All	Recycle	0.00	0	4.0	4.0	$49.0	$0.0
9102	HVAC Equipment	ECM Furnace Fan	MH	All	Retrofit	0.00	0	20.0	20.0	$97.0	$0.0
9103	HVAC Equipment	Programmable Thermostat - Gas/AC - Tier 1	MH	All	Retrofit	1.59	0	10.0	10.0	$130.0	$0.0
9104	HVAC Equipment	Smart Thermostat - Gas Heat / AC - Tier 2	MH	All	Retrofit	2.38	0	10.0	10.0	$210.0	$0.0
9105	HVAC Equipment	Peak Period Thermostat - Gas Heat / AC - Tier 3	MH	All	Retrofit	3.92	0	10.0	10.0	$300.0	$0.0

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9106	HVAC Equipment	Programmable Thermostat - ASHP - Tier 1	MH	All	Retrofit	6,090.4	4%	219.3	0.000	0.000
9107	HVAC Equipment	Smart Thermostat - ASHP - Tier 2	MH	All	Retrofit	6,090.4	5%	328.9	0.000	0.000
9108	HVAC Equipment	Peak Period Thermostat - ASHP - Tier 3	MH	All	Retrofit	6,090.4	9%	542.0	0.000	0.000
9109	HVAC Equipment	Programmable Thermostat - Elec Furnace/AC - Tier 1	MH	All	Retrofit	11,384.2	4%	409.8	0.000	0.000
9110	HVAC Equipment	Smart Thermostat - Elec Furnace/AC - Tier 2	MH	All	Retrofit	11,384.2	5%	614.7	0.000	0.000
9111	HVAC Equipment	Peak Period Thermostat - Elec Furnace/AC - Tier 3	MH	All	Retrofit	11,384.2	9%	1,013.2	0.000	0.000
9112	HVAC Equipment	High Efficiency Central AC - 16 SEER	SF	All	NC	2,378.3	11%	286.7	0.278	0.220
9113	HVAC Equipment	High Efficiency Central AC - 17 SEER	SF	All	NC	2,378.3	18%	437.0	0.488	0.221
9114	HVAC Equipment	High Efficiency Central AC - 18 SEER	SF	All	NC	2,378.3	23%	538.6	0.603	0.221
9115	HVAC Equipment	High Efficiency Central AC - 19 SEER	SF	All	NC	2,378.3	26%	630.1	0.705	0.221
9116	HVAC Equipment	High Efficiency Central AC - 20 SEER	SF	All	NC	2,378.3	30%	721.5	0.810	0.221
9117	HVAC Equipment	Ductless mini-split AC	SF	All	NC	2,378.3	33%	794.2	0.801	0.000
9118	HVAC Equipment	High Efficiency Heat Pump (HP Upgrade) - 16 SEER/9.0 HSPF	SF	All	NC	5,911.2	7%	393.9	0.367	-0.032
9119	HVAC Equipment	High Efficiency Heat Pump (HP Upgrade) - 17 SEER/9.5 HSPF	SF	All	NC	5,911.2	9%	547.9	0.489	0.046
9120	HVAC Equipment	High Efficiency Heat Pump (HP Upgrade) - 18 SEER/10 HSPF	SF	All	NC	5,911.2	15%	909.8	0.575	0.548
9121	HVAC Equipment	Ground Source Heat Pump (HP Upgrade)	SF	All	NC	5,911.2	13%	740.1	0.167	0.814
9122	HVAC Equipment	Dual Fuel Heat Pump Upgrade (Replacing New ASHP)	SF	All	NC	5,911.2	35%	2,048.0	0.367	2.210
9123	HVAC Equipment	Ductless mini-split HP (Replacing ASHP)	SF	All	NC	5,911.2	28%	1,646.2	0.486	0.971
9124	HVAC Equipment	Energy Star Room A/C	SF	All	NC	288.4	4%	12.6	0.035	0.000
9125	HVAC Equipment	ECM Furnace Fan	SF	All	NC	2,743.2	19%	514.6	0.000	0.000
9126	HVAC Equipment	Programmable Thermostat - Gas/AC - Tier 1	SF	All	NC	2,743.2	0%	13.1	0.000	0.000

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Measure #	End-Use	Measure Name	Home Type	Income Type	Replacement Type	Per unit NG Saving	Per Unit Water Savings	RC EUL	EE EUL	Initial Measure Cost	O&M Benefits
9106	HVAC Equipment	Programmable Thermostat - ASHP - Tier 1	MH	All	Retrofit	0.00	0	10.0	10.0	$130.0	$0.0
9107	HVAC Equipment	Smart Thermostat - ASHP - Tier 2	MH	All	Retrofit	0.00	0	10.0	10.0	$210.0	$0.0
9108	HVAC Equipment	Peak Period Thermostat - ASHP - Tier 3	MH	All	Retrofit	0.00	0	10.0	10.0	$300.0	$0.0
9109	HVAC Equipment	Programmable Thermostat - Elec Furnace/AC - Tier 1	MH	All	Retrofit	0.00	0	10.0	10.0	$130.0	$0.0
9110	HVAC Equipment	Smart Thermostat - Elec Furnace/AC - Tier 2	MH	All	Retrofit	0.00	0	10.0	10.0	$210.0	$0.0
9111	HVAC Equipment	Peak Period Thermostat - Elec Furnace/AC - Tier 3	MH	All	Retrofit	0.00	0	10.0	10.0	$300.0	$0.0
9112	HVAC Equipment	High Efficiency Central AC - 16 SEER	SF	All	NC	-0.62	0	18.0	18.0	$553.0	$0.0
9113	HVAC Equipment	High Efficiency Central AC - 17 SEER	SF	All	NC	-0.63	0	18.0	18.0	$829.0	$0.0
9114	HVAC Equipment	High Efficiency Central AC - 18 SEER	SF	All	NC	-0.63	0	18.0	18.0	$1,106.0	$0.0
9115	HVAC Equipment	High Efficiency Central AC - 19 SEER	SF	All	NC	-0.63	0	18.0	18.0	$1,382.0	$0.0
9116	HVAC Equipment	High Efficiency Central AC - 20 SEER	SF	All	NC	-0.63	0	18.0	18.0	$1,658.0	$0.0
9117	HVAC Equipment	Ductless mini-split AC	SF	All	NC	0.00	0	18.0	18.0	$3,913.0	$0.0
9118	HVAC Equipment	High Efficiency Heat Pump (HP Upgrade) - 16 SEER/9.0 HSPF	SF	All	NC	0.00	0	18.0	18.0	$1,097.0	$0.0
9119	HVAC Equipment	High Efficiency Heat Pump (HP Upgrade) - 17 SEER/9.5 HSPF	SF	All	NC	0.00	0	18.0	18.0	$1,645.0	$0.0
9120	HVAC Equipment	High Efficiency Heat Pump (HP Upgrade) - 18 SEER/10 HSPF	SF	All	NC	0.00	0	18.0	18.0	$2,193.0	$0.0
9121	HVAC Equipment	Ground Source Heat Pump (HP Upgrade)	SF	All	NC	0.00	0	25.0	25.0	$18,931.0	$0.0
9122	HVAC Equipment	Dual Fuel Heat Pump Upgrade (Replacing New ASHP)	SF	All	NC	-18.97	0	18.0	18.0	$1,097.0	$0.0
9123	HVAC Equipment	Ductless mini-split HP (Replacing ASHP)	SF	All	NC	0.00	0	18.0	18.0	$3,125.0	$0.0
9124	HVAC Equipment	Energy Star Room A/C	SF	All	NC	0.00	0	12.0	12.0	$40.0	$0.0
9125	HVAC Equipment	ECM Furnace Fan	SF	All	NC	0.00	0	20.0	20.0	$97.0	$0.0
9126	HVAC Equipment	Programmable Thermostat - Gas/AC - Tier 1	SF	All	NC	1.75	0	10.0	10.0	$30.0	$0.0

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9127	HVAC Equipment	Smart Thermostat - Gas Heat / AC - Tier 2	SF	All	NC	2,743.2	5%	148.1	0.000	0.000
9128	HVAC Equipment	Peak Period Thermostat - Gas Heat / AC - Tier 3	SF	All	NC	2,743.2	9%	244.1	0.000	0.000
9129	HVAC Equipment	Programmable Thermostat - ASHP - Tier 1	SF	All	NC	5,911.2	4%	212.8	0.000	0.000
9130	HVAC Equipment	Smart Thermostat - ASHP - Tier 2	SF	All	NC	5,911.2	5%	319.2	0.000	0.000
9131	HVAC Equipment	Peak Period Thermostat - ASHP - Tier 3	SF	All	NC	5,911.2	9%	526.1	0.000	0.000
9132	HVAC Equipment	High Efficiency Central AC - 16 SEER	MH	All	NC	1,932.1	13%	248.3	0.291	0.193
9133	HVAC Equipment	High Efficiency Central AC - 17 SEER	MH	All	NC	1,932.1	20%	380.6	0.461	0.254
9134	HVAC Equipment	High Efficiency Central AC - 18 SEER	MH	All	NC	1,932.1	24%	455.1	0.555	0.254
9135	HVAC Equipment	High Efficiency Central AC - 19 SEER	MH	All	NC	1,932.1	27%	522.2	0.641	0.254
9136	HVAC Equipment	High Efficiency Central AC - 20 SEER	MH	All	NC	1,932.1	31%	589.4	0.728	0.254
9137	HVAC Equipment	Ductless mini-split AC	MH	All	NC	1,932.1	31%	596.2	0.653	0.000
9138	HVAC Equipment	High Efficiency Heat Pump (HP Upgrade) - 16 SEER/9.0 HSPF	MH	All	NC	5,636.8	8%	447.1	0.399	0.041
9139	HVAC Equipment	High Efficiency Heat Pump (HP Upgrade) - 17 SEER/9.5 HSPF	MH	All	NC	5,636.8	10%	573.7	0.502	0.113
9140	HVAC Equipment	High Efficiency Heat Pump (HP Upgrade) - 18 SEER/10 HSPF	MH	All	NC	5,636.8	16%	917.1	0.569	0.584
9141	HVAC Equipment	Dual Fuel Heat Pump Upgrade (Replacing New ASHP)	MH	All	NC	5,636.8	36%	2,012.8	0.399	1.943
9142	HVAC Equipment	Ductless mini-split HP (Replacing ASHP)	MH	All	NC	5,636.8	26%	1,457.0	0.439	0.794
9143	HVAC Equipment	Energy Star Room A/C	MH	All	NC	288.4	4%	12.6	0.035	0.000
9144	HVAC Equipment	ECM Furnace Fan	MH	All	NC	2,282.9	23%	514.6	0.000	0.000
9145	HVAC Equipment	Programmable Thermostat - Gas/AC - Tier 1	MH	All	NC	2,282.9	1%	12.6	0.000	0.000
9146	HVAC Equipment	Smart Thermostat - Gas Heat / AC - Tier 2	MH	All	NC	2,282.9	4%	82.2	0.000	0.000
9147	HVAC Equipment	Peak Period Thermostat - Gas Heat / AC - Tier 3	MH	All	NC	2,282.9	9%	203.2	0.000	0.000

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9127	HVAC Equipment	Smart Thermostat - Gas Heat / AC - Tier 2	SF	All	NC	2.63	0	10.0	10.0	$110.0	$0.0
9128	HVAC Equipment	Peak Period Thermostat - Gas Heat / AC - Tier 3	SF	All	NC	4.33	0	10.0	10.0	$200.0	$0.0
9129	HVAC Equipment	Programmable Thermostat - ASHP - Tier 1	SF	All	NC	0.00	0	10.0	10.0	$30.0	$0.0
9130	HVAC Equipment	Smart Thermostat - ASHP - Tier 2	SF	All	NC	0.00	0	10.0	10.0	$110.0	$0.0
9131	HVAC Equipment	Peak Period Thermostat - ASHP - Tier 3	SF	All	NC	0.00	0	10.0	10.0	$200.0	$0.0
9132	HVAC Equipment	High Efficiency Central AC - 16 SEER	MH	All	NC	-0.62	0	18.0	18.0	$553.0	$0.0
9133	HVAC Equipment	High Efficiency Central AC - 17 SEER	MH	All	NC	-1.04	0	18.0	18.0	$829.0	$0.0
9134	HVAC Equipment	High Efficiency Central AC - 18 SEER	MH	All	NC	-1.04	0	18.0	18.0	$1,106.0	$0.0
9135	HVAC Equipment	High Efficiency Central AC - 19 SEER	MH	All	NC	-1.04	0	18.0	18.0	$1,382.0	$0.0
9136	HVAC Equipment	High Efficiency Central AC - 20 SEER	MH	All	NC	-1.04	0	18.0	18.0	$1,658.0	$0.0
9137	HVAC Equipment	Ductless mini-split AC	MH	All	NC	0.00	0	18.0	18.0	$3,913.0	$0.0
9138	HVAC Equipment	High Efficiency Heat Pump (HP Upgrade) - 16 SEER/9.0 HSPF	MH	All	NC	0.00	0	18.0	18.0	$1,097.0	$0.0
9139	HVAC Equipment	High Efficiency Heat Pump (HP Upgrade) - 17 SEER/9.8 HSPF	MH	All	NC	0.00	0	18.0	18.0	$1,645.0	$0.0
9140	HVAC Equipment	High Efficiency Heat Pump (HP Upgrade) - 18 SEER/10 HSPF	MH	All	NC	0.00	0	18.0	18.0	$2,193.0	$0.0
9141	HVAC Equipment	Dual Fuel Heat Pump Upgrade (Replacing New ASHP)	MH	All	NC	-16.98	0	18.0	18.0	$1,097.0	$0.0
9142	HVAC Equipment	Ductless mini-split HP (Replacing ASHP)	MH	All	NC	0.00	0	18.0	18.0	$3,128.0	$0.0
9143	HVAC Equipment	Energy Star Room A/C	MH	All	NC	0.00	0	12.0	12.0	$40.0	$0.0
9144	HVAC Equipment	ECM Furnace Fan	MH	All	NC	0.00	0	20.0	20.0	$97.0	$0.0
9145	HVAC Equipment	Programmable Thermostat - Gas/AC - Tier 1	MH	All	NC	1.67	0	10.0	10.0	$30.0	$0.0
9146	HVAC Equipment	Smart Thermostat - Gas Heat / AC - Tier 2	MH	All	NC	1.67	0	10.0	10.0	$110.0	$0.0
9147	HVAC Equipment	Peak Period Thermostat - Gas Heat / AC - Tier 3	MH	All	NC	4.14	0	10.0	10.0	$200.0	$0.0

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Measure #	End-Use	Measure Name	Home Type	Income Type	Replacement Type	Base Annual Electric	% Electric Savings	Per Unit Elec Savings	Per Unit Summer NCP kW	Per Unit Winter NCP kW
9148	HVAC Equipment	Programmable Thermostat - ASHP - Tier 1	MH	All	NC	6,636.8	4%	202.9	0.000	0.000
9149	HVAC Equipment	Smart Thermostat - ASHP - Tier 2	MH	All	NC	8,636.8	6%	304.4	0.000	0.000
9150	HVAC Equipment	Peak Period Thermostat - ASHP - Tier 3	MH	All	NC	5,636.8	9%	501.7	0.000	0.000
10001	Behavioral	In Home Energy Display Monitor - Gas/CAC	SF	All	Retrofit	3,456.8	9%	311.0	0.159	0.010
10002	Behavioral	Home Energy Reports - Gas/CAC	SF	All	OptOut	3,455.8	2%	69.1	0.035	0.002
10003	Behavioral	In Home Energy Display Monitor - ASHP	SF	All	Retrofit	7,471.1	9%	672.4	0.138	0.112
10004	Behavioral	Home Energy Reports - ASHP	SF	All	OptOut	7,471.1	2%	149.4	0.031	0.025
10005	Behavioral	In Home Energy Display Monitor - Elec Furn/CAC	SF	All	Retrofit	14,235.0	9%	1,281.2	0.145	0.265
10006	Behavioral	Home Energy Reports - Elec Furn/CAC	SF	All	OptOut	14,235.0	2%	284.7	0.115	0.012
10007	Behavioral	In Home Energy Display Monitor - Gas/CAC	MH	All	Retrofit	2,615.2	9%	235.4	0.072	0.011
10008	Behavioral	Home Energy Reports - Gas/CAC	MH	All	OptOut	2,615.2	2%	52.3	-0.028	0.005
10009	Behavioral	In Home Energy Display Monitor - ASHP	MH	All	Retrofit	6,090.4	9%	548.1	0.048	0.216
10010	Behavioral	Home Energy Reports - ASHP	MH	All	OptOut	6,090.4	2%	121.8	-0.040	0.153
10011	Behavioral	In Home Energy Display Monitor - Elec Furn/CAC	MH	All	Retrofit	11,384.2	9%	1,024.6	0.049	0.251
10012	Behavioral	Home Energy Reports - Elec Furn/CAC	MH	All	OptOut	11,384.2	2%	227.7	-0.042	0.086
10013	Behavioral	In Home Energy Display Monitor - Gas/CAC	SF	All	NC	11,864.2	9%	1,067.8	0.118	0.009
10014	Behavioral	Home Energy Reports - Gas/CAC	SF	All	NC	11,864.2	2%	237.3	0.026	0.002
10015	Behavioral	In Home Energy Display Monitor - ASHP	SF	All	NC	15,031.5	9%	1,352.8	0.103	0.091
10016	Behavioral	Home Energy Reports - ASHP	SF	All	NC	15,031.5	2%	300.6	0.023	0.020
10017	Behavioral	In Home Energy Display Monitor - Gas/CAC	MH	All	NC	9,885.6	9%	889.7	0.049	0.014
10018	Behavioral	Home Energy Reports - Gas/CAC	MH	All	NC	9,886.6	2%	197.7	-0.036	0.008
10019	Behavioral	In Home Energy Display Monitor - ASHP	MH	All	NC	13,239.0	9%	1,191.5	0.028	0.167
10020	Behavioral	Home Energy Reports - ASHP	MH	All	NC	13,239.0	2%	264.8	-0.050	0.101
11001	Pool/Spa	Two Speed Pool Pumps	SF	All	MO	2,622.0	61%	1,596.0	1.377	1.377
11002	Pool/Spa	Variable Speed Pool Pumps	SF	All	MO	2,622.0	73%	1,921.6	1.529	1.529
11003	Pool/Spa	Two Speed Pool Pumps	SF	All	NC	2,622.0	61%	1,596.0	1.377	1.377

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Measure #	End-Use	Measure Name	Home Type	Income Type	Replacement Type	Per unit NG Saving	Per Unit Water Savings	RC EUL	EE EUL	Initial Measure Cost	O&M Benefits
9148	HVAC Equipment	Programmable Thermostat - ASHP - Tier 1	MH	All	NC	0.00	0	10.0	10.0	$30.0	$0.0
9149	HVAC Equipment	Smart Thermostat - ASHP - Tier 2	MH	All	NC	0.00	0	10.0	10.0	$110.0	$0.0
9150	HVAC Equipment	Peak Period Thermostat - ASHP - Tier 3	MH	All	NC	0.00	0	10.0	10.0	$200.0	$0.0
10001	Behavioral	In Home Energy Display Monitor - Gas/CAC	SF	All	Retrofit	5.26	0	5.0	5.0	$250.0	$0.0
10002	Behavioral	Home Energy Reports - Gas/CAC	SF	All	OptOut	1.17	0	1.0	1.0	$6.8	$0.0
10003	Behavioral	In Home Energy Display Monitor - ASHP	SF	All	Retrofit	0.00	0	5.0	5.0	$250.0	$0.0
10004	Behavioral	Home Energy Reports - ASHP	SF	All	OptOut	0.00	0	1.0	1.0	$6.8	$0.0
10005	Behavioral	In Home Energy Display Monitor - Elec Furn/CAC	SF	All	Retrofit	0.00	0	5.0	5.0	$250.0	$0.0
10006	Behavioral	Home Energy Reports - Elec Furn/CAC	SF	All	OptOut	0.00	0	1.0	1.0	$6.8	$0.0
10007	Behavioral	In Home Energy Display Monitor - Gas/CAC	MH	All	Retrofit	3.97	0	5.0	5.0	$250.0	$0.0
10008	Behavioral	Home Energy Reports - Gas/CAC	MH	All	OptOut	0.88	0	1.0	1.0	$6.8	$0.0
10009	Behavioral	In Home Energy Display Monitor - ASHP	MH	All	Retrofit	0.00	0	5.0	5.0	$250.0	$0.0
10010	Behavioral	Home Energy Reports - ASHP	MH	All	OptOut	0.00	0	1.0	1.0	$6.8	$0.0
10011	Behavioral	In Home Energy Display Monitor - Elec Furn/CAC	MH	All	Retrofit	0.00	0	5.0	5.0	$250.0	$0.0
10012	Behavioral	Home Energy Reports - Elec Furn/CAC	MH	All	OptOut	0.00	0	1.0	1.0	$6.8	$0.0
10013	Behavioral	In Home Energy Display Monitor - Gas/CAC	SF	All	NC	4.38	0	5.0	5.0	$250.0	$0.0
10014	Behavioral	Home Energy Reports - Gas/CAC	SF	All	NC	0.97	0	1.0	1.0	$6.8	$0.0
10015	Behavioral	In Home Energy Display Monitor - ASHP	SF	All	NC	0.00	0	5.0	5.0	$250.0	$0.0
10016	Behavioral	Home Energy Reports - ASHP	SF	All	NC	0.00	0	1.0	1.0	$6.8	$0.0
10017	Behavioral	In Home Energy Display Monitor - Gas/CAC	MH	All	NC	4.18	0	5.0	5.0	$250.0	$0.0
10018	Behavioral	Home Energy Reports - Gas/CAC	MH	All	NC	0.93	0	1.0	1.0	$6.8	$0.0
10019	Behavioral	In Home Energy Display Monitor - ASHP	MH	All	NC	0.00	0	5.0	5.0	$250.0	$0.0
10020	Behavioral	Home Energy Reports - ASHP	MH	All	NC	0.00	0	1.0	1.0	$6.8	$0.0
11001	Pool/Spa	Two Speed Pool Pumps	SF	All	MO	0.00	0	10.0	10.0	$235.0	$0.0
11002	Pool/Spa	Variable Speed Pool Pumps	SF	All	MO	0.00	0	10.0	10.0	$549.0	$0.0
11003	Pool/Spa	Two Speed Pool Pumps	SF	All	NC	0.00	0	10.0	10.0	$235.0	$0.0

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Measure #	End-Use	Measure Name	Home Type	Income Type	Replacement Type	Base Annual Electric	% Electric Savings	Per Unit Elec Savings	Per Unit Summer NCP kW	Per Unit Winter NCP kW
11004	Pool/Spa	Variable Speed Pool Pumps	SF	All	NC	2,622.0	73%	1,921.6	1.529	1.529
12001	Cross-Cutting	Multi-Family Homes Efficiency Kit	MF	All	Retrofit	9,460.0	4%	347.0	0.056	0.061
12002	Cross-Cutting	Multi-Family Homes Efficiency Kit	MF	All	NC	9,460.0	4%	347.0	0.056	0.061
13001	New Construction	Touchstone Home -15% more efficient (w/AC only) - New Single-family home	SF	All	NC	11,864.2	15%	1,779.6	0.403	0.082
13002	New Construction	Touchstone Home - 30% more efficient (w/AC only) - New Single-family home	SF	All	NC	11,864.2	30%	3,559.3	0.807	0.165
13003	New Construction	Touchstone Home - 15% more efficient (w/Elec. HP) - New Single-family home	SF	All	NC	15,031.5	15%	2,254.7	0.366	0.750
13004	New Construction	Touchstone Home - 30% more efficient (w/Elec. HP) - New Single-family home	SF	All	NC	15,031.5	30%	4,509.5	0.713	1.500
13005	New Construction	Touchstone Home - 15% more efficient (w/AC only) - New manufactured home	MH	All	NC	9,885.6	15%	1,482.8	0.373	0.072
13006	New Construction	Touchstone Home - 30% more efficient (w/AC only) - New manufactured home	MH	All	NC	9,885.6	30%	2,965.7	0.745	0.145
13007	New Construction	Touchstone Home - 15% more efficient (w/Elec. HP) - New manufactured home	MH	All	NC	13,239.0	15%	1,985.8	0.347	0.697
13008	New Construction	Touchstone Home - 30% more efficient (w/Elec. HP) - New manufactured home	MH	All	NC	13,239.0	30%	3,971.7	0.694	1.393

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Measure #	End-Use	Measure Name	Home Type	Income Type	Replacement Type	Per unit NG Saving	Per Unit Water Savings	RC EUL	EE EUL	Initial Measure Cost	O&M Benefits
11004	Pool/Spa	Variable Speed Pool Pumps	SF	All	NC	0.00	0	10.0	10.0	$849.0	$0.0
12001	Cross-Cutting	Multi-Family Homes Efficiency Kit	MF	All	Retrofit	0.00	1,396	7.0	7.0	$1,000.0	$4.1
12002	Cross-Cutting	Multi-Family Homes Efficiency Kit	MF	All	NC	0.00	1,396	7.0	7.0	$1,000.0	$4.1
13001	New Construction	Touchstone Home -15% more efficient (w/AC only) - New Single-family home	SF	All	NC	7.29	0	20.0	20.0	$2,599.0	$0.0
13002	New Construction	Touchstone Home - 30% more efficient (w/AC only) - New Single-family home	SF	All	NC	14.59	0	20.0	20.0	$6,677.0	$0.0
13003	New Construction	Touchstone Home - 15% more efficient (w/Elec. HP) - New Single-family home	SF	All	NC	0.00	0	20.0	20.0	$2,599.0	$0.0
13004	New Construction	Touchstone Home - 30% more efficient (w/Elec. HP) - New Single-family home	SF	All	NC	0.00	0	20.0	20.0	$6,677.0	$0.0
13005	New Construction	Touchstone Home - 15% more efficient (w/AC only) - New manufactured home	MH	All	NC	6.97	0	20.0	20.0	$1,286.0	$0.0
13006	New Construction	Touchstone Home - 30% more efficient (w/AC only) - New manufactured home	MH	All	NC	13.94	0	20.0	20.0	$4,922.0	$0.0
13007	New Construction	Touchstone Home - 15% more efficient (w/Elec. HP) - New manufactured home	MH	All	NC	0.00	0	20.0	20.0	$1,286.0	$0.0
13008	New Construction	Touchstone Home - 30% more efficient (w/Elec. HP) - New manufactured home	MH	All	NC	0.00	0	20.0	20.0	$4,922.0	$0.0

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Measure #	End-Use	Measure Name	Home Type	Income Type	Replacement Type	Base Annual Electric	% Electric Savings	Per Unit Elec Savings	Per Unit Summer NCP kW	Per Unit Winter NCP kW	Per unit NG Saving	Per Unit Water Savings	RC EUL	EE EUL	Initial Measure Cost	O&M Benefits
1001	Refrigeration	Energy Star Compliant Top-Mount Refrigerator	SF	All	MO	Ill TRM	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM
1002	Refrigeration	CEE Tier 2 Compliant Top-Mount Refrigerator	SF	All	MO	Ill TRM	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM
1003	Refrigeration	Energy Star Compliant Side-by-Side Refrigerator	SF	All	MO	Ill TRM	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM
1004	Refrigeration	CEE Tier 2 Compliant Side-by-Side Refrigerator	SF	All	MO	Ill TRM	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM
1005	Refrigeration	Energy Star Compliant Chest Freezer	SF	All	MO	Ill TRM	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM
1006	Refrigeration	Energy Star Compliant Upright Freezer (Manual Def.)	SF	All	MO	Ill TRM	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM
1007	Refrigeration	Second Refrigerator Turn In	SF	All	Recycle	Ill TRM	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM
1008	Refrigeration	Second Freezer Turn In	SF	All	Recycle	Ill TRM	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM
1009	Refrigeration	Energy Star Compliant Top-Mount Refrigerator	MH	All	MO	Ill TRM	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM
1010	Refrigeration	CEE Tier 2 Compliant Top-Mount Refrigerator	MH	All	MO	Ill TRM	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM
1011	Refrigeration	Energy Star Compliant Side-by-Side Refrigerator	MH	All	MO	Ill TRM	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM
1012	Refrigeration	CEE Tier 2 Compliant Side-by-Side Refrigerator	MH	All	MO	Ill TRM	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM
1013	Refrigeration	Energy Star Compliant Chest Freezer	MH	All	MO	Ill TRM	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM
1014	Refrigeration	Energy Star Compliant Upright Freezer (Manual Def.)	MH	All	MO	Ill TRM	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM
1015	Refrigeration	Second Refrigerator Turn In	MH	All	Recycle	Ill TRM	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM
1016	Refrigeration	Second Freezer Turn In	MH	All	Recycle	Ill TRM	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM
1017	Refrigeration	Energy Star Compliant Top-Mount Refrigerator	SF	All	NC	Ill TRM	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM
1018	Refrigeration	CEE Tier 2 Compliant Top-Mount Refrigerator	SF	All	NC	Ill TRM	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM
1019	Refrigeration	Energy Star Compliant Side-by-Side Refrigerator	SF	All	NC	Ill TRM	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM
1020	Refrigeration	CEE Tier 2 Compliant Side-by-Side Refrigerator	SF	All	NC	Ill TRM	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM
1021	Refrigeration	Energy Star Compliant Chest Freezer	SF	All	NC	Ill TRM	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM
1022	Refrigeration	Energy Star Compliant Upright Freezer (Manual Def.)	SF	All	NC	Ill TRM	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM
1023	Refrigeration	Energy Star Compliant Top-Mount Refrigerator	MH	All	NC	Ill TRM	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM
1024	Refrigeration	CEE Tier 2 Compliant Top-Mount Refrigerator	MH	All	NC	Ill TRM	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM
1025	Refrigeration	Energy Star Compliant Side-by-Side Refrigerator	MH	All	NC	Ill TRM	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM

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Measure #	End-Use	Measure Name	Home Type	Income Type	Replacement Type	Base Annual Electric	% Electric Savings	Per Unit Elec Savings	Per Unit Summer NCP kW	Per Unit Winter NCP kW	Per unit NG Saving	Per Unit Water Savings	RC EUL	EE EUL	Initial Measure Cost	O&M Benefits
1026	Refrigeration	CEE Tier 2 Compliant Side-by-Side Refrigerator	MH	All	NC	Ill TRM	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM
1027	Refrigeration	Energy Star Compliant Chest Freezer	MH	All	NC	Ill TRM	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM
1028	Refrigeration	Energy Star Compliant Upright Freezer (Manual Def.)	MH	All	NC	Ill TRM	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM
2001	Clothes Washer/Dryer	Energy Star Clothes Washer (w/ Elec. WH & Elec. Dryer)	SF	All	MO	Ill TRM	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM
2002	Clothes Washer/Dryer	Energy Star Most Efficient Clothes Washer (w/ Elec. WH & Elec. Dryer)	SF	All	MO	Ill TRM	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM
2003	Clothes Washer/Dryer	Energy Star Clothes Washer (w/ NG WH & Elec. Dryer)	SF	All	MO	Ill TRM	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM
2004	Clothes Washer/Dryer	Energy Star Most Efficient Clothes Washer (w/ NG WH & Elec. Dryer)	SF	All	MO	Ill TRM	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM
2005	Clothes Washer/Dryer	ENERGY STAR Clothes Dryer	SF	All	MO	Ill TRM	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM
2006	Clothes Washer/Dryer	Energy Star Clothes Washer (w/ Elec. WH & Elec. Dryer)	MH	All	MO	Ill TRM	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM
2007	Clothes Washer/Dryer	Energy Star Most Efficient Clothes Washer (w/ Elec. WH & Elec. Dryer)	MH	All	MO	Ill TRM	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM
2008	Clothes Washer/Dryer	Energy Star Clothes Washer (w/ NG WH & Elec. Dryer)	MH	All	MO	Ill TRM	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM
2009	Clothes Washer/Dryer	Energy Star Most Efficient Clothes Washer (w/ NG WH & Elec. Dryer)	MH	All	MO	Ill TRM	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM
2010	Clothes Washer/Dryer	ENERGY STAR Clothes Dryer	MH	All	MO	Ill TRM	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM
2011	Clothes Washer/Dryer	Energy Star Clothes Washer (w/ Elec. WH & Elec. Dryer)	SF	All	NC	Ill TRM	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM
2012	Clothes Washer/Dryer	Energy Star Most Efficient Clothes Washer (w/ Elec. WH & Elec. Dryer)	SF	All	NC	Ill TRM	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM
2013	Clothes Washer/Dryer	Energy Star Clothes Washer (w/ NG WH & Elec. Dryer)	SF	All	NC	Ill TRM	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM
2014	Clothes Washer/Dryer	Energy Star Most Efficient Clothes Washer (w/ NG WH & Elec. Dryer)	SF	All	NC	Ill TRM	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM
2015	Clothes Washer/Dryer	ENERGY STAR Clothes Dryer	SF	All	NC	Ill TRM	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM

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2016	Clothes Washer/Dryer	Energy Star Clothes Washer (w/ Elec. WH & Elec. Dryer)	MH	All	NC	Ill TRM	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM
2017	Clothes Washer/Dryer	Energy Star Most Efficient Clothes Washer (w/ Elec. WH & Elec. Dryer)	MH	All	NC	Ill TRM	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM
2018	Clothes Washer/Dryer	Energy Star Clothes Washer (w/ NG WH & Elec. Dryer)	MH	All	NC	Ill TRM	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM
2019	Clothes Washer/Dryer	Energy Star Most Efficient Clothes Washer (w/ NG WH & Elec. Dryer)	MH	All	NC	Ill TRM	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM
2020	Clothes Washer/Dryer	ENERGY STAR Clothes Dryer	MH	All	NC	Ill TRM	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM
3001	Dishwasher	Energy Star Dishwasher (Electric Water Heating)	SF	All	MO	Ill TRM	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM
3002	Dishwasher	Energy Star Dishwasher (Non-Electric WH)	SF	All	MO	Ill TRM	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM
3003	Dishwasher	Energy Star Dishwasher (Electric Water Heating)	MH	All	MO	Ill TRM	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM
3004	Dishwasher	Energy Star Dishwasher (Non-Electric WH)	MH	All	MO	Ill TRM	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM
3005	Dishwasher	Energy Star Dishwasher (Electric Water Heating)	SF	All	NC	Ill TRM	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM
3006	Dishwasher	Energy Star Dishwasher (Non-Electric WH)	SF	All	NC	Ill TRM	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM
3007	Dishwasher	Energy Star Dishwasher (Electric Water Heating)	MH	All	NC	Ill TRM	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM
3008	Dishwasher	Energy Star Dishwasher (Non-Electric WH)	MH	All	NC	Ill TRM	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM
4001	Misc. Plug Load	Energy Star Dehumidifer	SF	All	MO	Ill TRM	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM
4002	Misc. Plug Load	Energy Star Room Air Cleaner	SF	All	MO	Ill TRM	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM
4003	Misc. Plug Load	Energy Star Dehumidifer	MH	All	MO	Ill TRM	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM
4004	Misc. Plug Load	Energy Star Room Air Cleaner	MH	All	MO	Ill TRM	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM
4005	Misc. Plug Load	Energy Star Dehumidifer	SF	All	NC	Ill TRM	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM
4006	Misc. Plug Load	Energy Star Room Air Cleaner	SF	All	NC	Ill TRM	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM
4007	Misc. Plug Load	Energy Star Dehumidifer	MH	All	NC	Ill TRM	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM
4008	Misc. Plug Load	Energy Star Room Air Cleaner	MH	All	NC	Ill TRM	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM

