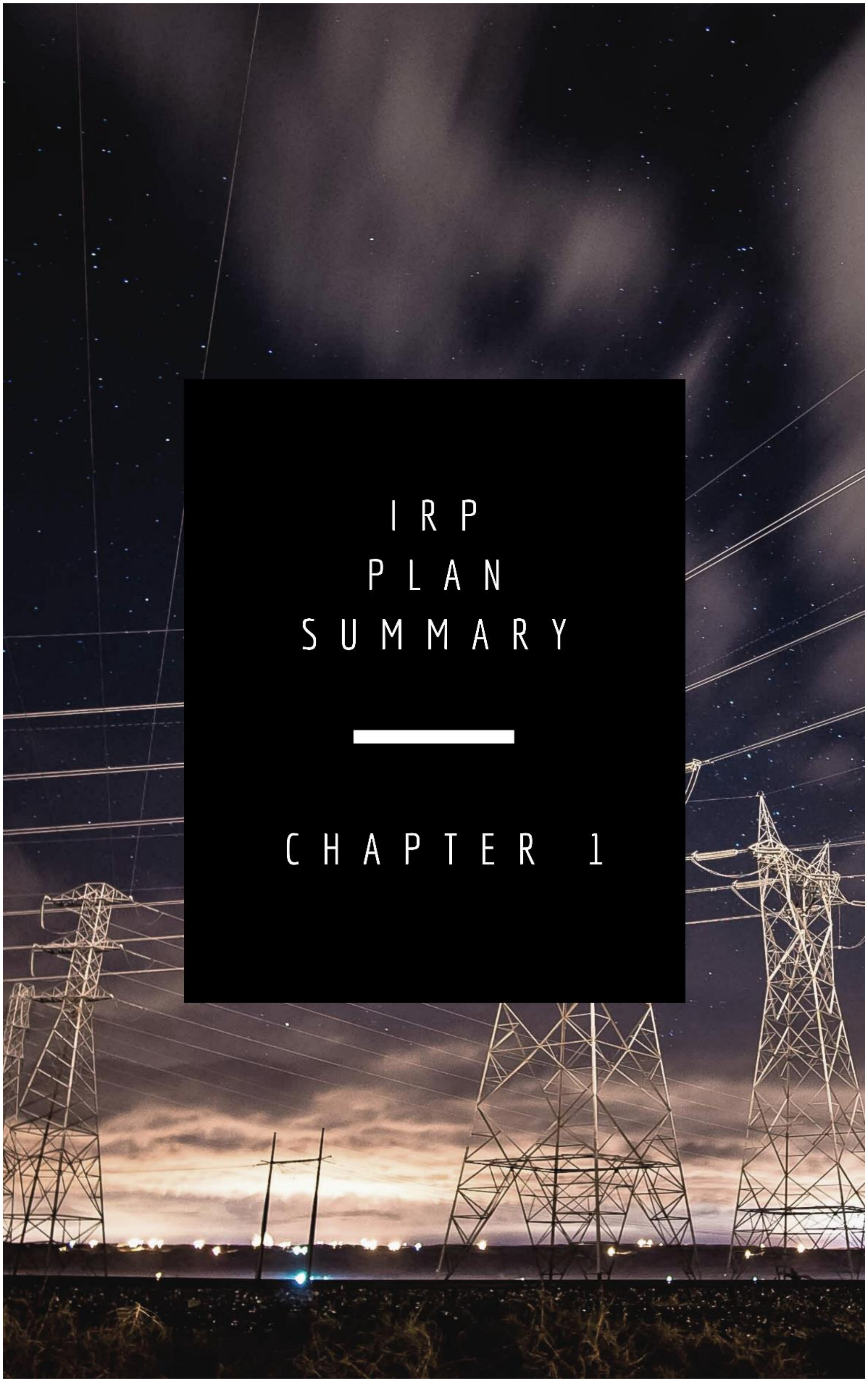
INTEGRATED RESOURCE PLAN

2020

Big Rivers
ELECTRIC CORPORATION


IRP
PLAN
SUMMARY
CHAPTER 1

IRP PLAN SUMMARY

This Integrated Resource Plan ("IRP" or "2020 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 needed 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 because of the uncertainty of 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 IRP is not to be considered a commitment to any specific course of action, but rather a plan that considers market conditions, load requirements, regulation, and legislation as of a certain point in time.

This 2020 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, 2017 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 H.

[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."

1.1 Overview

Big Rivers last filed an IRP with the Commission on September 21, 2017, in Case No. 2017-00384[2] ("2017 IRP"). The Commission, by order dated October 1, 2019, entered the Commission Staff's report summarizing its review of Big Rivers' 2017 IRP into the record, and by order dated November 4, 2019, the Commission issued a filing date of September 21, 2020, for Big Rivers' next IRP, and closed Case No. 2017-00384.

This 2020 IRP was prepared by Big Rivers' staff, with supporting inputs from Clearspring Energy Advisors, LLC ("Clearspring") for load forecasting and Demand Side Management ("DSM") analysis. The individuals responsible for preparation of this IRP and who will be available to respond to inquiries are listed in Table 1.1.

Appendix H to this 2020 IRP provides a complete listing of the acronyms used throughout this document.

[2] *In the Matter of: The 2017 Integrated Resource Plan of Big Rivers Electric Corporation*, Case No. 2017-00384.

Table 1.1

2020 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*
	David Blank	*Modeling*
	Jason Burden	*Power Production*
	Michael Mizell	*V. P. Environmental Compliance*
	Chris Bradley	*Transmission*
	Nicholas Castlen	*Finance*
	Tyson Kamuf	*Corporate Attorney*
	Roger Hickman	*Regulatory Affairs*
	Greg Mayes	*Associate Attorney*
	Senthia Santana	*Associate Attorney*
Clearspring Energy Advisors, LLC	*Joshua P. Hoyt*	*Demand Side Management*
	Douglas Carlson	*Demand Side Management*
	Matt Sekeres	*Load Forecast*
	Steve Fenrick	*Model Development*

This IRP presents Big Rivers' plan for meeting projected power requirements through 2034. 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 resources. Supporting documents, figures, and tables are provided throughout this document and in the appendices, which are an integral part of the 2020 IRP.

The remainder of this chapter contains a description of Big Rivers and its service territory; a summary of its capacity resources, transmission assets, and projected load growth; and a discussion of planning goals and objectives.

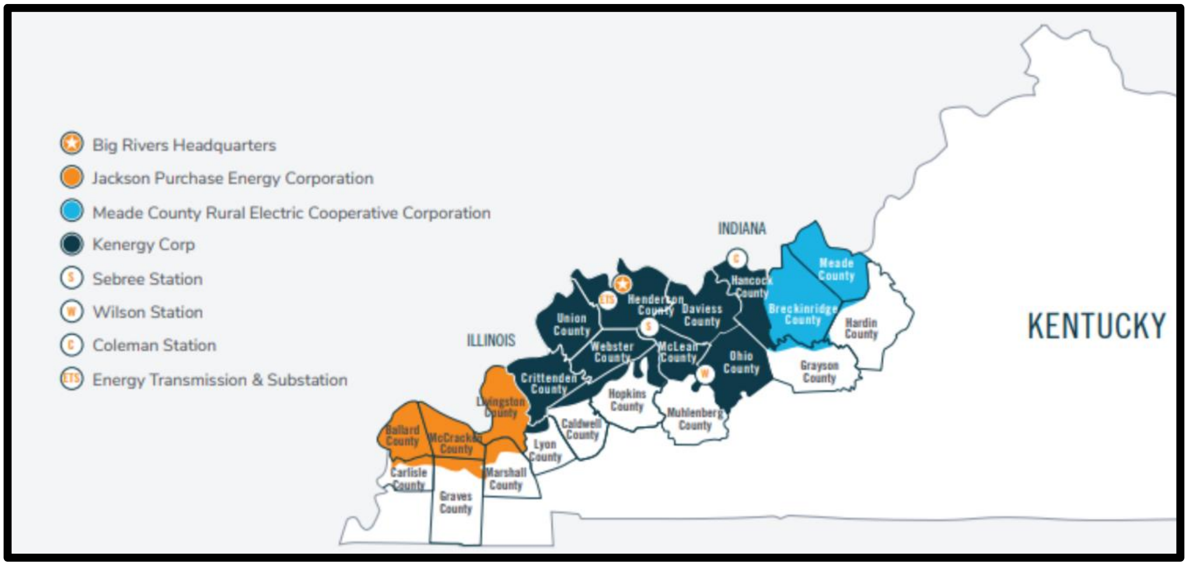
1.2 Description of the Utility

1.2.1 Service Territory and Member-Owners

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 more than 118,000 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.

Figure 1.1

Big Rivers' Members Service Area Map



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 from the Regulatory Affairs webpage of Big Rivers' internet site **(** http://www.bigrivers.com/regulatory-affairs/) **.** See Chapter 2 – "Changes since 2017 IRP" for regulatory activity since Big Rivers' last IRP.

Also on file with the Commission are wholesale power contracts for Big Rivers' Member-Owners and Commission – approved wholesale power agreements: (https://psc.ky.gov/Home/Library?type=Tariffs&folder=Electric%5CBig%20Rivers%20Electric%20Corporation%5CContracts)

Additionally, Big Rivers provides transmission and ancillary services under the Midcontinent Independent System Operator, Inc. ("MISO") tariff (https://www.misoenergy.org/legal/tariff/) and serves load in the Southwest Power Pool ("SPP") (https://spp.etariff.biz:8443/viewer/viewer.aspx).

1.2.2 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. Big Rivers' total power capacity is 1622 MW, when 178 MW of contracted hydroelectric capacity from the Southeastern Power Administration ("SEPA") is included. Announced retirements of the 443 MW Coleman Plant and 65 MW Reid 1, to be completed by the end of 2020, and proposed additions of three solar power purchase agreements totaling 260 MW (see Sections 1.2.3 and 2.9) will bring total generation resources to 1,374 MW. In 2017, Big Rivers installed seven solar arrays in the Member-Owner service areas to provide data on solar energy generators[3]. The arrays provide retail members, first responders and students the opportunity to view solar technology up close, learning about its construction, production, and costs. Located in McCracken, Marshall, Livingston, Henderson, Daviess, Meade, and Breckinridge Counties, the arrays generate a combined 165,000 kWh each year. See Figures 1.2 and 1.3 for an overview of Big Rivers' Green, Reid, and Wilson generation facilities.

[3] https://solar.bigrivers.com/

Figure 1.2

Generation Facility Overview

Sebree Station

SEBREE STATION CONSISTS OF TWO STATIONS, ROBERT D. GREEN STATION AND ROBERT A. REID STATION, WITH A COMBINED NET GENERATING CAPACITY OF 519 MW, AFTER THE RETIREMENT OF REID 1. THE FACILITY CONSISTS OF THREE UNITS: TWO COAL-FIRED AND ONE NATURAL GAS-FIRED.

Robert D. Green Station:

- **In 2015, Activated Carbon injection (ACI) and Dry Sorbent Injection (DSI) system 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:

- **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.**

Figure 1.3

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%. Big Rivers plans to replace and upgrade the FGD system by recycling the Coleman Station FGD/absorber system, a project approved in a Commission order dated August 6, 2020 (Case No. 2019-00435).**
- **The electrostatic precipitator is designed to remove 99.87% of the particulate.**
- **The selective catalytic reduction (SCR) system is Babcock Borsig delta wing design that uses catalyst and ammonia reagent to remove 90% of the unit's nitrous oxide (NO_x) 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 Toxic Standards (MATS) that went into effect on April 16, 2016.**

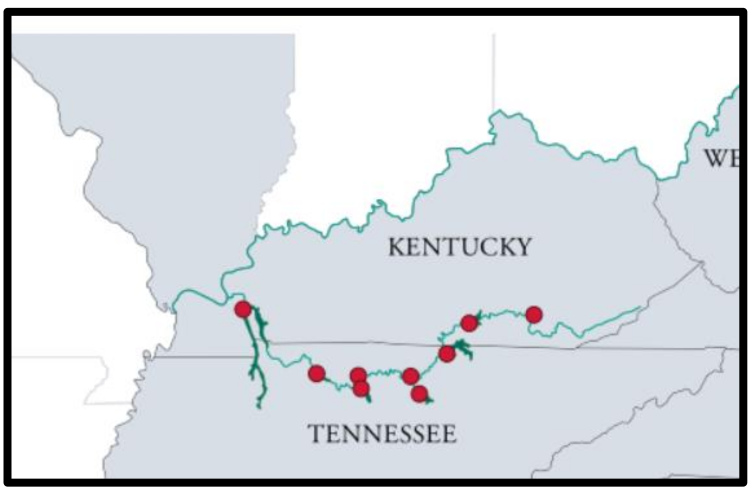
1.2.3 Big Rivers SEPA Cumberland Hydro Capacity Resource

SEPA was created in 1950 by the Secretary of the Interior to carry out the functions assigned to the Secretary by the Flood Control Act of 1944, and now functions under the Department of Energy ("DOE"). The objectives of SEPA are to market electric power and energy generated by Federal reservoir projects while encouraging widespread use of the power at the lowest possible cost to consumers. Preference in the sale of power is given to public bodies and cooperatives, referred to as preference customers.

There are nine projects in the Cumberland System located in Kentucky and Tennessee. The power produced at these projects is delivered to 25 preference entities that serve 210 preference customers in 8 states including Kentucky. Figure 1.4 is a map of the Cumberland system projects.

Figure 1.4

SEPA Cumberland System Map



Big Rivers is one of the earliest preference customers outside of Tennessee Valley Authority ("TVA") and began purchasing power from the Cumberland System of projects in 1963. The Big Rivers allocation of 178 MW is one of the largest single allocations of Cumberland System power and is an important carbon-free part of Big Rivers' generation portfolio.

1.2.4 Resources to Meet Load Growth

In addition to the capacity resources above, Big Rivers has contracted to purchase 260 MWs of Solar Power consisting of 160 MWs from Geronimo Energy from a facility located on the Henderson/Webster County line and 100 MWs from Community Energy at two different sites; 40 MW located in Meade County and 60 MW located in McCracken County. These solar power purchase contracts are currently awaiting Commission approval. See *In the Matter of: Electronic Application of Big Rivers Electric Corporation for Approval of Solar Power Contracts*, P.S.C. Case No. 2020-00183. Chapters 8 and 9 of this IRP also discuss Big Rivers' optimal plan to idle the 454 MW Green units and add up to 90 MW of a new 592 MW natural gas combined cycle unit situated at Big Rivers' Sebree location.

1.2.5 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 **CONFIDENTIAL** map of the transmission system is provided in Figure 1.4, and a more detailed map is provided in **CONFIDENTIAL** Appendix E. Discussion of Big Rivers' transmission planning is provided in Chapter 6.

Figure 1.5

[redacted]

1.2.6 Big Rivers' Member Load and Load Growth

Unless otherwise noted, references to total system energy and peak demand requirements in the 2020 Load Forecast are to Big Rivers' Members' native system and Big Rivers' Non-Member load.[4] Member native system is the cumulative requirement of the Members' customer base load that Big 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 3.3.8 and Appendix A Long Term Load Forecast for more discussion of Non-Member load.