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5001	Consumer Electronics	Efficient Televisions	SF	All	MO	VT TRM	-	VT TRM	VT TRM	VT TRM	VT TRM	VT TRM	VT TRM	VT TRM	CPUC	VT TRM
5002	Consumer Electronics	Energy Star Desktop Computer	SF	All	MO	VT TRM	-	VT TRM	VT TRM	VT TRM	VT TRM	VT TRM	VT TRM	VT TRM	CPUC	VT TRM
5003	Consumer Electronics	Energy Star Computer Monitor	SF	All	MO	VT TRM	-	VT TRM	VT TRM	VT TRM	VT TRM	VT TRM	VT TRM	VT TRM	CPUC	VT TRM
5004	Consumer Electronics	Energy Star Laptop Computer	SF	All	MO	VT TRM	-	VT TRM	VT TRM	VT TRM	VT TRM	VT TRM	VT TRM	VT TRM	CPUC	VT TRM
5005	Consumer Electronics	Tier 1 Power Strip	SF	All	MO	VT TRM	-	VT TRM	VT TRM	VT TRM	VT TRM	VT TRM	VT TRM	VT TRM	VT TRM	VT TRM
5006	Consumer Electronics	Tier 2 Power Strip	SF	All	MO	VT TRM	-	VT TRM	VT TRM	VT TRM	VT TRM	VT TRM	VT TRM	VT TRM	VT TRM	VT TRM
5007	Consumer Electronics	Efficient Televisions	MH	All	MO	VT TRM	-	VT TRM	VT TRM	VT TRM	VT TRM	VT TRM	VT TRM	VT TRM	VT TRM	VT TRM
5008	Consumer Electronics	Energy Star Desktop Computer	MH	All	MO	VT TRM	-	VT TRM	VT TRM	VT TRM	VT TRM	VT TRM	VT TRM	VT TRM	VT TRM	VT TRM
5009	Consumer Electronics	Energy Star Computer Monitor	MH	All	MO	GDS/ES	-	GDS/ES	GDS/ES	GDS/ES	GDS	GDS	VT TRM	VT TRM	VT TRM	GDS
5010	Consumer Electronics	Energy Star Laptop Computer	MH	All	MO	GDS/ES	-	GDS/ES	GDS/ES	GDS/ES	GDS	GDS	VT TRM	VT TRM	VT TRM	GDS
5011	Consumer Electronics	Tier 1 Power Strip	MH	All	MO	GDS/ES	-	GDS/ES	GDS/ES	GDS/ES	GDS	GDS	VT TRM	VT TRM	VT TRM	GDS
5012	Consumer Electronics	Tier 2 Power Strip	MH	All	MO	GDS/ES	-	GDS/ES	GDS/ES	GDS/ES	GDS	GDS	VT TRM	VT TRM	VT TRM	GDS
5013	Consumer Electronics	Efficient Televisions	SF	All	NC	GDS/ES	-	GDS/ES	GDS/ES	GDS/ES	GDS	GDS	VT TRM	VT TRM	VT TRM	GDS
5014	Consumer Electronics	Energy Star Desktop Computer	SF	All	NC	GDS/ES	-	GDS/ES	GDS/ES	GDS/ES	GDS	GDS	VT TRM	VT TRM	VT TRM	GDS
5015	Consumer Electronics	Energy Star Computer Monitor	SF	All	NC	GDS/ES	-	GDS/ES	GDS/ES	GDS/ES	GDS	GDS	VT TRM	VT TRM	VT TRM	GDS
5016	Consumer Electronics	Energy Star Laptop Computer	SF	All	NC	GDS/ES	-	GDS/ES	GDS/ES	GDS/ES	GDS	GDS	VT TRM	VT TRM	VT TRM	GDS
5017	Consumer Electronics	Tier 1 Power Strip	SF	All	NC	Ill TRM / GDS	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM

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5018	Consumer Electronics	Tier 2 Power Strip	*SF*	All	NC	Ill TRM / GDS	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM
5019	Consumer Electronics	Efficient Televisions	MH	All	NC	Ill TRM / GDS	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM
5020	Consumer Electronics	Energy Star Desktop Computer	MH	All	NC	Ill TRM / GDS	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM
5021	Consumer Electronics	Energy Star Computer Monitor	MH	All	NC	Ill TRM	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	MEMD	Ill TRM
5022	Consumer Electronics	Energy Star Laptop Computer	MH	All	NC	Ill TRM	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	MEMD	Ill TRM
5023	Consumer Electronics	Tier 1 Power Strip	MH	All	NC	Ill TRM	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	MEMD	Ill TRM
5024	Consumer Electronics	Tier 2 Power Strip	MH	All	NC	Ill TRM	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	MEMD	Ill TRM
6001	Lighting	Standard CFL	SF	All	MO	GDS calc	-	GDS calc	GDS calc	GDS calc	GDS calc	Ill TRM	GDS	Ill TRM	EIA	GDS calc
6002	Lighting	Standard LED	SF	All	MO	GDS calc	-	GDS calc	GDS calc	GDS calc	GDS calc	Ill TRM	GDS	Ill TRM	EIA	GDS calc
6003	Lighting	Specialty CFL	SF	All	MO	GDS calc	-	GDS calc	GDS calc	GDS calc	GDS calc	Ill TRM	GDS	Ill TRM	EIA	GDS calc
6004	Lighting	Specialty LED	SF	All	MO	GDS calc	-	GDS calc	GDS calc	GDS calc	GDS calc	Ill TRM	GDS	Ill TRM	EIA	GDS calc
6005	Lighting	Reflector CFL	SF	All	MO	GDS calc	-	GDS calc	GDS calc	GDS calc	GDS calc	Ill TRM	GDS	Ill TRM	LED ICS	GDS calc
6006	Lighting	Reflector LED	SF	All	MO	GDS calc	-	GDS calc	GDS calc	GDS calc	GDS calc	Ill TRM	GDS	Ill TRM	LED ICS	GDS calc
6007	Lighting	Energy Star Torchiere	SF	All	MO	GDS calc	-	GDS calc	GDS calc	GDS calc	GDS calc	Ill TRM	GDS	Ill TRM	LED ICS	GDS calc
6008	Lighting	LED Nightlight	SF	All	MO	GDS calc	-	GDS calc	GDS calc	GDS calc	GDS calc	Ill TRM	GDS	Ill TRM	LED ICS	GDS calc
6009	Lighting	Exterior CFL Fixture	SF	All	MO	GDS calc	-	GDS calc	GDS calc	GDS calc	GDS calc	Ill TRM	GDS	Ill TRM	LED ICS	GDS calc
6010	Lighting	Exterior LED Fixture	SF	All	MO	GDS calc	-	GDS calc	GDS calc	GDS calc	GDS calc	Ill TRM	GDS	Ill TRM	EIA	GDS calc
6011	Lighting	Standard CFL	*MH*	All	MO	GDS calc	-	GDS calc	GDS calc	GDS calc	GDS calc	Ill TRM	GDS	Ill TRM	EIA	GDS calc
6012	Lighting	Standard LED	*MH*	All	MO	GDS calc	-	GDS calc	GDS calc	GDS calc	GDS calc	Ill TRM	GDS	Ill TRM	EIA	GDS calc
6013	Lighting	Specialty CFL	MH	All	MO	GDS calc	-	GDS calc	GDS calc	GDS calc	GDS calc	Ill TRM	GDS	Ill TRM	EIA	GDS calc
6014	Lighting	Specialty LED	MH	All	MO	GDS calc	-	GDS calc	GDS calc	GDS calc	GDS calc	Ill TRM	GDS	Ill TRM	LED ICS	GDS calc
6015	Lighting	Reflector CFL	MH	All	MO	GDS calc	-	GDS calc	GDS calc	GDS calc	GDS calc	Ill TRM	GDS	Ill TRM	LED ICS	GDS calc
6016	Lighting	Reflector LED	MH	All	MO	GDS calc	-	GDS calc	GDS calc	GDS calc	GDS calc	Ill TRM	GDS	Ill TRM	LED ICS	GDS calc
6017	Lighting	Energy Star Torchiere	MH	All	MO	GDS calc	-	GDS calc	GDS calc	GDS calc	GDS calc	Ill TRM	GDS	Ill TRM	EIA	GDS calc
6018	Lighting	LED Nightlight	MH	All	MO	GDS calc	-	GDS calc	GDS calc	GDS calc	GDS calc	Ill TRM	GDS	Ill TRM	EIA	GDS calc
6019	Lighting	Exterior CFL Fixture	MH	All	MO	GDS calc	-	GDS calc	GDS calc	GDS calc	GDS calc	Ill TRM	GDS	Ill TRM	EIA	GDS calc
6020	Lighting	Exterior LED Fixture	MH	All	MO	GDS calc	-	GDS calc	GDS calc	GDS calc	GDS calc	Ill TRM	GDS	Ill TRM	EIA	GDS calc
6021	Lighting	Standard CFL	SF	All	NC	GDS calc	-	GDS calc	GDS calc	GDS calc	GDS calc	Ill TRM	GDS	Ill TRM	LED ICS	GDS calc

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6022	Lighting	Standard LED	SF	All	NC	GDS calc	-	GDS calc	GDS calc	GDS calc	GDS calc	Ill TRM	GDS	Ill TRM	LED ICS	GDS calc
6023	Lighting	Specialty CFL	SF	All	NC	GDS calc	-	GDS calc	GDS calc	GDS calc	GDS calc	Ill TRM	GDS	Ill TRM	LED ICS	GDS calc
6024	Lighting	Specialty LED	SF	All	NC	GDS calc	-	GDS calc	GDS calc	GDS calc	GDS calc	Ill TRM	GDS	Ill TRM	LED ICS	GDS calc
6025	Lighting	Reflector CFL	SF	All	NC	GDS calc	-	GDS calc	GDS calc	GDS calc	GDS calc	Ill TRM	GDS	Ill TRM	Ill TRM	GDS
6026	Lighting	Reflector LED	SF	All	NC	GDS calc	-	GDS calc	GDS calc	GDS calc	GDS calc	Ill TRM	GDS	Ill TRM	Ill TRM	GDS
6027	Lighting	Energy Star Torchiere	SF	All	NC	GDS calc	-	GDS calc	GDS calc	GDS calc	GDS calc	Ill TRM	GDS	Ill TRM	Ill TRM	GDS
6028	Lighting	LED Nightlight	SF	All	NC	GDS calc	-	GDS calc	GDS calc	GDS calc	GDS calc	Ill TRM	GDS	Ill TRM	Ill TRM	GDS
6029	Lighting	Exterior CFL Fixture	SF	All	NC	MEMD	-	MEMD	MEMD	MEMD	MEMD	MEMD	MEMD	MEMD	MEMD	MEMD
6030	Lighting	Exterior LED Fixture	SF	All	NC	MEMD	-	MEMD	MEMD	MEMD	MEMD	MEMD	MEMD	MEMD	MEMD	MEMD
6031	Lighting	Standard CFL	MH	All	NC	MEMD	-	MEMD	MEMD	MEMD	MEMD	MEMD	MEMD	MEMD	MEMD	MEMD
6032	Lighting	Standard LED	MH	All	NC	MEMD	-	MEMD	MEMD	MEMD	MEMD	MEMD	MEMD	MEMD	MEMD	MEMD
6033	Lighting	Specialty CFL	MH	All	NC	GDS calc	-	GDS calc	GDS calc	GDS calc	GDS calc	Ill TRM	GDS	Ill TRM	Ill TRM	GDS
6034	Lighting	Specialty LED	MH	All	NC	GDS calc	-	GDS calc	GDS calc	GDS calc	GDS calc	Ill TRM	GDS	Ill TRM	Ill TRM	GDS
6035	Lighting	Reflector CFL	MH	All	NC	GDS calc	-	GDS calc	GDS calc	GDS calc	GDS calc	Ill TRM	GDS	Ill TRM	Ill TRM	GDS
6036	Lighting	Reflector LED	MH	All	NC	GDS calc	-	GDS calc	GDS calc	GDS calc	GDS calc	Ill TRM	GDS	Ill TRM	Ill TRM	GDS
6037	Lighting	Energy Star Torchiere	MH	All	NC	GDS calc	-	GDS calc	GDS calc	GDS calc	GDS calc	Ill TRM	GDS	Ill TRM	GDS	GDS
6038	Lighting	LED Nightlight	MH	All	NC	GDS calc	-	GDS calc	GDS calc	GDS calc	GDS calc	Ill TRM	GDS	Ill TRM	GDS	GDS
6039	Lighting	Exterior CFL Fixture	MH	All	NC	GDS calc	-	GDS calc	GDS calc	GDS calc	GDS calc	Ill TRM	GDS	Ill TRM	GDS	GDS
6040	Lighting	Exterior LED Fixture	MH	All	NC	GDS calc	-	GDS calc	GDS calc	GDS calc	GDS calc	Ill TRM	GDS	Ill TRM	GDS	GDS
7001	Water Heating	Low Flow Faucet Aerators	SF	All	Retrofit	Ill TRM	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM
7002	Water Heating	Low Flow Showerhead	SF	All	Retrofit	Ill TRM	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM
7003	Water Heating	Thermostatic Restriction Valve	SF	All	Retrofit	Ill TRM	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM
7004	Water Heating	Water Heater Blanket	SF	All	Retrofit	Ill TRM	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM
7005	Water Heating	Water Heater Pipe Wrap	SF	All	Retrofit	Ill TRM	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM
7006	Water Heating	Heat Pump Water Heater (Resistance heat)	SF	All	MO	Ill TRM	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM
7007	Water Heating	Heat Pump Water Heater (ASHP heat)	SF	All	MO	Ill TRM	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM
7008	Water Heating	Solar Water Heating	SF	All	MO	Ill TRM	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM
7009	Water Heating	Low Flow Faucet Aerators	MH	All	Retrofit	Ill TRM	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Mid-Atl TRM	Ill TRM
7010	Water Heating	Low Flow Showerhead	MH	All	Retrofit	Ill TRM	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Mid-Atl TRM	Ill TRM
7011	Water Heating	Thermostatic Restriction Valve	MH	All	Retrofit	Ill TRM	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Mid-Atl TRM	Ill TRM
7012	Water Heating	Water Heater Blanket	MH	All	Retrofit	Ill TRM	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Mid-Atl TRM	Ill TRM
7013	Water Heating	Water Heater Pipe Wrap	MH	All	Retrofit	Ill TRM	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM

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7014	Water Heating	Heat Pump Water Heater (Resistance heat)	MH	All	MO	Ill TRM	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM
7015	Water Heating	Heat Pump Water Heater (ASHP heat)	MH	All	MO	Ill TRM	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM
7016	Water Heating	Low Flow Faucet Aerators	SF	All	NC	Ill TRM	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM
7017	Water Heating	Low Flow Showerhead	SF	All	NC	Ill TRM	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM
7018	Water Heating	Thermostatic Restriction Valve	SF	All	NC	Ill TRM	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM
7019	Water Heating	Water Heater Blanket	SF	All	NC	Ill TRM	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM
7020	Water Heating	Water Heater Pipe Wrap	SF	All	NC	Ill TRM	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM
7021	Water Heating	Heat Pump Water Heater (ASHP heat)	SF	All	NC	Ill TRM	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM
7022	Water Heating	Solar Water Heating	SF	All	NC	Ill TRM	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM
7023	Water Heating	Low Flow Faucet Aerators	MH	All	NC	Ill TRM	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM
7024	Water Heating	Low Flow Showerhead	MH	All	NC	Ill TRM	-	MEMD	MEMD	MEMD	GDS	GDS	Ill TRM	MEMD	MEMD	IN TRM
7025	Water Heating	Thermostatic Restriction Valve	MH	All	NC	Ill TRM	-	MEMD	MEMD	MEMD	GDS	GDS	Ill TRM	MEMD	MEMD	IN TRM
7026	Water Heating	Water Heater Blanket	MH	All	NC	Ill TRM	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM
7027	Water Heating	Water Heater Pipe Wrap	MH	All	NC	Ill TRM	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM
7028	Water Heating	Heat Pump Water Heater (ASHP heat)	MH	All	NC	Ill TRM	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM
8001	HVAC Shell	Insulation - Ceiling (R-0 to R-38) - (Elec AC & Gas Heat)	SF	All	Retrofit	BEopt	-	BEopt	BEopt	BEopt	BEopt	GDS	Ill TRM	Ill TRM	NEEP	Ill TRM
8002	HVAC Shell	Insulation - Ceiling (R-11 to R-49) - (Elec AC & Gas Heat)	SF	All	Retrofit	BEopt	-	BEopt	BEopt	BEopt	BEopt	GDS	Ill TRM	Ill TRM	NEEP	Ill TRM
8003	HVAC Shell	Insulation - Ceiling (R-19 to R-49) - (Elec AC & Gas Heat)	SF	All	Retrofit	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	NEEP	Ill TRM
8004	HVAC Shell	Insulation - Floor (R-0 to R-19) - (Elec AC & Gas Heat)	SF	All	Retrofit	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	NEEP / GDS	Ill TRM
8005	HVAC Shell	Insulation - Floor (R-11 to R-30) - (Elec AC & Gas Heat)	SF	All	Retrofit	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	NREL	Ill TRM
8006	HVAC Shell	Energy Star Windows - (Elec AC & Gas Heat)	SF	All	Retrofit	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	NREL	Ill TRM
8007	HVAC Shell	Air Sealing - (Elec AC & Gas Heat)	SF	All	Retrofit	BEopt	-	BEopt	BEopt	BEopt	BEopt	Mid Atl TRM	Mid Atl TRM	Mid Atl TRM	MEMD	Mid Atl TRM
8008	HVAC Shell	Duct Sealing - (Elec AC & Gas Heat)	SF	All	Retrofit	BEopt	-	BEopt	BEopt	BEopt	BEopt	Mid Atl TRM	Mid Atl TRM	Mid Atl TRM	MEMD	Mid Atl TRM

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Measure #	End-Use	Measure Name	Home Type	Income Type	Replacement Type	Base Annual Electric	% Electric Savings	Per Unit Elec Savings	Per Unit Summer NCP kW	Per Unit Winter NCP kW	Per unit NG Saving	Per Unit Water Savings	RC EUL	EE EUL	Initial Measure Cost	O&M Benefits
8009	HVAC Shell	Radiant Barriers - (Elec AC & Gas Heat)	SF	All	Retrofit	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	NEEP	Ill TRM
8010	HVAC Shell	Insulation - Ceiling (R-0 to R-38) - (Elec HP)	SF	All	Retrofit	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	NEEP	Ill TRM
8011	HVAC Shell	Insulation - Ceiling (R-11 to R-49) - (Elec HP)	SF	All	Retrofit	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	MEMD	Ill TRM
8012	HVAC Shell	Insulation - Ceiling (R-19 to R-49) - (Elec HP)	SF	All	Retrofit	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	MEMD	Ill TRM
8013	HVAC Shell	Insulation - Floor (R-0 to R-19) - (Elec HP)	SF	All	Retrofit	BEopt	-	BEopt	BEopt	BEopt	BEopt	GDS	Ark TRM	Ark TRM	NREL	Ill TRM
8014	HVAC Shell	Insulation - Floor (R-11 to R-30) - (Elec HP)	SF	All	Retrofit	BEopt	-	BEopt	BEopt	BEopt	BEopt	GDS	Ill TRM	Ill TRM	NEEP	Ill TRM
8015	HVAC Shell	Energy Star Windows - (Elec HP)	SF	All	Retrofit	BEopt	-	BEopt	BEopt	BEopt	BEopt	GDS	Ill TRM	Ill TRM	NEEP	Ill TRM
8016	HVAC Shell	Air Sealing - (Elec HP)	SF	All	Retrofit	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	NEEP	Ill TRM
8017	HVAC Shell	Duct Sealing - (Elec HP)	SF	All	Retrofit	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	NEEP / GDS	Ill TRM
8018	HVAC Shell	Radiant Barriers - (Elec HP)	SF	All	Retrofit	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	NREL	Ill TRM
8019	HVAC Shell	Insulation - Ceiling (R-0 to R-38) - (Elec Furnace / AC)	SF	All	Retrofit	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	NREL	Ill TRM
8020	HVAC Shell	Insulation - Ceiling (R-11 to R-49) - (Elec Furnace / AC)	SF	All	Retrofit	BEopt	-	BEopt	BEopt	BEopt	BEopt	Mid Atl TRM	Mid Atl TRM	Mid Atl TRM	MEMD	Mid Atl TRM
8021	HVAC Shell	Insulation - Ceiling (R-19 to R-49) - (Elec Furnace / AC)	SF	All	Retrofit	BEopt	-	BEopt	BEopt	BEopt	BEopt	Mid Atl TRM	Mid Atl TRM	Mid Atl TRM	MEMD	Mid Atl TRM
8022	HVAC Shell	Insulation - Floor (R-0 to R-19) - (Elec Furnace / AC)	SF	All	Retrofit	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	NEEP	Ill TRM
8023	HVAC Shell	Insulation - Floor (R-11 to R-30) - (Elec Furnace / AC)	SF	All	Retrofit	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	NEEP	Ill TRM
8024	HVAC Shell	Energy Star Windows - (Elec Furnace / AC)	SF	All	Retrofit	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	MEMD	Ill TRM
8025	HVAC Shell	Air Sealing - (Elec Furnace / AC)	SF	All	Retrofit	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	MEMD	Ill TRM

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Measure #	End-Use	Measure Name	Home Type	Income Type	Replacement Type	Base Annual Electric	% Electric Savings	Per Unit Elec Savings	Per Unit Summer NCP kW	Per Unit Winter NCP kW	Per unit NG Saving	Per Unit Water Savings	RC EUL	EE EUL	Initial Measure Cost	O&M Benefits
8026	HVAC Shell	Duct Sealing - (Elec Furnace / AC)	SF	All	Retrofit	BEopt	-	BEopt	BEopt	BEopt	BEopt	GDS	Ark TRM	Ark TRM	NREL	Ill TRM
8027	HVAC Shell	Radiant Barriers - (Elec Furnace / AC)	SF	All	Retrofit	BEopt	-	BEopt	BEopt	BEopt	BEopt	GDS	Ill TRM	Ill TRM	NEEP	Ill TRM
8028	HVAC Shell	Insulation - Ceiling (R-0 to R-38) - (Elec AC & Gas Heat)	MH	All	Retrofit	BEopt	-	BEopt	BEopt	BEopt	BEopt	GDS	Ill TRM	Ill TRM	NEEP	Ill TRM
8029	HVAC Shell	Energy Star Windows - (Elec AC & Gas Heat)	MH	All	Retrofit	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	NEEP	Ill TRM
8030	HVAC Shell	Air Sealing - (Elec AC & Gas Heat)	MH	All	Retrofit	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	NEEP / GDS	Ill TRM
8031	HVAC Shell	Duct Sealing - (Elec AC & Gas Heat)	MH	All	Retrofit	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	NREL	Ill TRM
8032	HVAC Shell	Insulation - Ceiling (R-0 to R-38) - (Elec HP)	MH	All	Retrofit	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	NREL	Ill TRM
8033	HVAC Shell	Energy Star Windows - (Elec HP)	MH	All	Retrofit	BEopt	-	BEopt	BEopt	BEopt	BEopt	Mid Atl TRM	Mid Atl TRM	Mid Atl TRM	MEMD	Mid Atl TRM
8034	HVAC Shell	Air Sealing - (Elec HP)	MH	All	Retrofit	BEopt	-	BEopt	BEopt	BEopt	BEopt	Mid Atl TRM	Mid Atl TRM	Mid Atl TRM	MEMD	Mid Atl TRM
8035	HVAC Shell	Duct Sealing - (Elec HP)	MH	All	Retrofit	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	NEEP	Ill TRM
8036	HVAC Shell	Insulation - Ceiling (R-0 to R-38) - (Elec Furnace / AC)	MH	All	Retrofit	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	NEEP	Ill TRM
8037	HVAC Shell	Energy Star Windows - (Elec Furnace / AC)	MH	All	Retrofit	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	MEMD	Ill TRM
8038	HVAC Shell	Air Sealing - (Elec Furnace / AC)	MH	All	Retrofit	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	MEMD	Ill TRM
8039	HVAC Shell	Duct Sealing - (Elec Furnace / AC)	MH	All	Retrofit	BEopt	-	BEopt	BEopt	BEopt	BEopt	GDS	Ark TRM	Ark TRM	NREL	Ill TRM
9001	HVAC Equipment	HVAC Tune-Up (Central AC)	SF	All	Retrofit	BEopt	-	Ill TRM	Ill TRM	Ill TRM	GDS	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM
9002	HVAC Equipment	High Efficiency Central AC - 16 SEER	SF	All	MO	BEopt	-	Ill TRM	Ill TRM	Ill TRM	GDS	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM
9003	HVAC Equipment	High Efficiency Central AC - 16 SEER	SF	All	ER1	BEopt	-	Ill TRM	Ill TRM	Ill TRM	GDS	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM
9004	HVAC Equipment	High Efficiency Central AC - 16 SEER	SF	All	ER2	BEopt	-	Ill TRM	Ill TRM	Ill TRM	GDS	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM
9005	HVAC Equipment	High Efficiency Central AC - 17 SEER	SF	All	MO	Mid-Atl TRM / GDS calc	-	Mid-Atl TRM / GDS calc	Mid-Atl TRM / GDS calc	GDS	GDS	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM

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Measure #	End-Use	Measure Name	Home Type	Income Type	Replacement Type	Base Annual Electric	% Electric Savings	Per Unit Elec Savings	Per Unit Summer NCP kW	Per Unit Winter NCP kW	Per unit NG Saving	Per Unit Water Savings	RC EUL	EE EUL	Initial Measure Cost	O&M Benefits
9006	HVAC Equipment	High Efficiency Central AC - 17 SEER	SF	All	ER1	Mid-Atl TRM / GDS calc	-	Mid-Atl TRM / GDS calc	Mid-Atl TRM / GDS calc	GDS	GDS	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM
9007	HVAC Equipment	High Efficiency Central AC - 17 SEER	SF	All	ER2	Mid-Atl TRM / GDS calc	-	Mid-Atl TRM / GDS calc	Mid-Atl TRM / GDS calc	GDS	GDS	Ill TRM	Ill TRM	Ill TRM	GDS	Ill TRM
9008	HVAC Equipment	High Efficiency Central AC - 18 SEER	SF	All	MO	Mid-Atl TRM / GDS calc	-	Mid-Atl TRM / GDS calc	Mid-Atl TRM / GDS calc	GDS	GDS	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM
9009	HVAC Equipment	High Efficiency Central AC - 18 SEER	SF	All	ER1	Mid-Atl TRM / GDS calc	-	Mid-Atl TRM / GDS calc	Mid-Atl TRM / GDS calc	GDS	GDS	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM
9010	HVAC Equipment	High Efficiency Central AC - 18 SEER	SF	All	ER2	Mid-Atl TRM / GDS calc	-	Mid-Atl TRM / GDS calc	Mid-Atl TRM / GDS calc	GDS	GDS	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM
9011	HVAC Equipment	High Efficiency Central AC - 19 SEER	SF	All	MO	Mid-Atl TRM / GDS calc	-	Mid-Atl TRM / GDS calc	Mid-Atl TRM / GDS calc	GDS	GDS	Ill TRM	Ill TRM	Ill TRM	GDS	Ill TRM
9012	HVAC Equipment	High Efficiency Central AC - 19 SEER	SF	All	ER1	Mid-Atl TRM / GDS calc	-	Mid-Atl TRM / GDS calc	Mid-Atl TRM / GDS calc	GDS	GDS	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM
9013	HVAC Equipment	High Efficiency Central AC - 19 SEER	SF	All	ER2	Ill TRM	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	MEMD	Ill TRM
9014	HVAC Equipment	High Efficiency Central AC - 20 SEER	SF	All	MO	Ill TRM	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	MEMD	Ill TRM
9015	HVAC Equipment	High Efficiency Central AC - 20 SEER	SF	All	ER1	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	DEER 2016	Ill TRM
9016	HVAC Equipment	High Efficiency Central AC - 20 SEER	SF	All	ER2	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	DEER 2016	Ill TRM
9017	HVAC Equipment	Ductless mini-split AC	SF	All	MO	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	GDS	Ill TRM
9018	HVAC Equipment	HVAC Tune-Up (Heat Pump)	SF	All	Retrofit	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	DEER 2016	Ill TRM
9019	HVAC Equipment	High Efficiency Heat Pump (HP Upgrade) - 16 SEER/9.0 HSPF	SF	All	MO	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	DEER 2016	Ill TRM
9020	HVAC Equipment	High Efficiency Heat Pump (HP Upgrade) - 16 SEER/9.0 HSPF	SF	All	ER1	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	DEER 2016	Ill TRM
9021	HVAC Equipment	High Efficiency Heat Pump (HP Upgrade) - 16 SEER/9.0 HSPF	SF	All	ER2	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	GDS	Ill TRM
9022	HVAC Equipment	High Efficiency Heat Pump (HP Upgrade) - 17 SEER/9.5 HSPF	SF	All	MO	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	DEER 2016	Ill TRM

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Measure #	End-Use	Measure Name	Home Type	Income Type	Replacement Type	Base Annual Electric	% Electric Savings	Per Unit Elec Savings	Per Unit Summer NCP kW	Per Unit Winter NCP kW	Per unit NG Saving	Per Unit Water Savings	RC EUL	EE EUL	Initial Measure Cost	O&M Benefits
9023	HVAC Equipment	High Efficiency Heat Pump (HP Upgrade) - 17 SEER/9.5 HSPF	SF	All	ER1	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	DEER 2016	Ill TRM
9024	HVAC Equipment	High Efficiency Heat Pump (HP Upgrade) - 17 SEER/9.5 HSPF	SF	All	ER2	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	DEER 2016	Ill TRM
9025	HVAC Equipment	High Efficiency Heat Pump (HP Upgrade) - 18 SEER/10 HSPF	SF	All	MO	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	GDS	Ill TRM
9026	HVAC Equipment	High Efficiency Heat Pump (HP Upgrade) - 18 SEER/10 HSPF	SF	All	ER1	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	DEER 2016	Ill TRM
9027	HVAC Equipment	High Efficiency Heat Pump (HP Upgrade) - 18 SEER/10 HSPF	SF	All	ER2	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	DEER 2016	Ill TRM
9028	HVAC Equipment	Ground Source Heat Pump (HP Upgrade)	SF	All	MO	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	DEER 2016	Ill TRM
9029	HVAC Equipment	Ground Source Heat Pump (HP Upgrade)	SF	All	ER1	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	GDS	Ill TRM
9030	HVAC Equipment	Ground Source Heat Pump (HP Upgrade)	SF	All	ER2	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	DEER 2016	Ill TRM
9031	HVAC Equipment	Dual Fuel Heat Pump Upgrade (Replacing New ASHP)	SF	All	MO	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	DEER 2016	Ill TRM
9032	HVAC Equipment	Ductless mini-split HP (replacing ASHP)	SF	All	MO	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	DEER 2016	Ill TRM
9033	HVAC Equipment	Heat Pump (Replacing Electric Furnace) - 16 SEER/9.0 HSPF	SF	All	MO	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	GDS	Ill TRM
9034	HVAC Equipment	Heat Pump (Replacing Electric Furnace) - 16 SEER/9.0 HSPF	SF	All	ER1	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	DEER 2016	Ill TRM
9035	HVAC Equipment	Heat Pump (Replacing Electric Furnace) - 16 SEER/9.0 HSPF	SF	All	ER2	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	DEER 2016	Ill TRM
9036	HVAC Equipment	Heat Pump (Replacing Electric Furnace) - 17 SEER/9.5 HSPF	SF	All	MO	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	DEER 2016	Ill TRM
9037	HVAC Equipment	Heat Pump (Replacing Electric Furnace) - 17 SEER/9.5 HSPF	SF	All	ER1	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	GDS	Ill TRM
9038	HVAC Equipment	Heat Pump (Replacing Electric Furnace) - 17 SEER/9.5 HSPF	SF	All	ER2	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	DEER 2016	Ill TRM
9039	HVAC Equipment	Heat Pump (Replacing Electric Furnace) - 18 SEER/10 HSPF	SF	All	MO	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	DEER 2016 / GDS	Ill TRM
9040	HVAC Equipment	Heat Pump (Replacing Electric Furnace) - 18 SEER/10 HSPF	SF	All	ER1	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	DEER 2016 / GDS	Ill TRM
9041	HVAC Equipment	Heat Pump (Replacing Electric Furnace) - 18 SEER/10 HSPF	SF	All	ER2	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	GDS	Ill TRM

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Measure #	End-Use	Measure Name	Home Type	Income Type	Replacement Type	Base Annual Electric	% Electric Savings	Per Unit Elec Savings	Per Unit Summer NCP kW	Per Unit Winter NCP kW	Per unit NG Saving	Per Unit Water Savings	RC EUL	EE EUL	Initial Measure Cost	O&M Benefits
9042	HVAC Equipment	Dual Fuel Heat Pump (Replacing Electric Furnace)	SF	All	MO	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	DEER 2016 / GDS	Ill TRM
9043	HVAC Equipment	Ductless mini-split HP (Replacing Furnace)	SF	All	MO	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	DEER 2016 / GDS	Ill TRM
9044	HVAC Equipment	Energy Star Room A/C	SF	All	MO	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	DEER 2016 / GDS	Ill TRM
9045	HVAC Equipment	Energy Star Room A/C	SF	All	ER1	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	GDS	Ill TRM
9046	HVAC Equipment	Energy Star Room A/C	SF	All	ER2	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	DEER 2016 / GDS	Ill TRM
9047	HVAC Equipment	Room Air Conditioner Recycling	SF	All	Recycle	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	DEER 2016 / GDS	Ill TRM
9048	HVAC Equipment	ECM Furnace Fan	SF	All	Retrofit	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	DEER 2016 / GDS	Ill TRM
9049	HVAC Equipment	Programmable Thermostat - Gas/AC - Tier 1	SF	All	Retrofit	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	GDS	Ill TRM
9050	HVAC Equipment	Smart Thermostat - Gas Heat / AC - Tier 2	SF	All	Retrofit	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	DEER 2016 / GDS	Ill TRM
9051	HVAC Equipment	Peak Period Thermostat - Gas Heat / AC - Tier 3	SF	All	Retrofit	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	DEER 2016 / GDS	Ill TRM
9052	HVAC Equipment	Programmable Thermostat - ASHP - Tier 1	SF	All	Retrofit	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	DEER 2016 / GDS	Ill TRM
9053	HVAC Equipment	Smart Thermostat - ASHP - Tier 2	SF	All	Retrofit	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	GDS	Ill TRM
9054	HVAC Equipment	Peak Period Thermostat - ASHP - Tier 3	SF	All	Retrofit	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	DEER 2016 / GDS	Ill TRM
9055	HVAC Equipment	Programmable Thermostat - Elec Furnace/AC - Tier 1	SF	All	Retrofit	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	Ill TRM / DEER 2016	Ill TRM
9056	HVAC Equipment	Smart Thermostat - Elec Furnace/AC - Tier 2	SF	All	Retrofit	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	Ill TRM / DEER 2016	Ill TRM
9057	HVAC Equipment	Peak Period Thermostat - Elec Furnace/AC - Tier 3	SF	All	Retrofit	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	Ill TRM / DEER 2016	Ill TRM
9058	HVAC Equipment	HVAC Tune-Up (Central AC)	MH	All	Retrofit	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	Ill TRM / DEER 2016	Ill TRM
9059	HVAC Equipment	High Efficiency Central AC - 16 SEER	MH	All	MO	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	DEER 2016	Ill TRM

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Measure #	End-Use	Measure Name	Home Type	Income Type	Replacement Type	Base Annual Electric	% Electric Savings	Per Unit Elec Savings	Per Unit Summer NCP kW	Per Unit Winter NCP kW	Per unit NG Saving	Per Unit Water Savings	RC EUL	EE EUL	Initial Measure Cost	O&M Benefits
9060	HVAC Equipment	High Efficiency Central AC - 16 SEER	MH	All	ER1	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	DEER 2016	Ill TRM
9061	HVAC Equipment	High Efficiency Central AC - 16 SEER	MH	All	ER2	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	GDS	Ill TRM
9062	HVAC Equipment	High Efficiency Central AC - 17 SEER	MH	All	MO	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	DEER 2016	Ill TRM
9063	HVAC Equipment	High Efficiency Central AC - 17 SEER	MH	All	ER1	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	DEER 2016	Ill TRM
9064	HVAC Equipment	High Efficiency Central AC - 17 SEER	MH	All	ER2	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	DEER 2016	Ill TRM
9065	HVAC Equipment	High Efficiency Central AC - 18 SEER	MH	All	MO	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	GDS	Ill TRM
9066	HVAC Equipment	High Efficiency Central AC - 18 SEER	MH	All	ER1	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	DEER 2016	Ill TRM
9067	HVAC Equipment	High Efficiency Central AC - 18 SEER	MH	All	ER2	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	DEER 2016	Ill TRM
9068	HVAC Equipment	High Efficiency Central AC - 19 SEER	MH	All	MO	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	DEER 2016	Ill TRM
9069	HVAC Equipment	High Efficiency Central AC - 19 SEER	MH	All	ER1	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	GDS	Ill TRM
9070	HVAC Equipment	High Efficiency Central AC - 19 SEER	MH	All	ER2	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	DEER 2016	Ill TRM
9071	HVAC Equipment	High Efficiency Central AC - 20 SEER	MH	All	MO	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	DEER 2016	Ill TRM
9072	HVAC Equipment	High Efficiency Central AC - 20 SEER	MH	All	ER1	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	DEER 2016	Ill TRM
9073	HVAC Equipment	High Efficiency Central AC - 20 SEER	MH	All	ER2	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	GDS	Ill TRM
9074	HVAC Equipment	Ductless mini-split AC	MH	All	MO	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	DEER 2016	Ill TRM
9075	HVAC Equipment	HVAC Tune-Up (Heat Pump)	MH	All	Retrofit	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	DEER 2016	Ill TRM
9076	HVAC Equipment	High Efficiency Heat Pump (HP Upgrade) - 16 SEER/9.0 HSPF	MH	All	MO	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	DEER 2016	Ill TRM
9077	HVAC Equipment	High Efficiency Heat Pump (HP Upgrade) - 16 SEER/9.0 HSPF	MH	All	ER1	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	GDS	Ill TRM
9078	HVAC Equipment	High Efficiency Heat Pump (HP Upgrade) - 16 SEER/9.0 HSPF	MH	All	ER2	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	DEER 2016	Ill TRM
9079	HVAC Equipment	High Efficiency Heat Pump (HP Upgrade) - 17 SEER/9.5 HSPF	MH	All	MO	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	DEER 2016	Ill TRM
9080	HVAC Equipment	High Efficiency Heat Pump (HP Upgrade) - 17 SEER/9.5 HSPF	MH	All	ER1	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	DEER 2016	Ill TRM
9081	HVAC Equipment	High Efficiency Heat Pump (HP Upgrade) - 17 SEER/9.5 HSPF	MH	All	ER2	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	GDS	Ill TRM
9082	HVAC Equipment	High Efficiency Heat Pump (HP Upgrade) - 18 SEER/10 HSPF	MH	All	MO	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	DEER 2016	Ill TRM
9083	HVAC Equipment	High Efficiency Heat Pump (HP Upgrade) - 18 SEER/10 HSPF	MH	All	ER1	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	DEER 2016	Ill TRM
9084	HVAC Equipment	High Efficiency Heat Pump (HP Upgrade) - 18 SEER/10 HSPF	MH	All	ER2	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	DEER 2016	Ill TRM