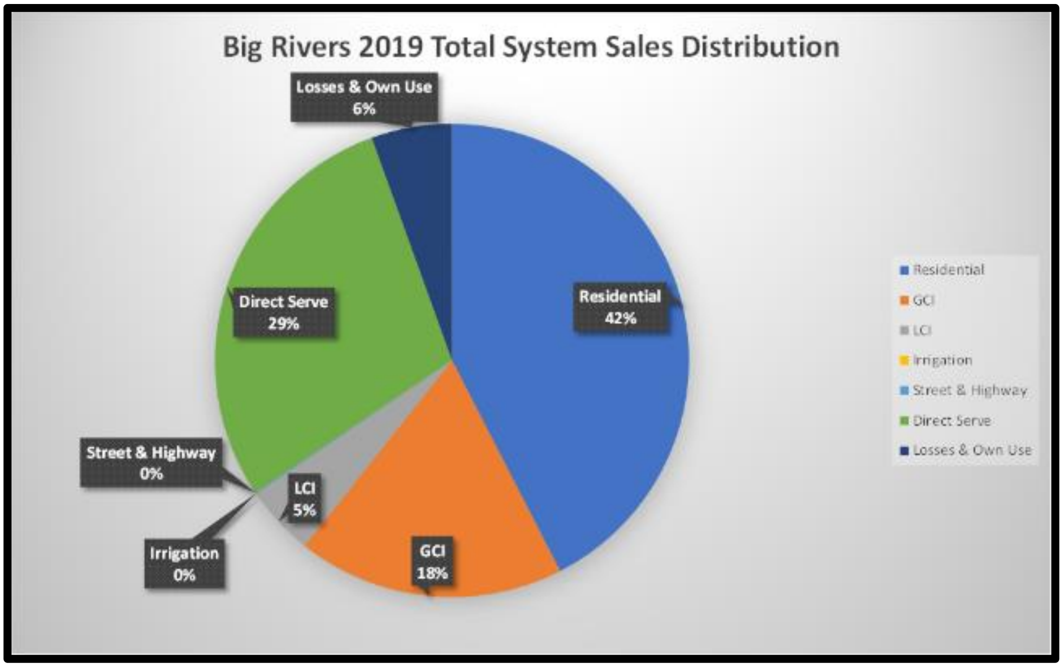
[4] See Appendix A, 2020 Load Forecast

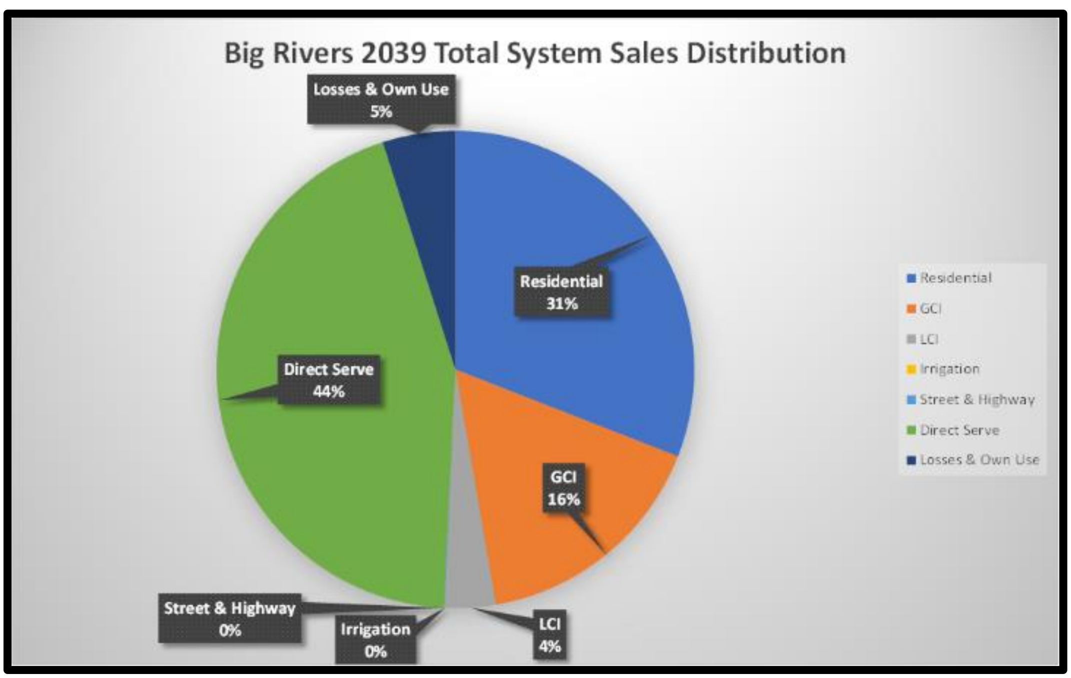
Big Rivers categorizes Member energy and peak demand into two classes: rural system and direct serve. The rural system is comprised of all retail residential, commercial, and industrial customers served by Big Rivers' Members, except for retail customers served under Big Rivers' Large Industrial Customer ("LIC") tariff or special contracts. Direct-serve customers are served under special contracts or Big Rivers' LIC tariff. There were 21 large industrial consumers in 2019, with an additional LIC added with the Commission's approval of the Nucor Corporation ("Nucor") contracts on August 17, 2020, in Case No. 2019-00365. The Direct- Serve class contributed 29% of Big Rivers' Member kWh Sales in 2019 and is projected to contribute 44% of Big Rivers' Member kWh Sales in 2039.

A breakdown of actual energy sales for 2019 and projected sales for 2039 is presented in Figure 1.5.

Figure 1.6

Class Energy kWH Sales Proportions for Member Load





As mentioned above, Big Rivers' total system energy and peak demand requirements are comprised of its Member system load and Non-Member load. Total requirements include transmission losses. Member system energy and peak demand requirements are projected to reach 4,602 GWH and 852 MW, respectively, by 2039. Annual Member load coincident peak ("CP") projections are presented in Table 1.2. Refer to Section 3.3.8 for details on additional Non-Member sales included in the 2020 Long Term Load Forecast Report. Chapter 3 and Appendix A provide detailed descriptions of the load forecast.

Table 1.2

2020 Big Rivers Member CP Load Forecast

Year	Rural Summer CP	Rural Winter CP	Rural Annual CP	Direct Serve Annual CP	Transmission Losses	**Total Annual CP**
2015	504,990	566,553	566,553	121,143	11,253	**698,949**
2016	486,690	484,768	486,690	120,750	13,855	**621,295**
2017	504,269	474,971	504,269	114,378	15,538	**634,184**
2018	502,549	556,742	556,742	95,530	16,382	**668,654**
2019	480,171	490,895	490,895	117,931	15,995	**624,821**
2020	483,946	484,817	483,946	127,101	15,668	**626,715**
2021	489,218	489,893	489,218	127,101	15,803	**632,122**
2022	489,558	491,914	489,558	322,043	20,810	**832,412**
2023	491,639	494,177	491,639	322,043	20,864	**834,546**
2024	493,376	495,970	493,376	322,043	20,908	**836,327**
2025	495,136	497,935	495,136	322,043	20,953	**838,132**
2026	496,879	499,794	496,879	322,043	20,998	**839,920**
2027	497,133	499,957	497,133	322,043	21,005	**840,180**
2028	498,359	500,820	498,359	322,043	21,036	**841,438**
2029	499,422	501,685	499,422	322,043	21,063	**842,528**
2030	500,004	501,900	500,004	322,043	21,078	**843,125**
2031	501,074	502,687	501,074	322,043	21,106	**844,223**
2032	503,128	504,331	503,128	322,043	21,158	**846,330**
2033	504,103	505,032	504,103	322,043	21,183	**847,329**
2034	504,841	505,432	504,841	322,043	21,202	**848,086**
2035	505,663	506,010	505,663	322,043	21,223	**848,929**
2036	506,495	506,574	506,495	322,043	21,245	**849,782**
2037	507,349	507,238	507,349	322,043	21,266	**850,659**
2038	508,129	507,810	508,129	322,043	21,286	**851,459**
2039	508,968	508,470	508,968	322,043	21,308	**852,319**
Average Annual Growth Rates						
Previous 10 Years	-0.34%	-1.32%	-1.32%	0.98%	11.50%	**-0.74%**
Previous 5 Years	-0.04%	-4.44%	-4.44%	-1.03%	9.24%	**-3.60%**
Next 5 Years	0.54%	0.21%	0.10%	22.25%	5.50%	**6.00%**
Next 10 Years	0.39%	0.22%	0.17%	10.57%	2.79%	**3.03%**
Next 20 Years	0.29%	0.18%	0.18%	5.15%	1.44%	**1.56%**

Table 1.3

Big Rivers Total Member System Energy Summary

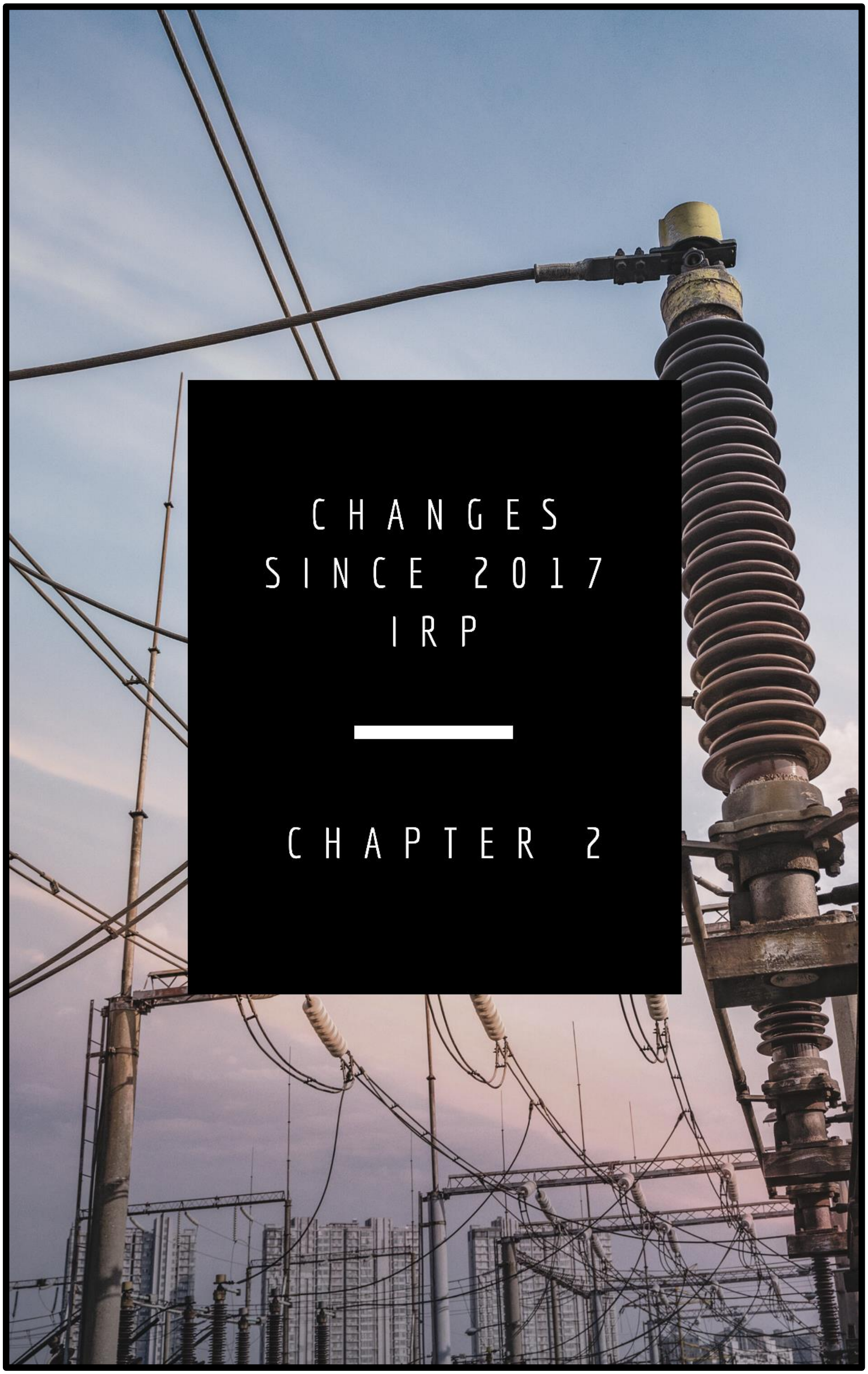
Year	Total Rural Requirements	Direct Serve	Transmission Losses	**Total System Energy Requirements**
2015	2,325,204	946,873	66,970	**3,339,047**
2016	2,330,037	915,310	73,420	**3,318,766**
2017	2,209,837	919,895	77,928	**3,207,660**
2018	2,366,988	953,822	86,858	**3,407,668**
2019	2,271,772	957,994	83,431	**3,317,632**
2020	2,313,997	987,552	84,688	**3,386,237**
2021	2,342,004	987,552	85,373	**3,414,929**
2022	2,345,137	2,038,752	112,407	**4,496,296**
2023	2,357,028	2,038,752	112,712	**4,508,492**
2024	2,366,988	2,041,632	113,042	**4,521,662**
2025	2,376,885	2,038,752	113,221	**4,528,859**
2026	2,386,410	2,038,752	113,466	**4,538,628**
2027	2,388,504	2,038,752	113,519	**4,540,776**
2028	2,394,976	2,041,632	113,759	**4,550,367**
2029	2,400,628	2,038,752	113,830	**4,553,210**
2030	2,403,821	2,038,752	113,912	**4,556,486**
2031	2,409,248	2,038,752	114,051	**4,562,051**
2032	2,419,240	2,038,752	114,307	**4,572,299**
2033	2,424,117	2,038,752	114,433	**4,577,302**
2034	2,427,766	2,038,752	114,526	**4,581,044**
2035	2,431,849	2,038,752	114,631	**4,585,232**
2036	2,435,950	2,038,752	114,736	**4,589,439**
2037	2,440,157	2,038,752	114,844	**4,593,753**
2038	2,444,021	2,038,752	114,943	**4,597,716**
2039	2,448,197	2,038,752	115,050	**4,601,999**
Average Annual Growth Rates				
Previous 10 Years	0.15%	-2.27%	11.89%	**-0.45%**
Previous 5 Years	-1.22%	-0.17%	8.91%	**-0.70%**
Next 5 Years	0.82%	16.34%	6.26%	**6.39%**
Next 10 Years	0.55%	7.85%	3.16%	**3.22%**
Next 20 Years	0.37%	3.85%	1.62%	**1.65%**

Member system energy and peak demand requirements are projected to increase at average compound rates of 1.65% and 1.56%, respectively, per year from 2019 through 2039. Continued increases in employment and number of households, air conditioning saturation levels, appliance efficiencies, consumer energy conservation awareness, and decreases in the price of retail electricity are expected to impact growth in Member energy sales over the near term; however, increased sales to direct-serve customers will have positive impacts on Member sales over the near term. Member peak requirements are projected to increase from 627 MW in 2020 to 852 MW (including transmission losses) by the summer of 2039.

1.3 Planning Goals and Objectives

Big Rivers' primary planning goal in its 2020 IRP is to reliably and efficiently provide for its Members' electricity needs over the next 15 years through an appropriate mix of resources at the lowest reasonable cost by minimizing the net present value of the production and capital cost for serving the load. An overarching goal was to diversify Big Rivers' historically coal-heavy portfolio while maintaining a "least cost" approach. No additional solar power was assumed beyond what has already been proposed in Case No. 2020-00183. Big Rivers has established other planning objectives to guide its 2020 IRP process:

- Maintain a current and reliable load forecast,
- Provide competitively priced power to its Members,
- Maximize reliability while ensuring safety, minimizing costs, risks, and environmental impacts,
- Identify potential new supply-side resources,
- Maintain adequate planning reserve margins,
- Develop and maintain a more diversified supply portfolio aligned with anticipated Member-Owner load, and
- Meet North American Electric Reliability Corporation ("NERC") guidelines and requirements.


CHANGES
SINCE 2017
IRP
CHAPTER 2

CHANGES SINCE 2017 IRP

2.1 Changes to Load Forecast

Big Rivers chose Clearspring of Madison, Wisconsin to prepare the 2020 Long–Term Load Forecast and Demand–Side Management/Energy Efficiency ("DSM/EE") Analysis. Clearspring was formed in 2004 and has provided consulting services not only to electric cooperatives, including over one hundred fifty (150) distribution cooperatives and fifteen (15) generation and transmission (G&T) cooperatives, but also to investor-owned utilities and municipalities. Clearspring has provided utility-scale energy efficiency studies for eight (8) G&Ts.

Compared to the previous forecast performed by GDS Associates, Inc., Clearspring's method of analysis includes: (a) direct estimates of impacts to use–per–consumer or consumer counts; (b) direct modeling of electricity price; (c) calculated price elasticity based on the relative impact of the electricity price and the alternative fuel index; (d) 15–year weather normalization for base case load forecasts; and (e) changes to weather details such as using temperature values in the econometric model.[5]

2.2 Southeastern Power Administration (SEPA)

In January of 2020, force majeure conditions due to dam safety issues on SEPA's Cumberland River system, which had been in effect since 2007, ceased, raising Big Rivers' SEPA allocation from 154 MW to 178 MW. On March 26, 2018, in Federal Energy Regulatory Commission Docket No. ER18-1173, MISO's Locational Enhancement to Resource Adequacy created External Resource Zones. As an External Resource, the price for SEPA Cumberland ZRCs will settle at an External Resource Zone Market Clearing Price, which may be different than the Market Clearing Price in MISO Zone 6, where Big Rivers generation and load reside.

[5] Methodology are included in Appendix A Long Term Load Forecast Section 7.4.

2.3 Senior Management and Personnel Development at Big Rivers

Big Rivers' employees continue to be its greatest asset. Big Rivers remains focused on growing this asset through leadership development efforts, employee education and training, and a focus on employee engagement, wellness and performance management.

Big Rivers has had several changes in senior management since 2017. Lindsay N. Durbin, formerly Chief Financial Officer (CFO), assumed the Vice President Human Resources position in 2018 following the retirement of Thomas W. (Tom) Davis. Big Rivers hired Paul G. Smith to fill the vacant CFO position in the same year. In February 2020, Michael T. (Mike) Pullen was promoted to Executive Vice President Operations, and, in April 2020, Big Rivers hired Michael S. (Mike) Mizell as Vice President Environmental Compliance to enhance Big Rivers' focus on changing environmental regulations.

Since 2017, Big Rivers has implemented a Pay–for–Performance Plan into its Performance Management Process for Non–Bargaining employees, and has continued to utilize Individual Development Plans for each employee. Big Rivers also engaged the National Rural Electric Cooperative Association to conduct its bi-annual Employee Engagement Survey and, to provide better employee feedback, used survey questions with a more detailed 5–point scale to gain greater insights. In 2019, Big Rivers held its first annual Leadership Forum, bringing together leaders throughout the organization for a day of learning and fellowship. Big Rivers continues its succession planning process to attract and retain top talent. Big Rivers' focus on strategic planning remains evident through annual workshops with executives, employees, and board members to update the corporate strategic plan and ensure a continued focus on meeting our corporate mission.

2.4 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. Safety is the foundation for all decisions and expectations of Big Rivers' work force, and is a major component of Big Rivers' incentive program. 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 or 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. 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:

- Fifty-Two Governor's Safety and Health Awards from the Kentucky Labor Cabinet, each award based on number of hours worked without experiencing a lost-time injury;
- One year or greater no lost-time incident milestones achieved in 2020:
  - Transmission: 10 years,
  - Green Station: 11 years,
  - Headquarters: 9 years, and
  - Wilson Station: 4 years;
- Headquarters employees have worked four years without an Occupational Safety and Health Administration ("OSHA") recordable incident;
- Transmission employees have worked five years without an OSHA recordable incident;
- Green Station employees have worked one year without an OSHA recordable incident; and
- Big Rivers won the 2016, 2017, 2018 and 2019 Kentucky Employers' Mutual Insurance ("KEMI") Destiny award for Big Rivers' commitment and success in maintaining a safe

workplace. This award requires that Big Rivers be in KEMI's Preferred TIER, maintain an Experience Modification Rate of .8 or below and maintain a loss ratio of 45% or below, which places Big Rivers in an elite group. With nearly 30,000 KEMI policyholders in Kentucky, Big Rivers was one of 24 organizations that won the award in 2019.

2.5 Transmission

Big Rivers operates and maintains a 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. These upgrades included innovative and automated technology that further enhance Big Rivers' ability to respond to outages with Automatic Restoration and Sectionalization ("ARS") schemes. ARS automatically sheds any unneeded transmission line sections in an attempt to expedite the sectionalization of a 69 kV circuit that is experiencing an outage, and quickly reenergizes the rural or industrial delivery point substation. ARS also automatically transfers 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.

In 2019, the SERC Reliability Corporation ("SERC"), responsible for ensuring a reliable and secure electric grid across 16 southeastern and central states including Kentucky, completed a comprehensive audit of Big Rivers' compliance with NERC Planning Standards and Operating Standards. The audit was very successful with many positive observations noted by the audit teams.

Big Rivers, in partnership with Republic Transmission, LLC, completed MISO's first competitively bid transmission project. The new 345 kV transmission line was energized on June 11, 2020, ahead of schedule and under budget, and extends approximately 31 miles from the Big Rivers Coleman extra high voltage ("EHV") substation in Hancock County, Kentucky, to Dubois County, Indiana. Big Rivers owns and operates the Kentucky portion of the project.

2.6 Focused Management Audit

In its final Order in the second rate case Big Rivers filed to address the loss of two aluminum smelters in Big Rivers' service area,[6] the Kentucky Public Service Commission initiated a Focused Management Audit of Big Rivers' plan to address the loss of the smelter load, i.e., the Load Concentration Analysis and Mitigation Plan (<u>"Mitigation Plan"</u>). The resulting Focused Management Audit Report generally confirmed Big Rivers' past decisions and future plans as outlined in the Mitigation Plan. Since the filing of its 2017 Integrated Resource Plan in September 2017, Big Rivers has continued to file Focused Management Audit Progress Reports. As Table 2.1 shows, in October 2020, Big Rivers will file its seventh Progress Report. Also as shown in Table 2.1, of the original five (5) recommendations, Recommendation No. 3 is ON-GOING, while Recommendation No. 5, pursuant to the Commission Staff's October 22, 2019, reply to Big Rivers' fourth, fifth, and sixth Progress Reports, is listed as ON-GOING Held in Abeyance.

[6] See *In the Matter of: Application of Big Rivers Electric Corporation for a General Adjustment in Rates Supported by Fully Forecasted Test Period* – Case No. 2013-00199, Order (April 25, 2014).

Table 2.1

Big Rivers Electric Corporation Focused Management Audit Progress Report Summary

Progress Report No. and Date	Recommendations	Big Rivers Proposed Status	Commission Staff's Response on Status
Progress Report Number 1 April 1, 2016	Recommendation No. 1	ON-GOING	ON-GOING
	Recommendation No. 2	ON-GOING	ON-GOING
	Recommendation No. 3	ON-GOING	ON-GOING
	Recommendation No. 4	ON-GOING	ON-GOING
	Recommendation No. 5	ON-GOING	ON-GOING
Progress Report Number 2 October 3, 2016	Recommendation No. 1	COMPLETE	COMPLETE
	Recommendation No. 2	ON-GOING	ON-GOING
	Recommendation No. 3	ON-GOING	ON-GOING
	Recommendation No. 4	COMPLETE	ON-GOING
	Recommendation No. 5	ON-GOING	ON-GOING
Progress Report Number 3 April 3, 2017	Recommendation No. 2	COMPLETE	ON-GOING
	Recommendation No. 3	ON-GOING	ON-GOING
	Recommendation No. 4	COMPLETE	COMPLETE
	Recommendation No. 5	ON-GOING	ON-GOING
Progress Report Number 4 October 4, 2017	Recommendation No. 2	COMPLETE	COMPLETE
	Recommendation No. 3	ON-GOING	ON-GOING
	Recommendation No. 5	ON-GOING	ON-GOING – Held in Abeyance
Progress Report Number 5 October 5, 2018	Recommendation No. 3	ON-GOING	ON-GOING
	Recommendation No. 5	COMPLETE	ON-GOING – Held in Abeyance
Progress Report Number 6 October 8, 2019	Recommendation No. 3	ON-GOING	ON-GOING
Progress Report Number 7 October 8, 2020	Recommendation No. 3		
Recommendation No. 1	Big Rivers should consider adding a member with energy expertise to the Board of Directors.		
Recommendation No. 2	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 No. 3	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 No. 4	Big Rivers should continue to pursue increased sales to existing and new load, including new Members		
Recommendation No. 5	Big Rivers should pursue discussions with Lenders and the Commission to address restrictions around the sale of Coleman and commence a study on the strategic options for the facility.		

2.7 Credit Rating Changes

In 2017, Big Rivers did not have an investment grade rating from any of the three credit rating agencies (Moody's Investor Services ("Moody's"), Fitch Ratings ("Fitch"), and S&P Global Ratings ("S&P")). In fact, Big Rivers was two levels or "notches" below an investment grade rating by all three agencies. In July of 2018, with continued improvement in financial metrics and cash flow, Big Rivers was able to obtain an investment grade rating from Fitch. Also in 2018, both Moody's and S&P upgraded Big Rivers one notch, which left the company still short of investment grade. In 2019, Moody's upgraded the Big Rivers outlook from "stable" to "positive," but did not upgrade the rating.

Big Rivers continues to enhance its credit profile and believes a number of recent milestone events will lead to either Moody's or S&P, or both, upgrading the company to investment grade. Such milestone events include the Commission Order in Case No. 2020-00064 which approved the cost recovery of Big Rivers' regulated assets and implementation of an innovative sharing of net margins in excess of a 1.30 times interest earned ratio, the call and refinancing of pollution control bonds which will result in a significant reduction in annual interest expense, and the approval of the Meade County contract with Nucor Corporation.

2.8 Big Rivers Business Plan Development

During the three years since the 2017 IRP, Big Rivers maintained its financial health by rebalancing its supply portfolio with demand and executing several long–term non-member agreements. The Electrical Integration Analysis, Chapter 7 of Big Rivers' 2017 IRP, presented Big Rivers' least–cost option to continue operating the Wilson and Green Units as coal-fired generators, continue the contract with SEPA, and exit the Station Two Contracts with Henderson Municipal Power & Light ("HMP&L"). Both of the first two points were achieved. As explained in further detail below, Big Rivers did exit the Station Two Contracts in 2019, except for the Joint Facilities Agreement. In addition, Big Rivers continued to follow its business plan, which included selling Big Rivers' length above cost in short and intermediate terms while pursuing long–term sales including participating with local partners in economic development efforts to increase Member load. Such transactions along with the generation and supply changes discussed below, better align Big Rivers' load with supply to safely deliver competitive and reliable wholesale power to our Member-Owners.

2.9 Resource Plan

The optimal (least cost) plan for the Base Case includes adding the three solar facilities Power Purchase Agreements ("PPA") totaling 260 MW of new solar capacity, entering a partnership to own or purchase 90 MW in 2024 of a new 592 MW natural gas combined cycle unit located at Sebree (NGCC – Sebree), and idling both the Green coal units. Wilson continues to operate as a coal-fired station, the Reid Station Combustion Turbine ("Reid CT") remains available as a natural gas peaking unit and Big Rivers remains in the SEPA contract. It should be emphasized that this resource plan option assumes the creation of a coalition of partners for the 592 MW natural gas combined cycle ("NGCC") unit. A unit of at least that size is required to realize the economies of scale that come with a larger facility, but Big Rivers does not project a requirement for the entire output of the facility to serve is Member load.

2.10 Other Regulatory Events

Since the filing of Big Rivers' 2017 IRP, the Commission has conducted semi-annual and biennial reviews of the operation of Big Rivers' Fuel Adjustment Clause ("FAC") and Environmental Surcharge ("ES") tariffs. Those reviews have resulted in no changes to the application of Big Rivers' FAC[7] or its ES.[8]

Three months prior to filing its 2017 IRP, Big Rivers made a tariff filing with the Commission in which it requested Commission approval to withdraw tariff sheets for two of its DSM and Energy Efficiency ("EE") programs while simultaneously requesting Commission approval to change one other DSM/EE program. On December 21, 2017, the Commission issued an Order denying in part and accepting in part the changes proposed by Big Rivers.[9] Ordering Paragraph No. 3 of that Order directed Big Rivers to make a tariff filing no later than June 30, 2018, detailing which other DSM/EE programs should continue.

---

[7] See: *In the Matter of: Electronic Examination of the Application of the Fuel Adjustment Clause of Big Rivers Electric Corporation from May 1, 2017 through October 31, 2017* – Case No. 2018-00023; *In the Matter of: Electronic Examination of the Application of the Fuel Adjustment Clause of Big Rivers Electric Corporation from November 1, 2017 through April 30, 2018* – Case No. 2018-00221; *In the Matter of: Electronic Examination of the Application of the Fuel Adjustment Clause of Big Rivers Electric Corporation from November 1, 2016 through October 31, 2018* – Case No. 2019-00007; *In the Matter of: An Electronic Examination of the Application of the Fuel Adjustment Clause of Big Rivers Electric Corporation from November 1, 2018 through April 30, 2019* – Case No. 2019-00231; *In the Matter of: An Electronic Examination of the Application of the Fuel Adjustment Clause of Big Rivers Electric Corporation from May 1, 2019 through October 31, 2019* – Case No. 2020-00009; and *In the Matter of: An Electronic Examination of the Application of the Fuel Adjustment Clause of Big Rivers Electric Corporation from November 1, 2019 through April 30, 2020* – Case No. 2020-00250. On September 2, 2020, Big Rivers filed its response to Commission Staff's Information Request in the Appendix to the Commission's August 19, 2020, Order in Case No. 2020-00250.