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9085	HVAC Equipment	Dual Fuel Heat Pump Upgrade (Replacing New ASHP)	MH	All	MO	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	GDS	Ill TRM
9086	HVAC Equipment	Ductless mini-split HP (Replacing ASHP)	MH	All	MO	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	DEER 2016	Ill TRM
9087	HVAC Equipment	Heat Pump (Replacing Electric Furnace) - 16 SEER/9.0 HSPF	MH	All	MO	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	DEER 2016	Ill TRM
9088	HVAC Equipment	Heat Pump (Replacing Electric Furnace) - 16 SEER/9.0 HSPF	MH	All	ER1	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	DEER 2016	Ill TRM
9089	HVAC Equipment	Heat Pump (Replacing Electric Furnace) - 16 SEER/9.0 HSPF	MH	All	ER2	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	GDS	Ill TRM
9090	HVAC Equipment	Heat Pump (Replacing Electric Furnace) - 17 SEER/9.5 HSPF	MH	All	MO	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	DEER 2016	Ill TRM
9091	HVAC Equipment	Heat Pump (Replacing Electric Furnace) - 17 SEER/9.5 HSPF	MH	All	ER1	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	DEER 2016	Ill TRM
9092	HVAC Equipment	Heat Pump (Replacing Electric Furnace) - 17 SEER/9.5 HSPF	MH	All	ER2	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	GDS	Ill TRM
9093	HVAC Equipment	Heat Pump (Replacing Electric Furnace) - 18 SEER/10 HSPF	MH	All	MO	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	DEER 2016	Ill TRM
9094	HVAC Equipment	Heat Pump (Replacing Electric Furnace) - 18 SEER/10 HSPF	MH	All	ER1	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	DEER 2016	Ill TRM
9095	HVAC Equipment	Heat Pump (Replacing Electric Furnace) - 18 SEER/10 HSPF	MH	All	ER2	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	GDS	Ill TRM
9096	HVAC Equipment	Dual Fuel Heat Pump (Replacing Electric Furnace)	MH	All	MO	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	DEER 2016	Ill TRM
9097	HVAC Equipment	Ductless mini-split HP (Replacing furnace)	MH	All	MO	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	DEER 2016	Ill TRM
9098	HVAC Equipment	Energy Star Room A/C	MH	All	MO	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	GDS	Ill TRM
9099	HVAC Equipment	Energy Star Room A/C	MH	All	ER1	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	DEER 2016	Ill TRM
9100	HVAC Equipment	Energy Star Room A/C	MH	All	ER2	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	DEER 2016	Ill TRM
9101	HVAC Equipment	Room Air Conditioner Recycling	MH	All	Recycle	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	GDS	Ill TRM
9102	HVAC Equipment	ECM Furnace Fan	MH	All	Retrofit	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	DEER 2016	Ill TRM
9103	HVAC Equipment	Programmable Thermostat - Gas/AC - Tier 1	MH	All	Retrofit	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	DEER 2016	Ill TRM
9104	HVAC Equipment	Smart Thermostat - Gas Heat / AC - Tier 2	MH	All	Retrofit	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	GDS	Ill TRM

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9105	HVAC Equipment	Peak Period Thermostat - Gas Heat / AC - Tier 3	MH	All	Retrofit	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	DEER 2016	Ill TRM
9106	HVAC Equipment	Programmable Thermostat - ASHP - Tier 1	MH	All	Retrofit	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	DEER 2016	Ill TRM
9107	HVAC Equipment	Smart Thermostat - ASHP - Tier 2	MH	All	Retrofit	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	DEER 2016	Ill TRM
9108	HVAC Equipment	Peak Period Thermostat - ASHP - Tier 3	MH	All	Retrofit	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	DEER 2016	Ill TRM
9109	HVAC Equipment	Programmable Thermostat - Elec Furnace/AC - Tier 1	MH	All	Retrofit	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	DEER 2016	Ill TRM
9110	HVAC Equipment	Smart Thermostat - Elec Furnace/AC - Tier 2	MH	All	Retrofit	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	DEER 2016	Ill TRM
9111	HVAC Equipment	Peak Period Thermostat - Elec Furnace/AC - Tier 3	MH	All	Retrofit	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	Ill TRM / DEER 2016	Ill TRM
9112	HVAC Equipment	High Efficiency Central AC - 16 SEER	SF	All	NC	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	Ill TRM / DEER 2016	Ill TRM
9113	HVAC Equipment	High Efficiency Central AC - 17 SEER	SF	All	NC	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	Ill TRM / DEER 2016	Ill TRM
9114	HVAC Equipment	High Efficiency Central AC - 18 SEER	SF	All	NC	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	Ill TRM / DEER 2016	Ill TRM
9115	HVAC Equipment	High Efficiency Central AC - 19 SEER	SF	All	NC	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	Ill TRM / DEER 2016	Ill TRM
9116	HVAC Equipment	High Efficiency Central AC - 20 SEER	SF	All	NC	BEopt	-	BEopt	BEopt	BEopt	BEopt	Ill TRM	Ill TRM	Ill TRM	Ill TRM / DEER 2016	Ill TRM
9117	HVAC Equipment	Ductless mini-split AC	SF	All	NC	BEopt	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM
9118	HVAC Equipment	High Efficiency Heat Pump (HP Upgrade) - 16 SEER/9.0 HSPF	SF	All	NC	BEopt	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM
9119	HVAC Equipment	High Efficiency Heat Pump (HP Upgrade) - 17 SEER/9.5 HSPF	SF	All	NC	BEopt	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM
9120	HVAC Equipment	High Efficiency Heat Pump (HP Upgrade) - 18 SEER/10 HSPF	SF	All	NC	BEopt	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM
9121	HVAC Equipment	Ground Source Heat Pump (HP Upgrade)	SF	All	NC	BEopt	-	MN TRM	MN TRM	MN TRM	MN TRM	GDS	MN TRM	MN TRM	MN TRM / Mid-Atl TRM	Ill TRM

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9122	HVAC Equipment	Dual Fuel Heat Pump Upgrade (Replacing New ASHP)	SF	All	NC	BEopt	-	MN TRM	MN TRM	MN TRM	MN TRM	GDS	MN TRM	MN TRM	MN TRM	Ill TRM
9123	HVAC Equipment	Ductless mini-split HP (replacing ASHP)	SF	All	NC	BEopt	-	MN TRM	MN TRM	MN TRM	MN TRM	GDS	MN TRM	MN TRM	MN TRM / Mid-Atl TRM	Ill TRM
9124	HVAC Equipment	Energy Star Room A/C	SF	All	NC	BEopt	-	MN TRM	MN TRM	MN TRM	MN TRM	GDS	MN TRM	MN TRM	MN TRM	Ill TRM
9125	HVAC Equipment	ECM Furnace Fan	SF	All	NC	BEopt	-	MN TRM	MN TRM	MN TRM	MN TRM	GDS	MN TRM	MN TRM	MN TRM / Mid-Atl TRM	Ill TRM
9126	HVAC Equipment	Programmable Thermostat - Gas/AC - Tier 1	SF	All	NC	BEopt	-	MN TRM	MN TRM	MN TRM	MN TRM	GDS	MN TRM	MN TRM	MN TRM	Ill TRM
9127	HVAC Equipment	Smart Thermostat - Gas Heat / AC - Tier 2	SF	All	NC	BEopt	-	MN TRM	MN TRM	MN TRM	MN TRM	GDS	MN TRM	MN TRM	MN TRM / Mid-Atl TRM	Ill TRM
9128	HVAC Equipment	Peak Period Thermostat - Gas Heat / AC - Tier 3	SF	All	NC	BEopt	-	MN TRM	MN TRM	MN TRM	MN TRM	GDS	MN TRM	MN TRM	MN TRM	Ill TRM
9129	HVAC Equipment	Programmable Thermostat - ASHP - Tier 1	SF	All	NC	BEopt	-	MN TRM	MN TRM	MN TRM	MN TRM	GDS	MN TRM	MN TRM	MN TRM / Mid-Atl TRM	Ill TRM
9130	HVAC Equipment	Smart Thermostat - ASHP - Tier 2	SF	All	NC	BEopt	-	MN TRM	MN TRM	MN TRM	MN TRM	GDS	MN TRM	MN TRM	MN TRM / Mid-Atl TRM	Ill TRM
9131	HVAC Equipment	Peak Period Thermostat - ASHP - Tier 3	SF	All	NC	BEopt	-	MN TRM	MN TRM	MN TRM	MN TRM	GDS	MN TRM	MN TRM	MN TRM / Mid-Atl TRM	Ill TRM
9132	HVAC Equipment	High Efficiency Central AC - 16 SEER	MH	All	NC	BEopt	-	MN TRM	MN TRM	MN TRM	MN TRM	GDS	MN TRM	MN TRM	MN TRM	Ill TRM
9133	HVAC Equipment	High Efficiency Central AC - 17 SEER	MH	All	NC	BEopt	-	MN TRM	MN TRM	MN TRM	MN TRM	GDS	MN TRM	MN TRM	MN TRM / Mid-Atl TRM	Ill TRM
9134	HVAC Equipment	High Efficiency Central AC - 18 SEER	MH	All	NC	BEopt	-	MN TRM	MN TRM	MN TRM	MN TRM	GDS	MN TRM	MN TRM	MN TRM	Ill TRM
9135	HVAC Equipment	High Efficiency Central AC - 19 SEER	MH	All	NC	BEopt	-	MN TRM	MN TRM	MN TRM	MN TRM	GDS	MN TRM	MN TRM	MN TRM / Mid-Atl TRM	Ill TRM
9136	HVAC Equipment	High Efficiency Central AC - 20 SEER	MH	All	NC	BEopt	-	MN TRM	MN TRM	MN TRM	MN TRM	GDS	MN TRM	MN TRM	MN TRM	Ill TRM
9137	HVAC Equipment	Ductless mini-split AC	MH	All	NC	BEopt	-	MN TRM	MN TRM	MN TRM	MN TRM	GDS	MN TRM	MN TRM	MN TRM / Mid-Atl TRM	Ill TRM
9138	HVAC Equipment	High Efficiency Heat Pump (HP Upgrade) - 16 SEER/9.0 HSPF	MH	All	NC	BEopt	-	MN TRM	MN TRM	MN TRM	MN TRM	GDS	MN TRM	MN TRM	MN TRM	Ill TRM

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9139	HVAC Equipment	High Efficiency Heat Pump (HP Upgrade) - 17 SEER/9.5 HSPF	MH	All	NC	BEopt	-	MN TRM	MN TRM	MN TRM	MN TRM	GDS	MN TRM	MN TRM	MN TRM / Mid-Atl TRM	Ill TRM
9140	HVAC Equipment	High Efficiency Heat Pump (HP Upgrade) - 18 SEER/10 HSPF	MH	All	NC	BEopt	-	MN TRM	MN TRM	MN TRM	MN TRM	GDS	MN TRM	MN TRM	MN TRM / Mid-Atl TRM	Ill TRM
9141	HVAC Equipment	Dual Fuel Heat Pump Upgrade (Replacing New ASHP)	MH	All	NC	BEopt	-	MN TRM	MN TRM	MN TRM	MN TRM	GDS	MN TRM	MN TRM	MN TRM / Mid-Atl TRM	Ill TRM
9142	HVAC Equipment	Ductless mini-split HP (Replacing ASHP)	MH	All	NC	BEopt	-	MN TRM	MN TRM	MN TRM	MN TRM	GDS	MN TRM	MN TRM	MN TRM	Ill TRM
9143	HVAC Equipment	Energy Star Room A/C	MH	All	NC	BEopt	-	MN TRM	MN TRM	MN TRM	MN TRM	GDS	MN TRM	MN TRM	MN TRM / Mid-Atl TRM	Ill TRM
9144	HVAC Equipment	ECM Furnace Fan	MH	All	NC	BEopt	-	MN TRM	MN TRM	MN TRM	MN TRM	GDS	MN TRM	MN TRM	MN TRM	Ill TRM
9145	HVAC Equipment	Programmable Thermostat - Gas/AC - Tier 1	MH	All	NC	BEopt	-	MN TRM	MN TRM	MN TRM	MN TRM	GDS	MN TRM	MN TRM	MN TRM / Mid-Atl TRM	Ill TRM
9146	HVAC Equipment	Smart Thermostat - Gas Heat / AC - Tier 2	MH	All	NC	BEopt	-	MN TRM	MN TRM	MN TRM	MN TRM	GDS	MN TRM	MN TRM	MN TRM	Ill TRM
9147	HVAC Equipment	Peak Period Thermostat - Gas Heat / AC - Tier 3	MH	All	NC	BEopt	-	MN TRM	MN TRM	MN TRM	MN TRM	GDS	MN TRM	MN TRM	MN TRM / Mid-Atl TRM	Ill TRM
9148	HVAC Equipment	Programmable Thermostat - ASHP - Tier 1	MH	All	NC	BEopt	-	MN TRM	MN TRM	MN TRM	MN TRM	GDS	MN TRM	MN TRM	MN TRM	Ill TRM
9149	HVAC Equipment	Smart Thermostat - ASHP - Tier 2	MH	All	NC	BEopt	-	MN TRM	MN TRM	MN TRM	MN TRM	GDS	MN TRM	MN TRM	MN TRM / Mid-Atl TRM	Ill TRM
9150	HVAC Equipment	Peak Period Thermostat - ASHP - Tier 3	MH	All	NC	BEopt	-	MN TRM	MN TRM	MN TRM	MN TRM	GDS	MN TRM	MN TRM	MN TRM / Mid-Atl TRM	Ill TRM
10001	Behavioral	In Home Energy Display Monitor - Gas/CAC	SF	All	Retrofit	BEopt	-	E3T	E3T	E3T	E3T	GDS	VT TRM 2010	VT TRM 2010	E3T	GDS
10002	Behavioral	Home Energy Reports - Gas/CAC	SF	All	OptOut	BEopt	-	E3T	E3T	E3T	E3T	GDS	VT TRM 2010	VT TRM 2010	E3T	GDS
10003	Behavioral	In Home Energy Display Monitor - ASHP	SF	All	Retrofit	BEopt	-	E3T	E3T	E3T	E3T	GDS	VT TRM 2010	VT TRM 2010	E3T	GDS
10004	Behavioral	Home Energy Reports - ASHP	SF	All	OptOut	BEopt	-	E3T	E3T	E3T	E3T	GDS	VT TRM 2010	VT TRM 2010	E3T	GDS
10005	Behavioral	In Home Energy Display Monitor - Elec Furn/CAC	SF	All	Retrofit	BEopt	-	E3T	E3T	E3T	E3T	GDS	VT TRM 2010	VT TRM 2010	E3T	GDS

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10006	Behavioral	Home Energy Reports - Elec Furn/CAC	SF	All	OptOut	BEopt	-	E3T	E3T	E3T	E3T	GDS	VT TRM 2010	VT TRM 2010	E3T	GDS
10007	Behavioral	In Home Energy Display Monitor - Gas/CAC	MH	All	Retrofit	BEopt	-	E3T	E3T	E3T	E3T	GDS	VT TRM 2010	VT TRM 2010	E3T	GDS
10008	Behavioral	Home Energy Reports - Gas/CAC	MH	All	OptOut	BEopt	-	E3T	E3T	E3T	E3T	GDS	VT TRM 2010	VT TRM 2010	E3T	GDS
10009	Behavioral	In Home Energy Display Monitor - ASHP	MH	All	Retrofit	BEopt	-	E3T	E3T	E3T	E3T	GDS	VT TRM 2010	VT TRM 2010	E3T	GDS
10010	Behavioral	Home Energy Reports - ASHP	MH	All	OptOut	BEopt	-	E3T	E3T	E3T	E3T	GDS	VT TRM 2010	VT TRM 2010	E3T	GDS
10011	Behavioral	In Home Energy Display Monitor - Elec Furn/CAC	MH	All	Retrofit	BEopt	-	MEMD	MEMD	MEMD	MEMD	GDS	MEMD	MEMD	MEMD	GDS
10012	Behavioral	Home Energy Reports - Elec Furn/CAC	MH	All	OptOut	BEopt	-	MEMD	MEMD	MEMD	MEMD	GDS	MEMD	MEMD	MEMD	GDS
10013	Behavioral	In Home Energy Display Monitor - Gas/CAC	SF	All	NC	BEopt	-	MEMD	MEMD	MEMD	MEMD	GDS	MEMD	MEMD	MEMD	GDS
10014	Behavioral	Home Energy Reports - Gas/CAC	SF	All	NC	BEopt	-	MEMD	MEMD	MEMD	MEMD	GDS	MEMD	MEMD	MEMD	GDS
10015	Behavioral	In Home Energy Display Monitor - ASHP	SF	All	NC	BEopt	-	MEMD	MEMD	MEMD	MEMD	GDS	MEMD	MEMD	MEMD	GDS
10016	Behavioral	Home Energy Reports - ASHP	SF	All	NC	BEopt	-	MEMD	MEMD	MEMD	MEMD	GDS	MEMD	MEMD	MEMD	GDS
10017	Behavioral	In Home Energy Display Monitor - Gas/CAC	MH	All	NC	BEopt	-	MEMD	MEMD	MEMD	MEMD	GDS	MEMD	MEMD	MEMD	GDS
10018	Behavioral	Home Energy Reports - Gas/CAC	MH	All	NC	BEopt	-	MEMD	MEMD	MEMD	MEMD	GDS	MEMD	MEMD	MEMD	GDS
10019	Behavioral	In Home Energy Display Monitor - ASHP	MH	All	NC	BEopt	-	MEMD	MEMD	MEMD	MEMD	GDS	MEMD	MEMD	MEMD	GDS
10020	Behavioral	Home Energy Reports - ASHP	MH	All	NC	BEopt	-	MEMD	MEMD	MEMD	MEMD	GDS	MEMD	MEMD	MEMD	GDS
11001	Pool/Spa	Two Speed Pool Pumps	SF	All	MO	Ill TRM	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM
11002	Pool/Spa	Variable Speed Pool Pumps	SF	All	MO	Ill TRM	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM
11003	Pool/Spa	Two Speed Pool Pumps	SF	All	NC	Ill TRM	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM
11004	Pool/Spa	Variable Speed Pool Pumps	SF	All	NC	Ill TRM	-	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM	Ill TRM

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Appendix B - Residential Measure Detail
Source Reference

Measure #	End-Use	Measure Name	Home Type	Income Type	Replacement Type	Base Annual Electric	% Electric Savings	Per Unit Elec Savings	Per Unit Summer NCP kW	Per Unit Winter NCP kW	Per unit NG Saving	Per Unit Water Savings	RC EUL	EE EUL	Initial Measure Cost	O&M Benefits
12001	Cross-Cutting	Multi-Family Homes Efficiency Kit	MF	All	Retrofit	GDS	-	DEC RNP	DEC RNP	DEC RNP	GDS	GDS	DEC RNP / Mid-Atl TRM	DEC RNP	GDS	GDS
12002	Cross-Cutting	Multi-Family Homes Efficiency Kit	MF	All	NC	GDS	-	DEC RNP	DEC RNP	DEC RNP	GDS	GDS	DEC RNP / Mid-Atl TRM	DEC RNP	GDS	GDS
13001	New Construction	Touchstone Home - 15% more efficient (w/AC only) - New Single-family home	SF	All	NC	BEopt	-	BEopt	BEopt	BEopt	BEopt	GDS	PA TRM	PA TRM	ACEEE 2008 SS	GDS
13002	New Construction	Touchstone Home - 30% more efficient (w/AC only) - New Single-family home	SF	All	NC	BEopt	-	BEopt	BEopt	BEopt	BEopt	GDS	PA TRM	PA TRM	ACEEE 2008 SS	GDS
13003	New Construction	Touchstone Home - 15% more efficient (w/Elec. HP) - New Single-family home	SF	All	NC	BEopt	-	BEopt	BEopt	BEopt	BEopt	GDS	PA TRM	PA TRM	ACEEE 2008 SS	GDS
13004	New Construction	Touchstone Home - 30% more efficient (w/Elec. HP) - New Single-family home	SF	All	NC	BEopt	-	BEopt	BEopt	BEopt	BEopt	GDS	PA TRM	PA TRM	ACEEE 2008 SS	GDS
13005	New Construction	Touchstone Home - 15% more efficient (w/AC only) - New manufactured home	MH	All	NC	BEopt	-	BEopt	BEopt	BEopt	BEopt	GDS	PA TRM	PA TRM	ACEEE 2008 SS	GDS
13006	New Construction	Touchstone Home - 30% more efficient (w/AC only) - New manufactured home	MH	All	NC	BEopt	-	BEopt	BEopt	BEopt	BEopt	GDS	PA TRM	PA TRM	ACEEE 2008 SS	GDS
13007	New Construction	Touchstone Home - 15% more efficient (w/Elec. HP) - New manufactured home	MH	All	NC	BEopt	-	BEopt	BEopt	BEopt	BEopt	GDS	PA TRM	PA TRM	ACEEE 2008 SS	GDS
13008	New Construction	Touchstone Home - 30% more efficient (w/Elec. HP) - New manufactured home	MH	All	NC	BEopt	-	BEopt	BEopt	BEopt	BEopt	GDS	PA TRM	PA TRM	ACEEE 2008 SS	GDS

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Appendix B - Residential Measure Detail
Source Reference

Measure #	End-Use	Measure Name	Home Type	Income Type	Replacement Type	Base Annual Electric	% Electric Savings	Per Unit Elec Savings	Per Unit Summer NCP kW	Per Unit Winter NCP kW	Per unit NG Saving	Per Unit Water Savings	RC EUL	EE EUL	Initial Measure Cost	O&M Benefits

Definitions

ACEEE 2008 SS:	How Much More Does It Cost to Build an ENERGY STAR® Home? Incremental Cost Estimation Process. 2008 ACEEE Summer Study on Energy Efficiency in Buildings.
Ark TRM:	Arkansas Technical Reference Manual Version 5.0
BEopt:	Building Energy Optimization software
CPUC:	2010-2012 WO 017 Ex Ante Measure Cost Study Final Report
DEC RNP:	Duke Energy Carolinas 2015 Residential Neighborhoods Program Final Evaluation Report
EIA:	EIA -Technology Forecast Updates – Residential and Commercial Building Technologies –Reference Case
E3T:	Energy Efficiency Emerging Technologies (E3T) Program E3TNM database (Washington State University Extension Energy Program)
GDS:	Engineering judgment by GDS Assocaites, Inc. (GDS) professional staff
GDS calc:	Calculation by GDS - see Notes column for any additional details
GDS/ES:	GDS calculation based on ENERGY STAR specifications - see Notes column for any additional details
Ill TRM:	Illinois Statewide Technical Reference Manual for Energy Efficiency Version 6.0
IN TRM:	Indiana Technical Resource Manual, version 1.0. January 10, 2013
LED ICS:	LED Incremental Cost Study Overall Final Report, February 2016. Cadmus.
MEMD:	2017 Michigan Energy Measures Database
Mid-Atl TRM:	Mid-Atlantic Technical Reference Manual Version 6.0
MN TRM:	Minnesota Technical Reference Manual Version 2.0
NEEP:	Northeast Energy Efficiency Partnerships, Incremental Cost Study
NREL:	National Residential Efficiency Measures Database, National Renewable Energy Laboratory
PA TRM:	Technical Reference Manual 2016, Pennsylvania Public Utility Commission
VT TRM:	Efficiency Vermont Technical Reference Manual (TRM) Measure Savings Algrorithms and Cost Assumptions
VT TRM 2010:	Efficiency Vermont Technical Reference Manual (TRM) Measure Savings Algrorithms and Cost Assumptions (2010 version)

Appendix C – Commercial & Industrial Measure Detail

APPENDIX C: COMMERCIAL & INDUSTRIAL MEASURE DETAIL

Big Rivers Electric Corporation
2017 DSM Potential Study
Appendix C - Commercial and Industrial Measure Detail

	Measure Name	Unit Notes	Annual kWh Saved	Percent Savings (kWh)	Per Unit NCP kW	Summer KW Savings	Incremental Cost	Measure Useful Life	TRC	Direct Utility	Societal	Participant	RIM
	Lighting -												
1	Compact Fluorescent	bulb	151.3	67.8%	0.039	0.033	$1.20	3	17.6	42.8	17.6	32.9	0.5
2	LED Exit Sign	exit sign	88.6	81.8%	0.009	0.012	$30.00	16	3.8	5.4	3.8	6.3	0.4
3	High Performance T8 (vs T8) 4ft	fixture	152.7	40.7%	0.033	0.028	$18.00	15	6.4	20.4	6.4	10.8	0.6
4	Wall Mounted Occupancy Sensor	sensor	338.7	24.0%	0.000	0.062	$51.00	8	1.2	4.5	1.2	5.3	0.3
5	Fixture Mounted Occupancy Sensor	sensor	199.9	24.0%	0.000	0.036	$91.83	8	0.4	1.5	0.4	2.0	0.2
6	Remote Mounted Occupancy Sensor	sensor	574.1	24.0%	0.000	0.104	$101.00	8	1.0	3.9	1.0	4.6	0.3
7	High Bay 3 or 4 lamp T8VHO vs (Metal Halide 100W - 300W)	fixture	683.8	50.1%	0.148	0.124	$200.00	15	2.6	8.2	2.6	4.6	0.6
8	High Bay 6 or 8 lamp T8VHO vs (Metal Halide > 300W)	fixture	1,506.5	52.7%	0.326	0.274	$250.00	15	4.5	14.5	4.5	7.8	0.6
9	High performance T5 (replacing T8)	fixture	240.6	22.4%	0.052	0.044	$100.00	15	1.8	5.8	1.8	3.3	0.6
10	CFL Hard Wired Fixture	fixture	201.3	69.0%	0.044	0.037	$37.50	12	3.3	10.6	3.3	5.9	0.6
11	CFL High Wattage 31-115	bulb	387.1	55.4%	0.084	0.070	$21.00	3	2.0	5.9	2.0	4.7	0.4
12	CFL High Wattage 150-199	bulb	1,098.9	57.6%	0.238	0.200	$57.00	3	1.9	6.1	1.9	4.7	0.4
13	Low Bay LED (vs Metal Halide)	bulb	308.6	42.5%	0.067	0.056	$331.00	15	0.7	2.2	0.7	1.5	0.5
14	High Bay LED (vs Metal Halide)	bulb	476.6	35.0%	0.103	0.087	$482.00	15	0.7	2.4	0.7	1.6	0.5
15	Outdoor LED (vs Metal Halide)	bulb	348.1	62.5%	0.061	0.000	$190.00	15	2.6	1.9	2.6	2.3	1.9
16	Outdoor Induction (vs Metal Halide)	bulb	792.3	56.9%	0.061	0.000	$355.00	15	1.4	1.0	1.4	1.4	1.0
17	LED Screw-In Bulb	bulb	207.7	63.9%	0.046	0.039	$1.20	15	131.9	421.5	131.9	213.8	0.6
18	LED Downlight Fixtures	fixture	169.8	67.6%	0.037	0.031	$27.00	15	4.7	15.1	4.7	8.1	0.6
19	LED Linear Replacement Lamps	bulb	68.9	44.3%	0.015	0.013	$24.00	15	2.2	6.9	2.2	3.9	0.6

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Appendix C - Commercial and Industrial Measure Detail

	Measure Name	Unit Notes	Annual kWh Saved	Percent Savings (kWh)	Per Unit NCP kW	Summer KW Savings	Incremental Cost	Measure Useful Life	TRC	Direct Utility	Societal	Participant	RIM
	Space Cooling -												
22	Split AC (13 SEER to 14.5 SEER)	5 ton	172.1	3.4%	0.148	0.071	$315.00	15	0.8	2.3	0.8	1.1	0.8
23	Split AC (13 SEER to 15 SEER)	5 ton	332.8	6.7%	0.286	0.137	$315.00	15	1.6	4.5	1.6	1.7	0.9
24	Split AC (13 SEER to 16 SEER)	5 ton	623.9	12.5%	0.536	0.256	$635.00	15	1.5	4.1	1.5	1.7	0.9
25	Split AC (11.4 IEER to 13 IEER)	8.3 ton	1,257.4	12.3%	1.080	0.516	$522.90	15	3.6	10.1	3.6	3.5	1.0
26	Split AC (11.4 IEER to 14 IEER)	8.3 ton	1,897.4	18.6%	1.629	0.779	$1,054.10	15	2.7	7.6	2.7	2.7	1.0
27	Split AC (11.4 IEER to 15 IEER)	8.3 ton	2,452.0	24.0%	2.105	1.006	$1,054.10	15	3.4	9.8	3.4	3.4	1.0
28	DX Packaged System (CEE Tier 2)	10 ton	2,351.1	18.8%	2.019	0.965	$1,270.00	15	2.7	7.8	2.7	2.8	1.0
29	DX Packaged System (CEE Tier 2)	< 20 ton	2,932.1	15.4%	2.517	1.203	$1,905.00	15	2.3	6.5	2.3	2.4	1.0
30	DX Packaged System (CEE Tier 2)	> 20 ton	7,700.5	18.2%	6.612	3.160	$3,810.00	15	3.0	8.5	3.0	3.0	1.0
31	Air Cooled Chiller	20 ton	9,295.1	13.1%	3.281	1.568	$2,540.00	20	3.9	11.1	3.9	6.3	0.6
32	Air Cooled Chiller	100 ton	46,475.6	13.1%	16.406	7.842	$12,700.00	20	3.9	11.1	3.9	6.3	0.6
33	PTAC	1/2 ton	197.8	22.9%	0.110	0.053	$42.00	15	5.2	14.8	5.2	6.6	0.8
34	PTAC	3/4 ton	250.2	21.9%	0.140	0.067	$63.00	15	4.4	12.5	4.4	5.6	0.8
35	PTAC	1 ton	354.2	23.2%	0.198	0.094	$84.00	15	4.6	13.3	4.6	5.9	0.8
36	PTAC	1 1/4 ton	416.2	19.5%	0.232	0.111	$105.00	15	4.4	12.5	4.4	5.6	0.8
37	HVAC Tune-Up	5 ton	349.4	7.0%	0.300	0.143	$175.00	3	0.6	1.7	0.6	1.0	0.6
	Space Heating -												
43	PTHP	1/2 ton	1,548.4	56.7%	0.119	0.057	$42.00	15	17.2	49.2	17.2	49.1	0.4
44	PTHP	3/4 ton	1,902.8	53.8%	0.132	0.063	$63.00	15	13.9	39.7	13.9	40.3	0.3
45	PTHP	1 ton	2,583.6	54.0%	0.206	0.099	$84.00	15	14.4	41.3	14.4	41.0	0.4
46	PTHP	1 1/4 ton	3,123.8	51.6%	0.234	0.112	$105.00	15	13.8	39.5	13.8	39.7	0.3
	Ventilation -												
52	Variable Frequency Drives	<2 HP	1,846.8	65.4%	0.228	0.228	$1,330.00	15	0.9	2.6	0.9	2.2	0.4
53	Variable Frequency Drives	3 to 10 HP	13,014.1	65.4%	1.604	1.604	$1,622.00	15	5.3	15.1	5.3	11.0	0.5
54	Variable Frequency Drives	11 to 50 HP	50,341.5	65.4%	6.206	6.206	$3,089.00	15	10.8	31.0	10.8	22.1	0.5

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Appendix C - Commercial and Industrial Measure Detail

	Measure Name	Unit Notes	Annual kWh Saved	Percent Savings (kWh)	Per Unit NCP kW	Summer KW Savings	Incremental Cost	Measure Useful Life	TRC	Direct Utility	Societal	Participant	RIM
	Motors (Non-Ventilation) -												
60	Variable Frequency Drives	<2 HP	734.4	41.1%	0.170	0.170	$1,330.00	10	0.2	0.6	0.2	0.9	0.2
61	Variable Frequency Drives	3 to 10 HP	5,175.2	41.1%	1.195	1.195	$1,622.00	10	1.2	3.3	1.2	3.4	0.3
62	Variable Frequency Drives	11 to 50 HP	20,018.8	41.1%	4.622	4.622	$3,059.00	10	2.4	6.9	2.4	6.7	0.4
	Water Heating -												
67	High Efficiency Storage (Tank)	40 gallon unit	8.6	0.2%	0.001	0.001	$70.00	15	0.1	0.2	0.1	0.5	0.1
68	Pre-Rinse Sprayer, Low flow, Commercial Application		4,155.6	44.2%	0.000	0.000	$92.90	5	7.1	20.2	7.1	24.0	0.3
69	On Demand (Tankless)	10 gpm unit	7,905.0	7.4%	0.000	0.900	$1,050.00	5	1.2	3.4	1.2	4.3	0.3
70	Tank Insulation		512.0	30.0%	0.262	0.091	$60.00	12	6.2	17.6	6.2	9.9	0.6
71	Heat Pump Water Heater		2,401.0	58.8%	0.372	0.344	$1,050.00	15	1.2	3.6	1.2	3.4	0.4
	Cooking -												
77	Electric Energy Star Fryers		469.8	3.9%	0.080	0.080	$210.00	12	1.2	3.4	1.2	2.8	0.4
78	Electric Energy Star Steamers,3-6 pan		13,649.4	70.2%	6.228	2.491	$2,490.00	12	4.7	13.5	4.7	6.5	0.7
79	Energy Star Hot Food Holding Cabinet	3/4 Size (12 ft^3)	3,942.0	60.0%	0.720	0.288	$1,800.00	12	1.2	3.4	1.2	2.8	0.4
80	Energy Star Convection Ovens		2,201.8	28.2%	1.005	0.402	$1,000.00	12	1.9	5.4	1.9	2.8	0.7
81	Energy Star Griddles		2,597.0	10.0%	0.593	0.237	$2,090.00	12	0.7	2.1	0.7	1.7	0.4

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Appendix C - Commercial and Industrial Measure Detail

	Measure Name	Unit Notes	Annual kWh Saved	Percent Savings (kWh)	Per Unit NCP kW	Summer KW Savings	Incremental Cost	Measure Useful Life	TRC	Direct Utility	Societal	Participant	RIM
	Refrigeration -												
87	Glass Door Freezer, <15-49 cu ft, Energy Star	25 cu ft	2,018.0	24.2%	0.344	0.266	$256.00	12	5.7	16.4	5.7	9.2	0.6
88	Glass Door Freezer, 50+ cu ft, Energy Star	75 cu ft	8,437.3	38.3%	1.440	1.112	$256.00	12	24.0	68.6	24.0	37.1	0.6
89	Solid Door Freezer, <15-49 cu ft, Energy Star	25 cu ft	869.3	20.9%	0.148	0.115	$158.00	12	4.0	11.4	4.0	6.5	0.6
90	Solid Door Freezer, 50+ cu ft, Energy Star	75 cu ft	4,820.2	42.1%	0.823	0.635	$407.00	12	8.6	24.6	8.6	13.6	0.6
91	Glass Door Refrigerator, <15 - 49 cu ft	25 cu ft	653.8	28.2%	0.112	0.086	$158.00	12	3.0	8.6	3.0	5.0	0.6
92	Glass Door Refrigerator, 50+ cu ft, Energy Star	75 cu ft	1,219.9	27.1%	0.208	0.161	$158.00	12	5.6	16.1	5.6	9.0	0.6
93	Solid Door Refrigerator, <15-49 cu ft, Energy Star	25 cu ft	516.8	31.2%	0.088	0.068	$157.00	12	2.4	6.9	2.4	4.0	0.6
94	Solid Door Refrigerator, 50+ cu ft, Energy Star	75 cu ft	1,323.7	38.0%	0.226	0.174	$249.00	12	3.9	11.1	3.9	6.3	0.6
95	Commercial Refrigeration Tune-Up, Medium Temp, not self-contained		537.0	7.0%	0.125	0.125	$75.00	1	0.5	1.5	0.5	1.2	0.5
96	Commercial Refrigeration Tune-Up, Low Temp, not self contained		1,388.0	7.0%	0.241	0.241	$75.00	1	1.2	3.4	1.2	2.5	0.5
97	Anti-sweat heater controls on freezers	2 doors	2,557.2	74.8%	0.000	0.000	$300.00	12	2.7	7.7	2.7	9.9	0.3
98	Anti-sweat heater controls, on refrigerators	2 doors	1,082.3	67.1%	0.000	0.000	$300.00	12	1.1	3.3	1.1	4.4	0.3
99	Vending Miser, Cold Beverage		1,613.0	46.0%	0.000	0.000	$180.00	5	1.3	3.6	1.3	5.1	0.3
100	Brushless DC Motors for freezers and coolers	1/15 to 1/20 HP	1,064.0	8.8%	0.121	0.121	$177.00	15	4.3	12.4	4.3	8.3	0.5
101	Humidity Door Heater Controls for freezers and coolers	2 doors	1,819.8	71.0%	0.000	0.000	$300.00	12	1.9	5.5	1.9	7.1	0.3
102	Refrigerated Case Covers	6 linear feet	1,009.7	9.0%	0.000	0.000	$252.00	5	0.6	1.8	0.6	2.5	0.3
103	Zero Energy Doors for freezers and coolers		800.0	20.0%	0.208	0.208	$538.00	10	1.2	3.3	1.2	1.8	0.7
104	Evaporator Coil Defrost Control		600.0	43.6%	0.510	0.510	$500.00	10	2.3	6.6	2.3	1.5	1.5
105	Evaporator Fan Motor Control for freezers and coolers	1/3 HP	1,524.0	35.8%	0.174	0.174	$291.00	16	2.5	7.1	2.5	7.6	0.3
106	Ice Machine, Energy Star, Self-Contained		270.0	10.2%	0.037	0.037	$56.00	9	2.4	6.8	2.4	4.6	0.5
107	LED Case Lighting (per door)	per 4 feet	266.0	50.0%	0.043	0.041	$136.60	8	1.2	2.7	1.2	2.1	0.5