[8] See: *In the Matter of: An Examination by the Public Service Commission of the Environmental Surcharge Mechanism of Big Rivers Electric Corporation for the Six-Month Billing Period ending January 31, 2018, and the Pass Through Mechanism of its Three Member Distribution Cooperatives* – Case No. 2018-00163; *In the Matter of: An Electronic Examination by the Public Service Commission of the Environmental Surcharge Mechanism of Big Rivers Electric Corporation for the Six-Month Billing Period ending July 31, 2018, and the Pass Through Mechanism of its Three Member Distribution Cooperatives* – Case No. 2018-00338; *In the Matter of: An Electronic Examination by the Public Service Commission of the Environmental Surcharge Mechanism of Big Rivers Electric Corporation for the Six-Month Billing Period ending January 31, 2019, and the Pass Through Mechanism of its Three Member Distribution Cooperatives* – Case No. 2019-00172; and *In the Matter of: Electronic Examination by the Public Service Commission of the Environmental Surcharge Mechanism of Big Rivers Electric Corporation for the Two-Year Billing Period ending July 31, 2019, and the Pass Through Mechanism of its Three Member Distribution Cooperatives* – Case No. 2020-00144. On September 1, 2020, Big Rivers requested a decision on the record in Case No. 2020-00144.

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

On July 6, 2018, Big Rivers made a tariff filing requesting the Commission's approval to discontinue immediately seven (7) of its then existing DSM/EE programs, and to phase out the remaining programs over time.[10,11] Big Rivers also sought approval to establish an Energy Use Education DSM/EE program and a Low-Income Weatherization Support DSM/EE program. The Commission's December 12, 2018 Order approved the immediate discontinuance of the seven programs so identified; approved the phase out, by June 30, 2019, of the programs so identified; denied the Energy Use Education program; and approved the Low-Income Weatherization Support program.

Pursuant to Ordering Paragraph No. 4 of the December 2018 Order, on May 15, 2019, Big Rivers made a tariff filing with the Commission to implement the Low-Income Weatherization Support program, DSM-14 Low-Income Weatherization Support.[12] The Commission's November 13, 2019 Order approved DSM-14 as a pilot program. The Commission also directed Big Rivers to file an annual status report, beginning on March 31, 2021, with metrics showing the prior calendar year's result for the program. As of the filing of this 2020 IRP, the DSM-14 Low-Income Weatherization Support Program – Pilot is the only operational DSM/EE program listed in Big Rivers' tariff on file with the Commission.

On March 16, 2018, Big Rivers filed an application with the Commission in which it requested the Commission issue a Certificate of Public Convenience and Necessity ("CPCN") for the construction of a

[10] See: *In the Matter: DSM Filing of Big Rivers Electric Corporation on Behalf of Itself, Jackson Purchase Energy Corporation, and Meade County Rural Electric Cooperative Corporation and Request to Establish a Regulatory Liability* – Case No. 2018-00236.

[11] The DSM/EE programs to be discontinued immediately were DSM-01 - High Efficiency Lighting Replacement, DSM-02 - ENERGY STAR® Clothes Washer Replacement Incentive, DSM-03 - ENERGY STAR® Refrigerator Replacement Incentive, DSM-06 - Touchstone Energy® New Home, DSM-07 - Residential/Commercial HVAC & Refrigeration Tune-Up, DSM-09 - Commercial/Industrial General Energy Efficiency, and DSM-13 - Residential Weatherization A La Carte. The DSM/EE programs to be phased out over time were DSM-04 - Residential High Efficiency Heating, Ventilation and Air Conditioning ("HVAC"), DSM-08 - Commercial / Industrial High Efficiency Lighting Replacement Incentive, DSM-11 - Commercial High Efficiency Heating, Ventilation and Air Conditioning ("HVAC"), and DSM-12 – High Efficiency Outdoor Lighting.

[12] See: *In the Matter of: Demand-Side Management Filing of Big Rivers Electric Corporation to Implement a Low-Income Weatherization Support Program* – Case No. 2019-00193.

345 kV transmission line in Hancock County, Kentucky.[13] This transmission line was part of a larger MISO Transmission Expansion Plan project, which included a new single-circuit 345 kV transmission line between CenterPoint Energy's Duff Substation located in Dubois County, Indiana, and Big Rivers' Coleman Extra High Voltage substation located in Hancock County, Kentucky. Republic Transmission, LLC constructed the entire project and, through an Asset Purchase Agreement ("APA"), Big Rivers would purchase, own, and operate the Kentucky portion of the project. In its order dated July 12, 2018, the Commission granted the CPCN and approved the APA. On June 11, 2020, construction of the line was completed, the Kentucky portion of the line was transferred to Big Rivers, and the line was placed into service.

On May 1, 2018, Big Rivers filed an application with the Commission in Case No. 2018-00146, asking the Commission, among other things, to confirm that the Station Two units were no longer capable of normal, continuous, reliable operation for the economically competitive production of electricity and that as a result, the Station Two Contracts, except the Joint Facilities Agreement, had terminated. The Commission granted that request by Order dated August 29, 2018. In that Order, the Commission also granted Big Rivers' request to allow it to continue to operate Station Two under the terms of the Station Two Contracts, for a period ending no later than May 31, 2019, to give HMP&L time to make alternate arrangements for its power supply. By agreement between Big Rivers and HMP&L, Big Rivers operated Station Two until February 1, 2019, at which time it was retired. On October 23, 2018, the Commission approved a settlement agreement in the case among Big Rivers, Kentucky Industrial Utility Customers ("KIUC"), and the Attorney General, under which Big Rivers was authorized to establish a regulatory asset to the defer recovery of expenses related to termination of the Station Two Contracts, to implement a Station Two Depreciation Credit to pass through bill credits to its Members reflecting approximately two years' worth

[13] See: *In the Matter of: Application of Big Rivers Electric Corporation for a Certificate of Public Convenience and Necessity to Construct and Acquire a 345 KV Transmission Line in Hancock County, Kentucky* – Case No. 2018-00004.

of depreciation expense savings resulting from the Station Two Contract termination, and to implement a Times Interest Earned Ratio (“TIER”) credit mechanism to reduce regulatory assets by utilizing the savings resulting from the Station Two Contract termination that would otherwise result in a TIER above a 1.45 TIER in any year.

On July 31, 2019, Big Rivers filed an application with the Commission seeking an order enforcing the rates and service standards contained in the Station Two Contracts. Specifically, Big Rivers asked the Commission to find that that: 1) Big Rivers correctly performed the calculations contained in the Interim Accounting Summary, HMP&L is contractually obligated to pay its share of costs as reflected therein, and Big Rivers correctly determined each party’s ownership of the coal and lime reagent remaining at Station Two; 2) HMP&L has both a current and an ongoing contractual obligation to share in the costs of decommissioning Station Two; 3) HMP&L has current and ongoing contractual obligations to share in the costs of maintaining Station Two waste in Big Rives’ Green Station landfill; and 4) HMP&L is contractually obligated to allow Big Rivers to continue utilizing city-owned joint use facilities. The Commission granted HMP&L’s motion to intervene, and a formal hearing is scheduled to begin October 22, 2020.

In March 2019, Nucor Corporation, the largest steel maker in the United States, announced plans to construct a $1.3 billion plant in Brandenburg, Meade County, Kentucky. Brandenburg is the home for the main office of a Big Rivers’ Member, Meade County Rural Electric Cooperative Corporation (Meade County RECC). Since Big Rivers is the wholesale electric supplier to Meade County RECC, on September 27, 2019, and January 17, 2020, Big Rivers filed applications seeking the Commission’s review of transmission projects that would enable service to Nucor and would strengthen the transmission system in the area.[14] On January 23, 2020, and May 1, 2020, the Commission granted Big Rivers CPCNs to construct the projects outlined in its applications.

On October 18, 2019, Big Rivers and its Member Meade County RECC filed a joint application seeking the Commission's approval of agreements to provide electric service to Nucor Corporation, and of a proposed Large Industrial Customer Expansion ("LICX") tariff.[15] On August 17, 2020, the Commission issued its final order, approving the agreements and the LICX tariff.

On February 7, 2020, Big Rivers filed its 2020 Environmental Compliance Plan ("ECP") application with the Commission.[16] Among other things, Big Rivers requested that the Commission approve its 2020 ECP as filed and issue CPCNs for certain environmental compliance projects. On August 6, 2020, the Commission issued its final order approving or conditionally approving the projects in Big Rivers' 2020 ECP and the related CPCNs.

On February 28, 2020, Big Rivers filed an application with the Commission[17] requesting that the Commission allow Big Rivers to establish regulatory assets for the remaining net book value and decommissioning costs for its Coleman and Reid 1 generating units and to discontinue deferring DSM savings in a regulatory liability, authorize Big Rivers to recover those and other regulatory assets through existing rates after the utilization of 80% of its equity headroom and the existing DSM regulatory liability

[14] See: *In the Matter of: Application of Big Rivers Electric Corporation for a Certificate of Public Convenience and Necessity to Construct a 161 KV Transmission Line, and a 345 KV Transmission Line in Meade County, Kentucky* – Case No. 2019-00270.

[15] *See: In the Matter of: Electronic Joint Application of Big Rivers Electric Corporation and Meade County Rural Electric Cooperative Corporation for (1) Approval of Contracts for Electric Service with Nucor Corporation; and (2) Approval of Tariff* – Case No. 2019-00365.

[16] See: *In the Matter of: Electronic Application of Big Rivers Electric Corporation for Approval of its 2020 Environmental Compliance Plan, Authority to Recover Costs through a Revised Environmental Surcharge and Tariff, the Issuance of a Certificate of Public Convenience and Necessity for Certain Projects, and Appropriate Accounting and Other Relief* – Case No. 2019-00435.

[17] See: *In the Matter of: Electronic Application of Big Rivers Electric Corporation for Approval to Modify its MRSM Tariff, Cease Deferring Depreciation Expenses, Establish Regulatory Assets, Amortize Regulatory Assets, and Other Appropriate Relief* – Case No. 2020-00064.

to reduce those regulatory assets, approve Big Rivers' proposed changes to its Member Rate Stability Mechanism ("MRSM") tariff, and permit Big Rivers' to cease deferring certain depreciation expenses. The MRSM tariff changes would primarily allow Big Rivers to return funds to its Members depending on the level of its adjusted net margins versus those margins calculated using a 1.30 TIER. The deferred depreciation expenses arose from Big Rivers' two prior general rate cases.[18] On June 25, 2020, the Commission entered a final order, which granted Big Rivers' requests to establish regulatory assets for the remaining net book value of Coleman Station and Reid Station Unit 1 at retirement and for the costs to decommission those units, to cease deferring DSM savings in a regulatory liability account, to utilize the existing DSM regulatory liability and 80% of equity headroom to reduce certain regulatory assets, and to recover the amounts deferred in those regulatory assets through amortization. The Commission ordered modifications of the proposed changes to the TIER Credit in the MRSM tariff. Under the new TIER Credit, as modified, in years in which Big Rivers earns in excess of a 1.30 TIER, 40% of the excess margins will be returned to Members over the following year through a Monthly Bill credit, and the remaining 60% of the excess margins will be deferred in a regulatory liability account to be utilized in a year in which Big Rivers does not achieve a 1.30 TIER or to further decrease the balance of certain regulatory assets with Commission approval.

On April 28, 2020, Big Rivers filed with the Commission an electronic application for approval to issue evidences of indebtedness.[19] Specifically, Big Rivers' application requested the Commission's approval of a new $150,000,000 Secured Credit Agreement to replace its expiring, existing $100,000,000 Secured

---

[18] See: *In the Matter of: Application of Big Rivers Electric Corporation for an Adjustment of Rates* – Case No. 2012-00535 (Application filed January 15, 2013); See: *In the Matter of: Application of Big Rivers Electric Corporation for a General Adjustment in Rates Supported by Fully Forecasted Test Period* – Case No. 2013-00199 (Application filed June 28, 2013).

[19] *See: In the Matter of: Electronic Application of Big Rivers Corporation for Approval to Issue Evidences of Indebtedness,* Case No. 2020-00129

Credit Agreement. On May 8, 2020, the Commission issued an Order authorizing Big Rivers to enter into the 2020 Secured Credit Agreement.

On June 17, 2020, Big Rivers filed with the Commission an electronic application for approval to issue certain evidences of indebtedness.[20] Specifically, Big Rivers' application requested the Commission's approval of evidences of indebtedness in connection with the issuance by the County of Ohio, Kentucky, of Pollution Control Refunding Revenue Bonds, Series 2020, in the aggregate principal amount of $83,300,000. The new bonds would replace similar bonds issued into 2010, which were called and redeemed in July 2020. On August 13, 2020, the Commission issued a final order granting approval to issue the requested evidences of indebtedness.

On June 24, 2020, Big Rivers filed with the Commission an electronic application for approval of three solar power purchase agreements: (1) a twenty-year contract with Henderson Solar, LLC for the purchase of the entire output of a 160 MW solar generation facility to be built in Henderson County and Webster County, Kentucky; (2) a twenty-year contract with Meade County Solar, LLC for the purchase of the entire output of a 40 MW solar generation facility to be built in Meade County, Kentucky; and (3) a twenty-year contract with McCracken County Solar, LLC for the purchase of the entire output of 60 MW solar generation facility to be built in McCracken County, Kentucky.[21] As of filing of this Integrated Resource Plan, this proceeding was pending.

2.11 Coronavirus Pandemic Update

The COVID-19 pandemic has exploded since cases were first reported in China in December 2019. As of mid- September 2020, more than 31 million cases of COVID-19 have been reported globally, including more than 960,000 deaths. The United States has reported more than 6.8 million cases and 199,000 deaths.

[20] *See: In the Matter of: Electronic Application of Big Rivers Electric Corporation for Approval to Issue Evidences of Indebtedness*, Case No. 2020-00153.

[21] *See: In the Matter of: Electronic Application of Big Rivers Electric Corporation for Approval of Solar Contracts*, Case No. 2020-00183.