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	Measure Name	Unit Notes	Annual kWh Saved	Percent Savings (kWh)	Per Unit NCP kW	Summer KW Savings	Incremental Cost	Measure Useful Life	TRC	Direct Utility	Societal	Participant	RIM
	Office Equipment/Appliances -												
113	Watt Sensors on Office Electronics	50 Watt	50.0	37.5%	0.000	0.000	$29.00	5	0.2	0.7	0.2	1.3	0.2
114	Watt Sensors on Office Electronics	200 Watt	200.0	39.4%	0.000	0.000	$29.00	5	1.0	2.8	1.0	4.0	0.2
	Compressed Air -												
120	Fix Air Leaks	<5HP	262.5	15.0%	0.107	0.080	$75.00	1	0.2	0.7	0.2	0.7	0.3
121	Fix Air Leaks	10-50HP	2,009.7	15.0%	0.815	0.612	$75.00	1	1.8	5.2	1.8	3.4	0.5
122	Fix Air Leaks	50-100HP	6,134.5	15.0%	2.489	1.867	$75.00	1	5.5	15.8	5.5	9.7	0.6
123	Engineered Nozzles for blow-off	Avg of 1/8" and 1/4"	788.3	50.0%	0.138	0.131	$49.50	15	10.1	28.8	10.1	21.4	0.5

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	Measure Name	Annual kWh Saved	Per Unit NCP kW	Summer KW Savings	Incremental Cost	Measure Useful Life
	Lighting -					
1	Compact Fluorescent	1 - Illinois	1 - Illinois	1 - Illinois	1 - Illinois	1 - Illinois
2	LED Exit Sign	1 - Illinois	1 - Illinois	1 - Illinois	1 - Illinois	1 - Illinois
3	High Performance T8 (vs T8) 4ft	1 - Illinois	1 - Illinois	1 - Illinois	1 - Illinois	1 - Illinois
4	Wall Mounted Occupancy Sensor	1 - Illinois	1 - Illinois	1 - Illinois	1 - Illinois	1 - Illinois
5	Fixture Mounted Occupancy Sensor	1 - Illinois	1 - Illinois	1 - Illinois	1 - Illinois	1 - Illinois
6	Remote Mounted Occupancy Sensor	1 - Illinois	1 - Illinois	1 - Illinois	1 - Illinois	1 - Illinois
7	High Bay 3 or 4 lamp T8VHO vs (Metal Halide 100W - 300W)	1 - Illinois	1 - Illinois	1 - Illinois	1 - Illinois	1 - Illinois
8	High Bay 6 or 8 lamp T8VHO vs (Metal Halide > 300W)	1 - Illinois	1 - Illinois	1 - Illinois	1 - Illinois	1 - Illinois
9	High performance T5 (replacing T8)	1 - Illinois	1 - Illinois	1 - Illinois	1 - Illinois	1 - Illinois
10	CFL Hard Wired Fixture	2 - Indiana	2 - Indiana	2 - Indiana	2 - Indiana	2 - Indiana
11	CFL High Wattage 31-115	4 - GDS	4 - GDS	4 - GDS	9 - Green Elec	2 - Indiana
12	CFL High Wattage 150-199	4 - GDS	4 - GDS	4 - GDS	9 - Green Elec	2 - Indiana
13	Low Bay LED (vs Metal Halide)	1 - Illinois	1 - Illinois	1 - Illinois	1 - Illinois	1 - Illinois
14	High Bay LED (vs Metal Halide)	1 - Illinois	1 - Illinois	1 - Illinois	1 - Illinois	1 - Illinois
15	Outdoor LED (vs Metal Halide)	1 - Illinois	1 - Illinois	1 - Illinois	1 - Illinois	1 - Illinois
16	Outdoor Induction (vs Metal Halide)	1 - Illinois	1 - Illinois	1 - Illinois	1 - Illinois	1 - Illinois
17	LED Screw-In Bulb	1 - Illinois	1 - Illinois	1 - Illinois	1 - Illinois	1 - Illinois
18	LED Downlight Fixtures	1 - Illinois	1 - Illinois	1 - Illinois	1 - Illinois	1 - Illinois
19	LED Linear Replacement Lamps	1 - Illinois	1 - Illinois	1 - Illinois	1 - Illinois	1 - Illinois

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	Measure Name	Annual kWh Saved	Per Unit NCP kW	Summer KW Savings	Incremental Cost	Measure Useful Life
	Space Cooling -					
22	Split AC (13 SEER to 14.5 SEER)	4 - GDS	4 - GDS	1 - Illinois	1 - Illinois	1 - Illinois
23	Split AC (13 SEER to 15 SEER)	4 - GDS	4 - GDS	1 - Illinois	1 - Illinois	1 - Illinois
24	Split AC (13 SEER to 16 SEER)	4 - GDS	4 - GDS	1 - Illinois	1 - Illinois	1 - Illinois
25	Split AC (11.4 IEER to 13 IEER)	4 - GDS	4 - GDS	1 - Illinois	1 - Illinois	1 - Illinois
26	Split AC (11.4 IEER to 14 IEER)	4 - GDS	4 - GDS	1 - Illinois	1 - Illinois	1 - Illinois
27	Split AC (11.4 IEER to 15 IEER)	4 - GDS	4 - GDS	1 - Illinois	1 - Illinois	1 - Illinois
28	DX Packaged System (CEE Tier 2)	4 - GDS	4 - GDS	1 - Illinois	1 - Illinois	1 - Illinois
29	DX Packaged System (CEE Tier 2)	4 - GDS	4 - GDS	1 - Illinois	1 - Illinois	1 - Illinois
30	DX Packaged System (CEE Tier 2)	4 - GDS	4 - GDS	1 - Illinois	1 - Illinois	1 - Illinois
31	Air Cooled Chiller	2 - Indiana	2 - Indiana	1 - Illinois	1 - Illinois	2 - Indiana
32	Air Cooled Chiller	2 - Indiana	2 - Indiana	1 - Illinois	1 - Illinois	2 - Indiana
33	PTAC	1 - Illinois	1 - Illinois	1 - Illinois	1 - Illinois	1 - Illinois
34	PTAC	1 - Illinois	1 - Illinois	1 - Illinois	1 - Illinois	1 - Illinois
35	PTAC	1 - Illinois	1 - Illinois	1 - Illinois	1 - Illinois	1 - Illinois
36	PTAC	1 - Illinois	1 - Illinois	1 - Illinois	1 - Illinois	1 - Illinois
37	HVAC Tune-Up	1 - Illinois	1 - Illinois	1 - Illinois	1 - Illinois	1 - Illinois
	Space Heating -					
43	PTHP	1 - Illinois	1 - Illinois	1 - Illinois	1 - Illinois	1 - Illinois
44	PTHP	1 - Illinois	1 - Illinois	1 - Illinois	1 - Illinois	1 - Illinois
45	PTHP	1 - Illinois	1 - Illinois	1 - Illinois	1 - Illinois	1 - Illinois
46	PTHP	1 - Illinois	1 - Illinois	1 - Illinois	1 - Illinois	1 - Illinois
	Ventilation -					
52	Variable Frequency Drives	1 - Illinois	1 - Illinois	1 - Illinois	1 - Illinois	1 - Illinois
53	Variable Frequency Drives	1 - Illinois	1 - Illinois	1 - Illinois	1 - Illinois	2 - Indiana
54	Variable Frequency Drives	1 - Illinois	1 - Illinois	1 - Illinois	1 - Illinois	2 - Indiana

Big Rivers Electric Corporation
2017 DSM Potential Study
Appendix C - Commercial and Industrial Measure Detail
Source Reference

	Measure Name	Annual kWh Saved	Per Unit NCP kW	Summer KW Savings	Incremental Cost	Measure Useful Life
	Motors (Non-Ventilation) -					
60	Variable Frequency Drives	1 - Illinois	1 - Illinois	1 - Illinois	1 - Illinois	1 - Illinois
61	Variable Frequency Drives	1 - Illinois	1 - Illinois	1 - Illinois	1 - Illinois	1 - Illinois
62	Variable Frequency Drives	1 - Illinois	1 - Illinois	1 - Illinois	1 - Illinois	1 - Illinois
	Water Heating -					
67	High Efficiency Storage (Tank)	4 - GDS	4 - GDS	1 - Illinois	6 - MPRP	1 - Illinois
68	Pre-Rinse Sprayer, Low flow, Commercial Application	1 - Illinois	1 - Illinois	1 - Illinois	1 - Illinois	1 - Illinois
69	On Demand (Tankless)	1 - Illinois	1 - Illinois	1 - Illinois	1 - Illinois	1 - Illinois
70	Tank Insulation	7 - Energy Experts	7 - Energy Experts	8 - Vermont/ 4 -GDS	4 - GDS	7 - Energy Experts
71	Heat Pump Water Heater	2 - Indiana	4 - GDS	1 - Illinois	1 - Illinois	1 - Illinois
	Cooking -					
77	Electric Energy Star Fryers	3 - Mid-Atlantic	3 - Mid-Atlantic	3 - Mid-Atlantic	3 - Mid-Atlantic	3 - Mid-Atlantic
78	Electric Energy Star Steamers,3-6 pan	1 - Illinois	1 - Illinois	1 - Illinois	1 - Illinois	1 - Illinois
79	Energy Star Hot Food Holding Cabinet	1 - Illinois	1 - Illinois	1 - Illinois	1 - Illinois	1 - Illinois
80	Energy Star Convection Ovens	1 - Illinois	1 - Illinois	1 - Illinois	1 - Illinois	1 - Illinois
81	Energy Star Griddles	1 - Illinois	1 - Illinois	1 - Illinois	1 - Illinois	1 - Illinois

Big Rivers Electric Corporation
2017 DSM Potential Study
Appendix C - Commercial and Industrial Measure Detail
Source Reference

	Measure Name	Annual kWh Saved	Per Unit NCP kW	Summer KW Savings	Incremental Cost	Measure Useful Life
	Refrigeration -					
87	Glass Door Freezer, <15-49 cu ft, Energy Star	3 - Mid-Atlantic	3 - Mid-Atlantic	3 - Mid-Atlantic	3 - Mid-Atlantic	3 - Mid-Atlantic
88	Glass Door Freezer, 50+ cu ft, Energy Star	3 - Mid-Atlantic	3 - Mid-Atlantic	3 - Mid-Atlantic	3 - Mid-Atlantic	3 - Mid-Atlantic
89	Solid Door Freezer, <15-49 cu ft, Energy Star	3 - Mid-Atlantic	3 - Mid-Atlantic	3 - Mid-Atlantic	3 - Mid-Atlantic	3 - Mid-Atlantic
90	Solid Door Freezer, 50+ cu ft, Energy Star	3 - Mid-Atlantic	3 - Mid-Atlantic	3 - Mid-Atlantic	3 - Mid-Atlantic	3 - Mid-Atlantic
91	Glass Door Refrigerator, <15 - 49 cu ft	3 - Mid-Atlantic	3 - Mid-Atlantic	3 - Mid-Atlantic	3 - Mid-Atlantic	3 - Mid-Atlantic
92	Glass Door Refrigerator, 50+ cu ft, Energy Star	3 - Mid-Atlantic	3 - Mid-Atlantic	3 - Mid-Atlantic	3 - Mid-Atlantic	3 - Mid-Atlantic
93	Solid Door Refrigerator, <15-49 cu ft, Energy Star	3 - Mid-Atlantic	3 - Mid-Atlantic	3 - Mid-Atlantic	3 - Mid-Atlantic	3 - Mid-Atlantic
94	Solid Door Refrigerator, 50+ cu ft, Energy Star	3 - Mid-Atlantic	3 - Mid-Atlantic	3 - Mid-Atlantic	3 - Mid-Atlantic	3 - Mid-Atlantic
95	Commercial Refrigeration Tune-Up, Medium Temp ,not self contained	5 - Wisconsin	5 - Wisconsin	11 - Arkansas	10 - Refrig	10 - Refrig
96	Commercial Refrigeration Tune-Up, Low Temp, not self contained	5 - Wisconsin	5 - Wisconsin	11 - Arkansas	10 - Refrig	10 - Refrig
97	Anti-sweat heater controls on freezers	1 - Illinois	1 - Illinois	1 - Illinois	1 - Illinois	1 - Illinois
98	Anti-sweat heater controls, on refrigerators	1 - Illinois	1 - Illinois	1 - Illinois	1 - Illinois	1 - Illinois
99	Vending Miser, Cold Beverage	1 - Illinois	1 - Illinois	1 - Illinois	1 - Illinois	1 - Illinois
100	Brushless DC Motors for freezers and coolers	1 - Illinois	1 - Illinois	1 - Illinois	1 - Illinois	1 - Illinois
101	Humidity Door Heater Controls for freezers and coolers	1 - Illinois	1 - Illinois	1 - Illinois	1 - Illinois	1 - Illinois
102	Refrigerated Case Covers	1 - Illinois	1 - Illinois	1 - Illinois	1 - Illinois	1 - Illinois
103	Zero Energy Doors for freezers and coolers	8 - Vermont	8 - Vermont	11 - Arkansas	8 - Vermont	8 - Vermont
104	Evaporator Coil Defrost Control	8 - Vermont	8 - Vermont	11 - Arkansas	8 - Vermont	8 - Vermont
105	Evaporator Fan Motor Control for freezers and coolers	1 - Illinois	1 - Illinois	1 - Illinois	1 - Illinois	1 - Illinois
106	Ice Machine, Energy Star, Self-Contained	5 - Wisconsin	5 - Wisconsin	11 - Arkansas	8 - Vermont	2 - Indiana
107	LED Case Lighting (per door)	3 - Mid-Atlantic	3 - Mid-Atlantic	3 - Mid-Atlantic	3 - Mid-Atlantic	3 - Mid-Atlantic
	Office Equipment/Appliances -					
113	Watt Sensors on Office Electronics	1 - Illinois	1 - Illinois	1 - Illinois	1 - Illinois	1 - Illinois
114	Watt Sensors on Office Electronics	1 - Illinois	1 - Illinois	1 - Illinois	1 - Illinois	1 - Illinois

Big Rivers Electric Corporation
2017 DSM Potential Study
Appendix C - Commercial and Industrial Measure Detail
Source Reference

	Measure Name	Annual kWh Saved	Per Unit NCP kW	Summer KW Savings	Incremental Cost	Measure Useful Life
	Compressed Air -					
120	Fix Air Leaks	12 - Alliant	4 - GDS	4 - GDS	4 - GDS	4 - GDS
121	Fix Air Leaks	12 - Alliant	4 - GDS	4 - GDS	4 - GDS	4 - GDS
122	Fix Air Leaks	12 - Alliant	4 - GDS	4 - GDS	4 - GDS	4 - GDS
123	Engineered Nozzles for blow-off	1 - Illinois	1 - Illinois	1 - Illinois	1 - Illinois	1 - Illinois

Big Rivers Electric Corporation
2017 DSM Potential Study
Appendix C - Commercial and Industrial Measure Detail
Source Reference

Measure Name		Annual kWh Saved	Per Unit NCP kW	Summer KW Savings	Incremental Cost	Measure Useful Life

Descriptions -

1 - Illinois:	2018 Illinois Statewide Technical Reference Manual
2 - Indiana:	Indiana: Indiana Technical Resource Manual Version 1.0 January 10, 2013; TecMarket Works
3 - Mid-Atlantic:	Mid-Atlantic Technical Reference Manual Version 5.0, June 2015
4- GDS:	GDS Associates, Inc. (GDS) Calculation/Estimation
5 - Wisconsin:	Wisconsin KEMA Technical Manual
6 - MPRP:	MPRP Commercial Energy Efficiency and Demand Response Update Spreadsheet, June 2009.
7 - Energy Experts:	http://energyexperts.org/EnergySolutionsDatabase/ResourceDetail.aspx?id=1243
8 - Vermont:	Efficiency Vermont Technical Reference User Manual - Measure Savinsg Algorithms and Cost assumptions
9 - Green Elec:	http://www.greenelectricalsupply.com
10 - Refrig:	http://hvacrdistributionbusiness.com/hot_topics/refrigeration_new_commercial/
11 - Arkansas:	Arkansas Deemed Savings Manual Coincidence factor calculation
12 - Alliant:	Alliant Energy Calculator for Variable Frequency Drives - http://www.alliantenergy.com/UtilityServices/ForYourBusiness/EnergyExpertise/EnergySafety/010794

Appendix D – General Modeling Assumptions

APPENDIX D: GENERAL MODELING ASSUMPTIONS

Big Rivers Electric Corporation
2017 DSM Potential Study
Appendix D - General Modeling Assumptions

Analysis Start Year	2017	
Length of Analysis	10	Years
Nominal Discount Rate	[redacted]	Big Rivers
Inflation Rate		Big Rivers
Reserve Margin Multiplier	15.10%	MISO

	Electric Line Losses				**Demand Line Losses**		
	Winter On Peak	**Winter Off Peak**	**Summer On Peak**	**Summer Off Peak**	**Winter Gen.**	**Summer Gen.**	**T&D Capacity**
Residential	1.073	1.073	1.073	1.073	1.073	1.073	0.000
C&I	1.073	1.073	1.073	1.073	1.073	1.073	0.000

Big Rivers Electric Corporation
2017 DSM Potential Study
Appendix D - General Modeling Assumptions

	Avoided Costs (Nominal Dollars)								Retail Rates (Nominal Dollars)						
Data Year	Natural Gas Wholesale Forecast $/MMBTU	Winter Peak Energy $/kWh	Winter Off-Peak Energy $/kWh	Summer Peak Energy $/kWh	Summer Off-Peak Energy $/kWh	Summer Capacity $/kW-yr	Winter Capacity $/kW-yr	Avoided T&D Capacity $/kW-yr	Residential $/kWh	Commercial $/kWh	Industrial $/kWh	Residential $/MMBTU	Commercial $/MMBTU	Industrial $/MMBTU	Water $/gallon
2017															
2018															
2019															
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Appendix C

Cross-Reference to

Staff Recommendations to 2014 IRP

and

807 KAR 5:058

Commission Staff's Recommendation from Big Rivers 2014 Integrated Resource Plan

Recommendation	Recommendation Description	2017 IRP Reference
Load Forecasting 1	Big Rivers should develop a more diverse group of forecast scenarios which includes a meaningful number of alternatives that are not part of its Mitigation Plan	Section 7.2.1; Section 7.2.3
Load Forecasting 2	Big Rivers 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	Section 1.7 Section 6.6; Section 6.7; Section 7.1.2
Load Forecasting 3	Big Rivers' 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.	Section 4.8
DSM and EE 1	Include estimates of costs associated with proposed and potential environmental rules in future DSM/EE benefit/cost analyses	Section 6.5
DSM and EE 2	Research and report on best practices for DSM/EE program promotion, educational programs, and innovative marketing opportunities	Section 6.5
DSM and EE 3	Research and report on possible partnering with its member cooperatives in order to enhance marketing and reduce advertising costs	Section 6.5
DSM and EE 4	Report on the work undertaken to enhance the evaluation, measurement, and verification procedures to ensure DSM/EE programs are achieving expected goals	Section 6.5
DSM and EE 5	Continue to monitor opportunities for demand response	Section 5.8; Appendix B

Commission Staff's Recommendation from Big Rivers 2014 Integrated Resource Plan

Recommendation	Recommendation Description	2017 IRP Reference
DSM and EE 6	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") and enables eligible students to complete a paper or online energy audit of their homes. Each eligible student who completes a home energy audit receives home EE measures, such as a package of CFL bulbs or an EE starter kit.	Section 6.5
Supply-Side Resource Assessment 1	Big Rivers next IRP should include scenarios where one or more existing units are retired, converted to use alternate fuels, or sold.	Section 7.1.2
Supply-Side Resource Assessment 2	Big Rivers should perform a utility specific reserve margin study, as has been requested previously.	Section 9.4
Supply-Side Resource Assessment 3	Big Rivers 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 CO2	Section 6.5; Section 6.6.6; Section 7.1.1; Section 7.2.3.5
Supply-Side Resource Assessment 4	Big Rivers should include a discussion of its consideration of distributed generation in its next IRP.	Section 2.3, Section 6.5
Supply-Side Resource Assessment 5	Big Rivers should provide information from its member-owner cooperatives on their customers' net metering statistics and activities in its next IRP.	Section 2.3

Commission Staff's Recommendation from Big Rivers 2014 Integrated Resource Plan

Recommendation	Recommendation Description	2017 IRP Reference
Supply-Side Resource Assessment 6	In its next IRP, Big Rivers should continue to provide a detailed discussion of specific generation efficiency improvements and activities undertaken.	Section 6.1
Supply-side Resource Assessment 7	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	Section 6.1; Section 6.6; Section 8.3
Supply-Side Resource Assessment 8	Big Rivers should develop a comprehensive list of options, plans, and costs to achieve compliance with existing, proposed, and anticipated environmental regulations in its next IRP.	Section 7.1.2
Supply-Side Resource Assessment 9	A full and detailed discussion of compliance actions relating to current and pending environmental regulations should be included in Big Rivers' next IRP.	Section 1.7; Section 6.6
Integration and Plan Optimization 1	Big Rivers' 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.	Section 4.2.6; Section 7.2.1; Section 7.2.3
Integration and Plan Optimization 2	Given the timing of its next IRP, Big Rivers should not be constrained in considering increased levels of DSM/EE programs as it was with this IRP. Hence, the optimization and integration analysis in the next IRP should include increased DSM/EE levels.	Section 5.2; Section 7.2.3.6

Kentucky Administrative Regulations – 807 KAR 5:058

Regulation	Regulation Language	2017 IRP Reference
807 KAR 5:058 Section 1 (1)	General Provisions. This administrative regulation shall apply to electric utilities under commission jurisdiction except a distribution company with less than $10,000,000 annual revenue or a distribution cooperative organized under KRS Chapter 279.	Noted
807 KAR 5:058 Section 1 (2)	Each electric utility shall file triennially with the commission an integrated resource plan. The plan shall include historical and projected demand, resource, and financial data, and other operating performance and system information, and shall discuss the facts, assumptions, and conclusions, upon which the plan is based and the actions it proposes.	Noted
807 KAR 5:058 Section 1 (3)	Each electric utility shall file ten (10) bound copies and one (1) unbound, reproducible copy of its integrated resource plan with the commission	Noted
807 KAR 5:058 Section 2 (1)	Filing Schedule. Each electric utility shall file its integrated resource plan according to a staggered schedule which provides for the filing of integrated resource plans one (1) every six (6) months beginning nine (9) months from the effective date of this administrative regulation.	Noted

Kentucky Administrative Regulations – 807 KAR 5:058

Regulation	Regulation Language	2017 IRP Reference
807 KAR 5:058 Section 2 (1) (a)	The integrated resource plans shall be filed at the specified times following the effective date of this administrative regulation:	Noted
	1. Kentucky Utilities Company shall file nine (9) months from the effective date;	
	2. Kentucky Power Company shall file fifteen (15) months from the effective date;	
	3. East Kentucky Power Cooperative, Inc. shall file twenty-one (21) months from the effective date;	
	4. The Union Light, Heat & Power Company shall file twenty-seven (27) months from the effective date;	
	5. Big Rivers Electric Corporation shall file thirty-three (33) months from the effective date; and	
	6. Louisville Gas & Electric Company shall file thirty-nine (39) months from the effective date.	
	The schedule shall provide at such time as all electric utilities have filed integrated resource plans, the sequence shall repeat.	
807 KAR 5:058 Section 2 (1) (c)	The schedule shall remain in effect until changed by the commission on its own motion or on motion of one (1) or more electric utilities for good cause shown. Good cause may include a change in a utility's financial or resource conditions.	Section 1.2
807 KAR 5:058 Section 2 (1) (d)	If any filing date falls on a weekend or holiday, the plan shall be submitted on the first business day following the scheduled filing date.	Noted

Kentucky Administrative Regulations – 807 KAR 5:058

Regulation	Regulation Language	2017 IRP Reference
807 KAR 5:058 Section 2 (2)	Immediately upon filing of an integrated resource plan, each utility shall provide notice to intervenors in its last integrated resource plan review proceeding, that its plan has been filed and is available from the utility upon request.	Notice was provided
807 KAR 5:058 Section 2 (3)	Upon receipt of a utility's integrated resource plan, the commission shall establish a review schedule which may include interrogatories, comments, informal conferences, and staff reports.	Noted
807 KAR 5:058 Section 3	Waiver. A utility may file a motion requesting a waiver of specific provisions of this administrative regulation. Any request shall be made no later than ninety (90) days prior to the date established for filing the integrated resource plan. The commission shall rule on the request within thirty (30) days. The motion shall clearly identify the provision from which the utility seeks a waiver and provide justification for the requested relief which shall include an estimate of costs and benefits of compliance with the specific provision. Notice shall be given in the manner provided in Section 2(2) of this administrative regulation.	Noted
807 KAR 5:058 Section 4 (1)	Format. The integrated resource plan shall be clearly and concisely organized so that it is evident to the commission that the utility has complied with reporting requirements described in subsequent sections.	Appendix "C" Cross-Reference
807 KAR 5:058 Section 4 (2)	Each plan filed shall identify the individuals responsible for its preparation, who shall be available to respond to inquiries during the commission's review of the plan.	Table 1.1

Kentucky Administrative Regulations – 807 KAR 5:058

Regulation	Regulation Language	2017 IRP Reference
807 KAR 5:058 Section 5 (1)	Plan Summary. The plan shall contain a summary which discusses the utility's projected load growth and the resources planned to meet that growth. The summary shall include at a minimum: Description of the utility, its customers, service territory, current facilities, and planning objectives	Chapter 1
807 KAR 5:058 Section 5 (2)	Description of models, methods, data, and key assumptions used to develop the results contained in the plan	Chapters 4, 5, 7, 9; Appendices A, B
807 KAR 5:058 Section 5 (3)	Summary of forecasts of energy and peak demand, and key economic and demographic assumptions or projections underlying these forecasts	Chapter 4; Appendix A
807 KAR 5:058 Section 5 (4)	Summary of the utility's planned resource acquisitions including improvements in operating efficiency of existing facilities, demand-side programs, nonutility sources of generation, new power plants, transmission improvements, bulk power purchases and sales, and interconnections with other utilities	Section 1.6; Section 2.3; Section 4.2.6; Section 6.1; Section 6.4; Chapters 5, 7, 8
807 KAR 5:058 Section 5 (5)	Steps to be taken during the next three (3) years to implement the plan	Section 10.3

Kentucky Administrative Regulations – 807 KAR 5:058

Regulation	Regulation Language	2017 IRP Reference
807 KAR 5:058 Section 5 (6)	Discussion of key issues or uncertainties that could affect successful implementation of the plan.	Section 1.7
807 KAR 5:058 Section 6	Significant Changes. All integrated resource plans, shall have a summary of significant changes since the plan most recently filed. This summary shall describe, in narrative and tabular form, changes in load forecasts, resource plans, assumptions, or methodologies from the previous plan. Where appropriate, the utility may also use graphic displays to illustrate changes.	Chapter 3
807 KAR 5:058 Section 7 (1) (a - g)	Load Forecasts. The plan shall include historical and forecasted information regarding loads. The information shall be provided for the total system and, where available, disaggregated by the following customer classes:	Section 4.1 Section 4.2.1; Section 4.2.2; Section 4.2.3; Section 4.2.5; Section 4.2.6; Appendix A- Section 3.2.7
	(a) Residential heating;	
	(b) Residential non-heating;	
	(c) Total residential (total of paragraphs (a) and (b) of this subsection);	
	(d) Commercial;	
	(e) Industrial;	
	(f) Sales for resale;	
	(g) Utility use and other.	
	The utility shall also provide data at any greater level of disaggregation available.	

Kentucky Administrative Regulations – 807 KAR 5:058

Regulation	Regulation Language	2017 IRP Reference
807 KAR 5:058 Section 7 (2)	The utility shall provide the following historical information for the base year, which shall be the most recent calendar year for which actual energy sales and system peak demand data are available, and the four (4) years preceding the base year:	Section 4.1
807 KAR 5:058 Section 7 (2) (a)	Average annual number of customers by class as defined in subsection (1) of this section;	Section 4.2; Appendix A
807 KAR 5:058 Section 7 (2) (b)	Recorded and weather-normalized annual energy sales and generation for the system, and sales disaggregated by class as defined in subsection (1) of this section	Section 4.1; Section 4.2; Appendix A
807 KAR 5:058 Section 7 (2) (c)	Recorded and weather-normalized coincident peak demand in summer and winter for the system	Section 4.3; Appendix A
807 KAR 5:058 Section 7 (2) (d)	Total energy sales and coincident peak demand to retail and wholesale customers for which the utility has firm, contractual commitments	Section 4.1; Appendix A
807 KAR 5:058 Section 7 (2) (e)	Total energy sales and coincident peak demand to retail and wholesale customers for which service is provided under an interruptible or curtailable contract or tariff or under some other nonfirm basis	Section 4.2.7
807 KAR 5:058 Section 7 (2) (f)	Annual energy losses for the system	Section 4.1; Appendix A
807 KAR 5:058 Section 7 (2) (g)	Identification and description of existing demand-side programs and an estimate of their impact on utility sales and coincident peak demands including utility or government sponsored conservation and load management programs	Section 4.4; Appendix A

Kentucky Administrative Regulations – 807 KAR 5:058

Regulation	Regulation Language	2017 IRP Reference
807 KAR 5:058 Section 7 (2) (h)	Any other data or exhibits, such as load duration curves or average energy usage per customer, which illustrate historical changes in load or load characteristics.	Section 4.5
807 KAR 5:058 Section 7 (3)	For each of the fifteen (15) years succeeding the base year, the utility shall provide a base load forecast it considers most likely to occur and, to the extent available, alternate forecasts representing lower and upper ranges of expected future growth of the load on its system. Forecasts shall not include load impacts of additional, future demand-side programs or customer generation included as part of planned resource acquisitions estimated separately and reported in Section 8(4) of this administrative regulation. Forecasts shall include the utility's estimates of existing and continuing demand-side programs as described in subsection (5) of this section.	Section 4.1; Section 4.7
807 KAR 5:058 Section 7 (4) (a)	Annual energy sales and generation for the system and sales disaggregated by class as defined in subsection (1) of this section	Section 4.1: Section 4.2
807 KAR 5:058 Section 7 (4) (b)	Summer and winter coincident peak demand for the system	Section 4.3

Kentucky Administrative Regulations – 807 KAR 5:058

Regulation	Regulation Language	2017 IRP Reference
807 KAR 5:058 Section 7 (4) (c)	If available for the first two (2) years of the forecast, monthly forecasts of energy sales and generation for the system and disaggregated by class as defined in subsection (1) of this section and system peak demand	Section 4.1
807 KAR 5:058 Section 7 (4) (d)	The impact of existing and continuing demand-side programs on both energy sales and system peak demands, including utility and government sponsored conservation and load management programs	Section 4.4
807 KAR 5:058 Section 7 (4) (e)	Any other data or exhibits which illustrate projected changes in load or load characteristics	Section 4.5
807 KAR 5:058 Section 7 (5) (a)	The additional following data shall be provided for the integrated system, when the utility is part of a multistate integrated utility system, and for the selling company, when the utility purchases fifty (50) percent of its energy from another company	Not applicable as Big Rivers is not part of a multistate integrated utility system
	For the base year and the four (4) years preceding the base year:	
	1. Recorded and weather normalized annual energy sales and generation;	
	2. Recorded and weather-normalized coincident peak demand in summer and winter.	
807 KAR 5:058 Section 7 (5) (b)	The additional following data shall be provided for the integrated system, when the utility is part of a multistate integrated utility system, and for the selling company, when the utility purchases fifty (50) percent of its energy from another company:	Not Applicable as Big Rivers is not part of a multistate integrated utility system
	For each of the fifteen (15) years succeeding the base year:	
	1. Forecasted annual energy sales and generation;	
	2. Forecasted summer and winter coincident peak demand	

Kentucky Administrative Regulations – 807 KAR 5:058

Regulation	Regulation Language	2017 IRP Reference
807 KAR 5:058 Section 7 (6)	A utility shall file all updates of load forecasts with the commission when they are adopted by the utility.	Noted
807 KAR 5:058 Section 7 (7) (a)	The plan shall include a complete description and discussion of all data sets used in producing the forecasts	Section 4.6; Appendix A
807 KAR 5:058 Section 7 (7) (b)	The plan shall include a complete description and discussion of key assumptions and judgments used in producing forecasts and determining their reasonableness	Chapter 4; Appendix A
807 KAR 5:058 Section 7 (7) (c)	The plan shall include a complete description and discussion of the general methodological approach taken to load forecasting (for example, econometric, or structural) and the model design, model specification, and estimation of key model parameters (for example, price elasticities of demand or average energy usage per type of appliance)	Section 1.5; Section 4.6; Appendix A
807 KAR 5:058 Section 7 (7) (d)	The plan shall include a complete description and discussion of the utility's treatment and assessment of load forecast uncertainty	Section 4.7
807 KAR 5:058 Section 7 (7) (e)	The extent to which the utility's load forecasting methods and models explicitly address and incorporate the following factors: 1. Changes in prices of electricity and prices of competing fuels; 2. Changes in population and economic conditions in the utility's service territory and general region; 3. Development and potential market penetration of new appliances, equipment, and technologies that use electricity or competing fuels; and 4. Continuation of existing company and government sponsored conservation and load management or other demand-side programs	Section 1.5; Section 4.4; Section 4.7; Section 4.9 Appendix A

Kentucky Administrative Regulations – 807 KAR 5:058

Regulation	Regulation Language	2017 IRP Reference
807 KAR 5:058 Section 7 (7) (f)	Research and development efforts underway or planned to improve performance, efficiency, or capabilities of the utility's load forecasting methods	Section 4.9
807 KAR 5:058 Section 7 (7) (g)	Description of and schedule for efforts underway or planned to develop end-use load and market data for analyzing demand-side resource options including load research and market research studies, customer appliance saturation studies, and conservation and load management program pilot or demonstration projects.	Section 4.9; Appendix B
	Technical discussions, descriptions, and supporting documentation shall be contained in a technical appendix	
807 KAR 5:058 Section 8 (1)	Resource Assessment and Acquisition Plan. The plan shall include the utility's resource assessment and acquisition plan for providing an adequate and reliable supply of electricity to meet forecasted electricity requirements at the lowest possible cost. The plan shall consider the potential impacts of selected, key uncertainties and shall include assessment of potentially cost-effective resource options available to the utility.	Section 1.7; Chapter 7
807 KAR 5:058 Section 8 (2) (a)	The utility shall describe and discuss all options considered for inclusion in the plan including Improvements to and more efficient utilization of existing utility generation, transmission, and distribution facilities	Section 6.1; Section 7.1.2
807 KAR 5:058 Section 8 (2) (b)	The utility shall describe and discuss all options considered for inclusion in the plan including Conservation and load management or other demand-side programs not already in place	Section 4.4; Section 7.2.3.6

Kentucky Administrative Regulations – 807 KAR 5:058

Regulation	Regulation Language	2017 IRP Reference
807 KAR 5:058 Section 8 (2) (c)	The utility shall describe and discuss all options considered for inclusion in the plan including: expansion of generating facilities, including assessment of economic opportunities for coordination with other utilities in constructing and operating new units	Section 7.1.2
807 KAR 5:058 Section 8 (2) (d)	The utility shall describe and discuss all options considered for inclusion in the plan including: assessment of nonutility generation, including generating capacity provided by cogeneration, technologies relying on renewable resources, and other nonutility sources	Section 7.1.2
807 KAR 5:058 Section 8 (3)	The following information regarding the utility's existing and planned resources shall be provided. A utility which operates as part of a multistate integrated system shall submit the following information for its operations within Kentucky and for the multistate utility system of which it is a part. A utility which purchases fifty (50) percent or more of its energy needs from another company shall submit the following information for its operations within Kentucky and for the company from which it purchases its energy needs	Noted
807 KAR 5:058 Section 8 (3) (a)	A map of existing and planned generating facilities, transmission facilities with a voltage rating of sixty-nine (69) kilovolts or greater, indicating their type and capacity, and locations and capacities of all interconnections with other utilities. The utility shall discuss any known, significant conditions which restrict transfer capabilities with other utilities	Section 1.3.3; Appendix E

Kentucky Administrative Regulations – 807 KAR 5:058

Regulation	Regulation Language	2017 IRP Reference
807 KAR 5:058 Section 8 (3) (b) *(1-11)*	A list of all existing and planned electric generating facilities which the utility plans to have in service in the base year or during any of the fifteen (15) years of the forecast period, including for each facility:	Section 6.2; Section 1.3.2 (for item 8)
	1. Plant name;	
	2. Unit number(s);	
	3. Existing or proposed location;	
	4. Status (existing, planned, under construction, etc.);	
	5. Actual or projected commercial operation date;	
	6. Type of facility;	
	7. Net dependable capability, summer and winter;	
	8. Entitlement if jointly owned or unit purchase;	
	9. Primary and secondary fuel types, by unit;	
	10. Fuel storage capacity;	
	11. Scheduled upgrades, deratings, and retirement dates	
807 KAR 5:058 Section 8 (3) (b) *(12)*	Actual and projected cost and operating information for the base year (for existing units) or first full year of operations (for new units) and the basis for projecting the information to each of the fifteen (15) forecast years (for example, cost escalation rates). All cost data shall be expressed in nominal and real base year dollars	Section 7.2.2
	a. Capacity and availability factors;	
	b. Anticipated annual average heat rate;	
	c. Costs of fuel(s) per millions of British thermal units (MMBtu);	
	d. Estimate of capital costs for planned units (total and per kilowatt of rated capacity);	
	e. Variable and fixed operating and maintenance costs;	
	f. Capital and operating and maintenance cost escalation factors;	
	g. Projected average variable and total electricity production costs (in cents per kilowatt-hour).	