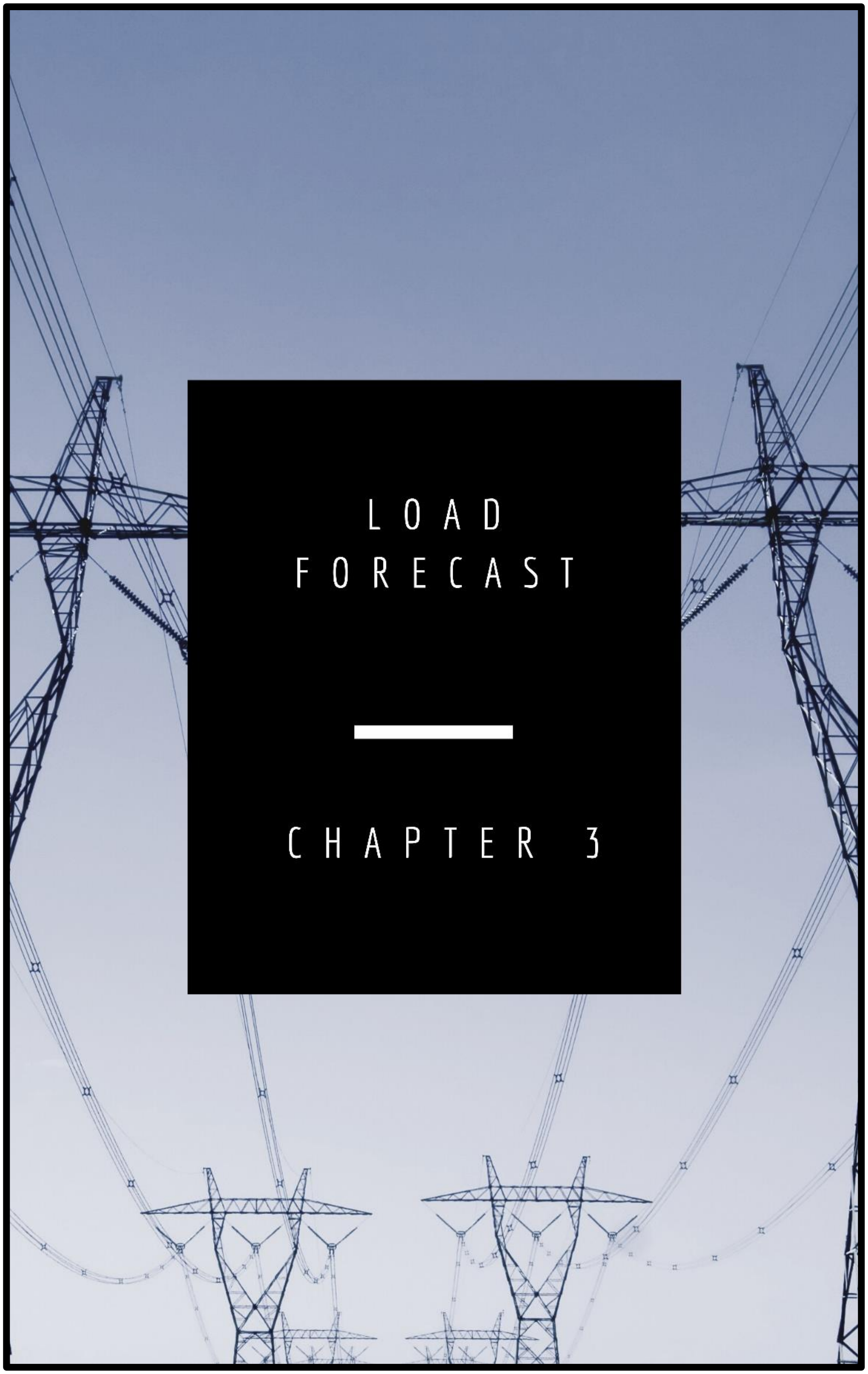
Big Rivers has been aggressive in its approach to ensuring the health and safety of its employees. The steps taken to ensure employee wellbeing include but are not limited to:

- Suspending all non-essential travel;
- Requiring all employees whose job will allow, to work from home;
- Limiting access to its facilities to only those who have an essential need to access them;
- For those employees who cannot work remotely, Big Rivers put together work reporting expectations to guide behavior to avoid the potential spread of COVID 19 virus;
- Mandatory temperature checks of all employees and contractors who are continuing to report to local facilities as they come on site to determine if they have the potential to spread illness;
- Enhanced cleaning and disinfection of all facilities; and
- Monitoring employee travel outside the Commonwealth.

Big Rivers considers these measures, among others, to be prudent and to have contributed to the continued health and safety of its greatest strength—the employees.

Big Rivers requested that its load forecast consultant, Clearspring, review the COVID impact to load by analyzing the weather-normalized energy usage for the Residential and General Commercial and Industrial classes for each Member-Owner and then aggregating the data up to the Big Rivers level for the period January through April 2020. Clearspring's analysis indicated possible COVID Residential sales impact of +0.9% in March 2020 and +5.8% in April 2020. Internal pandemic-related analysis shows April through June Rural load has been marginally lower with a 5.5% demand reduction and 1.3% energy reduction. General Commercial and Industrial sales, however showed no obvious COVID impact in March 2020, and an April 2020 decline of -18.2%. Direct-serve load was not analyzed by Clearspring, but internal pandemic-related analysis showed a 3.8% reduction in Large Industrial demand and 19.8% reduction in energy MWH April through June, 2020.

Big Rivers' low-income weatherization program was launched in early 2020 in coordination with the regional Community Action Agencies ("CAA"). The COVID outbreak in Kentucky disrupted work on the program as weatherization work in rural counties was slow to develop. Currently only one application for weatherization has been received. Big Rivers will continue to work with the Kentucky Housing Corp. and local CAA's to initiate weatherization projects as the COVID restrictions wane.


LOAD
FORECAST
CHAPTER 3

LOAD FORECAST

The 2020 IRP is based on Big Rivers' 2020 Load Forecast base case prepared by Clearspring, who created models for each of Big Rivers' three distribution systems. In addition to the base case, sensitivities examining weather and economic extremes were also prepared. The long-term load forecast process is repeated every few years; however, Big Rivers also updates its forecast as needed for planning purposes. The 2020 Load Forecast was completed in July 2020, and adopted by Big Rivers' Board of Directors in August 2020. The most recent historical year included in the 2020 Load Forecast is 2019, and 2019 is the base forecast year for both that load forecast and this IRP. The forecast horizon covers years 2020 through 2039.

3.1 Total System Load

The total system includes Member load and Non-Member Sales. Member requirements consist of the Rural system requirements, Direct Serve energy, and transmission losses. The Rural System includes retail classes: Residential, General Commercial and Industrial ("GCI"), Large Commercial and Industrial ("LCI"), Irrigation, and Street & Highway. The Direct Serve class contains consumers that are directly served from the transmission system. Non-Member Sales under contract to Big Rivers includes sales to Owensboro Municipal Utilities ("OMU"), Kentucky Municipal Energy Agency ("KYMEA"), several Nebraska Entities in SPP, and Short Term Bilateral Capacity sold into MISO. Class results are discussed in later sections of this chapter, and in Appendix A Long–Term Load Forecast. Transmission losses were 2.51% in 2019 and are forecasted at 2.50% beginning in February 2020 for the remainder of the forecast.

Table 3.1 below shows each component of the total system energy requirements, and Table 3.2 shows Total System Non-Coincident Peak ("NCP") forecast.

Total System Energy Requirements are forecasted at 4,853 GWH in 2020, then increase through 2022 with the addition of significant Direct Serve load and Non-Member load. Declines are seen between 2027 and

2029 with the expiration of Non-Member contracts, with slow growth seen from that point through 2039. Compound Annual Growth Rates for the Total System are 13.51% for 2019-2024, and 1.66% through 2039. Shaded years indicate historical values.

Table 3.1

Big Rivers Total System Energy Summary

Big Rivers Total System Energy Summary (MWh)					
Year	Total Rural Requirements	Direct Serve	Transmission Losses	Non-Member Requirements	**Total System Energy Requirements**
2015	2,325,204	946,873	66,970		**3,339,047**
2016	2,330,037	915,310	73,420		**3,318,766**
2017	2,209,837	919,895	77,928		**3,207,660**
2018	2,366,988	953,822	86,858	75,404	**3,483,072**
2019	2,271,772	957,994	83,431	578,276	**3,891,473**
2020	2,313,997	987,552	84,688	1,466,620	**4,852,857**
2021	2,342,004	987,552	85,373	1,750,832	**5,165,761**
2022	2,345,137	2,038,752	112,407	1,784,986	**6,281,282**
2023	2,357,028	2,038,752	112,712	1,713,663	**6,222,155**
2024	2,366,988	2,041,632	113,042	1,722,453	**6,244,114**
2025	2,376,885	2,038,752	113,221	1,726,630	**6,255,489**
2026	2,386,410	2,038,752	113,466	1,732,865	**6,271,493**
2027	2,388,504	2,038,752	113,519	613,200	**5,153,976**
2028	2,394,976	2,041,632	113,759	613,200	**5,163,567**
2029	2,400,628	2,038,752	113,830	255,500	**4,808,710**
2030	2,403,821	2,038,752	113,912		**4,556,486**
2031	2,409,248	2,038,752	114,051		**4,562,051**
2032	2,419,240	2,038,752	114,307		**4,572,299**
2033	2,424,117	2,038,752	114,433		**4,577,302**
2034	2,427,766	2,038,752	114,526		**4,581,044**
2035	2,431,849	2,038,752	114,631		**4,585,232**
2036	2,435,950	2,038,752	114,736		**4,589,439**
2037	2,440,157	2,038,752	114,844		**4,593,753**
2038	2,444,021	2,038,752	114,943		**4,597,716**
2039	2,448,197	2,038,752	115,050		**4,601,999**
Average Annual Growth Rates					
Previous 10 Years	0.15%	-2.27%	11.89%	-	**1.15%**
Previous 5 Years	-1.22%	-0.17%	8.91%	-	**2.52%**
Next 5 Years	0.82%	16.34%	6.26%	-	**9.92%**
Next 10 Years	0.55%	7.85%	3.16%	-	**2.14%**
Next 20 Years	0.37%	3.85%	1.62%	-	**0.84%**

Total System Non-Coincident Peak is forecasted at 1,048 MW in 2020, then increases through 2022 to 1,254 MW with the addition of significant Direct Serve load and Non-Member load. Declines are seen between 2027 and 2029 with the expiration of Non-Member contracts, with slow growth from that point through 2039. Non-Member sales are Capacity sales with or without associated energy sales (spot energy sales not included) and are discussed further in Section 3.3.8.

Table 3.2

Big Rivers Total System Non Coincident Peak (kW) Forecast[22]

Total System NCP (kW)			
Year	Total Annual CP	Non-Member Sales	Total NCP
2015	698,949	513,000	1,211,949
2016	621,295	450,000	1,071,295
2017	634,184	487,000	1,121,184
2018	668,654	314,200	982,854
2019	624,821	376,200	1,001,021
2020	626,715	421,500	1,048,215
2021	632,122	421,900	1,054,022
2022	832,412	421,500	1,253,912
2023	834,546	305,900	1,140,446
2024	836,327	210,300	1,046,627
2025	838,132	310,700	1,148,832
2026	839,920	311,100	1,151,020
2027	840,180	100,000	940,180
2028	841,438	100,000	941,438
2029	842,528		842,528
2030	843,125		843,125
2031	844,223		844,223
2032	846,330		846,330
2033	847,329		847,329
2034	848,086		848,086
2035	848,929		848,929
2036	849,782		849,782
2037	850,659		850,659
2038	851,459		851,459
2039	852,319		852,319

[22] Total Annual CP in Table 3.2 includes Losses.

3.2 Member Load

Member Energy Requirements consist of the Rural system requirements, Direct Serve energy, and transmission losses. Big Rivers' Member Energy Requirements are forecasted at 3,386 GWH in 2020, increasing to 4,602 GWH by 2039, with a Compound Average Growth Rate of 6.39% over 2019-2024 fueled by the addition of [redacted], and 1.65% over the next 20 years.

Table 3.3

Big Rivers Total Member Energy Summary (MWH)

Year	Total Rural Requirements	Direct Serve	Transmission Losses	**Total System Energy Requirements**
2015	2,325,204	946,873	66,970	**3,339,047**
2016	2,330,037	915,310	73,420	**3,318,766**
2017	2,209,837	919,895	77,928	**3,207,660**
2018	2,366,988	953,822	86,858	**3,407,668**
2019	2,271,772	957,994	83,431	**3,317,632**
2020	2,313,997	987,552	84,688	**3,386,237**
2021	2,342,004	987,552	85,373	**3,414,929**
2022	2,345,137	2,038,752	112,407	**4,496,296**
2023	2,357,028	2,038,752	112,712	**4,508,492**
2024	2,366,988	2,041,632	113,042	**4,521,662**
2025	2,376,885	2,038,752	113,221	**4,528,859**
2026	2,386,410	2,038,752	113,466	**4,538,628**
2027	2,388,504	2,038,752	113,519	**4,540,776**
2028	2,394,976	2,041,632	113,759	**4,550,367**
2029	2,400,628	2,038,752	113,830	**4,553,210**
2030	2,403,821	2,038,752	113,912	**4,556,486**
2031	2,409,248	2,038,752	114,051	**4,562,051**
2032	2,419,240	2,038,752	114,307	**4,572,299**
2033	2,424,117	2,038,752	114,433	**4,577,302**
2034	2,427,766	2,038,752	114,526	**4,581,044**
2035	2,431,849	2,038,752	114,631	**4,585,232**
2036	2,435,950	2,038,752	114,736	**4,589,439**
2037	2,440,157	2,038,752	114,844	**4,593,753**
2038	2,444,021	2,038,752	114,943	**4,597,716**
2039	2,448,197	2,038,752	115,050	**4,601,999**
Average Annual Growth Rates				
Previous 10 Years	0.15%	-2.27%	11.89%	**-0.45%**
Previous 5 Years	-1.22%	-0.17%	8.91%	**-0.70%**
Next 5 Years	0.82%	16.34%	6.26%	**6.39%**
Next 10 Years	0.55%	7.85%	3.16%	**3.22%**
Next 20 Years	0.37%	3.85%	1.62%	**1.65%**

Big River's Member Coincident Peak including losses is forecasted at 627 MW in 2020, then increases significantly in 2022 with the addition of Nucor, and continues to rise to 852 MW by 2039.

Table 3.4

Big Rivers Member Coincident Peak

Big Rivers Coincident Peak (kW)						
Year	Rural Summer CP	Rural Winter CP	Rural Annual CP	Direct Serve Annual CP	Transmission Losses	**Total Annual CP**
2015	504,990	566,553	566,553	121,143	11,253	**698,949**
2016	486,690	484,768	486,690	120,750	13,855	**621,295**
2017	504,269	474,971	504,269	114,378	15,538	**634,184**
2018	502,549	556,742	556,742	95,530	16,382	**668,654**
2019	480,171	490,895	490,895	117,931	15,995	**624,821**
2020	483,946	484,817	483,946	127,101	15,668	**626,715**
2021	489,218	489,893	489,218	127,101	15,803	**632,122**
2022	489,558	491,914	489,558	322,043	20,810	**832,412**
2023	491,639	494,177	491,639	322,043	20,864	**834,546**
2024	493,376	495,970	493,376	322,043	20,908	**836,327**
2025	495,136	497,935	495,136	322,043	20,953	**838,132**
2026	496,879	499,794	496,879	322,043	20,998	**839,920**
2027	497,133	499,957	497,133	322,043	21,005	**840,180**
2028	498,359	500,820	498,359	322,043	21,036	**841,438**
2029	499,422	501,685	499,422	322,043	21,063	**842,528**
2030	500,004	501,900	500,004	322,043	21,078	**843,125**
2031	501,074	502,687	501,074	322,043	21,106	**844,223**
2032	503,128	504,331	503,128	322,043	21,158	**846,330**
2033	504,103	505,032	504,103	322,043	21,183	**847,329**
2034	504,841	505,432	504,841	322,043	21,202	**848,086**
2035	505,663	506,010	505,663	322,043	21,223	**848,929**
2036	506,495	506,574	506,495	322,043	21,245	**849,782**
2037	507,349	507,238	507,349	322,043	21,266	**850,659**
2038	508,129	507,810	508,129	322,043	21,286	**851,459**
2039	508,968	508,470	508,968	322,043	21,308	**852,319**
Average Annual Growth Rates						
Previous 10 Years	-0.34%	-1.32%	-1.32%	0.98%	11.50%	**-0.74%**
Previous 5 Years	-0.04%	-4.44%	-4.44%	-1.03%	9.24%	**-3.60%**
Next 5 Years	0.54%	0.21%	0.10%	22.25%	5.50%	**6.00%**
Next 10 Years	0.39%	0.22%	0.17%	10.57%	2.79%	**3.03%**
Next 20 Years	0.29%	0.18%	0.18%	5.15%	1.44%	**1.56%**

3.3 Customer Class Forecasts

This section presents historical and projected number of customers and energy sales by Member retail classifications.