Kentucky Administrative Regulations – 807 KAR 5:058

Regulation	Regulation Language	2017 IRP Reference
807 KAR 5:058 Section 8 (3) (c)	Description of purchases, sales, or exchanges of electricity during the base year or which the utility expects to enter during any of the fifteen (15) forecast years of the plan	Section 2.3; Section 4.2.6; Section 6.4; Section 7.1.2
807 KAR 5:058 Section 8 (3) (d)	Description of existing and projected amounts of electric energy and generating capacity from cogeneration, self-generation, technologies relying on renewable resources, and other nonutility sources available for purchase by the utility during the base year or during any of the fifteen (15) forecast years of the plan	Section 2.3; Section 6.2; Section 6.3; Section 6.4; Section 7.2
807 KAR 5:058 Section 8 (3) (e)	For each existing and new conservation and load management or other demand-side programs included in the plan:	Chapter 5; Appendix B
	1. Targeted classes and end-uses;	
	2. Expected duration of the program;	
	3. Projected energy changes by season, and summer and winter peak demand changes;	
	4. Projected cost, including any incentive payments and program administrative costs; and	
	5. Projected cost savings, including savings in utility's generation, transmission and distribution costs	

Kentucky Administrative Regulations – 807 KAR 5:058

Regulation	Regulation Language	2017 IRP Reference
807 KAR 5:058 Section 8 (4) (a)	The utility shall describe and discuss its resource assessment and acquisition plan which shall consist of resource options which produce adequate and reliable means to meet annual and seasonal peak demands and total energy requirements identified in the base load forecast at the lowest possible cost. The utility shall provide the following information for the base year and for each year covered by the forecast:	Section 7.2.2
	(a) On total resource capacity available at the winter and summer peak:	
	1. Forecast peak load;	
	2. Capacity from existing resources before consideration of retirements;	
	3. Capacity from planned utility-owned generating plant capacity additions;	
	4. Capacity available from firm purchases from other utilities;	
	5. Capacity available from firm purchases from nonutility sources of generation;	
	6. Reductions or increases in peak demand from new conservation and load management or other demand-side programs;	
	7. Committed capacity sales to wholesale customers coincident with peak;	
	8. Planned retirements;	
	9. Reserve requirements;	
	10. Capacity excess or deficit;	
	11. Capacity or reserve margin.	

Kentucky Administrative Regulations – 807 KAR 5:058

Regulation	Regulation Language	2017 IRP Reference
807 KAR 5:058 Section 8 (4) (b)	On planned annual generation:	Section 7.2.2
	1. Total forecast firm energy requirements;	
	2. Energy from existing and planned utility generating resources disaggregated by primary fuel type;	
	3. Energy from firm purchases from other utilities;	
	4. Energy from firm purchases from nonutility sources of generation; and	
	5. Reductions or increases in energy from new conservation and load management or other demand-side programs	
807 KAR 5:058 Section 8 (4) (c)	For each of the fifteen (15) years covered by the plan, the utility shall provide estimates of total energy input in primary fuels by fuel type and total generation by primary fuel type required to meet load. Primary fuels shall be organized by standard categories (coal, gas, etc.) and quantified on the basis of physical units (for example, barrels or tons) as well as in MMBtu.	Section 7.2.2
807 KAR 5:058 Section 8 (5) (a)	The resource assessment and acquisition plan shall include a description and discussion of: General methodological approach, models, data sets, and information used by the company;	Chapter 7
807 KAR 5:058 Section 8 (5) (b)	The resource assessment and acquisition plan shall include a description and discussion of: key assumption and judgments used in the assessment and how uncertainties in those assumptions and judgments were incorporated into analyses	Section 1.7; Section 7.2

Kentucky Administrative Regulations – 807 KAR 5:058

Regulation	Regulation Language	2017 IRP Reference
807 KAR 5:058 Section 8 (5) (c)	The resource assessment and acquisition plan shall include a description and discussion of: Criteria (for example, present value of revenue requirements, capital requirements, environmental impacts, flexibility, diversity) used to screen each resource alternative including demand-side programs, and criteria used to select the final mix of resources presented in the acquisition plan	Section 7.1.1;
807 KAR 5:058 Section 8 (5) (d)	The resource assessment and acquisition plan shall include a description and discussion of: Criteria used in determining the appropriate level of reliability and the required reserve or capacity margin, and discussion of how these determinations have influenced selection of options	Section 9.3
807 KAR 5:058 Section 8 (5) (e)	The resource assessment and acquisition plan shall include a description and discussion of: Existing and projected research efforts and programs which are directed at developing data for future assessments and refinements of analyses	Section 4.9
807 KAR 5:058 Section 8 (5) (f)	The resource assessment and acquisition plan shall include a description and discussion of: Actions to be undertaken during the fifteen (15) years covered by the plan to meet the requirements of the Clean Air Act amendments of 1990, and how these actions affect the utility's resource assessment	Section 6.6
807 KAR 5:058 Section 8 (5) (g)	The resource assessment and acquisition plan shall include a description and discussion of: Consideration given by the utility to market forces and competition in the development of the plan. Technical discussion, descriptions and supporting documentation shall be contained in a technical appendix	Section 7.2; Appendix G

Kentucky Administrative Regulations – 807 KAR 5:058

Regulation	Regulation Language	2017 IRP Reference
807 KAR 5:058 Section 9 (1)	Financial Information. The integrated resource plan shall, at a minimum, include and discuss the following financial information: Present (base year) value of revenue requirements stated in dollar terms	Section 7.2
807 KAR 5:058 Section 9 (2)	The integrated resource plan shall, at a minimum, include and discuss the following financial information: Discount rate used in present value calculations	Section 7.3
807 KAR 5:058 Section 9 (3)	The integrated resource plan shall, at a minimum, include and discuss the following financial information: Nominal and real revenue requirements by year	Appendix H
807 KAR 5:058 Section 9 (4)	The integrated resource plan shall, at a minimum, include and discuss the following financial information: Average system rates (revenues per kilowatt hour) by year	Section 7.3.1
807 KAR 5:058 Section 10	Notice. Each utility which files an integrated resource plan shall publish, in a form prescribed by the commission, notice of its filing in a newspaper of general circulation in the utility's service area. The notice shall be published not more than thirty (30) days after the filing date of the report	Noted
807 KAR 5:058 Section 11 (1)	Procedures for Review of the Integrated Resource Plan. Upon receipt of a utility's integrated resource plan, the commission shall develop a procedural schedule which allows for submission of written interrogatories to the utility by staff and intervenors, written comments by staff and intervenors, and responses to interrogatories and comments by the utility	Noted
807 KAR 5:058 Section 11 (2)	The commission may convene conferences to discuss the filed plan and all other matters relative to review of the plan	Noted

Kentucky Administrative Regulations – 807 KAR 5:058

Regulation	Regulation Language	2017 IRP Reference
807 KAR 5:058 Section 11 (3)	Based upon its review of a utility's plan and all related information, the commission staff shall issue a report summarizing its review and offering suggestions and recommendations to the utility for subsequent filings	Noted
807 KAR 5:058 Section 11 (4)	A utility shall respond to the staff's comments and recommendations in its next integrated resource plan filing	Appendix C

Appendix D

Big Rivers Responses to Staff Recommendation from the 2014 IRP

Commission Staff's Recommendation from Big Rivers 2014 Integrated Resource Plan

Recommendation	Recommendation Description	2017 IRP Reference	Big Rivers Response
Load Forecasting 1	Big Rivers should develop a more diverse group of forecast scenarios which includes a meaningful number of alternatives that are not part of its Mitigation Plan	Section 7.2.1;	The 2017 IRP Base Case assumes that Big Rivers does not secure any additional firm off-system sales aside from the contracts that have already been executed (Nebraska Customers and KyMEA).
		Section 7.2.3	In its Load Forecast, Big Rivers included a Base Case and four sensitivity cases that varied Big Rivers' load. Big Rivers then utilized the minimum and maximum load forecast scenarios as sensitivities in its Integration modeling. Big Rivers also ran an Integration sensitivity assuming Nebraska Customer and KyMEA load extended through the end of the analysis.
Load Forecasting 2	Big Rivers 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	Section 1.7	Big Rivers has completed an analysis of the newly finalized environmental regulations and has prepared a plan to achieve compliance within the time allowed by the regulations
		Section 6.6;	In this section, Big Rivers explains new and pending environmental regulations and options for compliance
		Section 7.1.1;	In the modeling Overview, Big Rivers explains that by including environmental costs for generator resource options, the analysis determines the least cost option inclusive of environmental strategy, as converting to gas, and/or retiring early, and/or staying on coal are some of the possibilities to help Big Rivers achieve compliance with environmental regulations
		Section 7.1.2	This section explains the costs included in the analysis model for the 2017 IRP

Commission Staff's Recommendation from Big Rivers 2014 Integrated Resource Plan

Recommendation	Recommendation Description	2017 IRP Reference	Big Rivers Response
Load Forecasting 3	Big Rivers' 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.	Section 4.8	Big Rivers contracted with GDS to perform weather normalization analysis using 10-year and 30-year historical periods. The small variances using these alternate terms were well within expected margins for error so no further analysis was conducted.
DSM and EE 1	Include estimates of costs associated with proposed and potential environmental rules in future DSM/EE benefit/cost analyses	Section 6.5	Big Rivers considered environmental costs in the DSM evaluation conducted for this IRP. No federal or state carbon emission legislation has been passed since 2014. For this reason, the DSM evaluation assumes a cost of $0/ton of carbon emissions in the avoided energy and capacity costs. This assumption properly estimates the cost of complying with environmental regulations at the present time. Big Rivers will continue to monitor state and federal policies to determine if it becomes appropriate in the future to include in its analysis any benefits related to environmental costs offset by DSM/EE programs
DSM and EE 2	Research and report on best practices for DSM/EE program promotion, educational programs, and innovative marketing opportunities	Section 6.5	Big Rivers and its Members will continue to study and evaluate other regional energy efficiency programs and promotional efforts as well as monitor other utility innovation in DSM through such publications as Best Practices Knowledgebase articles published on Cooperative.com and The 2016 State Energy Efficiency Scorecard published by the American Council for an Energy-Efficient Economy.

Commission Staff's Recommendation from Big Rivers 2014 Integrated Resource Plan

Recommendation	Recommendation Description	2017 IRP Reference	Big Rivers Response
DSM and EE 3	Research and report on possible partnering with its member cooperatives in order to enhance marketing and reduce advertising costs	Section 6.5	Big Rivers is working with its Members to provide design and production work of promotional material such as bill inserts and bill board design. Big Rivers is also providing funding to the Member Cooperatives to update websites to more effectively communicate the benefits of energy efficiency to the retail member-consumers.
DSM and EE 4	Report on the work undertaken to enhance the evaluation, measurement, and verification procedures to ensure DSM/EE programs are achieving expected goals	Section 6.5	All demand and energy impact measurement is based on modeling from the current DSM potential study and program participation requirements administered and documented by each Member. Big Rivers believes the current evaluation, measurement and verification procedures are appropriate for tracking its current energy efficiency program impacts. No additional procedures are warranted at this time.
DSM and EE 5	Continue to monitor opportunities for demand response	Section 5.8; Appendix B	A list of potential Demand Response (DR) programs representing the most common and most likely to be cost-effective were evaluated in this screening analysis. Details of the DSM Potential Study included

Commission Staff's Recommendation from Big Rivers 2014 Integrated Resource Plan

Recommendation	Recommendation Description	2017 IRP Reference	Big Rivers Response
DSM and EE 6	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") and enables eligible students to complete a paper or online energy audit of their homes. Each eligible student who completes a home energy audit receives home EE measures, such as a package of CFL bulbs or an EE starter kit.	Section 6.5	Big Rivers considered Duke's education program and determined, in consultation with its Members, designing an educational program built around Big Rivers' solar education and demonstration project would be beneficial at this time
Supply-Side Resource Assessment 1	Big Rivers next IRP should include scenarios where one or more existing units are retired, converted to use alternate fuels, or sold.	Section 7.1.2	Resource options in the 2017 IRP analysis included retirement, and/or natural gas conversion for several units, as well as additional options, which are detailed in Table 7.1

Commission Staff's Recommendation from Big Rivers 2014 Integrated Resource Plan

Recommendation	Recommendation Description	2017 IRP Reference	Big Rivers Response
Supply-Side Resource Assessment 2	Big Rivers should perform a utility specific reserve margin study, as has been requested previously.	Section 9.4	As a member of MISO, Big Rivers' Members receive benefits and are obligated to meet tariff requirements, a tariff which requires MISO to strive to minimize costs. That same tariff requires MISO to perform a study to determine a minimum amount of planning reserve requirements. A Big Rivers utility-specific study would be expected to return results consistent with the MISO analysis. Therefore, Big Rivers relies on MISO's analysis to determine an appropriate target reserve margin. Big Rivers easily satisfies any reasonable reserve margin requirement. The uncertainty and cost of conducting a utility-specific reserve margin study outweighs the value of such a study.
Supply-Side Resource Assessment 3	Big Rivers 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 CO2	Section 6.5; Section 6.6.6; Section 7.2.3.5	Big Rivers is in the process of constructing seven small solar generation sites located in the Members' service areas. These solar arrays are meant to provide demonstration of and education on photovoltaic generation to retail member-consumers and schools in the areas. Big Rivers will continue to monitor judicial, executive, and legislative action. In the event the CPP is restarted, Big Rivers will resume the task of developing a compliance plan commensurate with the rules included in the regulation at that time Big Rivers modeled a scenario assuming the State of Kentucky adopted a renewable portfolio standard

Commission Staff's Recommendation from Big Rivers 2014 Integrated Resource Plan

Recommendation	Recommendation Description	2017 IRP Reference	Big Rivers Response
Supply-Side Resource Assessment 4	Big Rivers should include a discussion of its consideration of distributed generation in its next IRP.	Section 2.3,	Big Rivers' Members continue to see moderate growth in renewable energy production by net metered photovoltaic (PV) generation. Also, Table 2.1 provides Net Metering Statistics of Big Rivers' Members
Supply-Side Resource Assessment 5	Big Rivers should provide information from its member-owner cooperatives on their customers' net metering statistics and activities in its next IRP.	Section 2.3	See Table 2.1 in Section 2.3

Commission Staff's Recommendation from Big Rivers 2014 Integrated Resource Plan

Recommendation	Recommendation Description	2017 IRP Reference	Big Rivers Response
Supply-Side Resource Assessment 6	In its next IRP, Big Rivers should continue to provide a detailed discussion of specific generation efficiency improvements and activities undertaken.	Section 6.1	Discussion provided in Section 6.1
Supply-side Resource Assessment 7	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	Section 6.1;	Big Rivers continues to make strides in generation efficiency. Specific generation improvement activities include: operations Training Simulators; Controllable Losses; Maintenance Activities; Instrument Tuning; coal Pulverizer Tuning, etc.
		Section 6.6;	Big Rivers has completed an analysis of newly finalized environmental regulations and has prepared a plan to achieve compliance within the time allowed by the regulations
		Section 8.3	Big Rivers' Transmission Planning Department continues plans its system to minimize losses

Commission Staff's Recommendation from Big Rivers 2014 Integrated Resource Plan

Recommendation	Recommendation Description	2017 IRP Reference	Big Rivers Response
Supply-Side Resource Assessment 8	Big Rivers should develop a comprehensive list of options, plans, and costs to achieve compliance with existing, proposed, and anticipated environmental regulations in its next IRP.	Section 7.1.2	Option and Plans are addressed in the development of the Base Case and Sensitivities and Costs are addressed in Table 7.2
Supply-Side Resource Assessment 9	A full and detailed discussion of compliance actions relating to current and pending environmental regulations should be included in Big Rivers' next IRP.	Section 6.6	In this section, Big Rivers explains new and pending environmental regulations and options for compliance

Commission Staff's Recommendation from Big Rivers 2014 Integrated Resource Plan

Recommendation	Recommendation Description	2017 IRP Reference	Big Rivers Response
Integration and Plan Optimization 1	Big Rivers' 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.	Section 4.2.6;	In the Long Term Load Forecast Report, both Executed and Projected Sales were included, however for purposes of the IRP analysis only Executed Sales are included (See Section 7.2 Modeling Results for how Non-Member load is treated in IRP analysis). Projected Sales could be comprised of long-term sales, short-term optimization sales, and possibly new Member additions, despite the 'Non-Member' moniker.
		Section 7.2.1;	The 2017 IRP Base Case includes New Non-Member load for Nebraska Customers and KyMEA, which are contracts that have been executed at the time of this 2017 IRP.
		Section 7.2.3	Big Rivers also ran sensitivities 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.

Commission Staff's Recommendation from Big Rivers 2014 Integrated Resource Plan

Recommendation	Recommendation Description	2017 IRP Reference	Big Rivers Response
Integration and Plan Optimization 2	Given the timing of its next IRP, Big Rivers should not be constrained in considering increased levels of DSM/EE programs as it was with this IRP. Hence, the optimization and integration analysis in the next IRP should include increased DSM/EE levels.	Section 5.2;	Big Rivers' Market Potential Study for Energy Efficiency estimated the potential savings over a ten-year period from the delivery of a portfolio of energy efficiency programs based on two funding scenarios: $1M and $2M incentive budget
		Section 7.2.3.6	Integration analysis for this 2017 IRP also included a Demand Side Management Scenario where additional DSM programs were modeled as an economic resource to see if additional $1M DSM spend would provide a least cost resource

Big Rivers
ELECTRIC CORPORATION

Your Touchstone Energy® Cooperative

In the Matter of:

2017 INTEGRATED RESOURCE PLAN OF BIG RIVERS ELECTRIC CORPORATION	))	**Case No. 2017-00**384

CONFIDENTIAL

Appendix E
Big Rivers Transmission System Map
FILED: September 21, 2017

INFORMATION SUBMITTED UNDER PETITION FOR CONFIDENTIAL TREATMENT

Appendix F – Generation Summary

Base Case

System								
Production Cost -(Annual inflation[1])		**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Production Cost (Nominal)	Total Production Cost, $000 (Incl. SEPA)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Production Cost, cents/kWh (Incl. SEPA)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Fixed O&M Cost, $000 (No SEPA)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Fixed O&M Cost, $/kW-yr (No SEPA)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Variable Cost, $000 (No SEPA)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Variable Cost, cents/kWh (No SEPA)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Production Cost -(2017$)		**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Production Cost (Real)	Total Production Cost, $000 (Incl. SEPA)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Production Cost, cents/kWh (Incl. SEPA)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Fixed O&M Cost, $000 (No SEPA)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Fixed O&M Cost, $/kW-yr (No SEPA)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Variable Cost, $000 (No SEPA)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Variable Cost, cents/kWh (No SEPA)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Operating Performance -KPIs		**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
KPIs	Net Capacity (Summer), MW	1,287	1,311	1,114	1,114	1,114	1,114	1,114
	Net Capacity (Winter), MW	1,287	1,311	1,114	1,114	1,114	1,114	1,114
	Net Generation, GWh	5,219	5,365	4,410	4,256	3,911	3,805	3,807

Base Case

System		2025	2026	2027	2028	2029	2030	2031
Production Cost -(Annual inflation[1])		**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Production Cost (Nominal)	Total Production Cost, $000 (Incl. SEPA)	[redacted]						
	Total Production Cost, cents/kWh (Incl. SEPA)	[redacted]						
	Total Fixed O&M Cost, $000 (No SEPA)	[redacted]						
	Total Fixed O&M Cost, $/kW-yr (No SEPA)	[redacted]						
	Total Variable Cost, $000 (No SEPA)	[redacted]						
	Total Variable Cost, cents/kWh (No SEPA)	[redacted]						
Production Cost -(2017$)		**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Production Cost (Real)	Total Production Cost, $000 (Incl. SEPA)	[redacted]						
	Total Production Cost, cents/kWh (Incl. SEPA)	[redacted]						
	Total Fixed O&M Cost, $000 (No SEPA)	[redacted]						
	Total Fixed O&M Cost, $/kW-yr (No SEPA)	[redacted]						
	Total Variable Cost, $000 (No SEPA)	[redacted]						
	Total Variable Cost, cents/kWh (No SEPA)	[redacted]						
Operating Performance -KPIs		**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
KPIs	Net Capacity (Summer), MW	1,114	1,114	1,114	1,114	1,114	1,114	1,114
	Net Capacity (Winter), MW	1,114	1,114	1,114	1,114	1,114	1,114	1,114
	Net Generation, GWh	4,006	4,120	4,503	4,515	5,072	5,326	6,088

Wilson - Coal								
Production Cost -(Annual inflation[1])		2018	2019	2020	2021	2022	2023	2024
Production Cost (Nominal)	Total Production Cost, $000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Production Cost, cents/kWh	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Fixed O&M Cost, $000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Fixed O&M Cost, $/kW-yr	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Variable Cost, $000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Variable Cost, cents/kWh	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Production Cost -(2017$)		2018	2019	2020	2021	2022	2023	2024
Production Cost (Real)	Total Production Cost, $000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Production Cost, cents/kWh	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Fixed O&M Cost, $000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Fixed O&M Cost, $/kW-yr	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Variable Cost, $000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Variable Cost, cents/kWh	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Operating Performance -KPIs		2018	2019	2020	2021	2022	2023	2024
KPIs	Net Capacity (Summer), MW	417	417	417	417	417	417	417
	Net Capacity (Winter), MW	417	417	417	417	417	417	417
	Net Generation, GWh	2,063	2,304	2,155	2,157	1,943	2,017	1,949
	EAF, %	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Net Heat Rate, BTU/kWh	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Net Capacity Factor, %	56.5%	63.1%	58.8%	59.1%	53.2%	55.2%	53.2%
Hours	Period Hours	8,760	8,760	8,784	8,760	8,760	8,760	8,784
	Service Hours	5,207	5,816	5,440	5,446	4,904	5,092	4,919
	Unplanned Outage Hours	379	438	414	438	413	438	414
	Planned Outage Hours	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Wilson - Coal								
Production Cost -(Annual inflation[1])		**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Production Cost (Nominal)	Total Production Cost, $000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Production Cost, cents/kWh	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Fixed O&M Cost, $000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Fixed O&M Cost, $/kW-yr	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Variable Cost, $000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Variable Cost, cents/kWh	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Production Cost -(2017$)		**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Production Cost (Real)	Total Production Cost, $000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Production Cost, cents/kWh	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Fixed O&M Cost, $000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Fixed O&M Cost, $/kW-yr	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Variable Cost, $000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Variable Cost, cents/kWh	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Operating Performance -KPIs		**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
KPIs	Net Capacity (Summer), MW	417	417	417	417	417	417	417
	Net Capacity (Winter), MW	417	417	417	417	417	417	417
	Net Generation, GWh	2,125	2,048	2,402	2,347	2,760	2,803	3,287
	EAF, %	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Net Heat Rate, BTU/kWh	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Net Capacity Factor, %	58.2%	56.1%	65.8%	64.1%	75.6%	76.7%	90.0%
Hours	Period Hours	8,760	8,760	8,760	8,784	8,760	8,760	8,760
	Service Hours	5,364	5,170	6,063	5,924	6,968	7,075	8,297
	Unplanned Outage Hours	438	379	438	414	438	407	438
	Planned Outage Hours	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Variable Costs		2018	2019	2020	2021	2022	2023	2024
Fuel	Fuel Used, GBtu	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Fuel Used, (000)Tons (11,500 BTU Fuel)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Fuel Cost, \$/MMBtu - Nominal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Fuel Cost, \$000 - Nominal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Fuel Cost, \$/MMBtu - 2017\$	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Fuel Cost, \$000 - 2017\$	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Non Fuel VOM	VOM Cost, \$/MWh - Nominal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	VOM Cost, \$000 - Nominal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	VOM Cost, \$/MWh - 2017\$	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	VOM Cost, \$000 - 2017\$	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Emissions	SO2 Emit Rate, lbs/MMBtu	0.430	0.430	0.430	0.430	0.430	0.430	0.430
	SO2 Tons Emitted	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	SO2 Cost, \$000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	NOx Emit Rate, lbs/MMBtu	0.060	0.060	0.060	0.060	0.060	0.060	0.060
	NOx Tons Emitted	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	NOx Cost, \$000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Emissions Cost, \$000 - Nominal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Emissions Cost, \$000 - 2017\$	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fixed O&M Costs		**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Fixed O&M Costs	Fixed O&M Costs (No Cap.), \$000 - Nominal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Plant Capital Cost, \$000 - Nominal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	ECP Capital Cost, \$000 - Nominal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Fixed O&M Costs (No Cap.), \$000 - 2017\$	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Plant Capital Cost, \$000 - 2017\$	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	ECP Capital Cost, \$000 - 2017\$	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Variable Costs		2025	2026	2027	2028	2029	2030	2031
Fuel	Fuel Used, GBtu	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Fuel Used, (000)Tons (11,500 BTU Fuel)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Fuel Cost, $/MMBtu - Nominal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Fuel Cost, $000 - Nominal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Fuel Cost, $/MMBtu - 2017$	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Fuel Cost, $000 - 2017$	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Non Fuel VOM	VOM Cost, $/MWh - Nominal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	VOM Cost, $000 - Nominal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	VOM Cost, $/MWh - 2017$	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	VOM Cost, $000 - 2017$	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Emissions	SO2 Emit Rate, lbs/MMBtu	0.430	0.430	0.430	0.430	0.430	0.430	0.430
	SO2 Tons Emitted	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	SO2 Cost, $000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	NOx Emit Rate, lbs/MMBtu	0.060	0.060	0.060	0.060	0.060	0.060	0.060
	NOx Tons Emitted	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	NOx Cost, $000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Emissions Cost, $000 - Nominal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Emissions Cost, $000 - 2017$	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Fixed O&M Costs		2025	2026	2027	2028	2029	2030	2031
Fixed O&M Costs	Fixed O&M Costs (No Cap.), $000 - Nominal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Plant Capital Cost, $000 - Nominal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	ECP Capital Cost, $000 - Nominal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Fixed O&M Costs (No Cap.), $000 - 2017$	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Plant Capital Cost, $000 - 2017$	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	ECP Capital Cost, $000 - 2017$	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Green Unit 1 - Coal								
Production Cost -(Annual inflation[1])		**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Production Cost (Nominal)	Total Production Cost, $000	[redacted]						
	Total Production Cost, cents/kWh							
	Total Fixed O&M Cost, $000							
	Total Fixed O&M Cost, $/kW-yr							
	Total Variable Cost, $000							
	Total Variable Cost, cents/kWh							
Production Cost -(2017$)		**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Production Cost (Real)	Total Production Cost, $000	[redacted]						
	Total Production Cost, cents/kWh							
	Total Fixed O&M Cost, $000							
	Total Fixed O&M Cost, $/kW-yr							
	Total Variable Cost, $000							
	Total Variable Cost, cents/kWh							
Operating Performance -KPIs		**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
KPIs	Net Capacity (Summer), MW	231	231	231	231	231	231	231
	Net Capacity (Winter), MW	231	231	231	231	231	231	231
	Net Generation, GWh	987	1,012	1,066	878	875	727	845
	EAF, %	[redacted]						
	Net Heat Rate, BTU/kWh							
	Net Capacity Factor, %	48.8%	50.0%	52.6%	43.4%	43.3%	35.9%	41.6%
Hours	Period Hours	8,760	8,760	8,784	8,760	8,760	8,760	8,784
	Service Hours	4,418	4,550	4,821	3,930	3,917	3,254	3,781
	Unplanned Outage Hours	268	328	373	268	285	246	285
	Planned Outage Hours	[redacted]						

Green Unit 1 - Coal								
Production Cost -(Annual inflation[1])		**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Production Cost (Nominal)	Total Production Cost, $000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Production Cost, cents/kWh	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Fixed O&M Cost, $000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Fixed O&M Cost, $/kW-yr	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Variable Cost, $000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Variable Cost, cents/kWh	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Production Cost -(2017$)		**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Production Cost (Real)	Total Production Cost, $000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Production Cost, cents/kWh	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Fixed O&M Cost, $000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Fixed O&M Cost, $/kW-yr	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Variable Cost, $000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Variable Cost, cents/kWh	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Operating Performance -KPIs		**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
KPIs	Net Capacity (Summer), MW	231	231	231	231	231	231	231
	Net Capacity (Winter), MW	231	231	231	231	231	231	231
	Net Generation, GWh	807	942	906	1,020	999	1,173	1,203
	EAF, %	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Net Heat Rate, BTU/kWh	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Net Capacity Factor, %	39.9%	46.5%	44.8%	50.3%	49.4%	58.0%	59.5%
Hours	Period Hours	8,760	8,760	8,760	8,784	8,760	8,760	8,760
	Service Hours	3,612	4,213	4,055	4,564	4,471	5,249	5,384
	Unplanned Outage Hours	268	285	268	285	268	285	246
	Planned Outage Hours	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Variable Costs		2018	2019	2020	2021	2022	2023	2024
Fuel	Fuel Used, GBtu	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Fuel Used, (000)Tons (11,000 BTU Fuel)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Fuel Cost, $/MMBtu - Nominal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Fuel Cost, $000 - Nominal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Fuel Cost, $/MMBtu - 2017$	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Fuel Cost, $000 - 2017$	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Non Fuel VOM	VOM Cost, $/MWh - Nominal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	VOM Cost, $000 - Nominal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	VOM Cost, $/MWh - 2017$	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	VOM Cost, $000 - 2017$	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Emissions	SO2 Emit Rate, lbs/MMBtu	0.180	0.180	0.180	0.180	0.180	0.180	0.180
	SO2 Tons Emitted	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	SO2 Cost, $000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	NOx Emit Rate, lbs/MMBtu	0.219	0.219	0.219	0.219	0.219	0.219	0.219
	NOx Tons Emitted	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	NOx Cost, $000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Emissions Cost, $000 - Nominal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Emissions Cost, $000 - 2017$	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fixed O&M Costs		**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Fixed O&M Costs	Fixed O&M Costs (No Cap.), $000 - Nominal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Plant Capital Cost, $000 - Nominal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	ECP Capital Cost, $000 - Nominal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Fixed O&M Costs (No Cap.), $000 - 2017$	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Plant Capital Cost, $000 - 2017$	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	ECP Capital Cost, $000 - 2017$	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Variable Costs		2025	2026	2027	2028	2029	2030	2031
Fuel	Fuel Used, GBtu	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Fuel Used, (000)Tons (11,000 BTU Fuel)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Fuel Cost, $/MMBtu - Nominal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Fuel Cost, $000 - Nominal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Fuel Cost, $/MMBtu - 2017$	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Fuel Cost, $000 - 2017$	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Non Fuel VOM	VOM Cost, $/MWh - Nominal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	VOM Cost, $000 - Nominal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	VOM Cost, $/MWh - 2017$	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	VOM Cost, $000 - 2017$	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Emissions	SO2 Emit Rate, lbs/MMBtu	0.180	0.180	0.180	0.180	0.180	0.180	0.180
	SO2 Tons Emitted	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	SO2 Cost, $000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	NOx Emit Rate, lbs/MMBtu	0.219	0.219	0.219	0.219	0.219	0.219	0.219
	NOx Tons Emitted	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	NOx Cost, $000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Emissions Cost, $000 - Nominal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Emissions Cost, $000 - 2017$	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fixed O&M Costs		**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Fixed O&M Costs	Fixed O&M Costs (No Cap.), $000 - Nominal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Plant Capital Cost, $000 - Nominal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	ECP Capital Cost, $000 - Nominal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Fixed O&M Costs (No Cap.), $000 - 2017$	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Plant Capital Cost, $000 - 2017$	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	ECP Capital Cost, $000 - 2017$	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Green Unit 2 - Coal								
Production Cost -(Annual inflation[1])		**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Production Cost (Nominal)	Total Production Cost, $000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Production Cost, cents/kWh	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Fixed O&M Cost, $000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Fixed O&M Cost, $/kW-yr	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Variable Cost, $000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Variable Cost, cents/kWh	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Production Cost -(2017$)		**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Production Cost (Real)	Total Production Cost, $000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Production Cost, cents/kWh	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Fixed O&M Cost, $000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Fixed O&M Cost, $/kW-yr	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Variable Cost, $000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Variable Cost, cents/kWh	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Operating Performance -KPIs		**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
KPIs	Net Capacity (Summer), MW	223	223	223	223	223	223	223
	Net Capacity (Winter), MW	223	223	223	223	223	223	223
	Net Generation, GWh	995	966	901	936	813	785	740
	EAF, %	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Net Heat Rate, BTU/kWh	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Net Capacity Factor, %	50.9%	49.5%	46.0%	47.9%	41.6%	40.2%	37.8%
Hours	Period Hours	8,760	8,760	8,784	8,760	8,760	8,760	8,784
	Service Hours	4,613	4,502	4,178	4,340	3,768	3,637	3,428
	Unplanned Outage Hours	285	328	247	285	265	285	269
	Planned Outage Hours	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Green Unit 2 - Coal								
Production Cost -(Annual inflation[1])		**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Production Cost (Nominal)	Total Production Cost, $000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Production Cost, cents/kWh	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Fixed O&M Cost, $000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Fixed O&M Cost, $/kW-yr	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Variable Cost, $000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Variable Cost, cents/kWh	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Production Cost -(2017$)		**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Production Cost (Real)	Total Production Cost, $000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Production Cost, cents/kWh	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Fixed O&M Cost, $000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Fixed O&M Cost, $/kW-yr	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Variable Cost, $000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Variable Cost, cents/kWh	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Operating Performance -KPIs		**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
KPIs	Net Capacity (Summer), MW	223	223	223	223	223	223	223
	Net Capacity (Winter), MW	223	223	223	223	223	223	223
	Net Generation, GWh	804	861	927	879	1,043	1,083	1,330
	EAF, %	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Net Heat Rate, BTU/kWh	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Net Capacity Factor, %	41.2%	44.1%	47.4%	44.9%	53.4%	55.4%	68.1%
Hours	Period Hours	8,760	8,760	8,760	8,784	8,760	8,760	8,760
	Service Hours	3,728	3,993	4,295	4,073	4,836	5,018	6,164
	Unplanned Outage Hours	285	268	285	247	285	268	285
	Planned Outage Hours	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Variable Costs		2018	2019	2020	2021	2022	2023	2024
Fuel	Fuel Used, GBtu	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Fuel Used, (000)Tons (11,000 BTU Fuel)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Fuel Cost, $/MMBtu - Nominal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Fuel Cost, $000 - Nominal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Fuel Cost, $/MMBtu - 2017$	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Fuel Cost, $000 - 2017$	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Non Fuel VOM	VOM Cost, $/MWh - Nominal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	VOM Cost, $000 - Nominal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	VOM Cost, $/MWh - 2017$	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	VOM Cost, $000 - 2017$	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Emissions	SO2 Emit Rate, lbs/MMBtu	0.180	0.180	0.180	0.180	0.180	0.180	0.180
	SO2 Tons Emitted	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	SO2 Cost, $000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	NOx Emit Rate, lbs/MMBtu	0.219	0.219	0.219	0.219	0.219	0.219	0.219
	NOx Tons Emitted	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	NOx Cost, $000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Emissions Cost, $000 - Nominal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Emissions Cost, $000 - 2017$	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fixed O&M Costs		**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Fixed O&M Costs	Fixed O&M Costs (No Cap.), $000 - Nominal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Plant Capital Cost, $000 - Nominal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	ECP Capital Cost, $000 - Nominal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Fixed O&M Costs (No Cap.), $000 - 2017$	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Plant Capital Cost, $000 - 2017$	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	ECP Capital Cost, $000 - 2017$	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Variable Costs		2025	2026	2027	2028	2029	2030	2031
Fuel	Fuel Used, GBtu	[redacted]						
	Fuel Used, (000)Tons (11,000 BTU Fuel)							
	Fuel Cost, $/MMBtu - Nominal							
	Fuel Cost, $000 - Nominal							
	Fuel Cost, $/MMBtu - 2017$							
	Fuel Cost, $000 - 2017$							
Non Fuel VOM	VOM Cost, $/MWh - Nominal							
	VOM Cost, $000 - Nominal							
	VOM Cost, $/MWh - 2017$							
	VOM Cost, $000 - 2017$							
Emissions	SO2 Emit Rate, lbs/MMBtu	0.180	0.180	0.180	0.180	0.180	0.180	0.180
	SO2 Tons Emitted	[redacted]						
	SO2 Cost, $000							
	NOx Emit Rate, lbs/MMBtu	0.219	0.219	0.219	0.219	0.219	0.219	0.219
	NOx Tons Emitted	[redacted]						
	NOx Cost, $000							
	Total Emissions Cost, $000 - Nominal							
	Total Emissions Cost, $000 - 2017$							
Fixed O&M Costs		**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Fixed O&M Costs	Fixed O&M Costs (No Cap.), $000 - Nominal	[redacted]						
	Plant Capital Cost, $000 - Nominal							
	ECP Capital Cost, $000 - Nominal							
	Fixed O&M Costs (No Cap.), $000 - 2017$							
	Plant Capital Cost, $000 - 2017$							
	ECP Capital Cost, $000 - 2017$							