3.3.1 Residential Class

The Residential sales forecast is comprised of a forecast for Residential use per consumer and a forecast of the number of Residential retail members. The product of the two disaggregated forecasts equals the Residential sales forecast.

Number of Consumers is forecasted to increase from 100,314 in 2020 to 101,718 in 2039. Residential consumers are projected to increase over the next five years at an average annual rate of 0.5% driven mostly by increased Commercial and Industrial ("C&I") activity creating a demand for new housing in the service territory. After the first five years of the forecast the housing growth is expected to slow and decline slightly in the later years of the forecast.

Use per consumer values are projected to fall slightly through the first five years of the forecast at an average annual rate of –0.01% (minus 0.01%). The reduction is due to continuing efficiency gains in appliance stocks as older, less efficient, appliances are replaced with more efficient ones. During the last ten years of the forecast additional efficiency gains are slower and the effect on use per consumer is balanced by the continuing decreasing real cost of electricity resulting in flat growth in the final years of the forecast period. The result is a fairly flat energy sales forecast at around 1,423 GWH annually, with a compound annual growth rate over the next 20 years of only 0.06%.

Table 3.5

Residential Consumers and Energy Sales (MWH)

Year	Number of Consumers	% Change per Year in Consumers	Use Per Consumer (kWh)	% Change per Year in Use Per Consumer	Energy Sales (MWh)	% Change per Year in Energy Sales
2015	97,971		14,783		1,448,343	
2016	98,583	0.62%	14,565	-1.48%	1,435,874	-0.86%
2017	99,451	0.88%	13,553	-6.95%	1,347,867	-6.13%
2018	99,724	0.27%	14,955	10.34%	1,491,338	10.64%
2019	99,891	0.17%	14,083	-5.83%	1,406,754	-5.67%
2020	100,314	0.42%	14,195	0.79%	1,423,914	1.22%
2021	101,044	0.73%	14,170	-0.17%	1,431,787	0.55%
2022	101,667	0.62%	14,153	-0.12%	1,438,903	0.50%
2023	102,180	0.50%	14,114	-0.28%	1,442,148	0.23%
2024	102,616	0.43%	14,073	-0.29%	1,444,122	0.14%
2025	102,990	0.36%	14,047	-0.18%	1,446,702	0.18%
2026	103,193	0.20%	14,040	-0.05%	1,448,868	0.15%
2027	103,256	0.06%	14,006	-0.25%	1,446,170	-0.19%
2028	103,282	0.03%	13,996	-0.07%	1,445,528	-0.04%
2029	103,263	-0.02%	13,985	-0.08%	1,444,108	-0.10%
2030	103,200	-0.06%	13,963	-0.16%	1,440,938	-0.22%
2031	103,101	-0.10%	13,955	-0.05%	1,438,824	-0.15%
2032	102,970	-0.13%	13,977	0.16%	1,439,236	0.03%
2033	102,815	-0.15%	13,978	0.01%	1,437,166	-0.14%
2034	102,644	-0.17%	13,975	-0.02%	1,434,434	-0.19%
2035	102,460	-0.18%	13,976	0.01%	1,431,962	-0.17%
2036	102,269	-0.19%	13,979	0.02%	1,429,572	-0.17%
2037	102,079	-0.19%	13,985	0.04%	1,427,550	-0.14%
2038	101,894	-0.18%	13,989	0.03%	1,425,414	-0.15%
2039	101,718	-0.17%	13,994	0.04%	1,423,491	-0.13%
Average Annual Growth Rates						
Previous 10 Years	0.29%		-0.43%		-0.14%	
Previous 5 Years	0.41%		-2.09%		-1.69%	
Next 5 Years	0.54%		-0.01%		0.53%	
Next 10 Years	0.33%		-0.07%		0.26%	
Next 20 Years	0.09%		-0.03%		0.06%	

3.3.2 General Commercial & Industrial Class

The GCI class is defined as the total commercial and industrial loads minus the Direct Serve and LCI loads. Given the importance of the GCI class, Clearspring used econometric modeling to project both the GCI consumer counts and the GCI use per consumer for the Big Rivers distribution Members.

GCI sales are projected to increase at an average rate of 1.11% per year from 2019 through 2039. Growth in the number of customers, projected at 1.12% per year, and consumption per customer is projected to increase by 0.01% per year from 2019-2039 due to increases in appliance efficiencies.

Table 3.6

General C & I Class

Year	Number of Consumers	% Change per Year in Consumers	Use Per Consumer (kWh)	% Change per Year in Use Per Consumer	Energy Sales (MWh)	% Change per Year in Energy Sales
2015	16,805		36,121		607,011	
2016	17,110	1.81%	35,949	-0.48%	615,083	1.33%
2017	17,290	1.05%	34,721	-3.42%	600,334	-2.40%
2018	17,483	1.12%	35,398	1.95%	618,866	3.09%
2019	17,732	1.42%	34,050	-3.81%	603,764	-2.44%
2020	18,188	2.57%	34,138	0.26%	620,892	2.84%
2021	18,406	1.20%	34,237	0.29%	630,164	1.49%
2022	18,641	1.28%	34,283	0.14%	639,079	1.41%
2023	18,872	1.24%	34,293	0.03%	647,167	1.27%
2024	19,104	1.23%	34,270	-0.07%	654,681	1.16%
2025	19,314	1.10%	34,251	-0.05%	661,534	1.05%
2026	19,524	1.09%	34,238	-0.04%	668,455	1.05%
2027	19,734	1.08%	34,110	-0.37%	673,141	0.70%
2028	19,942	1.06%	34,096	-0.04%	679,960	1.01%
2029	20,150	1.04%	34,082	-0.04%	686,774	1.00%
2030	20,357	1.03%	34,041	-0.12%	692,988	0.90%
2031	20,562	1.01%	34,056	0.04%	700,284	1.05%
2032	20,765	0.99%	34,164	0.32%	709,422	1.30%
2033	20,966	0.97%	34,157	-0.02%	716,148	0.95%
2034	21,166	0.95%	34,128	-0.08%	722,361	0.87%
2035	21,365	0.94%	34,109	-0.06%	728,729	0.88%
2036	21,562	0.92%	34,089	-0.06%	735,033	0.87%
2037	21,759	0.91%	34,059	-0.09%	741,068	0.82%
2038	21,954	0.90%	34,020	-0.11%	746,889	0.79%
2039	22,149	0.89%	33,988	-0.10%	752,795	0.79%
Average Annual Growth Rates						
Previous 10 Years	1.88%		-1.26%		0.59%	
Previous 5 Years	1.81%		-1.97%		-0.20%	
Next 5 Years	1.50%		0.13%		1.63%	
Next 10 Years	1.29%		0.01%		1.30%	
Next 20 Years	1.12%		-0.01%		1.11%	

3.3.3 Large Commercial & Industrial Class

The Large C&I class consists of the largest commercial and industrial customers at each distribution Member that do not qualify as Direct Serve consumers. The sales forecasts are based on staff knowledge and judgement with input from each cooperative. Projected growth rates for LCI consumers declines through 2039 at 0.07%, use per consumer declines an average of .12%, and sales declines an average of 0.06%. While the consumer count appears to be flat at 31, the historical value is an average of 12 monthly reports, and is a fractional value of 30.58.

Table 3.7

Large C & I Class

Year	Number of Consumers	% Change per Year in Consumers	Use Per Consumer (MWh)	% Change per Year in Use Per Consumer	Energy Sales (MWh)	% Change per Year in Energy Sales
2015	33		4,778		157,680	
2016	32	-3.28%	4,982	4.26%	158,999	0.84%
2017	29	-10.18%	5,143	3.24%	147,433	-7.27%
2018	29	1.16%	5,266	2.39%	152,708	3.58%
2019	31	5.46%	5,203	-1.20%	159,111	4.19%
2020	32	3.81%	5,064	-2.67%	160,778	1.05%
2021	32	0.79%	5,323	5.12%	170,333	5.94%
2022	31	-3.13%	5,075	-4.67%	157,311	-7.64%
2023	31	0.00%	5,075	0.00%	157,311	0.00%
2024	31	0.00%	5,075	0.00%	157,311	0.00%
2025	31	0.00%	5,075	0.00%	157,311	0.00%
2026	31	0.00%	5,075	0.00%	157,311	0.00%
2027	31	0.00%	5,075	0.00%	157,311	0.00%
2028	31	0.00%	5,075	0.00%	157,311	0.00%
2029	31	0.00%	5,075	0.00%	157,311	0.00%
2030	31	0.00%	5,075	0.00%	157,311	0.00%
2031	31	0.00%	5,075	0.00%	157,311	0.00%
2032	31	0.00%	5,075	0.00%	157,311	0.00%
2033	31	0.00%	5,075	0.00%	157,311	0.00%
2034	31	0.00%	5,075	0.00%	157,311	0.00%
2035	31	0.00%	5,075	0.00%	157,311	0.00%
2036	31	0.00%	5,075	0.00%	157,311	0.00%
2037	31	0.00%	5,075	0.00%	157,311	0.00%
2038	31	0.00%	5,075	0.00%	157,311	0.00%
2039	31	0.00%	5,075	0.00%	157,311	0.00%
Average Annual Growth Rates						
Previous 10 Years	5.49%		-2.79%		2.55%	
Previous 5 Years	-0.32%		0.86%		0.53%	
Next 5 Years	0.27%		-0.50%		-0.23%	
Next 10 Years	0.14%		-0.25%		-0.11%	
Next 20 Years	0.07%		-0.12%		-0.06%	

3.3.4 Direct Serve Class

The Direct Serve class contains consumers that are directly served from the transmission system. The sales forecasts are based on manager and staff knowledge and input from each cooperative. Big Rivers' Direct Serve class contained twenty-one (21) consumers in 2019. With the Commission's August 17, 2020, approval of the Nucor contracts in Case No. 2019-00365, the Direct Serve class will add one additional consumer with significant load. Projected growth rates for number of consumers increases 0.23% by 2039, use per consumer increases 3.61% and energy sales increases 3.85%.

Table 3.8

Big Rivers Direct Serve Class

Year	Number of Consumers	% Change per Year in Consumers	Use Per Consumer (MWh)	% Change per Year in Use Per Consumer	Energy Sales (MWh)	% Change per Year in Energy Sales
2015	20		47,344		946,873	
2016	20	0.00%	45,765	-3.33%	915,310	-3.33%
2017	20	0.00%	45,995	0.50%	919,895	0.50%
2018	21	4.17%	45,783	-0.46%	953,822	3.69%
2019	21	0.80%	45,619	-0.36%	957,994	0.44%
2020	21	0.00%	47,026	3.09%	987,552	3.09%
2021	21	0.00%	47,026	0.00%	987,552	0.00%
2022	22	4.76%	92,671	97.06%	2,038,752	106.45%
2023	22	0.00%	92,671	0.00%	2,038,752	0.00%
2024	22	0.00%	92,801	0.14%	2,041,632	0.14%
2025	22	0.00%	92,671	-0.14%	2,038,752	-0.14%
2026	22	0.00%	92,671	0.00%	2,038,752	0.00%
2027	22	0.00%	92,671	0.00%	2,038,752	0.00%
2028	22	0.00%	92,801	0.14%	2,041,632	0.14%
2029	22	0.00%	92,671	-0.14%	2,038,752	-0.14%
2030	22	0.00%	92,671	0.00%	2,038,752	0.00%
2031	22	0.00%	92,671	0.00%	2,038,752	0.00%
2032	22	0.00%	92,671	0.00%	2,038,752	0.00%
2033	22	0.00%	92,671	0.00%	2,038,752	0.00%
2034	22	0.00%	92,671	0.00%	2,038,752	0.00%
2035	22	0.00%	92,671	0.00%	2,038,752	0.00%
2036	22	0.00%	92,671	0.00%	2,038,752	0.00%
2037	22	0.00%	92,671	0.00%	2,038,752	0.00%
2038	22	0.00%	92,671	0.00%	2,038,752	0.00%
2039	22	0.00%	92,671	0.00%	2,038,752	0.00%
Average Annual Growth Rates						
Previous 10 Years	0.49%		-2.74%		-2.27%	
Previous 5 Years	0.98%		-1.14%		-0.17%	
Next 5 Years	0.93%		15.26%		16.34%	
Next 10 Years	0.47%		7.34%		7.85%	
Next 20 Years	0.23%		3.61%		3.85%	

3.3.5 Street and Highway Class

Given the small proportion of the Street and Highway class in total sales, the forecast for this class was calculated manually rather than through econometric modeling. The most recent consumer values were held constant through the forecast and the prior twelve months of usage was used to derive monthly energy forecasts for the forecast period.

Table 3.9

Street & Highway Class

Year	Number of Consumers	% Change per Year in Consumers	Use Per Consumer (kWh)	% Change per Year in Use Per Consumer	Energy Sales (MWh)	% Change per Year in Energy Sales
2015	100		34,234		3,429	
2016	103	3.16%	32,049	-6.38%	3,312	-3.43%
2017	104	0.73%	31,223	-2.58%	3,250	-1.87%
2018	107	3.20%	28,965	-7.23%	3,111	-4.26%
2019	106	-1.01%	28,914	-0.18%	3,074	-1.18%
2020	108	1.57%	28,892	-0.07%	3,120	1.49%
2021	108	0.00%	28,892	0.00%	3,120	0.00%
2022	108	0.00%	28,892	0.00%	3,120	0.00%
2023	108	0.00%	28,892	0.00%	3,120	0.00%
2024	108	0.00%	28,892	0.00%	3,120	0.00%
2025	108	0.00%	28,892	0.00%	3,120	0.00%
2026	108	0.00%	28,892	0.00%	3,120	0.00%
2027	108	0.00%	28,892	0.00%	3,120	0.00%
2028	108	0.00%	28,892	0.00%	3,120	0.00%
2029	108	0.00%	28,892	0.00%	3,120	0.00%
2030	108	0.00%	28,892	0.00%	3,120	0.00%
2031	108	0.00%	28,892	0.00%	3,120	0.00%
2032	108	0.00%	28,892	0.00%	3,120	0.00%
2033	108	0.00%	28,892	0.00%	3,120	0.00%
2034	108	0.00%	28,892	0.00%	3,120	0.00%
2035	108	0.00%	28,892	0.00%	3,120	0.00%
2036	108	0.00%	28,892	0.00%	3,120	0.00%
2037	108	0.00%	28,892	0.00%	3,120	0.00%
2038	108	0.00%	28,892	0.00%	3,120	0.00%
2039	108	0.00%	28,892	0.00%	3,120	0.00%
Average Annual Growth Rates						
Previous 10 Years	2.24%		-2.73%		-0.54%	
Previous 5 Years	3.16%		-5.34%		-2.34%	
Next 5 Years	0.31%		-0.01%		0.30%	
Next 10 Years	0.16%		-0.01%		0.15%	
Next 20 Years	0.08%		0.00%		0.07%	

3.3.6 Irrigation Class

Given the small proportion of the Irrigation class in total sales, the forecast for this class was calculated manually rather than through econometric modeling. The most recent consumer values were held constant through the forecast and the prior twelve months of usage was used to derive monthly energy forecasts for the forecast period.