HMP&L Station Two - Coal								
Production Cost -(Annual inflation[1])		**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Production Cost (Nominal)	Total Production Cost, $000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Production Cost, cents/kWh	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Fixed O&M Cost, $000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Fixed O&M Cost, $/kW-yr	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Variable Cost, $000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Variable Cost, cents/kWh	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Production Cost -(2017$)		**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Production Cost (Real)	Total Production Cost, $000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Production Cost, cents/kWh	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Fixed O&M Cost, $000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Fixed O&M Cost, $/kW-yr	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Variable Cost, $000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Variable Cost, cents/kWh	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Operating Performance -KPIs		**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
KPIs	Net Capacity (Summer), MW	197	197					
	Net Capacity (Winter), MW	197	197					
	Net Generation, GWh	937	796					
	EAF, %	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Net Heat Rate, BTU/kWh	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Net Capacity Factor, %	54.3%	46.1%					
Hours	Period Hours	8,760	8,760	8,784	8,760	8,760	8,760	8,784
	Service Hours	5,142	4,343					
	Unplanned Outage Hours	657	531	0	0	0	0	0
	Planned Outage Hours	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

HMP&L Station Two - Coal								
Production Cost -(Annual inflation[1])		**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Production Cost (Nominal)	Total Production Cost, $000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Production Cost, cents/kWh	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Fixed O&M Cost, $000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Fixed O&M Cost, $/kW-yr	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Variable Cost, $000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Variable Cost, cents/kWh	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Production Cost -(2017$)		**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Production Cost (Real)	Total Production Cost, $000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Production Cost, cents/kWh	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Fixed O&M Cost, $000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Fixed O&M Cost, $/kW-yr	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Variable Cost, $000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Variable Cost, cents/kWh	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Operating Performance -KPIs		**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
KPIs	Net Capacity (Summer), MW							
	Net Capacity (Winter), MW							
	Net Generation, GWh							
	EAF, %	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Net Heat Rate, BTU/kWh	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Net Capacity Factor, %							
Hours	Period Hours	8,760	8,760	8,760	8,784	8,760	8,760	8,760
	Service Hours							
	Unplanned Outage Hours	0	0	0	0	0	0	0
	Planned Outage Hours	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Variable Costs		2018	2019	2020	2021	2022	2023	2024
Fuel	Fuel Used, GBtu	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Fuel Used, (000)Tons (11,500 BTU Fuel)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Fuel Cost, $/MMBtu - Nominal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Fuel Cost, $000 - Nominal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Fuel Cost, $/MMBtu - 2017$	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Fuel Cost, $000 - 2017$	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Non Fuel VOM	VOM Cost, $/MWh - Nominal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	VOM Cost, $000 - Nominal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	VOM Cost, $/MWh - 2017$	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	VOM Cost, $000 - 2017$	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Emissions	SO2 Emit Rate, lbs/MMBtu	0.320	0.320					
	SO2 Tons Emitted	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	SO2 Cost, $000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	NOx Emit Rate, lbs/MMBtu	0.070	0.070					
	NOx Tons Emitted	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	NOx Cost, $000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Emissions Cost, $000 - Nominal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Emissions Cost, $000 - 2017$	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fixed O&M Costs		2018	2019	2020	2021	2022	2023	2024
Fixed O&M Costs	Fixed O&M Costs (No Cap.), $000 - Nominal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Plant Capital Cost, $000 - Nominal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	ECP Capital Cost, $000 - Nominal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Fixed O&M Costs (No Cap.), $000 - 2017$	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Plant Capital Cost, $000 - 2017$	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	ECP Capital Cost, $000 - 2017$	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Variable Costs		2025	2026	2027	2028	2029	2030	2031
Fuel	Fuel Used, GBtu	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Fuel Used, (000)Tons (11,500 BTU Fuel)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Fuel Cost, $/MMBtu - Nominal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Fuel Cost, $000 - Nominal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Fuel Cost, $/MMBtu - 2017$	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Fuel Cost, $000 - 2017$	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Non Fuel VOM	VOM Cost, $/MWh - Nominal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	VOM Cost, $000 - Nominal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	VOM Cost, $/MWh - 2017$	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	VOM Cost, $000 - 2017$	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Emissions	SO2 Emit Rate, lbs/MMBtu							
	SO2 Tons Emitted	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	SO2 Cost, $000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	NOx Emit Rate, lbs/MMBtu							
	NOx Tons Emitted	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	NOx Cost, $000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Emissions Cost, $000 - Nominal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Emissions Cost, $000 - 2017$	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fixed O&M Costs		**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Fixed O&M Costs	Fixed O&M Costs (No Cap.), $000 - Nominal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Plant Capital Cost, $000 - Nominal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	ECP Capital Cost, $000 - Nominal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Fixed O&M Costs (No Cap.), $000 - 2017$	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Plant Capital Cost, $000 - 2017$	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	ECP Capital Cost, $000 - 2017$	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Reid CT - Natural Gas								
Production Cost -(Annual inflation[1])		**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Production Cost (Nominal)	Total Production Cost, $000	[redacted]						
	Total Production Cost, cents/kWh							
	Total Fixed O&M Cost, $000							
	Total Fixed O&M Cost, $/kW-yr							
	Total Variable Cost, $000							
	Total Variable Cost, cents/kWh							
Production Cost -(2017$)		**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Production Cost (Real)	Total Production Cost, $000	[redacted]						
	Total Production Cost, cents/kWh							
	Total Fixed O&M Cost, $000							
	Total Fixed O&M Cost, $/kW-yr							
	Total Variable Cost, $000							
	Total Variable Cost, cents/kWh							
Operating Performance -KPIs		**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
KPIs	Net Capacity (Summer), MW	65	65	65	65	65	65	65
	Net Capacity (Winter), MW	65	65	65	65	65	65	65
	Net Generation, GWh	14	21	20	17	13	9	7
	EAF, %	[redacted]						
	Net Heat Rate, BTU/kWh							
	Net Capacity Factor, %	2.5%	3.7%	3.6%	3.0%	2.3%	1.6%	1.2%
Hours	Period Hours	8,760	8,760	8,784	8,760	8,760	8,760	8,784
	Service Hours	247	361	354	297	231	159	113
	Unplanned Outage Hours	876	876	878	876	876	876	878
	Planned Outage Hours	[redacted]						

Reid CT - Natural Gas								
Production Cost -(Annual inflation[1])		2025	2026	2027	2028	2029	2030	2031
Production Cost (Nominal)	Total Production Cost, $000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Production Cost, cents/kWh	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Fixed O&M Cost, $000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Fixed O&M Cost, $/kW-yr	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Variable Cost, $000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Variable Cost, cents/kWh	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Production Cost -(2017$)		2025	2026	2027	2028	2029	2030	2031
Production Cost (Real)	Total Production Cost, $000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Production Cost, cents/kWh	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Fixed O&M Cost, $000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Fixed O&M Cost, $/kW-yr	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Variable Cost, $000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Variable Cost, cents/kWh	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Operating Performance -KPIs		2025	2026	2027	2028	2029	2030	2031
KPIs	Net Capacity (Summer), MW	65	65	65	65	65	65	65
	Net Capacity (Winter), MW	65	65	65	65	65	65	65
	Net Generation, GWh	3	2	2	3	2	1	1
	EAF, %	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Net Heat Rate, BTU/kWh	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Net Capacity Factor, %	0.5%	0.3%	0.3%	0.4%	0.4%	0.1%	0.1%
Hours	Period Hours	8,760	8,760	8,760	8,784	8,760	8,760	8,760
	Service Hours	48	32	27	43	37	14	13
	Unplanned Outage Hours	876	876	876	878	876	876	876
	Planned Outage Hours	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Variable Costs		2018	2019	2020	2021	2022	2023	2024
Fuel	Fuel Used, GBtu	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Fuel Used, MMCF	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Fuel Cost, $/MMBtu - Nominal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Fuel Cost, $000 - Nominal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Fuel Cost, $/MMBtu - 2017$	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Fuel Cost, $000 - 2017$	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Non Fuel VOM	VOM Cost, $/MWh - Nominal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	VOM Cost, $000 - Nominal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	VOM Cost, $/MWh - 2017$	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	VOM Cost, $000 - 2017$	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Emissions	SO2 Emit Rate, lbs/MMBtu	0.060	0.060	0.060	0.060	0.060	0.060	0.060
	SO2 Tons Emitted	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	SO2 Cost, $000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	NOx Emit Rate, lbs/MMBtu	0.700	0.700	0.700	0.700	0.700	0.700	0.700
	NOx Tons Emitted	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	NOx Cost, $000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Emissions Cost, $000 - Nominal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Emissions Cost, $000 - 2017$	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fixed O&M Costs		**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Fixed O&M Costs	Fixed O&M Costs (No Cap.), $000 - Nominal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Plant Capital Cost, $000 - Nominal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	ECP Capital Cost, $000 - Nominal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Fixed O&M Costs (No Cap.), $000 - 2017$	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Plant Capital Cost, $000 - 2017$	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	ECP Capital Cost, $000 - 2017$	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Variable Costs		2025	2026	2027	2028	2029	2030	2031
Fuel	Fuel Used, GBtu	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Fuel Used, MMCF	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Fuel Cost, $/MMBtu - Nominal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Fuel Cost, $000 - Nominal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Fuel Cost, $/MMBtu - 2017$	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Fuel Cost, $000 - 2017$	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Non Fuel VOM	VOM Cost, $/MWh - Nominal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	VOM Cost, $000 - Nominal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	VOM Cost, $/MWh - 2017$	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	VOM Cost, $000 - 2017$	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Emissions	SO2 Emit Rate, lbs/MMBtu	0.060	0.060	0.060	0.060	0.060	0.060	0.060
	SO2 Tons Emitted	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	SO2 Cost, $000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	NOx Emit Rate, lbs/MMBtu	0.700	0.700	0.700	0.700	0.700	0.700	0.700
	NOx Tons Emitted	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	NOx Cost, $000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Emissions Cost, $000 - Nominal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Emissions Cost, $000 - 2017$	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fixed O&M Costs		**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Fixed O&M Costs	Fixed O&M Costs (No Cap.), $000 - Nominal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Plant Capital Cost, $000 - Nominal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	ECP Capital Cost, $000 - Nominal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Fixed O&M Costs (No Cap.), $000 - 2017$	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Plant Capital Cost, $000 - 2017$	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	ECP Capital Cost, $000 - 2017$	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

SEPA (Hydro)								
Production Cost -(Annual inflation[1])		2018	2019	2020	2021	2022	2023	2024
Prod. Cost (Nominal)	Total Production Cost, $000	[redacted]						
	Total Production Cost, cents/kWh							
Production Cost -(2017$)		2018	2019	2020	2021	2022	2023	2024
Prod. Cost (Real)	Total Production Cost, $000	[redacted]						
	Total Production Cost, cents/kWh							
Operating Performance -KPIs		2018	2019	2020	2021	2022	2023	2024
KPIs	Net Capacity (Summer), MW	154	178	178	178	178	178	178
	Net Capacity (Winter), MW	154	178	178	178	178	178	178
	Net Generation, GWh	222	267	267	267	267	267	267
	Net Capacity Factor, %	16.5%	17.1%	17.1%	17.1%	17.1%	17.1%	17.1%
Hours	Period Hours	8,760	8,760	8,784	8,760	8,760	8,760	8,784

[1] **Annual Inflation Rate** [redacted]

SEPA (Hydro)								
Production Cost -(Annual inflation[1])		2025	2026	2027	2028	2029	2030	2031
Prod. Cost (Nominal)	Total Production Cost, $000	[redacted]						
	Total Production Cost, cents/kWh							
Production Cost -(2017$)		2025	2026	2027	2028	2029	2030	2031
Prod. Cost (Real)	Total Production Cost, $000	[redacted]						
	Total Production Cost, cents/kWh							
Operating Performance -KPIs		2025	2026	2027	2028	2029	2030	2031
KPIs	Net Capacity (Summer), MW	178	178	178	178	178	178	178
	Net Capacity (Winter), MW	178	178	178	178	178	178	178
	Net Generation, GWh	267	267	267	267	267	267	267
	Net Capacity Factor, %	17.1%	17.1%	17.1%	17.1%	17.1%	17.1%	17.1%
Hours	Period Hours	8,760	8,760	8,760	8,784	8,760	8,760	8,760

[1] **Annual Inflation Rate** [redacted]

Big Rivers 2017 Integrated Resource Plan

Appendix F – Generator Operating Inputs

Full Load Net Heat Rate, BTU/kWh											
Year	Green 1 (Coal)	Green 2 (Coal)	HMPL Station (Coal)	Wilson (Coal)	Reid CT (NG)	Green 1 (NG)	Green 2 (NG)	HMPL Station (NG)	100 MW NGCT	20 MW Solar	702 MW NGCC
2018	[redacted]										
2019	[redacted]										
2020	[redacted]										
2021	[redacted]										
2022	[redacted]										
2023	[redacted]										
2024	[redacted]										
2025	[redacted]										
2026	[redacted]										
2027	[redacted]										
2028	[redacted]										
2029	[redacted]										
2030	[redacted]										
2031	[redacted]										

Non-Fuel Variable Cost (excluding Emisson Cost), $/MWh									
	Green 1 & Green 2 (Coal)	HMPL Station (Coal)	Wilson (Coal)	Reid CT (NG)	Green 1 & Green 2 (NG)	HMPL Station (NG)	100 MW NGCT	20 MW Solar	702 MW NGCC
2018	[redacted]								
2019									
2020									
2021									
2022									
2023									
2024									
2025									
2026									
2027									
2028									
2029									
2030									
2031									

Unplanned Outage Rate, %											
	Green 1 (Coal)	Green 2 (Coal)	HMPL Station (Coal)	Wilson (Coal)	Reid CT (NG)	Green 1 NG	Green 2 NG	HMPL Station NG	100 MW NGCT	20 MW Solar	702 MW NGCC
2018	3.25%	3.25%	7.5%	5.0%	10.0%						
2019	3.75%	3.75%	7.0%	5.0%	10.0%						
2020	4.25%	3.25%	7.0%	5.0%	10.0%	4.25%	3.25%	7.0%	7.0%	0.0%	7.0%
2021	3.25%	3.25%	7.5%	5.0%	10.0%	3.25%	3.25%	7.5%	7.0%	0.0%	7.0%
2022	3.25%	3.25%	7.0%	5.0%	10.0%	3.25%	3.25%	7.0%	7.0%	0.0%	7.0%
2023	3.25%	3.25%	7.0%	5.0%	10.0%	3.25%	3.25%	7.0%	7.0%	0.0%	7.0%
2024	3.25%	3.25%	7.0%	5.0%	10.0%	3.25%	3.25%	7.0%	7.0%	0.0%	7.0%
2025	3.25%	3.25%	7.0%	5.0%	10.0%	3.25%	3.25%	7.0%	7.0%	0.0%	7.0%
2026	3.25%	3.25%	7.0%	5.0%	10.0%	3.25%	3.25%	7.0%	7.0%	0.0%	7.0%
2027	3.25%	3.25%	7.0%	5.0%	10.0%	3.25%	3.25%	7.0%	7.0%	0.0%	7.0%
2028	3.25%	3.25%	7.0%	5.0%	10.0%	3.25%	3.25%	7.0%	7.0%	0.0%	7.0%
2029	3.25%	3.25%	7.0%	5.0%	10.0%	3.25%	3.25%	7.0%	7.0%	0.0%	7.0%
2030	3.25%	3.25%	7.0%	5.0%	10.0%	3.25%	3.25%	7.0%	7.0%	0.0%	7.0%
2031	3.25%	3.25%	7.0%	5.0%	10.0%	3.25%	3.25%	7.0%	7.0%	0.0%	7.0%

Generator Capacity, MW												
Max/Min	**SEPA***	**Green 1 (Coal)**	**Green 2 (Coal)**	**HMPL Station (Coal)**	**Wilson (Coal)**	**Reid CT (NG)**	**Green 1 (NG)**	**Green 2 (NG)**	**HMPL Station (NG)**	**100 MW NGCT**	**20 MW Solar**	**702 MW NGCC**
Maximum	154/178	231	223	197	417	65	208	201	177	100	20	702
Minimum	0	105	110	130	300	20	105	110	130	30	0	210

* SEPA maximum capacity increases from 154 to 178 in 2019

SO_2 Emission Rate, lbs/MMBtu											
Year	Green 1 (Coal)	Green 2 (Coal)	HMPL Station (Coal)	Wilson (Coal)	Reid CT (NG)	Green 1 (NG)	Green 2 (NG)	HMPL Station (NG)	100 MW NGCT	20 MW Solar	702 MW NGCC
2018	0.18	0.18	0.32	0.43	0.06						
2019	0.18	0.18	0.32	0.43	0.06						
2020	0.18	0.18	0.32	0.43	0.06	0.00	0.00	0.00	0.0010	N/A	0.0010
2021	0.18	0.18	0.32	0.43	0.06	0.00	0.00	0.00	0.0010	N/A	0.0010
2022	0.18	0.18	0.32	0.43	0.06	0.00	0.00	0.00	0.0010	N/A	0.0010
2023	0.18	0.18	0.32	0.43	0.06	0.00	0.00	0.00	0.0010	N/A	0.0010
2024	0.18	0.18	0.32	0.43	0.06	0.00	0.00	0.00	0.0010	N/A	0.0010
2025	0.18	0.18	0.32	0.43	0.06	0.00	0.00	0.00	0.0010	N/A	0.0010
2026	0.18	0.18	0.32	0.43	0.06	0.00	0.00	0.00	0.0010	N/A	0.0010
2027	0.18	0.18	0.32	0.43	0.06	0.00	0.00	0.00	0.0010	N/A	0.0010
2028	0.18	0.18	0.32	0.43	0.06	0.00	0.00	0.00	0.0010	N/A	0.0010
2029	0.18	0.18	0.32	0.43	0.06	0.00	0.00	0.00	0.0010	N/A	0.0010
2030	0.18	0.18	0.32	0.43	0.06	0.00	0.00	0.00	0.0010	N/A	0.0010
2031	0.18	0.18	0.32	0.43	0.06	0.00	0.00	0.00	0.0010	N/A	0.0010

NO_x Emission Rate, lbs/MMBtu											
Year	Green 1 (Coal)	Green 2 (Coal)	HMPL Station (Coal)	Wilson (Coal)	Reid CT (NG)	Green 1 (NG)	Green 2 (NG)	HMPL Station (NG)	100 MW NGCT	20 MW Solar	702 MW NGCC
2018	0.219	0.219	0.07	0.06	0.7						
2019	0.219	0.219	0.07	0.06	0.7						
2020	0.219	0.219	0.07	0.06	0.7	0.22	0.22	0.45	0.0300	N/A	0.0075
2021	0.219	0.219	0.07	0.06	0.7	0.22	0.22	0.45	0.0300	N/A	0.0075
2022	0.219	0.219	0.07	0.06	0.7	0.22	0.22	0.45	0.0300	N/A	0.0075
2023	0.219	0.219	0.07	0.06	0.7	0.22	0.22	0.45	0.0300	N/A	0.0075
2024	0.219	0.219	0.07	0.06	0.7	0.22	0.22	0.45	0.0300	N/A	0.0075
2025	0.219	0.219	0.07	0.06	0.7	0.22	0.22	0.45	0.0300	N/A	0.0075
2026	0.219	0.219	0.07	0.06	0.7	0.22	0.22	0.45	0.0300	N/A	0.0075
2027	0.219	0.219	0.07	0.06	0.7	0.22	0.22	0.45	0.0300	N/A	0.0075
2028	0.219	0.219	0.07	0.06	0.7	0.22	0.22	0.45	0.0300	N/A	0.0075
2029	0.219	0.219	0.07	0.06	0.7	0.22	0.22	0.45	0.0300	N/A	0.0075
2030	0.219	0.219	0.07	0.06	0.7	0.22	0.22	0.45	0.0300	N/A	0.0075
2031	0.219	0.219	0.07	0.06	0.7	0.22	0.22	0.45	0.0300	N/A	0.0075

Big Rivers
ELECTRIC CORPORATION

Your Touchstone Energy® Cooperative

In the Matter of:

2017 INTEGRATED RESOURCE PLAN OF BIG RIVERS ELECTRIC CORPORATION	))	**Case No. 2017-00**_384_

CONFIDENTIAL

Appendix G
J D Energy Long-Term Coal Price Forecast 2017-2045
FILED: September 21, 2017

INFORMATION SUBMITTED UNDER PETITION FOR CONFIDENTIAL TREATMENT

Big Rivers
ELECTRIC CORPORATION

Your Touchstone Energy® Cooperative

In the Matter of:

2017 INTEGRATED RESOURCE PLAN OF BIG RIVERS ELECTRIC CORPORATION	))	**Case No. 2017-00**384

CONFIDENTIAL

Appendix G
J D. Energy Long-Term Coal Price Forecast Tables
FILED: September 21, 2017

INFORMATION SUBMITTED UNDER PETITION FOR CONFIDENTIAL TREATMENT

Big Rivers
ELECTRIC CORPORATION

Your Touchstone Energy® Cooperative

In the Matter of:

2017 INTEGRATED RESOURCE PLAN OF BIG RIVERS ELECTRIC CORPORATION	))	**Case No. 2017-00**384

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Appendix G
ACES Methodology Report
FILED: September 21, 2017

INFORMATION SUBMITTED UNDER PETITION FOR CONFIDENTIAL TREATMENT

Base Case - ACES Price Forecast from 5/2/17			
IN Hub DA Prices Annual Average			
Year	On Peak	Off Peak	ATC
2013	$ 38.04	$ 27.50	$ 32.41
2014	$ 48.17	$ 32.45	$ 39.77
2015	$ 33.41	$ 24.51	$ 28.67
2016	$ 33.67	$ 23.29	$ 28.11
2017	[redacted]		
2018	[redacted]		
2019	[redacted]		
2020	[redacted]		
2021	[redacted]		
2022	[redacted]		
2023	[redacted]		
2024	[redacted]		
2025	[redacted]		
2026	[redacted]		
2027	[redacted]		
2028	[redacted]		
2029	[redacted]		
2030	[redacted]		
2031	[redacted]		

Base Case - ACES Price Forecast from 5/2/17					
IN Hub DA Prices Monthly Average					
Month	On Peak Hours	Off Peak Hours	On Peak	Off Peak	ATC
Jan-13	352	392	$ 32.68	$ 25.16	$ 28.71
Feb-13	320	352	$ 31.77	$ 26.13	$ 28.81
Mar-13	336	408	$ 38.00	$ 29.52	$ 33.35
Apr-13	352	368	$ 40.10	$ 30.94	$ 35.42
May-13	352	392	$ 42.43	$ 28.11	$ 34.89
Jun-13	320	400	$ 42.75	$ 27.66	$ 34.37
Jul-13	352	392	$ 40.90	$ 26.54	$ 33.33
Aug-13	352	392	$ 37.43	$ 25.53	$ 31.16
Sep-13	320	400	$ 36.89	$ 24.98	$ 30.27
Oct-13	368	376	$ 37.34	$ 26.65	$ 31.94
Nov-13	320	400	$ 35.46	$ 27.87	$ 31.24
Dec-13	336	408	$ 40.32	$ 30.82	$ 35.11
Jan-14	352	392	$ 82.48	$ 47.13	$ 63.86
Feb-14	320	352	$ 73.36	$ 44.59	$ 58.29
Mar-14	336	408	$ 58.26	$ 37.57	$ 46.91
Apr-14	352	368	$ 43.37	$ 31.49	$ 37.30
May-14	336	408	$ 46.69	$ 31.58	$ 38.40
Jun-14	336	384	$ 45.88	$ 28.01	$ 36.35
Jul-14	352	392	$ 37.99	$ 26.83	$ 32.11
Aug-14	336	408	$ 37.75	$ 28.15	$ 32.49
Sep-14	336	384	$ 37.96	$ 27.74	$ 32.51
Oct-14	368	376	$ 38.03	$ 28.28	$ 33.10
Nov-14	304	416	$ 42.09	$ 31.55	$ 36.00
Dec-14	352	392	$ 35.51	$ 27.36	$ 31.21
Jan-15	336	408	$ 35.67	$ 26.73	$ 30.77
Feb-15	320	352	$ 48.42	$ 33.12	$ 40.41
Mar-15	352	392	$ 33.71	$ 27.06	$ 30.21
Apr-15	352	368	$ 30.77	$ 24.64	$ 27.64
May-15	320	424	$ 35.54	$ 24.87	$ 29.46
Jun-15	352	368	$ 33.14	$ 22.16	$ 27.53
Jul-15	368	376	$ 33.27	$ 23.87	$ 28.52
Aug-15	336	408	$ 31.96	$ 23.59	$ 27.37
Sep-15	336	384	$ 34.03	$ 22.66	$ 27.97
Oct-15	352	392	$ 31.33	$ 22.94	$ 26.91
Nov-15	320	400	$ 28.22	$ 23.10	$ 25.38

Base Case - ACES Price Forecast from 5/2/17			
IN Hub DA Prices Annual Average			
Year	On Peak	Off Peak	ATC

Base Case - ACES Price Forecast from 5/2/17					
IN Hub DA Prices Monthly Average					
Month	On Peak Hours	Off Peak Hours	On Peak	Off Peak	ATC
Dec-15	352	392	$ 26.00	$ 19.97	$ 22.82
Jan-16	320	424	$ 26.87	$ 21.77	$ 23.96
Feb-16	336	360	$ 24.88	$ 19.75	$ 22.23
Mar-16	368	376	$ 25.09	$ 19.02	$ 22.02
Apr-16	336	384	$ 32.02	$ 24.47	$ 27.99
May-16	336	408	$ 29.22	$ 20.34	$ 24.35
Jun-16	352	368	$ 32.19	$ 22.29	$ 27.13
Jul-16	320	424	$ 40.33	$ 24.45	$ 31.28
Aug-16	368	376	$ 38.54	$ 23.89	$ 31.14
Sep-16	336	384	$ 41.70	$ 24.80	$ 32.69
Oct-16	336	408	$ 40.50	$ 26.21	$ 32.66
Nov-16	336	384	$ 32.78	$ 23.59	$ 27.88
Dec-16	336	408	$ 40.39	$ 28.29	$ 33.76
Jan-17	336	408	$ 36.19	$ 27.23	$ 31.28
Feb-17	320	352	$ 30.01	$ 23.22	$ 26.45
Mar-17	368	376	$ 31.75	$ 25.05	$ 28.37
Apr-17	320	400	$ 35.35	$ 25.46	$ 29.85
May-17	352	392	$ 35.48	$ 24.44	$ 29.66
Jun-17	352	368	$ 34.98	$ 24.08	$ 29.41
Jul-17	320	424	$ 42.62	$ 26.73	$ 33.56
Aug-17	368	376	$ 39.51	$ 24.61	$ 31.98
Sep-17	320	400	[redacted]	[redacted]	[redacted]
Oct-17	352	392	[redacted]	[redacted]	[redacted]
Nov-17	336	384	[redacted]	[redacted]	[redacted]
Dec-17	320	424	[redacted]	[redacted]	[redacted]
Jan-18	352	392	[redacted]	[redacted]	[redacted]
Feb-18	320	352	[redacted]	[redacted]	[redacted]
Mar-18	352	392	[redacted]	[redacted]	[redacted]
Apr-18	336	384	[redacted]	[redacted]	[redacted]
May-18	352	392	[redacted]	[redacted]	[redacted]
Jun-18	336	384	[redacted]	[redacted]	[redacted]
Jul-18	336	408	[redacted]	[redacted]	[redacted]
Aug-18	368	376	[redacted]	[redacted]	[redacted]
Sep-18	304	416	[redacted]	[redacted]	[redacted]
Oct-18	368	376	[redacted]	[redacted]	[redacted]
Nov-18	336	384	[redacted]	[redacted]	[redacted]

Base Case - ACES Price Forecast from 5/2/17			
IN Hub DA Prices Annual Average			
Year	On Peak	Off Peak	ATC

Base Case - ACES Price Forecast from 5/2/17					
IN Hub DA Prices Monthly Average					
Month	On Peak Hours	Off Peak Hours	On Peak	Off Peak	ATC
Dec-18	320	424	[redacted]		
Jan-19	352	392	[redacted]		
Feb-19	320	352	[redacted]		
Mar-19	336	408	[redacted]		
Apr-19	352	368	[redacted]		
May-19	352	392	[redacted]		
Jun-19	320	400	[redacted]		
Jul-19	352	392	[redacted]		
Aug-19	352	392	[redacted]		
Sep-19	320	400	[redacted]		
Oct-19	368	376	[redacted]		
Nov-19	320	400	[redacted]		
Dec-19	336	408	[redacted]		
Jan-20	352	392	[redacted]		
Feb-20	320	376	[redacted]		
Mar-20	352	392	[redacted]		
Apr-20	352	368	[redacted]		
May-20	320	424	[redacted]		
Jun-20	352	368	[redacted]		
Jul-20	368	376	[redacted]		
Aug-20	336	408	[redacted]		
Sep-20	336	384	[redacted]		
Oct-20	352	392	[redacted]		
Nov-20	320	400	[redacted]		
Dec-20	352	392	[redacted]		
Jan-21	320	424	[redacted]		
Feb-21	320	352	[redacted]		
Mar-21	368	376	[redacted]		
Apr-21	352	368	[redacted]		
May-21	320	424	[redacted]		
Jun-21	352	368	[redacted]		
Jul-21	336	408	[redacted]		
Aug-21	352	392	[redacted]		
Sep-21	336	384	[redacted]		
Oct-21	336	408	[redacted]		
Nov-21	336	384	[redacted]		

Base Case - ACES Price Forecast from 5/2/17			
IN Hub DA Prices Annual Average			
Year	On Peak	Off Peak	ATC

Base Case - ACES Price Forecast from 5/2/17					
IN Hub DA Prices Monthly Average					
Month	On Peak Hours	Off Peak Hours	On Peak	Off Peak	ATC
Dec-21	368	376	[redacted]		
Jan-22	336	408	[redacted]		
Feb-22	320	352	[redacted]		
Mar-22	368	376	[redacted]		
Apr-22	336	384	[redacted]		
May-22	336	408	[redacted]		
Jun-22	352	368	[redacted]		
Jul-22	320	424	[redacted]		
Aug-22	368	376	[redacted]		
Sep-22	336	384	[redacted]		
Oct-22	336	408	[redacted]		
Nov-22	336	384	[redacted]		
Dec-22	336	408	[redacted]		
Jan-23	336	408	[redacted]		
Feb-23	320	352	[redacted]		
Mar-23	368	376	[redacted]		
Apr-23	320	400	[redacted]		
May-23	352	392	[redacted]		
Jun-23	352	368	[redacted]		
Jul-23	320	424	[redacted]		
Aug-23	368	376	[redacted]		
Sep-23	320	400	[redacted]		
Oct-23	352	392	[redacted]		
Nov-23	336	384	[redacted]		
Dec-23	320	424	[redacted]		
Jan-24	352	392	[redacted]		
Feb-24	336	360	[redacted]		
Mar-24	336	408	[redacted]		
Apr-24	352	368	[redacted]		
May-24	352	392	[redacted]		
Jun-24	320	400	[redacted]		
Jul-24	352	392	[redacted]		
Aug-24	352	392	[redacted]		
Sep-24	320	400	[redacted]		
Oct-24	368	376	[redacted]		
Nov-24	320	400	[redacted]		

Base Case - ACES Price Forecast from 5/2/17			
IN Hub DA Prices Annual Average			
Year	On Peak	Off Peak	ATC

Base Case - ACES Price Forecast from 5/2/17					
IN Hub DA Prices Monthly Average					
Month	On Peak Hours	Off Peak Hours	On Peak	Off Peak	ATC
Dec-24	336	408	[redacted]		
Jan-25	352	392			
Feb-25	320	352			
Mar-25	336	408			
Apr-25	352	368			
May-25	336	408			
Jun-25	336	384			
Jul-25	352	392			
Aug-25	336	408			
Sep-25	336	384			
Oct-25	368	376			
Nov-25	304	416			
Dec-25	352	392			
Jan-26	336	408			
Feb-26	320	352			
Mar-26	352	392			
Apr-26	352	368			
May-26	320	424			
Jun-26	352	368			
Jul-26	368	376			
Aug-26	336	408			
Sep-26	336	384			
Oct-26	352	392			
Nov-26	320	400			
Dec-26	352	392			
Jan-27	320	424			
Feb-27	320	352			
Mar-27	368	376			
Apr-27	352	368			
May-27	320	424			
Jun-27	352	368			
Jul-27	336	408			
Aug-27	352	392			
Sep-27	336	384			
Oct-27	336	408			
Nov-27	336	384			

Base Case - ACES Price Forecast from 5/2/17			
IN Hub DA Prices Annual Average			
Year	On Peak	Off Peak	ATC

Base Case - ACES Price Forecast from 5/2/17					
IN Hub DA Prices Monthly Average					
Month	On Peak Hours	Off Peak Hours	On Peak	Off Peak	ATC
Dec-27	368	376	[redacted]	[redacted]	[redacted]
Jan-28	336	408	[redacted]	[redacted]	[redacted]
Feb-28	336	360	[redacted]	[redacted]	[redacted]
Mar-28	368	376	[redacted]	[redacted]	[redacted]
Apr-28	320	400	[redacted]	[redacted]	[redacted]
May-28	352	392	[redacted]	[redacted]	[redacted]
Jun-28	352	368	[redacted]	[redacted]	[redacted]
Jul-28	320	424	[redacted]	[redacted]	[redacted]
Aug-28	368	376	[redacted]	[redacted]	[redacted]
Sep-28	320	400	[redacted]	[redacted]	[redacted]
Oct-28	352	392	[redacted]	[redacted]	[redacted]
Nov-28	336	384	[redacted]	[redacted]	[redacted]
Dec-28	320	424	[redacted]	[redacted]	[redacted]
Jan-29	352	392	[redacted]	[redacted]	[redacted]
Feb-29	320	352	[redacted]	[redacted]	[redacted]
Mar-29	352	392	[redacted]	[redacted]	[redacted]
Apr-29	336	384	[redacted]	[redacted]	[redacted]
May-29	352	392	[redacted]	[redacted]	[redacted]
Jun-29	336	384	[redacted]	[redacted]	[redacted]
Jul-29	336	408	[redacted]	[redacted]	[redacted]
Aug-29	368	376	[redacted]	[redacted]	[redacted]
Sep-29	304	416	[redacted]	[redacted]	[redacted]
Oct-29	368	376	[redacted]	[redacted]	[redacted]
Nov-29	336	384	[redacted]	[redacted]	[redacted]
Dec-29	352	392	[redacted]	[redacted]	[redacted]
Jan-30	352	392	[redacted]	[redacted]	[redacted]
Feb-30	320	352	[redacted]	[redacted]	[redacted]
Mar-30	336	408	[redacted]	[redacted]	[redacted]
Apr-30	352	368	[redacted]	[redacted]	[redacted]
May-30	352	392	[redacted]	[redacted]	[redacted]
Jun-30	320	400	[redacted]	[redacted]	[redacted]
Jul-30	352	392	[redacted]	[redacted]	[redacted]
Aug-30	352	392	[redacted]	[redacted]	[redacted]
Sep-30	320	400	[redacted]	[redacted]	[redacted]
Oct-30	368	376	[redacted]	[redacted]	[redacted]
Nov-30	320	400	[redacted]	[redacted]	[redacted]

Base Case - ACES Price Forecast from 5/2/17			
IN Hub DA Prices Annual Average			
Year	On Peak	Off Peak	ATC

Base Case - ACES Price Forecast from 5/2/17					
IN Hub DA Prices Monthly Average					
Month	On Peak Hours	Off Peak Hours	On Peak	Off Peak	ATC
Dec-30	336	408	[redacted]	[redacted]	[redacted]
Jan-31	352	392	[redacted]	[redacted]	[redacted]
Feb-31	320	352	[redacted]	[redacted]	[redacted]
Mar-31	336	408	[redacted]	[redacted]	[redacted]
Apr-31	352	368	[redacted]	[redacted]	[redacted]
May-31	336	408	[redacted]	[redacted]	[redacted]
Jun-31	336	384	[redacted]	[redacted]	[redacted]
Jul-31	352	392	[redacted]	[redacted]	[redacted]
Aug-31	336	408	[redacted]	[redacted]	[redacted]
Sep-31	336	384	[redacted]	[redacted]	[redacted]
Oct-31	368	376	[redacted]	[redacted]	[redacted]
Nov-31	304	416	[redacted]	[redacted]	[redacted]
Dec-31	352	392	[redacted]	[redacted]	[redacted]

BIG RIVERS ELECTRIC CORPORATION
INTERGRATED RESOURCE PLAN

Model Results	Net Utility Costs NPV ($000)	Resources changes from Current (2017) Operation
Base Case	[redacted]	Exit Contracts with HMP&L Station Two in 2020

Scenario		Net Utility Costs NPV ($000)	Resource Changes from Base Case
Energy LMP Prices	10% Higher	[redacted]	Same as Base Case
	20% Higher		Remain in HMP&L Station Two Contracts with coal operation
	10% Lower		Green Units converted to NG in 2020
	20% Lower		Green Units converted to NG in 2020
Coal Prices	10% Higher		Green Units converted to NG in 2020
	20% Higher		Green Units converted to NG in 2020
	10% Lower		Same as Base Case
	20% Lower		Remain in HMP&L Station Two Contracts with coal operation
Natural Gas Prices	20% Higher		Same as Base Case
	10% Lower		Green Units converted to NG in 2020
	20% Lower		Green Units converted to NG in 2020
	30% Lower		Green Units converted to NG in 2020
Load Scenarios	High Load		Same as Base Case
	Low Load		Same as Base Case
Other Scenarios	HMP&L Early Exit		Exit Contracts with HMP&L Station Two in 2018
	Renewal Portfolio Standard		Build Solar capacity (140 MW in 2020 and 40 MW in 2025)
	Additional DSM		Same as Base Case

BIG RIVERS ELECTRIC CORPORATION
INTERGRATED RESOURCE PLAN
BASE CASE RESOURCE CAPACITY AND ENERGY

	Capacity Additions						Energy and Capacity Positions											
	(1)		(2)		(3)		(4)	(5)	(6)	7)=(4)+(5)+((	(8)	(9)	(10)=(8)-(9)	(11)=(7)-(10	(12)	(13)	14)=(12)-(1:	(15)
	Supply-Side Capacity		Incremental Energy Efficiency		Utility Solar		Thermal Generation + Hydro	Purchased Energy	New Utility Solar	= Market Sales	Load (Net of Embedded EE)	*Less: Energy Efficiency*	= Net Load Requirements	Energy Surplus	Capacity	Peak + Reserves	Capacity Surplus	Minimum Reserve Margin
	Incremental MW	Culm MW	Incremental MW	Culm MW	Incremental MW	Culm MW	GWh	GWh	GWh	GWh	GWh	GWh	GWh	GWh	MW	MW	MW	%
2018			(1.3)	(1.3)			5,219			5,219	3,420	(17.1)	3,403	1,816	1,287	763	524	15.8
2019			(1.2)	(2.5)			5,365			5,365	3,930	(25.3)	3,904	1,461	1,311	918	393	15.8
2020			(1.2)	(3.7)			4,410			4,410	4,356	(32.7)	4,323	87	1,114	937	177	15.8
2021			(0.4)	(4.1)			4,256			4,256	4,326	(35.0)	4,291	(34)	1,114	950	164	15.8
2022			(1.1)	(5.2)			3,911			3,911	4,355	(42.1)	4,313	(402)	1,114	959	155	15.8
2023			(1.1)	(6.3)			3,805			3,805	4,346	(49.2)	4,296	(491)	1,114	961	153	15.8
2024			(1.1)	(7.3)			3,807			3,807	4,376	(56.2)	4,320	(513)	1,114	963	151	15.8
2025			(0.9)	(8.3)			4,006			4,006	4,397	(62.3)	4,335	(328)	1,114	951	163	15.8
2026			(0.9)	(9.2)			4,120			4,120	4,454	(68.3)	4,386	(266)	1,114	966	148	15.8
2027			(0.9)	(10.1)			4,503			4,503	4,180	(74.3)	4,105	398	1,114	891	223	15.8
2028			(0.9)	(11.1)			4,515			4,515	4,226	(80.4)	4,145	370	1,114	892	222	15.8
2029			(0.9)	(11.9)			5,072			5,072	3,915	(86.0)	3,829	1,243	1,114	886	228	15.8
2030			(0.9)	(12.8)			5,326			5,326	3,627	(91.6)	3,535	1,791	1,114	780	334	15.8
2031			(0.8)	(13.6)			6,088			6,088	3,641	(97.1)	3,544	2,544	1,114	782	332	15.8

BIG RIVERS ELECTRIC CORPORATION
INTERGRATED RESOURCE PLAN
BASE CASE NET PRESENT VALUE

		Utility Costs ($000)											
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	=(1)thru(9)-(10)-(11)
		Load Cost (Energy)	Load Cost (Capacity)	Fuel Costs	FOM	Non-Fuel VOM	Emissions Cost	EE Program Costs	Annualized Build Costs	Retirement/Exit Costs	*Less: Market Revenue*	*Less: Capacity Revenue*	Net Utility Costs
		$000	$000	$000	$000	$000	$000	$000	$000	$000	$000	$000	$000
	2018	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	2019	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	2020	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	2021	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	2022	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	2023	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	2024	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	2025	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	2026	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	2027	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	2028	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	2029	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	2030	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	2031	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Net Present Value$000 (2017$)													
NPV 2017-2031	NPV	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	8,244	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

BIG RIVERS ELECTRIC CORPORATION
INTERGRATED RESOURCE PLAN
10% HIGHER ENERGY LMP PRICES SCENARIO

	Capacity Additions						Energy and Capacity Positions											
	(1)		(2)		(3)		(4)	(5)	(6)	7)=(4)+(5)+(	(8)	(9)	(10)=(8)-(9)	(11)=(7)-(10	(12)	(13)	14)=(12)-(13	(15)
	Supply-Side Capacity		Incremental Energy Efficiency		Utility Solar		Thermal Generation + Hydro	Purchased Energy	New Utility Solar	= Market Sales	Load (Net of Embedded EE)	*Less:* Energy Efficiency	= Net Load Requirements	Energy Surplus	Capacity	Peak + Reserves	Capacity Surplus	Minimum Reserve Margin
	Incremental MW	Culm MW	Incremental MW	Culm MW	Incremental MW	Culm MW	GWh	GWh	GWh	GWh	GWh	GWh	GWh	GWh	MW	MW	MW	%
2018			(1.3)	(1.3)			6,250			6,250	3,420	(17.1)	3,403	2,847	1,287	763	524	15.8
2019			(1.2)	(2.5)			6,296			6,296	3,930	(25.3)	3,904	2,392	1,311	918	393	15.8
2020			(1.2)	(3.7)			5,102			5,102	4,356	(32.7)	4,323	779	1,114	937	177	15.8
2021			(0.4)	(4.1)			5,068			5,068	4,326	(35.0)	4,291	777	1,114	950	164	15.8
2022			(1.1)	(5.2)			4,768			4,768	4,355	(42.1)	4,313	455	1,114	959	155	15.8
2023			(1.1)	(6.3)			4,787			4,787	4,346	(49.2)	4,296	491	1,114	961	153	15.8
2024			(1.1)	(7.3)			4,778			4,778	4,376	(56.2)	4,320	458	1,114	963	151	15.8
2025			(0.9)	(8.3)			5,044			5,044	4,397	(62.3)	4,335	709	1,114	951	163	15.8
2026			(0.9)	(9.2)			5,108			5,108	4,454	(68.3)	4,386	722	1,114	966	148	15.8
2027			(0.9)	(10.1)			5,675			5,675	4,180	(74.3)	4,105	1,569	1,114	891	223	15.8
2028			(0.9)	(11.1)			5,629			5,629	4,226	(80.4)	4,145	1,484	1,114	892	222	15.8
2029			(0.9)	(11.9)			6,179			6,179	3,915	(86.0)	3,829	2,350	1,114	886	228	15.8
2030			(0.9)	(12.8)			6,309			6,309	3,627	(91.6)	3,535	2,774	1,114	780	334	15.8
2031			(0.8)	(13.6)			6,839			6,839	3,641	(97.1)	3,544	3,295	1,114	782	332	15.8

BIG RIVERS ELECTRIC CORPORATION
INTERGRATED RESOURCE PLAN
10% HIGHER ENERGY LMP PRICES SCENARIO NET PRESENT VALUE

	Utility Costs ($000)											
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	=(1)thru(9)-(10)-(11)
	Load Cost (Energy)	Load Cost (Capacity)	Fuel Costs	FOM	Non-Fuel VOM	Emissions Cost	EE Program Costs	Annualized Build Costs	Retirement/Exit Costs	*Less: Market Revenue*	*Less: Capacity Revenue*	Net Utility Costs
	$000	$000	$000	$000	$000	$000	$000	$000	$000	$000	$000	$000
2018	[redacted]						1,000	[redacted]				
2019	[redacted]						1,000	[redacted]				
2020	[redacted]						1,000	[redacted]				
2021	[redacted]						1,000	[redacted]				
2022	[redacted]						1,000	[redacted]				
2023	[redacted]						1,000	[redacted]				
2024	[redacted]						1,000	[redacted]				
2025	[redacted]						1,000	[redacted]				
2026	[redacted]						1,000	[redacted]				
2027	[redacted]						1,000	[redacted]				
2028	[redacted]						1,000	[redacted]				
2029	[redacted]						1,000	[redacted]				
2030	[redacted]						1,000	[redacted]				
2031	[redacted]						1,000	[redacted]				
Net Present Value$000 (2017$) NPV 2017-2031	[redacted]						8,244	[redacted]				

BIG RIVERS ELECTRIC CORPORATION
INTERGRATED RESOURCE PLAN
20% HIGHER ENERGY LMP PRICES SCENARIO

	Capacity Additions						Energy and Capacity Positions											
	(1)		(2)		(3)		(4)	(5)	(6)	7)=(4)+(5)+(6	(8)	(9)	(10)=(8)-(9)	(11)=(7)-(10	(12)	(13)	14)=(12)-(13	(15)
	Supply-Side Capacity		Incremental Energy Efficiency		Utility Solar		Thermal Generation + Hydro	Purchased Energy	New Utility Solar	= Market Sales	Load (Net of Embedded EE)	*Less:* Energy Efficiency	= Net Load Requirements	Energy Surplus	Capacity	Peak + Reserves	Capacity Surplus	Minimum Reserve Margin
	Incremental MW	Culm MW	Incremental MW	Culm MW	Incremental MW	Culm MW	GWh	GWh	GWh	GWh	GWh	GWh	GWh	GWh	MW	MW	MW	%
2018			(1.3)	(1.3)			6,977			6,977	3,420	(17.1)	3,403	3,574	1,287	763	524	15.8
2019			(1.2)	(2.5)			7,033			7,033	3,930	(25.3)	3,904	3,129	1,311	918	393	15.8
2020			(1.2)	(3.7)			6,785			6,785	4,356	(32.7)	4,323	2,462	1,311	937	374	15.8
2021			(0.4)	(4.1)			6,711			6,711	4,326	(35.0)	4,291	2,420	1,311	950	361	15.8
2022			(1.1)	(5.2)			6,320			6,320	4,355	(42.1)	4,313	2,007	1,311	959	352	15.8
2023			(1.1)	(6.3)			6,439			6,439	4,346	(49.2)	4,296	2,143	1,311	961	350	15.8
2024			(1.1)	(7.3)			6,438			6,438	4,376	(56.2)	4,320	2,118	1,311	963	348	15.8
2025			(0.9)	(8.3)			6,764			6,764	4,397	(62.3)	4,335	2,429	1,311	951	360	15.8
2026			(0.9)	(9.2)			6,710			6,710	4,454	(68.3)	4,386	2,324	1,311	966	345	15.8
2027			(0.9)	(10.1)			7,384			7,384	4,180	(74.3)	4,105	3,279	1,311	891	420	15.8
2028			(0.9)	(11.1)			7,214			7,214	4,226	(80.4)	4,145	3,069	1,311	892	419	15.8
2029			(0.9)	(11.9)			8,161			8,161	3,915	(86.0)	3,829	4,331	1,311	886	425	15.8
2030			(0.9)	(12.8)			8,211			8,211	3,627	(91.6)	3,535	4,676	1,311	780	531	15.8
2031			(0.8)	(13.6)			8,724			8,724	3,641	(97.1)	3,544	5,180	1,311	782	529	15.8

BIG RIVERS ELECTRIC CORPORATION
INTERGRATED RESOURCE PLAN
20% HIGHER ENERGY LMP PRICES SCENARIO NET PRESENT VALUE

	Utility Costs ($000)											
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	=(1)thru(9)-(10)-(11)
	Load Cost (Energy)	Load Cost (Capacity)	Fuel Costs	FOM	Non-Fuel VOM	Emissions Cost	EE Program Costs	Annualized Build Costs	Retirement/Exit Costs	*Less: Market Revenue*	*Less: Capacity Revenue*	Net Utility Costs
	$000	$000	$000	$000	$000	$000	$000	$000	$000	$000	$000	$000
2018	[redacted]						1,000	[redacted]				
2019							1,000					
2020							1,000					
2021							1,000					
2022							1,000					
2023							1,000					
2024							1,000					
2025							1,000					
2026							1,000					
2027							1,000					
2028							1,000					
2029							1,000					
2030							1,000					
2031							1,000					
Net Present Value$000 (2017$) NPV 2017-2031	[redacted]						8,244	[redacted]				

BIG RIVERS ELECTRIC CORPORATION
INTERGRATED RESOURCE PLAN
10% LOWER ENERGY LMP PRICES SCENARIO

	Capacity Additions						Energy and Capacity Positions											
	(1)		(2)		(3)		(4)	(5)	(6)	7)=(4)+(5)+(	(8)	(9)	(10)=(8)-(9)	(11)=(7)-(10	(12)	(13)	14)=(12)-(13	(15)
	Supply-Side Capacity		Incremental Energy Efficiency		Utility Solar		Thermal Generation + Hydro	Purchased Energy	New Utility Solar	= Market Sales	Load (Net of Embedded EE)	*Less:* Energy Efficiency	= Net Load Requirements	Energy Surplus	Capacity	Peak + Reserves	Capacity Surplus	Minimum Reserve Margin
	Incremental MW	Culm MW	Incremental MW	Culm MW	Incremental MW	Culm MW	GWh	GWh	GWh	GWh	GWh	GWh	GWh	GWh	MW	MW	MW	%
2018			(1.3)	(1.3)			3,896			3,896	3,420	(17.1)	3,403	493	1,287	763	524	15.8
2019			(1.2)	(2.5)			3,904			3,904	3,930	(25.3)	3,904	(0)	1,311	918	393	15.8
2020			(1.2)	(3.7)			2,609			2,609	4,356	(32.7)	4,323	(1,714)	1,069	937	132	15.8
2021			(0.4)	(4.1)			2,507			2,507	4,326	(35.0)	4,291	(1,783)	1,069	950	119	15.8
2022			(1.1)	(5.2)			2,226			2,226	4,355	(42.1)	4,313	(2,087)	1,069	959	110	15.8
2023			(1.1)	(6.3)			2,180			2,180	4,346	(49.2)	4,296	(2,117)	1,069	961	107	15.8
2024			(1.1)	(7.3)			2,093			2,093	4,376	(56.2)	4,320	(2,227)	1,069	963	105	15.8
2025			(0.9)	(8.3)			2,197			2,197	4,397	(62.3)	4,335	(2,137)	1,069	951	118	15.8
2026			(0.9)	(9.2)			2,164			2,164	4,454	(68.3)	4,386	(2,222)	1,069	966	103	15.8
2027			(0.9)	(10.1)			2,445			2,445	4,180	(74.3)	4,105	(1,660)	1,069	891	178	15.8
2028			(0.9)	(11.1)			2,371			2,371	4,226	(80.4)	4,145	(1,774)	1,069	892	177	15.8
2029			(0.9)	(11.9)			2,576			2,576	3,915	(86.0)	3,829	(1,253)	1,069	886	183	15.8
2030			(0.9)	(12.8)			2,548			2,548	3,627	(91.6)	3,535	(987)	1,069	780	288	15.8
2031			(0.8)	(13.6)			3,072			3,072	3,641	(97.1)	3,544	(473)	1,069	782	287	15.8

BIG RIVERS ELECTRIC CORPORATION
INTERGRATED RESOURCE PLAN
10% LOWER ENERGY LMP PRICES SCENARIO NET PRESENT VALUE

	Utility Costs ($000)											
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	=(1)thru(9)-(10)-(11)
	Load Cost (Energy)	Load Cost (Capacity)	Fuel Costs	FOM	Non-Fuel VOM	Emissions Cost	EE Program Costs	Annualized Build Costs	Retirement/Exit Costs	*Less: Market Revenue*	*Less: Capacity Revenue*	Net Utility Costs
	$000	$000	$000	$000	$000	$000	$000	$000	$000	$000	$000	$000
2018	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2019	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2020	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2021	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2022	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2023	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2024	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2025	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2026	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2027	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2028	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2029	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2030	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2031	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Net Present Value$000 (2017$)												
NPV 2017-2031	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	8,244	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

BIG RIVERS ELECTRIC CORPORATION
INTERGRATED RESOURCE PLAN
20% LOWER ENERGY LMP PRICES SCENARIO

	Capacity Additions						Energy and Capacity Positions											
	(1)		(2)		(3)		(4)	(5)	(6)	7)=(4)+(5)+(	(8)	(9)	(10)=(8)-(9)	(11)=(7)-(10	(12)	(13)	14)=(12)-(13	(15)
	Supply-Side Capacity		Incremental Energy Efficiency		Utility Solar		Thermal Generation + Hydro	Purchased Energy	New Utility Solar	= Market Sales	Load (Net of Embedded EE)	*Less:* Energy Efficiency	= Net Load Requirements	Energy Surplus	Capacity	Peak + Reserves	Capacity Surplus	Minimum Reserve Margin
	Incremental MW	Culm MW	Incremental MW	Culm MW	Incremental MW	Culm MW	GWh	GWh	GWh	GWh	GWh	GWh	GWh	GWh	MW	MW	MW	%
2018			(1.3)	(1.3)			2,378			2,378	3,420	(17.1)	3,403	(1,025)	1,287	763	524	15.8
2019			(1.2)	(2.5)			2,321			2,321	3,930	(25.3)	3,904	(1,583)	1,311	918	393	15.8
2020			(1.2)	(3.7)			1,689			1,689	4,356	(32.7)	4,323	(2,634)	1,069	937	132	15.8
2021			(0.4)	(4.1)			1,491			1,491	4,326	(35.0)	4,291	(2,799)	1,069	950	119	15.8
2022			(1.1)	(5.2)			1,319			1,319	4,355	(42.1)	4,313	(2,994)	1,069	959	110	15.8
2023			(1.1)	(6.3)			1,225			1,225	4,346	(49.2)	4,296	(3,072)	1,069	961	107	15.8
2024			(1.1)	(7.3)			1,158			1,158	4,376	(56.2)	4,320	(3,162)	1,069	963	105	15.8
2025			(0.9)	(8.3)			1,157			1,157	4,397	(62.3)	4,335	(3,178)	1,069	951	118	15.8
2026			(0.9)	(9.2)			1,258			1,258	4,454	(68.3)	4,386	(3,128)	1,069	966	103	15.8
2027			(0.9)	(10.1)			1,344			1,344	4,180	(74.3)	4,105	(2,762)	1,069	891	178	15.8
2028			(0.9)	(11.1)			1,397			1,397	4,226	(80.4)	4,145	(2,749)	1,069	892	177	15.8
2029			(0.9)	(11.9)			1,495			1,495	3,915	(86.0)	3,829	(2,335)	1,069	886	183	15.8
2030			(0.9)	(12.8)			1,615			1,615	3,627	(91.6)	3,535	(1,920)	1,069	780	288	15.8
2031			(0.8)	(13.6)			2,018			2,018	3,641	(97.1)	3,544	(1,527)	1,069	782	287	15.8

BIG RIVERS ELECTRIC CORPORATION
INTERGRATED RESOURCE PLAN
20% LOWER ENERGY LMP PRICES SCENARIO NET PRESENT VALUE

	Utility Costs ($000)											
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	=(1)thru(9)-(10)-(11)
	Load Cost (Energy)	Load Cost (Capacity)	Fuel Costs	FOM	Non-Fuel VOM	Emissions Cost	EE Program Costs	Annualized Build Costs	Retirement/Exit Costs	*Less: Market Revenue*	*Less: Capacity Revenue*	Net Utility Costs
	$000	$000	$000	$000	$000	$000	$000	$000	$000	$000	$000	$000
2018	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2019	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2020	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2021	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2022	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2023	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2024	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2025	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2026	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2027	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2028	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2029	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2030	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2031	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Net Present Value$000 (2017$)												
NPV 2017-2031	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	8,244	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

BIG RIVERS ELECTRIC CORPORATION
INTERGRATED RESOURCE PLAN
10% HIGHER COAL PRICE SCENARIO

	Capacity Additions						Energy and Capacity Positions											
	(1)		(2)		(3)		(4)	(5)	(6)	7)=(4)+(5)+(6	(8)	(9)	(10)=(8)-(9)	(11)=(7)-(10	(12)	(13)	14)=(12)-(13	(15)
	Supply-Side Capacity		Incremental Energy Efficiency		Utility Solar		Thermal Generation + Hydro	Purchased Energy	New Utility Solar	= Market Sales	Load (Net of Embedded EE)	*Less:* Energy Efficiency	= Net Load Requirements	Energy Surplus	Capacity	Peak + Reserves	Capacity Surplus	Minimum Reserve Margin
	Incremental MW	Culm MW	Incremental MW	Culm MW	Incremental MW	Culm MW	GWh	GWh	GWh	GWh	GWh	GWh	GWh	GWh	MW	MW	MW	%
2018			(1.3)	(1.3)			4,303			4,303	3,420	(17.1)	3,403	901	1,287	763	524	15.8
2019			(1.2)	(2.5)			4,319			4,319	3,930	(25.3)	3,904	414	1,311	918	393	15.8
2020			(1.2)	(3.7)			2,974			2,974	4,356	(32.7)	4,323	(1,348)	1,069	937	132	15.8
2021			(0.4)	(4.1)			2,856			2,856	4,326	(35.0)	4,291	(1,434)	1,069	950	119	15.8
2022			(1.1)	(5.2)			2,581			2,581	4,355	(42.1)	4,313	(1,732)	1,069	959	110	15.8
2023			(1.1)	(6.3)			2,481			2,481	4,346	(49.2)	4,296	(1,815)	1,069	961	107	15.8
2024			(1.1)	(7.3)			2,344			2,344	4,376	(56.2)	4,320	(1,976)	1,069	963	105	15.8
2025			(0.9)	(8.3)			2,440			2,440	4,397	(62.3)	4,335	(1,895)	1,069	951	118	15.8
2026			(0.9)	(9.2)			2,360			2,360	4,454	(68.3)	4,386	(2,025)	1,069	966	103	15.8
2027			(0.9)	(10.1)			2,618			2,618	4,180	(74.3)	4,105	(1,488)	1,069	891	178	15.8
2028			(0.9)	(11.1)			2,556			2,556	4,226	(80.4)	4,145	(1,589)	1,069	892	177	15.8
2029			(0.9)	(11.9)			2,710			2,710	3,915	(86.0)	3,829	(1,120)	1,069	886	183	15.8
2030			(0.9)	(12.8)			2,646			2,646	3,627	(91.6)	3,535	(889)	1,069	780	288	15.8
2031			(0.8)	(13.6)			3,214			3,214	3,641	(97.1)	3,544	(331)	1,069	782	287	15.8

BIG RIVERS ELECTRIC CORPORATION
INTERGRATED RESOURCE PLAN
10% HIGHER COAL PRICE SCENARIO NET PRESENT VALUE

	Utility Costs ($000)											
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	=(1)thru(9)-(10)-(11)
	Load Cost (Energy)	Load Cost (Capacity)	Fuel Costs	FOM	Non-Fuel VOM	Emissions Cost	EE Program Costs	Annualized Build Costs	Retirement/Exit Costs	*Less: Market Revenue*	*Less: Capacity Revenue*	Net Utility Costs
	$000	$000	$000	$000	$000	$000	$000	$000	$000	$000	$000	$000
2018	[redacted]						1,000	[redacted]				
2019							1,000					
2020							1,000					
2021							1,000					
2022							1,000					
2023							1,000					
2024							1,000					
2025							1,000					
2026							1,000					
2027							1,000					
2028							1,000					
2029							1,000					
2030							1,000					
2031							1,000					
Net Present Value$000 (2017$)												
NPV 2017-2031	[redacted]						8,244	[redacted]				

BIG RIVERS ELECTRIC CORPORATION
INTERGRATED RESOURCE PLAN
10% LOWER COAL PRICE SCENARIO

	Capacity Additions						Energy and Capacity Positions											
	(1)		(2)		(3)		(4)	(5)	(6)	7)=(4)+(5)+(	(8)	(9)	(10)=(8)-(9)	(11)=(7)-(10	(12)	(13)	14)=(12)-(1	(15)
	Supply-Side Capacity		Incremental Energy Efficiency		Utility Solar		Thermal Generation + Hydro	Purchased Energy	New Utility Solar	= Market Sales	Load (Net of Embedded EE)	*Less:* Energy Efficiency	= Net Load Requirements	Energy Surplus	Capacity	Peak + Reserves	Capacity Surplus	Minimum Reserve Margin
	Incremental MW	Culm MW	Incremental MW	Culm MW	Incremental MW	Culm MW	GWh	GWh	GWh	GWh	GWh	GWh	GWh	GWh	MW	MW	MW	%
2018			(1.3)	(1.3)			6,123			6,123	3,420	(17.1)	3,403	2,720	1,287	763	524	15.8
2019			(1.2)	(2.5)			6,210			6,210	3,930	(25.3)	3,904	2,305	1,311	918	393	15.8
2020			(1.2)	(3.7)			5,040			5,040	4,356	(32.7)	4,323	717	1,114	937	177	15.8
2021			(0.4)	(4.1)			5,008			5,008	4,326	(35.0)	4,291	717	1,114	950	164	15.8
2022			(1.1)	(5.2)			4,697			4,697	4,355	(42.1)	4,313	383	1,114	959	155	15.8
2023			(1.1)	(6.3)			4,688			4,688	4,346	(49.2)	4,296	391	1,114	961	153	15.8
2024			(1.1)	(7.3)			4,700			4,700	4,376	(56.2)	4,320	380	1,114	963	151	15.8
2025			(0.9)	(8.3)			4,968			4,968	4,397	(62.3)	4,335	633	1,114	951	163	15.8
2026			(0.9)	(9.2)			5,050			5,050	4,454	(68.3)	4,386	665	1,114	966	148	15.8
2027			(0.9)	(10.1)			5,610			5,610	4,180	(74.3)	4,105	1,504	1,114	891	223	15.8
2028			(0.9)	(11.1)			5,569			5,569	4,226	(80.4)	4,145	1,424	1,114	892	222	15.8
2029			(0.9)	(11.9)			6,082			6,082	3,915	(86.0)	3,829	2,253	1,114	886	228	15.8
2030			(0.9)	(12.8)			6,157			6,157	3,627	(91.6)	3,535	2,622	1,114	780	334	15.8
2031			(0.8)	(13.6)			6,755			6,755	3,641	(97.1)	3,544	3,210	1,114	782	332	15.8

BIG RIVERS ELECTRIC CORPORATION
INTERGRATED RESOURCE PLAN
10% LOWER COAL PRICE SCENARIO NET PRESENT VALUE

	Utility Costs ($000)											
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	=(1)thru(9)-(10)-(11)
	Load Cost (Energy)	Load Cost (Capacity)	Fuel Costs	FOM	Non-Fuel VOM	Emissions Cost	EE Program Costs	Annualized Build Costs	Retirement/Exit Costs	*Less: Market Revenue*	*Less: Capacity Revenue*	Net Utility Costs
	$000	$000	$000	$000	$000	$000	$000	$000	$000	$000	$000	$000
2018	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2019	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2020	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2021	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2022	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2023	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2024	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2025	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2026	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2027	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2028	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2029	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2030	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2031	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Net Present Value$000 (2017$)												
NPV 2017-2031	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	8,244	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

BIG RIVERS ELECTRIC CORPORATION
INTERGRATED RESOURCE PLAN
20% HIGHER COAL PRICE SCENARIO

	Capacity Additions						Energy and Capacity Positions											
	(1)		(2)		(3)		(4)	(5)	(6)	7)=(4)+(5)+((	(8)	(9)	(10)=(8)-(9)	(11)=(7)-(10)	(12)	(13)	14)=(12)-(13	(15)
	Supply-Side Capacity		Incremental Energy Efficiency		Utility Solar		Thermal Generation + Hydro	Purchased Energy	New Utility Solar	= Market Sales	Load (Net of Embedded EE)	*Less:* Energy Efficiency	= Net Load Requirements	Energy Surplus	Capacity	Peak + Reserves	Capacity Surplus	Minimum Reserve Margin
	Incremental MW	Culm MW	Incremental MW	Culm MW	Incremental MW	Culm MW	GWh	GWh	GWh	GWh	GWh	GWh	GWh	GWh	MW	MW	MW	%
2018			(1.3)	(1.3)			3,244			3,244	3,420	(17.1)	3,403	(159)	1,287	763	524	15.8
2019			(1.2)	(2.5)			3,186			3,186	3,930	(25.3)	3,904	(718)	1,311	918	393	15.8
2020			(1.2)	(3.7)			2,572			2,572	4,356	(32.7)	4,323	(1,751)	1,069	937	132	15.8
2021			(0.4)	(4.1)			2,377			2,377	4,326	(35.0)	4,291	(1,914)	1,069	950	119	15.8
2022			(1.1)	(5.2)			2,119			2,119	4,355	(42.1)	4,313	(2,194)	1,069	959	110	15.8
2023			(1.1)	(6.3)			1,930			1,930	4,346	(49.2)	4,296	(2,366)	1,069	961	107	15.8
2024			(1.1)	(7.3)			1,823			1,823	4,376	(56.2)	4,320	(2,497)	1,069	963	105	15.8
2025			(0.9)	(8.3)			1,828			1,828	4,397	(62.3)	4,335	(2,507)	1,069	951	118	15.8
2026			(0.9)	(9.2)			1,863			1,863	4,454	(68.3)	4,386	(2,523)	1,069	966	103	15.8
2027			(0.9)	(10.1)			1,991			1,991	4,180	(74.3)	4,105	(2,115)	1,069	891	178	15.8
2028			(0.9)	(11.1)			1,980			1,980	4,226	(80.4)	4,145	(2,165)	1,069	892	177	15.8
2029			(0.9)	(11.9)			2,060			2,060	3,915	(86.0)	3,829	(1,769)	1,069	886	183	15.8
2030			(0.9)	(12.8)			2,184			2,184	3,627	(91.6)	3,535	(1,352)	1,069	780	288	15.8
2031			(0.8)	(13.6)			2,660			2,660	3,641	(97.1)	3,544	(884)	1,069	782	287	15.8

BIG RIVERS ELECTRIC CORPORATION
INTERGRATED RESOURCE PLAN
20% HIGHER COAL PRICE SCENARIO NET PRESENT VALUE

	Utility Costs ($000)											
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	=(1)thru(9)-(10)-(11)
	Load Cost (Energy)	Load Cost (Capacity)	Fuel Costs	FOM	Non-Fuel VOM	Emissions Cost	EE Program Costs	Annualized Build Costs	Retirement/Exit Costs	*Less: Market Revenue*	*Less: Capacity Revenue*	Net Utility Costs
	$000	$000	$000	$000	$000	$000	$000	$000	$000	$000	$000	$000
2018	[redacted]						1,000	[redacted]				
2019	[redacted]						1,000	[redacted]				
2020	[redacted]						1,000	[redacted]				
2021	[redacted]						1,000	[redacted]				
2022	[redacted]						1,000	[redacted]				
2023	[redacted]						1,000	[redacted]				
2024	[redacted]						1,000	[redacted]				
2025	[redacted]						1,000	[redacted]				
2026	[redacted]						1,000	[redacted]				
2027	[redacted]						1,000	[redacted]				
2028	[redacted]						1,000	[redacted]				
2029	[redacted]						1,000	[redacted]				
2030	[redacted]						1,000	[redacted]				
2031	[redacted]						1,000	[redacted]				
Net Present Value$000 (2017$)												
NPV 2017-2031	[redacted]						8,244	[redacted]				

BIG RIVERS ELECTRIC CORPORATION
INTERGRATED RESOURCE PLAN
20% LOWER COAL PRICE SCENARIO

	Capacity Additions						Energy and Capacity Positions												
	(1)		(2)		(3)		(4)	(5)	(6)	7)=(4)+(5)+(6	(8)	(9)	(10)=(8)-(9)	(11)=(7)-(10)	(12)	(13)	14)=(12)-(13	(15)
	Supply-Side Capacity		Incremental Energy Efficiency		Utility Solar		Thermal Generation + Hydro	Purchased Energy	New Utility Solar	= Market Sales	Load (Net of Embedded EE)	*Less:* Energy Efficiency	= Net Load Requirements	Energy Surplus	Capacity	Peak + Reserves	Capacity Surplus	Minimum Reserve Margin
	Incremental MW	Culm MW	Incremental MW	Culm MW	Incremental MW	Culm MW	GWh	GWh	GWh	GWh	GWh	GWh	GWh	GWh	MW	MW	MW	%
2018			(1.3)	(1.3)			6,907			6,907	3,420	(17.1)	3,403	3,504	1,287	763	524	15.8
2019			(1.2)	(2.5)			6,953			6,953	3,930	(25.3)	3,904	3,048	1,311	918	393	15.8
2020			(1.2)	(3.7)			6,708			6,708	4,356	(32.7)	4,323	2,385	1,311	937	374	15.8
2021			(0.4)	(4.1)			6,642			6,642	4,326	(35.0)	4,291	2,352	1,311	950	361	15.8
2022			(1.1)	(5.2)			6,292			6,292	4,355	(42.1)	4,313	1,978	1,311	959	352	15.8
2023			(1.1)	(6.3)			6,404			6,404	4,346	(49.2)	4,296	2,108	1,311	961	350	15.8
2024			(1.1)	(7.3)			6,375			6,375	4,376	(56.2)	4,320	2,054	1,311	963	348	15.8
2025			(0.9)	(8.3)			6,702			6,702	4,397	(62.3)	4,335	2,367	1,311	951	360	15.8
2026			(0.9)	(9.2)			6,617			6,617	4,454	(68.3)	4,386	2,232	1,311	966	345	15.8
2027			(0.9)	(10.1)			7,318			7,318	4,180	(74.3)	4,105	3,213	1,311	891	420	15.8
2028			(0.9)	(11.1)			7,120			7,120	4,226	(80.4)	4,145	2,975	1,311	892	419	15.8
2029			(0.9)	(11.9)			8,034			8,034	3,915	(86.0)	3,829	4,204	1,311	886	425	15.8
2030			(0.9)	(12.8)			8,131			8,131	3,627	(91.6)	3,535	4,596	1,311	780	531	15.8
2031			(0.8)	(13.6)			8,681			8,681	3,641	(97.1)	3,544	5,137	1,311	782	529	15.8

BIG RIVERS ELECTRIC CORPORATION
INTERGRATED RESOURCE PLAN
20% LOWER COAL PRICE SCENARIO NET PRESENT VALUE

	Utility Costs ($000)											
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	=(1)thru(9)-(10)-(11)
	Load Cost (Energy)	Load Cost (Capacity)	Fuel Costs	FOM	Non-Fuel VOM	Emissions Cost	EE Program Costs	Annualized Build Costs	Retirement/Exit Costs	*Less: Market Revenue*	*Less: Capacity Revenue*	Net Utility Costs
	$000	$000	$000	$000	$000	$000	$000	$000	$000	$000	$000	$000
2018	[redacted]						1,000	[redacted]				
2019							1,000					
2020							1,000					
2021							1,000					
2022							1,000					
2023							1,000					
2024							1,000					
2025							1,000					
2026							1,000					
2027							1,000					
2028							1,000					
2029							1,000					
2030							1,000					
2031							1,000					
Net Present Value$000 (2017$) NPV 2017-2031	[redacted]						8,244	[redacted]				