Table 3.10

Irrigation Class

Year	Number of Consumers	% Change per Year in Consumers	Use Per Consumer (kWh)	% Change per Year in Use Per Consumer	Energy Sales (MWh)	% Change per Year in Energy Sales
2015	4		15,428		62	
2016	4	0.00%	12,760	-17.29%	51	-17.29%
2017	4	0.00%	25,437	99.35%	102	99.35%
2018	5	12.50%	15,618	-38.60%	70	-30.93%
2019	5	11.11%	21,652	38.63%	108	54.04%
2020	5	0.00%	21,652	0.00%	108	0.00%
2021	5	0.00%	21,652	0.00%	108	0.00%
2022	5	0.00%	21,652	0.00%	108	0.00%
2023	5	0.00%	21,652	0.00%	108	0.00%
2024	5	0.00%	21,652	0.00%	108	0.00%
2025	5	0.00%	21,652	0.00%	108	0.00%
2026	5	0.00%	21,652	0.00%	108	0.00%
2027	5	0.00%	21,652	0.00%	108	0.00%
2028	5	0.00%	21,652	0.00%	108	0.00%
2029	5	0.00%	21,652	0.00%	108	0.00%
2030	5	0.00%	21,652	0.00%	108	0.00%
2031	5	0.00%	21,652	0.00%	108	0.00%
2032	5	0.00%	21,652	0.00%	108	0.00%
2033	5	0.00%	21,652	0.00%	108	0.00%
2034	5	0.00%	21,652	0.00%	108	0.00%
2035	5	0.00%	21,652	0.00%	108	0.00%
2036	5	0.00%	21,652	0.00%	108	0.00%
2037	5	0.00%	21,652	0.00%	108	0.00%
2038	5	0.00%	21,652	0.00%	108	0.00%
2039	5	0.00%	21,652	0.00%	108	0.00%
Average Annual Growth Rates						
Previous 10 Years	-5.17%		-7.62%		-12.39%	
Previous 5 Years	4.56%		-8.69%		-4.52%	
Next 5 Years	0.00%		0.00%		0.00%	
Next 10 Years	0.00%		0.00%		0.00%	
Next 20 Years	0.00%		0.00%		0.00%	

3.3.7 Rural System Energy Summary

The total Rural energy requirements are calculated by taking the sales forecasts for each class detailed in the previous sections of this report, other than the Direct Serve class, and adding distribution losses and own use. Distribution losses are estimated using a three-year historical average. This average is computed after any Direct Serve loads are removed since these loads are no distribution loss loads.

Total Rural Energy requirements grow over the next 5 years at a compound annual growth rate of 0.82% and over the next 20 at 0.37%.

Table 3.11

Rural Class Energy Summary

Year	Residential Energy Sales	General C&I Energy Sales	Large C&I Energy Sales	Irrigation Energy Sales	Street & Highway Energy Sales	Distribution Losses	Own Use	**Total Rural Energy Requirements**
2015	1,448,343	607,011	157,680	62	3,429	107,766	913	**2,325,204**
2016	1,435,874	615,083	158,999	51	3,312	115,265	1,454	**2,330,037**
2017	1,347,867	600,334	147,433	102	3,250	107,908	2,944	**2,209,837**
2018	1,491,338	618,866	152,708	70	3,111	97,684	3,211	**2,366,988**
2019	1,406,754	603,764	159,111	108	3,074	95,907	3,053	**2,271,772**
2020	1,423,914	620,892	160,778	108	3,120	102,077	3,108	**2,313,997**
2021	1,431,787	630,164	170,333	108	3,120	103,358	3,132	**2,342,004**
2022	1,438,903	639,079	157,311	108	3,120	103,460	3,154	**2,345,137**
2023	1,442,148	647,167	157,311	108	3,120	104,000	3,173	**2,357,028**
2024	1,444,122	654,681	157,311	108	3,120	104,455	3,190	**2,366,988**
2025	1,446,702	661,534	157,311	108	3,120	104,904	3,205	**2,376,885**
2026	1,448,868	668,455	157,311	108	3,120	105,330	3,216	**2,386,410**
2027	1,446,170	673,141	157,311	108	3,120	105,429	3,225	**2,388,504**
2028	1,445,528	679,960	157,311	108	3,120	105,716	3,232	**2,394,976**
2029	1,444,108	686,774	157,311	108	3,120	105,968	3,238	**2,400,628**
2030	1,440,938	692,988	157,311	108	3,120	106,112	3,243	**2,403,821**
2031	1,438,824	700,284	157,311	108	3,120	106,354	3,247	**2,409,248**
2032	1,439,236	709,422	157,311	108	3,120	106,793	3,249	**2,419,240**
2033	1,437,166	716,148	157,311	108	3,120	107,012	3,252	**2,424,117**
2034	1,434,434	722,361	157,311	108	3,120	107,178	3,254	**2,427,766**
2035	1,431,962	728,729	157,311	108	3,120	107,363	3,255	**2,431,849**
2036	1,429,572	735,033	157,311	108	3,120	107,549	3,256	**2,435,950**
2037	1,427,550	741,068	157,311	108	3,120	107,742	3,257	**2,440,157**
2038	1,425,414	746,889	157,311	108	3,120	107,919	3,259	**2,444,021**
2039	1,423,491	752,795	157,311	108	3,120	108,111	3,260	**2,448,197**
Average Annual Growth Rates								
Previous 10 Years	-0.14%	0.59%	2.55%	-12.39%	-0.54%	-1.65%	7.43%	**0.15%**
Previous 5 Years	-1.69%	-0.20%	0.53%	-4.52%	-2.34%	-3.46%	22.98%	**-1.22%**
Next 5 Years	0.53%	1.63%	-0.23%	0.00%	0.30%	1.72%	0.88%	**0.82%**
Next 10 Years	0.26%	1.30%	-0.11%	0.00%	0.15%	1.00%	0.59%	**0.55%**
Next 20 Years	0.06%	1.11%	-0.06%	0.00%	0.07%	0.60%	0.33%	**0.37%**

3.3.8 Non-Member Sales

In addition to the Member system loads described in the previous sections, Big Rivers engages in the sale of any resources not needed for Member load where those transactions derive value for Big Rivers' Members. These capacity and energy transactions are made bilaterally or through participation in the regional transmission organization day–ahead and real–time markets. Optimization of these transactions involves evaluating the costs to deliver Big Rivers' generation versus buying on the market, and when the costs of purchasing capacity or energy are more economical than the comparable generation and transmission costs, those purchases are made to secure the most value for Big Rivers' Member–Owners. The table below shows anticipated net Non-Member sales. The projections in the table below include sales or purchases for the following entities, and only include projections for the period of the current contracts:

- OMU,[23]
- KYMEA,[24]
- Nebraska Entities,[25] and
- Short Term Bilateral Capacity.[26]

[23] OMU load is net of their allocation of Southeastern Power Administration Cumberland system hydropower and a future purchase of renewable power.

[24] KYMEA is a block sale of power and the volume will vary based on economic conditions.

[25] Nebraska entities' load is net of their allocation of Western Area Power Administration hydropower, renewables purchases, and a small amount of purchased power from their former supplier.

[26] Short Term bilateral capacity with no associated energy.

Table 3.12

Non-Member Sales[27] as of 2020

Non-Member Sales Under Contract as of 2020		
Calendar Year	MW	MWH
2015	513	-
2016	450	-
2017	487	-
2018	314	75,404
2019	376	578,276
2020	422	1,466,620
2021	422	1,750,832
2022	322	1,784,986
2023	306	1,713,663
2024	310	1,722,453
2025	311	1,726,630
2026	311	1,732,865
2027	100	613,200
2028	100	613,200
2029	0	255,500

3.3.9 Interruptible or Curtailable Load

Big Rivers provides wholesale electric service to its three Member–Owners: JPEC, Kenergy, and MCRECC. The current tariff under which Big Rivers provides service is on file with the Commission.[28] 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

[27] Non-Member Capacity sales with or without associated energy sales – spot energy sales not included.

[28] That tariff is also accessible from Big Rivers' corporate internet site at http://www.bigrivers.com/regulatory-affairs/.

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.[29] Since the rider is voluntary, it is not considered as a means for reducing load in this IRP. As presented in Table 3.13, 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 3.13

2000-2019 Voluntary Industrial Curtailment Results

Year	***Number of Curtailments***	***Load Reduction (MW)***
2000-2007	*0*	*n/a*
2008	*1*	*20*
2009	*3*	*1 to 25*
2010-2019	*0*	*n/a*

3.4 Weather Normalized Values

Weather-sensitive electricity loads comprise a large portion of electricity end-uses. Weather conditions vary and will cause electricity sales and peak demands to increase during more extreme periods or decrease during milder periods. This section, provides estimates of energy and peak demands for Big Rivers during the last ten years with the assumption that temperatures had been at their 15-year normal amounts in each year. See Appendix A Load Forecast Section 8.1 for a discussion of the use of a variety of normalization periods and for tracking previous forecasts to actual.

[29] *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.

The weather normalized values are calculated using the econometric models that identified weather as a driver of electricity sales. These are the Residential use per consumer and the GCI use per consumer models. Additionally, the load factor model (used to project peak demands) also includes temperature variables. The weather impacts of the deviation from the actual weather to the weather normalized weather are estimated using these models. The weather impacts are then added to (or subtracted from) to the actual load in that year to determine the weather normalized energy or peak demand.

Since 2010, Big Rivers' All time Summer peak of 662.1 MW occurred on August 4, 2010, winter peak of 750.5 MW occurred on January 6, 2014, and the highest annual energy requirement was 4,214 GWH in 2010.

The following table provides the last ten years of historical data for the Big Rivers Total system. The normalized peak values displayed are a maximum of each monthly normalized value for the given season and therefore frequently occur in a different month than the actual value.

Table 3.14

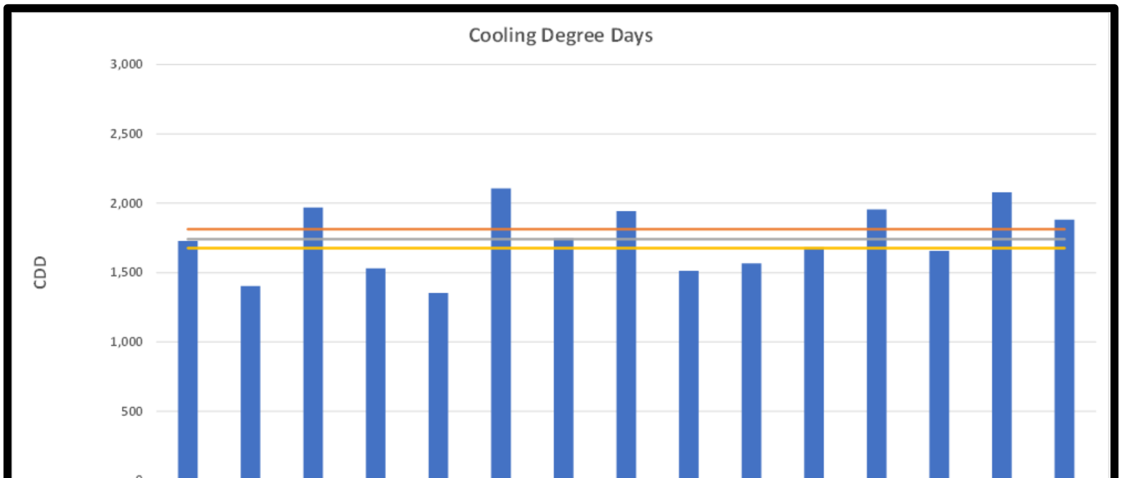
Big Rivers Member System Weather Normalized

Year	Energy (MWh)		Winter CP Demand (kW)		Summer CP Demand (kW)	
	Actual	Normalized	Actual	Normalized	Actual	Normalized
2010	4,214,187	4,071,823	652,163	621,367	662,129	613,470
2011	3,757,727	3,751,272	626,666	609,848	658,514	653,183
2012	3,326,245	3,354,869	574,579	623,473	661,427	606,020
2013	3,431,215	3,434,768	605,121	603,822	617,356	640,983
2014	3,436,352	3,377,837	750,485	671,034	611,785	621,847
2015	3,339,047	3,353,970	698,949	663,967	629,640	626,956
2016	3,318,766	3,309,582	612,568	607,623	621,295	622,525
2017	3,207,660	3,288,655	606,671	635,975	634,184	622,509
2018	3,407,668	3,335,436	668,654	618,974	626,212	615,604
2019	3,317,632	3,309,960	624,821	610,180	619,296	625,911

The historical weather normalized values in this section were completed using fifteen–year average values as the definition for normal weather. This is consistent with the normal weather definition used throughout the forecast. If the time span used to define normal weather is shortened to a ten–year average, the normal Cooling Degree Day ("CDD") values would be slightly higher and the normal Heating Degree Days ("HDD") values would be slightly lower. Conversely, if a twenty–year average is used, the normal CDD values would be slightly lower and the HDD values slightly higher. Altering the time span used to define normal weather to either ten (10) or twenty (20) years would cause one season to go up slightly and the other season to fall slightly. This creates a balancing effect resulting in very little overall annual impact in normalized sales figures by changing the normalization period. The following figures show CDD and HDD values for the last fifteen (15) years as well as the ten–, fifteen–, and twenty–year averages.