BIG RIVERS ELECTRIC CORPORATION
INTERGRATED RESOURCE PLAN
20% HIGHER NATURAL GAS PRICE SCENARIO

	Capacity Additions						Energy and Capacity Positions											
	(1)		(2)		(3)		(4)	(5)	(6)	7)=(4)+(5)+(	(8)	(9)	(10)=(8)-(9)	(11)=(7)-(10	(12)	(13)	14)=(12)-(13	(15)
	Supply-Side Capacity		Incremental Energy Efficiency		Utility Solar		Thermal Generation + Hydro	Purchased Energy	New Utility Solar	= Market Sales	Load (Net of Embedded EE)	*Less:* Energy Efficiency	= Net Load Requirements	Energy Surplus	Capacity	Peak + Reserves	Capacity Surplus	Minimum Reserve Margin
	Incremental MW	Culm MW	Incremental MW	Culm MW	Incremental MW	Culm MW	GWh	GWh	GWh	GWh	GWh	GWh	GWh	GWh	MW	MW	MW	%
2018			(1.3)	(1.3)			5,208			5,208	3,420	(17.1)	3,403	1,805	1,287	763	524	15.8
2019			(1.2)	(2.5)			5,347			5,347	3,930	(25.3)	3,904	1,443	1,311	918	393	15.8
2020			(1.2)	(3.7)			4,392			4,392	4,356	(32.7)	4,323	69	1,114	937	177	15.8
2021			(0.4)	(4.1)			4,241			4,241	4,326	(35.0)	4,291	(49)	1,114	950	164	15.8
2022			(1.1)	(5.2)			3,900			3,900	4,355	(42.1)	4,313	(414)	1,114	959	155	15.8
2023			(1.1)	(6.3)			3,799			3,799	4,346	(49.2)	4,296	(498)	1,114	961	153	15.8
2024			(1.1)	(7.3)			3,802			3,802	4,376	(56.2)	4,320	(518)	1,114	963	151	15.8
2025			(0.9)	(8.3)			4,004			4,004	4,397	(62.3)	4,335	(330)	1,114	951	163	15.8
2026			(0.9)	(9.2)			4,119			4,119	4,454	(68.3)	4,386	(267)	1,114	966	148	15.8
2027			(0.9)	(10.1)			4,502			4,502	4,180	(74.3)	4,105	397	1,114	891	223	15.8
2028			(0.9)	(11.1)			4,513			4,513	4,226	(80.4)	4,145	368	1,114	892	222	15.8
2029			(0.9)	(11.9)			5,070			5,070	3,915	(86.0)	3,829	1,241	1,114	886	228	15.8
2030			(0.9)	(12.8)			5,326			5,326	3,627	(91.6)	3,535	1,790	1,114	780	334	15.8
2031			(0.8)	(13.6)			6,087			6,087	3,641	(97.1)	3,544	2,543	1,114	782	332	15.8

BIG RIVERS ELECTRIC CORPORATION
INTERGRATED RESOURCE PLAN
20% HIGHER NATURAL GAS PRICE SCENARIO NET PRESENT VALUE

	Utility Costs ($000)											
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	=(1)thru(9)-(10)-(11)
	Load Cost (Energy)	Load Cost (Capacity)	Fuel Costs	FOM	Non-Fuel VOM	Emissions Cost	EE Program Costs	Annualized Build Costs	Retirement/Exit Costs	*Less: Market Revenue*	*Less: Capacity Revenue*	Net Utility Costs
	$000	$000	$000	$000	$000	$000	$000	$000	$000	$000	$000	$000
2018	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2019	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2020	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2021	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2022	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2023	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2024	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2025	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2026	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2027	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2028	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2029	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2030	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2031	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Net Present Value$000 (2017$)												
NPV 2017-2031	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	8,244	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

BIG RIVERS ELECTRIC CORPORATION
INTERGRATED RESOURCE PLAN
10% LOWER NATURAL GAS PRICE SCENARIO

	Capacity Additions						Energy and Capacity Positions											
	(1)		(2)		(3)		(4)	(5)	(6)	7)=(4)+(5)+(6	(8)	(9)	(10)=(8)-(9)	(11)=(7)-(10	(12)	(13)	14)=(12)-(13	(15)
	Supply-Side Capacity		Incremental Energy Efficiency		Utility Solar		Thermal Generation + Hydro	Purchased Energy	New Utility Solar	= Market Sales	Load (Net of Embedded EE)	*Less:* Energy Efficiency	= Net Load Requirements	Energy Surplus	Capacity	Peak + Reserves	Capacity Surplus	Minimum Reserve Margin
	Incremental MW	Culm MW	Incremental MW	Culm MW	Incremental MW	Culm MW	GWh	GWh	GWh	GWh	GWh	GWh	GWh	GWh	MW	MW	MW	%
2018			(1.3)	(1.3)			5,237			5,237	3,420	(17.1)	3,403	1,834	1,287	763	524	15.8
2019			(1.2)	(2.5)			5,388			5,388	3,930	(25.3)	3,904	1,484	1,311	918	393	15.8
2020			(1.2)	(3.7)			3,740			3,740	4,356	(32.7)	4,323	(583)	1,069	937	132	15.8
2021			(0.4)	(4.1)			3,632			3,632	4,326	(35.0)	4,291	(659)	1,069	950	119	15.8
2022			(1.1)	(5.2)			3,323			3,323	4,355	(42.1)	4,313	(990)	1,069	959	110	15.8
2023			(1.1)	(6.3)			3,150			3,150	4,346	(49.2)	4,296	(1,147)	1,069	961	107	15.8
2024			(1.1)	(7.3)			2,951			2,951	4,376	(56.2)	4,320	(1,369)	1,069	963	105	15.8
2025			(0.9)	(8.3)			2,871			2,871	4,397	(62.3)	4,335	(1,464)	1,069	951	118	15.8
2026			(0.9)	(9.2)			2,682			2,682	4,454	(68.3)	4,386	(1,704)	1,069	966	103	15.8
2027			(0.9)	(10.1)			2,938			2,938	4,180	(74.3)	4,105	(1,167)	1,069	891	178	15.8
2028			(0.9)	(11.1)			2,818			2,818	4,226	(80.4)	4,145	(1,327)	1,069	892	177	15.8
2029			(0.9)	(11.9)			3,161			3,161	3,915	(86.0)	3,829	(669)	1,069	886	183	15.8
2030			(0.9)	(12.8)			3,137			3,137	3,627	(91.6)	3,535	(399)	1,069	780	288	15.8
2031			(0.8)	(13.6)			3,575			3,575	3,641	(97.1)	3,544	31	1,069	782	287	15.8

BIG RIVERS ELECTRIC CORPORATION
INTERGRATED RESOURCE PLAN
10% LOWER NATURAL GAS PRICE SCENARIO NET PRESENT VALUE

	Utility Costs ($000)											
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	=(1)thru(9)-(10)-(11)
	Load Cost (Energy)	Load Cost (Capacity)	Fuel Costs	FOM	Non-Fuel VOM	Emissions Cost	EE Program Costs	Annualized Build Costs	Retirement/Exit Costs	*Less: Market Revenue*	*Less: Capacity Revenue*	Net Utility Costs
	$000	$000	$000	$000	$000	$000	$000	$000	$000	$000	$000	$000
2018	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2019	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2020	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2021	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2022	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2023	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2024	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2025	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2026	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2027	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2028	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2029	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2030	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2031	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Net Present Value$000 (2017$)												
NPV 2017-2031	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	8,244	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

BIG RIVERS ELECTRIC CORPORATION
INTERGRATED RESOURCE PLAN
20% LOWER NATURAL GAS PRICE SCENARIO

	Capacity Additions						Energy and Capacity Positions											
	(1)		(2)		(3)		(4)	(5)	(6)	7)=(4)+(5)+((	(8)	(9)	(10)=(8)-(9)	(11)=(7)-(10)	(12)	(13)	14)=(12)-(13	(15)
	Supply-Side Capacity		Incremental Energy Efficiency		Utility Solar		Thermal Generation + Hydro	Purchased Energy	New Utility Solar	= Market Sales	Load (Net of Embedded EE)	*Less:* Energy Efficiency	= Net Load Requirements	Energy Surplus	Capacity	Peak + Reserves	Capacity Surplus	Minimum Reserve Margin
	Incremental MW	Culm MW	Incremental MW	Culm MW	Incremental MW	Culm MW	GWh	GWh	GWh	GWh	GWh	GWh	GWh	GWh	MW	MW	MW	%
2018			(1.3)	(1.3)			5,272			5,272	3,420	(17.1)	3,403	1,869	1,287	763	524	15.8
2019			(1.2)	(2.5)			5,431			5,431	3,930	(25.3)	3,904	1,526	1,311	918	393	15.8
2020			(1.2)	(3.7)			4,516			4,516	4,356	(32.7)	4,323	193	1,069	937	132	15.8
2021			(0.4)	(4.1)			4,339			4,339	4,326	(35.0)	4,291	48	1,069	950	119	15.8
2022			(1.1)	(5.2)			4,033			4,033	4,355	(42.1)	4,313	(281)	1,069	959	110	15.8
2023			(1.1)	(6.3)			3,899			3,899	4,346	(49.2)	4,296	(398)	1,069	961	107	15.8
2024			(1.1)	(7.3)			3,751			3,751	4,376	(56.2)	4,320	(569)	1,069	963	105	15.8
2025			(0.9)	(8.3)			3,601			3,601	4,397	(62.3)	4,335	(734)	1,069	951	118	15.8
2026			(0.9)	(9.2)			3,207			3,207	4,454	(68.3)	4,386	(1,179)	1,069	966	103	15.8
2027			(0.9)	(10.1)			3,299			3,299	4,180	(74.3)	4,105	(806)	1,069	891	178	15.8
2028			(0.9)	(11.1)			3,085			3,085	4,226	(80.4)	4,145	(1,060)	1,069	892	177	15.8
2029			(0.9)	(11.9)			3,356			3,356	3,915	(86.0)	3,829	(473)	1,069	886	183	15.8
2030			(0.9)	(12.8)			3,287			3,287	3,627	(91.6)	3,535	(248)	1,069	780	288	15.8
2031			(0.8)	(13.6)			3,693			3,693	3,641	(97.1)	3,544	148	1,069	782	287	15.8

BIG RIVERS ELECTRIC CORPORATION
INTERGRATED RESOURCE PLAN
20% LOWER NATURAL GAS PRICE SCENARIO NET PRESENT VALUE

	Utility Costs ($000)											
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	=(1)thru(9)-(10)-(11)
	Load Cost (Energy)	Load Cost (Capacity)	Fuel Costs	FOM	Non-Fuel VOM	Emissions Cost	EE Program Costs	Annualized Build Costs	Retirement/Exit Costs	*Less: Market Revenue*	*Less: Capacity Revenue*	Net Utility Costs
	$000	$000	$000	$000	$000	$000	$000	$000	$000	$000	$000	$000
2018	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2019	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2020	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2021	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2022	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2023	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2024	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2025	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2026	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2027	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2028	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2029	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2030	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2031	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Net Present Value$000 (2017$)												
NPV 2017-2031	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	8,244	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

BIG RIVERS ELECTRIC CORPORATION
INTERGRATED RESOURCE PLAN
30% LOWER NATURAL GAS PRICE SCENARIO

	Capacity Additions						Energy and Capacity Positions											
	(1)		(2)		(3)		(4)	(5)	(6)	7)=(4)+(5)+((	(8)	(9)	(10)=(8)-(9)	(11)=(7)-(10	(12)	(13)	14)=(12)-(13	(15)
	Supply-Side Capacity		Incremental Energy Efficiency		Utility Solar		Thermal Generation + Hydro	Purchased Energy	New Utility Solar	= Market Sales	Load (Net of Embedded EE)	*Less:* Energy Efficiency	= Net Load Requirements	Energy Surplus	Capacity	Peak + Reserves	Capacity Surplus	Minimum Reserve Margin
	Incremental MW	Culm MW	Incremental MW	Culm MW	Incremental MW	Culm MW	GWh	GWh	GWh	GWh	GWh	GWh	GWh	GWh	MW	MW	MW	%
2018			(1.3)	(1.3)			5,372			5,372	3,420	(17.1)	3,403	1,969	1,287	763	524	15.8
2019			(1.2)	(2.5)			5,555			5,555	3,930	(25.3)	3,904	1,651	1,311	918	393	15.8
2020			(1.2)	(3.7)			4,990			4,990	4,356	(32.7)	4,323	668	1,069	937	132	15.8
2021			(0.4)	(4.1)			4,842			4,842	4,326	(35.0)	4,291	551	1,069	950	119	15.8
2022			(1.1)	(5.2)			4,548			4,548	4,355	(42.1)	4,313	235	1,069	959	110	15.8
2023			(1.1)	(6.3)			4,517			4,517	4,346	(49.2)	4,296	221	1,069	961	107	15.8
2024			(1.1)	(7.3)			4,459			4,459	4,376	(56.2)	4,320	139	1,069	963	105	15.8
2025			(0.9)	(8.3)			4,489			4,489	4,397	(62.3)	4,335	154	1,069	951	118	15.8
2026			(0.9)	(9.2)			4,289			4,289	4,454	(68.3)	4,386	(97)	1,069	966	103	15.8
2027			(0.9)	(10.1)			4,300			4,300	4,180	(74.3)	4,105	195	1,069	891	178	15.8
2028			(0.9)	(11.1)			3,945			3,945	4,226	(80.4)	4,145	(200)	1,069	892	177	15.8
2029			(0.9)	(11.9)			3,918			3,918	3,915	(86.0)	3,829	89	1,069	886	183	15.8
2030			(0.9)	(12.8)			3,663			3,663	3,627	(91.6)	3,535	127	1,069	780	288	15.8
2031			(0.8)	(13.6)			3,994			3,994	3,641	(97.1)	3,544	449	1,069	782	287	15.8

BIG RIVERS ELECTRIC CORPORATION
INTERGRATED RESOURCE PLAN
30% LOWER NATURAL GAS PRICE SCENARIO NET PRESENT VALUE

	Utility Costs ($000)											
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	=(1)thru(9)-(10)-(11)
	Load Cost (Energy)	Load Cost (Capacity)	Fuel Costs	FOM	Non-Fuel VOM	Emissions Cost	EE Program Costs	Annualized Build Costs	Retirement/Exit Costs	*Less: Market Revenue*	*Less: Capacity Revenue*	Net Utility Costs
	$000	$000	$000	$000	$000	$000	$000	$000	$000	$000	$000	$000
2018	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2019	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2020	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2021	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2022	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2023	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2024	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2025	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2026	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2027	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2028	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2029	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2030	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2031	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Net Present Value$000 (2017$) NPV 2017-2031	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	8,244	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

BIG RIVERS ELECTRIC CORPORATION
INTERGRATED RESOURCE PLAN
HIGH LOAD SCENARIO

	Capacity Additions						Energy and Capacity Positions												
	(1)		(2)		(3)		(4)	(5)	(6)	7)=(4)+(5)+(	(8)	(9)	(10)=(8)-(9)	(11)=(7)-(10	(12)	(13)	14)=(12)-(1	(15)
	Supply-Side Capacity		Incremental Energy Efficiency		Utility Solar		Thermal Generation + Hydro	Purchased Energy	New Utility Solar	= Market Sales	Load (Net of Embedded EE)	*Less:* Energy Efficiency	= Net Load Requirements	Energy Surplus	Capacity	Peak + Reserves	Capacity Surplus	Minimum Reserve Margin
	Incremental MW	Culm MW	Incremental MW	Culm MW	Incremental MW	Culm MW	GWh	GWh	GWh	GWh	GWh	GWh	GWh	GWh	MW	MW	MW	%
2018			(1.3)	(1.3)			5,211			5,211	3,572	(17.1)	3,555	1,656	1,287		1,287	15.8
2019			(1.2)	(2.5)			5,330			5,330	4,083	(25.3)	4,058	1,272	1,311		1,311	15.8
2020			(1.2)	(3.7)			4,407			4,407	4,511	(32.7)	4,478	(71)	1,114		1,114	15.8
2021			(0.4)	(4.1)			4,281			4,281	4,480	(35.0)	4,446	(165)	1,114		1,114	15.8
2022			(1.1)	(5.2)			3,914			3,914	4,511	(42.1)	4,469	(555)	1,114		1,114	15.8
2023			(1.1)	(6.3)			3,804			3,804	4,501	(49.2)	4,452	(648)	1,114		1,114	15.8
2024			(1.1)	(7.3)			3,806			3,806	4,533	(56.2)	4,477	(671)	1,114		1,114	15.8
2025			(0.9)	(8.3)			3,983			3,983	4,554	(62.3)	4,492	(508)	1,114		1,114	15.8
2026			(0.9)	(9.2)			4,078			4,078	4,611	(68.3)	4,543	(465)	1,114		1,114	15.8
2027			(0.9)	(10.1)			4,479			4,479	4,914	(74.3)	4,840	(360)	1,114		1,114	15.8
2028			(0.9)	(11.1)			4,537			4,537	4,982	(80.4)	4,902	(365)	1,114		1,114	15.8
2029			(0.9)	(11.9)			5,124			5,124	5,049	(86.0)	4,963	161	1,114		1,114	15.8
2030			(0.9)	(12.8)			5,357			5,357	5,141	(91.6)	5,050	308	1,114		1,114	15.8
2031			(0.8)	(13.6)			6,045			6,045	5,257	(97.1)	5,159	886	1,114		1,114	15.8

BIG RIVERS ELECTRIC CORPORATION
INTERGRATED RESOURCE PLAN
HIGH LOAD SCENARIO NET PRESENT VALUE

	Utility Costs ($000)											
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	=(1)thru(9)-(10)-(11)
	Load Cost (Energy)	Load Cost (Capacity)	Fuel Costs	FOM	Non-Fuel VOM	Emissions Cost	EE Program Costs	Annualized Build Costs	Retirement/Exit Costs	*Less: Market Revenue*	*Less: Capacity Revenue*	Net Utility Costs
	$000	$000	$000	$000	$000	$000	$000	$000	$000	$000	$000	$000
2018	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2019	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2020	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2021	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2022	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2023	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2024	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2025	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2026	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2027	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2028	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2029	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2030	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2031	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Net Present Value$000 (2017$)												
NPV 2017-2031	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	8,244	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

BIG RIVERS ELECTRIC CORPORATION
INTERGRATED RESOURCE PLAN
LOW LOAD SCENARIO

	Capacity Additions						Energy and Capacity Positions											
	(1)		(2)		(3)		(4)	(5)	(6)	7)=(4)+(5)+((	(8)	(9)	(10)=(8)-(9)	(11)=(7)-(10'	(12)	(13)	14)=(12)-(13	(15)
	Supply-Side Capacity		Incremental Energy Efficiency		Utility Solar		Thermal Generation + Hydro	Purchased Energy	New Utility Solar	= Market Sales	Load (Net of Embedded EE)	*Less:* Energy Efficiency	= Net Load Requirements	Energy Surplus	Capacity	Peak + Reserves	Capacity Surplus	Minimum Reserve Margin
	Incremental MW	Culm MW	Incremental MW	Culm MW	Incremental MW	Culm MW	GWh	GWh	GWh	GWh	GWh	GWh	GWh	GWh	MW	MW	MW	%
2018			(1.3)	(1.3)			5,244			5,244	3,209	(17.1)	3,192	2,052	1,287		1,287	15.8
2019			(1.2)	(2.5)			5,360			5,360	3,700	(25.3)	3,674	1,686	1,311		1,311	15.8
2020			(1.2)	(3.7)			4,390			4,390	4,108	(32.7)	4,075	315	1,114		1,114	15.8
2021			(0.4)	(4.1)			4,269			4,269	4,060	(35.0)	4,025	244	1,114		1,114	15.8
2022			(1.1)	(5.2)			3,933			3,933	4,073	(42.1)	4,031	(98)	1,114		1,114	15.8
2023			(1.1)	(6.3)			3,806			3,806	4,047	(49.2)	3,997	(191)	1,114		1,114	15.8
2024			(1.1)	(7.3)			3,800			3,800	4,062	(56.2)	4,006	(206)	1,114		1,114	15.8
2025			(0.9)	(8.3)			3,962			3,962	4,067	(62.3)	4,005	(43)	1,114		1,114	15.8
2026			(0.9)	(9.2)			4,084			4,084	4,108	(68.3)	4,039	44	1,114		1,114	15.8
2027			(0.9)	(10.1)			4,485			4,485	3,817	(74.3)	3,743	742	1,114		1,114	15.8
2028			(0.9)	(11.1)			4,526			4,526	3,846	(80.4)	3,765	761	1,114		1,114	15.8
2029			(0.9)	(11.9)			5,078			5,078	3,520	(86.0)	3,434	1,644	1,114		1,114	15.8
2030			(0.9)	(12.8)			5,322			5,322	3,215	(91.6)	3,123	2,198	1,114		1,114	15.8
2031			(0.8)	(13.6)			6,086			6,086	3,214	(97.1)	3,117	2,969	1,114		1,114	15.8

BIG RIVERS ELECTRIC CORPORATION
INTERGRATED RESOURCE PLAN
LOW LOAD SCENARIO NET PRESENT VALUE

	Utility Costs ($000)											
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	=(1)thru(9)-(10)-(11)
	Load Cost (Energy)	Load Cost (Capacity)	Fuel Costs	FOM	Non-Fuel VOM	Emissions Cost	EE Program Costs	Annualized Build Costs	Retirement/Exit Costs	*Less: Market Revenue*	*Less: Capacity Revenue*	Net Utility Costs
	$000	$000	$000	$000	$000	$000	$000	$000	$000	$000	$000	$000
2018	[redacted]						1,000	[redacted]				
2019							1,000					
2020							1,000					
2021							1,000					
2022							1,000					
2023							1,000					
2024							1,000					
2025							1,000					
2026							1,000					
2027							1,000					
2028							1,000					
2029							1,000					
2030							1,000					
2031							1,000					
Net Present Value$000 (2017$)												
NPV 2017-2031	[redacted]						8,244	[redacted]				

BIG RIVERS ELECTRIC CORPORATION
INTERGRATED RESOURCE PLAN
HMP&L EARLY EXIT SCENARIO

	Capacity Additions						Energy and Capacity Positions											
	(1)		(2)		(3)		(4)	(5)	(6)	7)=(4)+(5)+(6	(8)	(9)	(10)=(8)-(9)	(11)=(7)-(10	(12)	(13)	14)=(12)-(13	(15)
	Supply-Side Capacity		Incremental Energy Efficiency		Utility Solar		Thermal Generation + Hydro	Purchased Energy	New Utility Solar	= Market Sales	Load (Net of Embedded EE)	*Less:* Energy Efficiency	= Net Load Requirements	Energy Surplus	Capacity	Peak + Reserves	Capacity Surplus	Minimum Reserve Margin
	Incremental MW	Culm MW	Incremental MW	Culm MW	Incremental MW	Culm MW	GWh	GWh	GWh	GWh	GWh	GWh	GWh	GWh	MW	MW	MW	%
2018			(1.3)	(1.3)			4,282			4,282	3,420	(17.1)	3,403	879	1,090	763	327	15.8
2019			(1.2)	(2.5)			4,570			4,570	3,930	(25.3)	3,904	665	1,114	918	196	15.8
2020			(1.2)	(3.7)			4,410			4,410	4,356	(32.7)	4,323	87	1,114	937	177	15.8
2021			(0.4)	(4.1)			4,256			4,256	4,326	(35.0)	4,291	(34)	1,114	950	164	15.8
2022			(1.1)	(5.2)			3,911			3,911	4,355	(42.1)	4,313	(402)	1,114	959	155	15.8
2023			(1.1)	(6.3)			3,805			3,805	4,346	(49.2)	4,296	(491)	1,114	961	153	15.8
2024			(1.1)	(7.3)			3,807			3,807	4,376	(56.2)	4,320	(513)	1,114	963	151	15.8
2025			(0.9)	(8.3)			4,006			4,006	4,397	(62.3)	4,335	(328)	1,114	951	163	15.8
2026			(0.9)	(9.2)			4,120			4,120	4,454	(68.3)	4,386	(266)	1,114	966	148	15.8
2027			(0.9)	(10.1)			4,503			4,503	4,180	(74.3)	4,105	398	1,114	891	223	15.8
2028			(0.9)	(11.1)			4,515			4,515	4,226	(80.4)	4,145	370	1,114	892	222	15.8
2029			(0.9)	(11.9)			5,072			5,072	3,915	(86.0)	3,829	1,243	1,114	886	228	15.8
2030			(0.9)	(12.8)			5,326			5,326	3,627	(91.6)	3,535	1,791	1,114	780	334	15.8
2031			(0.8)	(13.6)			6,088			6,088	3,641	(97.1)	3,544	2,544	1,114	782	332	15.8

BIG RIVERS ELECTRIC CORPORATION
INTERGRATED RESOURCE PLAN
HMP&L EARLY EXIT NET PRESENT VALUE

	Utility Costs ($000)											
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	=(1)thru(9)-(10)-(11)
	Load Cost (Energy)	Load Cost (Capacity)	Fuel Costs	FOM	Non-Fuel VOM	Emissions Cost	EE Program Costs	Annualized Build Costs	Retirement/Exit Costs	*Less: Market Revenue*	*Less: Capacity Revenue*	Net Utility Costs
	$000	$000	$000	$000	$000	$000	$000	$000	$000	$000	$000	$000
2018	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	780	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2019	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	804	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2020	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	802	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2021	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	761	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2022	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	703	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2023	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	645	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2024	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	684	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2025	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	721	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2026	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	772	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2027	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	820	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2028	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	870	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2029	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	883	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2030	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	941	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2031	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,034	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Net Present Value$000 (2017$) NPV 2017-2031	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	6,469	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

BIG RIVERS ELECTRIC CORPORATION
INTERGRATED RESOURCE PLAN
RENEWABLE PORTFOILO STANDARD SCENARIO

	Capacity Additions						Energy and Capacity Positions											
	(1)		(2)		(3)		(4)	(5)	(6)	7)=(4)+(5)+(	(8)	(9)	(10)=(8)-(9)	(11)=(7)-(10	(12)	(13)	14)=(12)-(1	(15)
	Supply-Side Capacity		Incremental Energy Efficiency		Utility Solar		Thermal Generation + Hydro	Purchased Energy	New Utility Solar	= Market Sales	Load (Net of Embedded EE)	*Less:* Energy Efficiency	= Net Load Requirements	Energy Surplus	Capacity	Peak + Reserves	Capacity Surplus	Minimum Reserve Margin
	Incremental MW	Culm MW	Incremental MW	Culm MW	Incremental MW	Culm MW	GWh	GWh	GWh	GWh	GWh	GWh	GWh	GWh	MW	MW	MW	%
2018			(1.3)	(1.3)			5,219		0	5,219	3,420	(17.1)	3,403	1,816	1,287	763	524	15.8
2019			(1.2)	(2.5)			5,365		0	5,365	3,930	(25.3)	3,904	1,461	1,311	918	393	15.8
2020			(1.2)	(3.7)	100.0	100	4,410		133	4,544	4,356	(32.7)	4,323	221	1,214	937	277	15.8
2021			(0.4)	(4.1)			4,256		133	4,389	4,326	(35.0)	4,291	99	1,214	950	264	15.8
2022			(1.1)	(5.2)			3,911		133	4,044	4,355	(42.1)	4,313	(269)	1,214	959	255	15.8
2023			(1.1)	(6.3)			3,805		133	3,938	4,346	(49.2)	4,296	(358)	1,214	961	253	15.8
2024			(1.1)	(7.3)			3,807		133	3,940	4,376	(56.2)	4,320	(380)	1,214	963	251	15.8
2025			(0.9)	(8.3)	40.0	140	4,006		186	4,192	4,397	(62.3)	4,335	(142)	1,254	951	303	15.8
2026			(0.9)	(9.2)			4,120		186	4,306	4,454	(68.3)	4,386	(80)	1,254	966	288	15.8
2027			(0.9)	(10.1)			4,503		186	4,689	4,180	(74.3)	4,105	584	1,254	891	363	15.8
2028			(0.9)	(11.1)			4,515		187	4,702	4,226	(80.4)	4,145	557	1,254	892	362	15.8
2029			(0.9)	(11.9)			5,072		186	5,258	3,915	(86.0)	3,829	1,429	1,254	886	368	15.8
2030			(0.9)	(12.8)	40.0	180	5,326		239	5,566	3,627	(91.6)	3,535	2,030	1,294	780	514	15.8
2031			(0.8)	(13.6)			6,088		239	6,327	3,641	(97.1)	3,544	2,783	1,294	782	512	15.8

BIG RIVERS ELECTRIC CORPORATION
INTERGRATED RESOURCE PLAN
RENEWABLE PORTFOILO STANDARD NET PRESENT VALUE

	Utility Costs ($000)											
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	=(1)thru(9)-(10)-(11)
	Load Cost (Energy)	Load Cost (Capacity)	Fuel Costs	FOM	Non-Fuel VOM	Emissions Cost	EE Program Costs	Annualized Build Costs	Retirement/Exit Costs	*Less: Market Revenue*	*Less: Capacity Revenue*	Net Utility Costs
	$000	$000	$000	$000	$000	$000	$000	$000	$000	$000	$000	$000
2018	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2019	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2020	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2021	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2022	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2023	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2024	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2025	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2026	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2027	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2028	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2029	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2030	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2031	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Net Present Value$000 (2017$)												
NPV 2017-2031	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	8,244	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

BIG RIVERS ELECTRIC CORPORATION
INTERGRATED RESOURCE PLAN
ADDITIONAL DEMAND SIDE MANAGEMENTSCENARIO

	Capacity Additions						Energy and Capacity Positions											
	(1)		(2)		(3)		(4)	(5)	(6)	7)=(4)+(5)+(6	(8)	(9)	(10)=(8)-(9)	(11)=(7)-(10	(12)	(13)	14)=(12)-(13	(15)
	Supply-Side Capacity		Incremental Energy Efficiency		Utility Solar		Thermal Generation + Hydro	Purchased Energy	New Utility Solar	= Market Sales	Load (Net of Embedded EE)	*Less:* Energy Efficiency	= Net Load Requirements	Energy Surplus	Capacity	Peak + Reserves	Capacity Surplus	Minimum Reserve Margin
	Incremental MW	Culm MW	Incremental MW	Culm MW	Incremental MW	Culm MW	GWh	GWh	GWh	GWh	GWh	GWh	GWh	GWh	MW	MW	MW	%
2018			(1.3)	(1.3)			5,219			5,219	3,420	(17.1)	3,403	1,816	1,287	763	524	15.8
2019			(1.2)	(2.5)			5,365			5,365	3,930	(25.3)	3,904	1,461	1,311	918	393	15.8
2020			(1.2)	(3.7)			4,410			4,410	4,356	(32.7)	4,323	87	1,114	937	177	15.8
2021			(0.4)	(4.1)			4,256			4,256	4,326	(35.0)	4,291	(34)	1,114	937	164	15.8
2022			(1.1)	(5.2)			3,911			3,911	4,355	(42.1)	4,313	(402)	1,114	950	164	15.8
2023			(1.1)	(6.3)			3,805			3,805	4,346	(49.2)	4,296	(491)	1,114	959	155	15.8
2024			(1.1)	(7.3)			3,807			3,807	4,376	(56.2)	4,320	(513)	1,114	961	153	15.8
2025			(0.9)	(8.3)			4,006			4,006	4,397	(62.3)	4,335	(328)	1,114	963	151	15.8
2026			(0.9)	(9.2)			4,120			4,120	4,454	(68.3)	4,386	(266)	1,114	951	163	15.8
2027			(0.9)	(10.1)			4,503			4,503	4,180	(74.3)	4,105	398	1,114	966	148	15.8
2028			(0.9)	(11.1)			4,515			4,515	4,226	(80.4)	4,145	370	1,114	891	223	15.8
2029			(0.9)	(11.9)			5,072			5,072	3,915	(86.0)	3,829	1,243	1,114	892	222	15.8
2030			(0.9)	(12.8)			5,326			5,326	3,627	(91.6)	3,535	1,791	1,114	886	228	15.8
2031			(0.8)	(13.6)			6,088			6,088	3,641	(97.1)	3,544	2,544	1,114	782	332	15.8

BIG RIVERS ELECTRIC CORPORATION
INTERGRATED RESOURCE PLAN
ADDITIONAL DEMAND SIDE MANAGEMENT NET PRESENT VALUE

	Utility Costs ($000)											
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	=(1)thru(9)-(10)-(11)
	Load Cost (Energy)	Load Cost (Capacity)	Fuel Costs	FOM	Non-Fuel VOM	Emissions Cost	EE Program Costs	Annualized Build Costs	Retirement/Exit Costs	*Less: Market Revenue*	*Less: Capacity Revenue*	Net Utility Costs
	$000	$000	$000	$000	$000	$000	$000	$000	$000	$000	$000	$000
2018	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2019	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2020	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2021	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2022	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2023	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2024	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2025	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2026	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2027	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2028	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2029	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2030	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2031	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Net Present Value$000 (2017$)												
NPV 2017-2031	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	8,244	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Appendix I

Glossary

Glossary

ABB	Asea Brown Boveri
ACES	Formerly ACES Power Marketing
ACI	Activated Carbon Injection
ARS	Automatic Restoration and Sectionalizing
ATC	Around the Clock
BEopt	Building Energy Optimization
BTU	British Thermal Unit
C&I	Commercial and Industrial
CAIR	Clean Air Interstate Rule
CCR	Coal Combustion Residuals
CEL	Capacity Export Limits
CEO	Chief Executive Officer
CFO	Chief Financial Officer
CIL	Capacity Import Limits
Commission	Kentucky Public Service Commission
Company	Big Rivers Electric Corporation
CPCN	Certificate of Public Convenience and Necessity
CPP	Clean Power Plan or Critical Peak Pricing
CROs	Control Room Operators
CSAPR	Cross State Air Pollution Rule
CT	Combustion Turbine
dc	Direct Current
DCS	Distributed Control System
DOE	U. S. Department of Energy
DR	Demand Response
DSI	Dry Sorbent Injection
DSM	Demand Side Management
EE	Energy Efficiency
EFORd	Unit Forced Outage Rate
EHV	Extra High Voltage
EIA	U. S. Energy Information Administration
ELG	Effluent Limitation Guidelines
EMS	Energy Management System
EPA	U.S. Environmental Protection Agency
ES	Environmental Surcharge
FAC	Fuel Adjustment Clause
FERC	Federal Energy Regulatory Commission
FGD	Flue Gas Desulphurization

Focused Audit	Focused Management Audit
GADS	Generator Availability Data System
GDS	GDS Associates, Inc.
GDS Associates	GDS Associates, Inc.
GE MARS	GE's Multi-Area Reliability Simulation
GKS	Generation Knowledge Service
GVTC	Generator Verification Test Capacities
GWH	Gigawatt Hours
HMP&L	Henderson Municipal Power and Light
HMP&L Station Two	William L. Newman Station Two
HVAC	Heating, Ventilation, and Air Conditioning
ICAP	Installed Capacity
IRP	Integrated Resource Plan
JPEC	Jackson Purchase Energy Corporation
Kenergy	Kenergy Corp.
KPDES	Kentucky Pollutant Discharge Elimination System
KU	Kentucky Utilities Company
kV	Kilovolt
kW	Kilowatt
kWH	Kilowatt Hour
KYDAQ	Kentucky Department for Air Quality
KyMEA	Kentucky Municipal Energy Agency
LBA	Local Balancing Authority
LED	Light Emitting Diode
LFU	Load Forecast Uncertainty
LIC	Large Industrial Customer Tariff
LOI	Loss of Ignition
LOLE	Loss of Load Expectation
LMP	Locational Marginal Price
LRR	Local Reliability Requirement
LRZ	Local Resource Zone
LSE	Load Serving Entity
MATS	Mercury and Air Toxics Standards
MCRECC	Meade County Rural Electric Cooperative Corporation
Members	Collectively: MCRECC, Kenergy, and JPEC
Member-Owners	Collectively: MCRECC, Kenergy, and JPEC
MECT	Module E Capacity Tracking Tool
MISO	Midcontinent Independent System Operator, Inc.
Mitigation Plan	Load Concentration Analysis and Mitigation Plan
MRSM	Member Rate Stability Mechanism

MTEP	MISO Transmission Expansion Planning
MW	Megawatt
NAAQS	National Ambient Air Quality Standards
NDC	Net Dependable Capability
NERC	North American Electric Reliability Corporation
NOx	Nitrogen Oxides
NPV	Net Present Value
O&M	Operating and Maintenance
PCT	Participant Cost Tests
PM 2.5	Particulate Matter 2.5
PRA	Planning Resource Auction
PRM	Planning Reserve Margin
PV	Photovoltaic
RUS	Rural Utilities Services
SAE	Statistically Adjusted End Use
SCR	Selective Catalytic Reduction
Sebree Station	Big Rivers' Green and Reid Stations and HMP&L Station Two
SEPA	Southeastern Power Administration
SERC	Southeast Electric Reliability Corporation
SO2	Sulfur Dioxide
TOU	Time-of-Use Rates
TRC	Total Resource Cost
TRM	Technical Reference Manuals
UCAP	Unforced Capacity
UCT	Utility Cost Test
XEFORd	Unit Forced Outage Rate

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