Figure 3.1

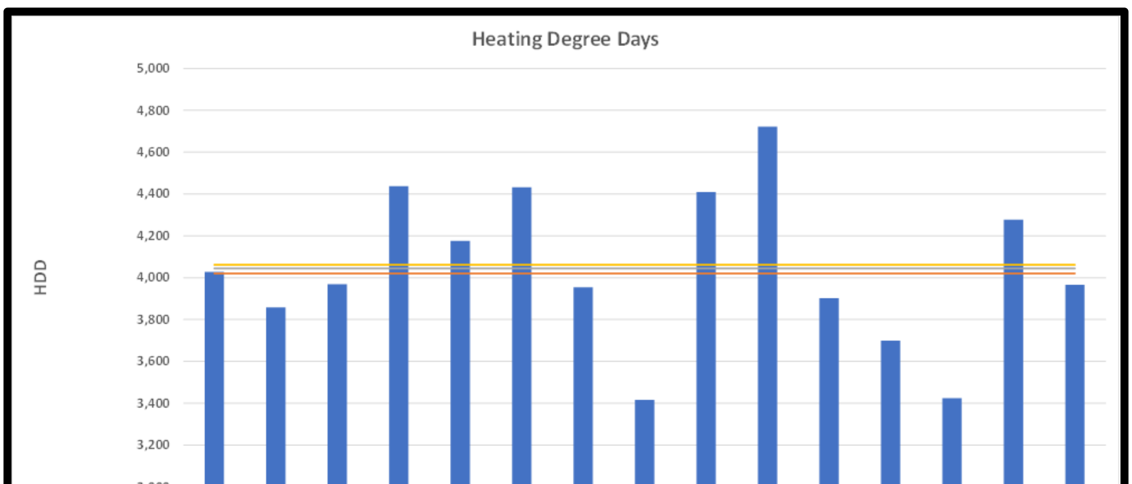
Cooling Degree Day Normal Values



	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
CDD	1,728	1,404	1,970	1,530	1,354	2,107	1,748	1,943	1,512	1,567	1,682	1,955	1,657	2,079	1,882
10 Year Avg CDD	1,813	1,813	1,813	1,813	1,813	1,813	1,813	1,813	1,813	1,813	1,813	1,813	1,813	1,813	1,813
15 Year Avg CDD	1,741	1,741	1,741	1,741	1,741	1,741	1,741	1,741	1,741	1,741	1,741	1,741	1,741	1,741	1,741
20 Year Avg CDD	1,676	1,676	1,676	1,676	1,676	1,676	1,676	1,676	1,676	1,676	1,676	1,676	1,676	1,676	1,676

Figure 3.2

Heating Degree Day Normal Values



	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
HDD	4,027	3,858	3,970	4,437	4,175	4,432	3,955	3,416	4,410	4,722	3,903	3,699	3,423	4,277	3,966
10 Year Average HDD	4,020	4,020	4,020	4,020	4,020	4,020	4,020	4,020	4,020	4,020	4,020	4,020	4,020	4,020	4,020
15 Year Average HDD	4,045	4,045	4,045	4,045	4,045	4,045	4,045	4,045	4,045	4,045	4,045	4,045	4,045	4,045	4,045
20 Year Average HDD	4,062	4,062	4,062	4,062	4,062	4,062	4,062	4,062	4,062	4,062	4,062	4,062	4,062	4,062	4,062

3.5 Impact of Existing and Future EE and DSM Programs

Clearspring was selected by Big Rivers to complete a Demand-Side Management ("DSM") potential study in 2020 that quantified the impact of additional DSM spending on future energy and peak requirements. For the base case forecast it is assumed that any impacts of prior DSM programs are captured indirectly through the historical energy and peak data used as an input to the modeling process. The base case forecast assumes no additional DSM spending in the future and additional future DSM impacts are set to zero.

Two alternate load forecast scenarios have been developed that are derived from the Big Rivers DSM potential study that outline the projected impacts of $1,000,000 and $2,000,000 DSM spending scenarios. The DSM study provides the impact at each appliance end–use. The DSM impacts were then scaled up to capture additional decreases in distribution and transmission losses. The tables below outline the anticipated annual impact of these two spending scenarios on total energy and coincident peak requirements, though neither scenario is included in the base case.

Table 3.15

DSM Spending Scenarios (kW)

Year	Total Big Rivers CP (Base Forecast)	Impact of $1,000,000 Spending Scenario on CP	Total Big Rivers CP ($1,000,000 Spending Scenario)	Impact of $2,000,000 Spending Scenario on CP	Total Big Rivers CP ($2,000,000 Spending Scenario)
2015	698,949	0	698,949	0	698,949
2016	621,295	0	621,295	0	621,295
2017	634,184	0	634,184	0	634,184
2018	668,654	0	668,654	0	668,654
2019	624,821	0	624,821	0	624,821
2020	626,715	0	626,715	0	626,715
2021	632,122	2,264	629,858	4,353	627,769
2022	832,412	4,527	827,885	8,706	823,706
2023	834,546	6,791	827,755	13,059	821,487
2024	836,327	9,054	827,273	17,412	818,915
2025	838,132	11,318	826,815	21,765	816,368
2026	839,920	13,581	826,339	26,118	813,802
2027	840,180	15,845	824,336	30,471	809,710
2028	841,438	18,108	823,330	34,824	806,614
2029	842,528	20,310	822,218	39,057	803,471
2030	843,125	22,511	820,614	43,291	799,834
2031	844,223	22,511	821,712	43,291	800,932
2032	846,330	22,511	823,818	43,291	803,039
2033	847,329	22,511	824,818	43,291	804,038
2034	848,086	22,511	825,575	43,291	804,795
2035	848,929	22,511	826,417	43,291	805,638
2036	849,782	22,511	827,271	43,291	806,491
2037	850,659	22,511	828,147	43,291	807,368
2038	851,459	22,512	828,947	43,291	808,167
2039	852,319	22,512	829,807	43,292	809,027
Average Annual Growth Rates					
Previous 10 Years	-0.74%		-0.74%		-0.74%
Previous 5 Years	-3.60%		-3.60%		-3.60%
Next 5 Years	6.00%		5.77%		5.56%
Next 10 Years	3.03%		2.78%		2.55%
Next 20 Years	1.56%		1.43%		1.30%

Table 3.16

DSM Spending Scenarios (MWh)

Year	Total Energy Requirements (Base Forecast)	Impact of $1,000,000 Spending Scenario on Energy	Total Energy Requirements ($1,000,000 Spending Scenario)	Impact of $2,000,000 Spending Scenario on Energy	Total Energy Requirements ($2,000,000 Spending Scenario)
2015	3,339,047	0	3,339,047	0	3,339,047
2016	3,318,766	0	3,318,766	0	3,318,766
2017	3,207,660	0	3,207,660	0	3,207,660
2018	3,407,668	0	3,407,668	0	3,407,668
2019	3,317,632	0	3,317,632	0	3,317,632
2020	3,386,237	0	3,386,237	0	3,386,237
2021	3,414,929	11,186	3,403,743	21,512	3,393,417
2022	4,496,296	22,372	4,473,924	43,023	4,453,273
2023	4,508,492	33,558	4,474,934	64,535	4,443,957
2024	4,521,662	44,745	4,476,917	86,048	4,435,614
2025	4,528,859	55,931	4,472,927	107,560	4,421,298
2026	4,538,628	67,118	4,471,510	129,073	4,409,555
2027	4,540,776	78,304	4,462,472	150,585	4,390,191
2028	4,550,367	89,491	4,460,877	172,098	4,378,270
2029	4,553,210	100,133	4,453,077	192,563	4,360,647
2030	4,556,486	110,775	4,445,711	213,028	4,343,457
2031	4,562,051	110,775	4,451,276	213,029	4,349,023
2032	4,572,299	110,775	4,461,525	213,028	4,359,271
2033	4,577,302	110,775	4,466,527	213,029	4,364,273
2034	4,581,044	110,775	4,470,269	213,029	4,368,015
2035	4,585,232	110,775	4,474,456	213,030	4,372,202
2036	4,589,439	110,776	4,478,663	213,030	4,376,408
2037	4,593,753	110,776	4,482,978	213,031	4,380,723
2038	4,597,716	110,776	4,486,940	213,031	4,384,685
2039	4,601,999	110,777	4,491,222	213,032	4,388,967
Average Annual Growth Rates					
Previous 10 Years	-0.45%		-0.45%		-0.45%
Previous 5 Years	-0.70%		-0.70%		-0.70%
Next 5 Years	6.39%		6.18%		5.98%
Next 10 Years	3.22%		2.99%		2.77%
Next 20 Years	1.65%		1.53%		1.41%

3.6 Alternative System Forecasts and Uncertainty Analysis

While the projections summarized in previous sections are considered the most probable outcome, it is important to remember that energy loads can be influenced by factors that are inherently difficult to predict, such as weather and the economy. Forecasting attempts to model reality and identify the primary drivers of growth and change. However, due to the unpredictable nature of these drivers, the base case forecast is unlikely to be fully accurate. Therefore, it is important to develop flexible plans for meeting future energy needs based on a range of forecast outcomes.

The study includes scenario analyses that show how the forecasts change under assumed variations in future weather and economic growth paths. The alternate growth scenarios that are included in Appendix A Long Term Load Forecast Section 5:

1. Extreme weather with normal economic growth,
2. Mild weather with normal economic growth,
3. High economic growth with normal weather, and
4. Low economic growth with normal weather.

3.6.1 Weather Scenarios

Weather is one of the critical components to explain year–to–year variation in load. Because of this, extreme and mild weather scenarios were developed for the forecast period. The Residential use per consumer and GCI use per consumer monthly energy models use cooling degree days and heating degree days. For the creation of the mild and extreme energy scenarios these two variables were altered to a fifteen–year historical annual maximum and minimum value. These annual extremes were then redistributed across each month based on an average monthly distribution of cooling degree days and heating degree days.

The Rural peak load factor model also contains cooling degree days and heating degree days for the month. Additionally, the load factor model captures peak day weather conditions. The extreme and mild weather scenarios alter the load factor model to use monthly weather conditions consistent with the energy models and change the peak day conditions to the most extreme or mild conditions found in the last fifteen (15) years of history for each given month. The peak values displayed are a maximum of each monthly scenario value for the given season and, therefore, can occur in a different month than the base case forecast. The following table provides the last five (5) years of historical data and the next twenty (20) years of forecasted data for the mild, base, and extreme weather scenarios. Direct Serve load is assumed to not be influenced by weather and is held constant to the base case forecast for the weather ranges. The extreme and mild ranges with the Direct Serve class included are shown below.

Table 3.17

Weather Scenarios (MWh)

Year	Energy (MWh)			Winter CP Demand (kW)			Summer CP Demand (kW)		
	Mild	Base	Extreme	Mild	Base	Extreme	Mild	Base	Extreme
2015		3,339,047			698,949			629,640	
2016		3,318,766			612,568			621,295	
2017		3,207,660			606,671			634,184	
2018		3,407,668			668,654			626,212	
2019		3,317,632			624,821			619,296	
2020	3,247,929	3,386,237	3,542,354	556,932	618,492	685,453	590,330	626,715	696,756
2021	3,276,302	3,414,929	3,571,301	561,852	623,635	690,783	595,735	632,122	702,278
2022	4,357,402	4,496,296	4,652,858	746,457	808,477	875,826	789,046	832,412	905,538
2023	4,369,975	4,508,492	4,664,485	748,827	810,798	878,015	791,419	834,546	907,089
2024	4,383,551	4,521,662	4,677,063	750,744	812,637	879,694	793,429	836,327	908,319
2025	4,391,060	4,528,859	4,683,797	752,795	814,652	881,598	795,425	838,132	909,654
2026	4,401,100	4,538,628	4,693,175	754,733	816,559	883,415	797,381	839,920	911,033
2027	4,403,895	4,540,776	4,694,521	755,147	816,726	883,262	797,906	840,180	910,740
2028	4,413,825	4,550,367	4,703,670	756,186	817,611	883,938	799,318	841,438	911,646
2029	4,416,996	4,553,210	4,706,088	757,206	818,499	884,638	800,548	842,528	912,417
2030	4,420,682	4,556,486	4,708,850	757,618	818,719	884,613	801,296	843,125	912,686
2031	4,426,479	4,562,051	4,714,112	758,533	819,526	885,264	802,481	844,223	913,576
2032	4,436,652	4,572,299	4,724,411	760,215	821,212	886,925	804,573	846,330	915,655
2033	4,441,797	4,577,302	4,729,216	761,007	821,931	887,534	805,621	847,329	916,527
2034	4,445,696	4,581,044	4,732,748	761,502	822,341	887,826	806,422	848,086	917,167
2035	4,449,964	4,585,232	4,736,814	762,136	822,934	888,350	807,284	848,929	917,944
2036	4,454,192	4,589,439	4,740,970	762,732	823,513	888,890	808,135	849,782	918,774
2037	4,458,453	4,593,753	4,745,321	763,387	824,194	889,583	808,984	850,659	919,677
2038	4,462,373	4,597,716	4,749,306	763,953	824,780	890,175	809,760	851,459	920,496
2039	4,466,588	4,601,999	4,753,640	764,593	825,457	890,874	810,589	852,319	921,388

3.6.2 Economic Scenarios

Another critical component of a long-term load forecast is the underlying economic variables within the service territory. Two scenarios have been developed: low economic growth and high economic growth. To create the economic scenarios, economic variables within each econometrically modeled class are altered by an additional plus or minus 1.0% in 2020. As the forecast is projected further into the future these variable values deviate by an additional 1.0% each additional year relative to the base case forecast (variable values in 2039 are +/- 20% of the base case forecast values). The altered variables include electricity price, gross regional product ("GRP"), employment, and total retail sales.

The forecast for Residential consumers, LCI, Irrigation, and Street and Highway are not modeled econometrically and are therefore directly modified by 1.0% per year relative to the base case forecast to create the high– and low–economic ranges. The Direct Serve class is not modeled using econometric modeling. The forecast for the Direct Serve class is increased by an additional 1.0% per year relative to the base case in the high scenario. In the low scenario the Direct Serve class is decreased by 1.0% per year relative to the base case. The high and low ranges with the Direct Serve class included are shown below.

Table 3.18

Total System Economic Scenarios

Year	Energy (MWh)			Winter CP Demand (kW)			Summer CP Demand (kW)		
	Low	Base	High	Low	Base	High	Low	Base	High
2015		3,339,047			698,949			629,640	
2016		3,318,766			612,568			621,295	
2017		3,207,660			606,671			634,184	
2018		3,407,668			668,654			626,212	
2019		3,317,632			624,821			619,296	
2020	3,367,634	3,386,237	3,404,861	617,960	618,492	619,025	622,371	626,715	631,064
2021	3,361,494	3,414,929	3,468,506	616,632	623,635	630,652	621,181	632,122	643,096
2022	4,380,613	4,496,296	4,612,361	791,151	808,477	825,854	810,273	832,412	854,633
2023	4,346,970	4,508,492	4,670,756	785,103	810,798	836,606	803,786	834,546	865,465
2024	4,314,099	4,521,662	4,730,448	778,563	812,637	846,911	796,936	836,327	875,980
2025	4,275,319	4,528,859	4,784,229	772,164	814,652	857,449	790,076	838,132	886,579
2026	4,238,868	4,538,628	4,840,954	765,621	816,559	867,942	783,177	839,920	897,210
2027	4,195,273	4,540,776	4,889,695	757,457	816,726	876,599	774,851	840,180	906,237
2028	4,158,485	4,550,367	4,946,655	749,944	817,611	886,069	767,438	841,438	916,374
2029	4,115,445	4,553,210	4,996,502	742,441	818,499	895,561	759,862	842,528	926,367
2030	4,072,831	4,556,486	5,046,913	734,325	818,719	904,354	751,841	843,125	935,845
2031	4,032,222	4,562,051	5,100,046	726,745	819,526	913,812	744,261	844,223	945,916
2032	3,995,613	4,572,299	5,158,713	719,918	821,212	924,311	737,544	846,330	957,177
2033	3,954,392	4,577,302	5,211,613	712,248	821,931	933,740	729,854	847,329	967,219
2034	3,912,081	4,581,044	5,263,217	704,308	822,341	942,847	721,956	848,086	977,013
2035	3,870,140	4,585,232	5,315,488	696,534	822,934	952,182	714,129	848,929	986,938
2036	3,828,209	4,589,439	5,367,935	688,746	823,513	961,533	706,311	849,782	996,907
2037	3,786,361	4,593,753	5,420,660	681,051	824,194	971,024	698,511	850,659	1,006,935
2038	3,744,225	4,597,716	5,473,117	673,276	824,780	980,433	690,648	851,459	1,016,902
2039	3,702,342	4,601,999	5,526,116	665,581	825,457	989,974	682,834	852,319	1,026,975

The following figures display the 2019 annual load shape and descending load curve for the Big Rivers Member system.

Figure 3.3

2019 Load Shape

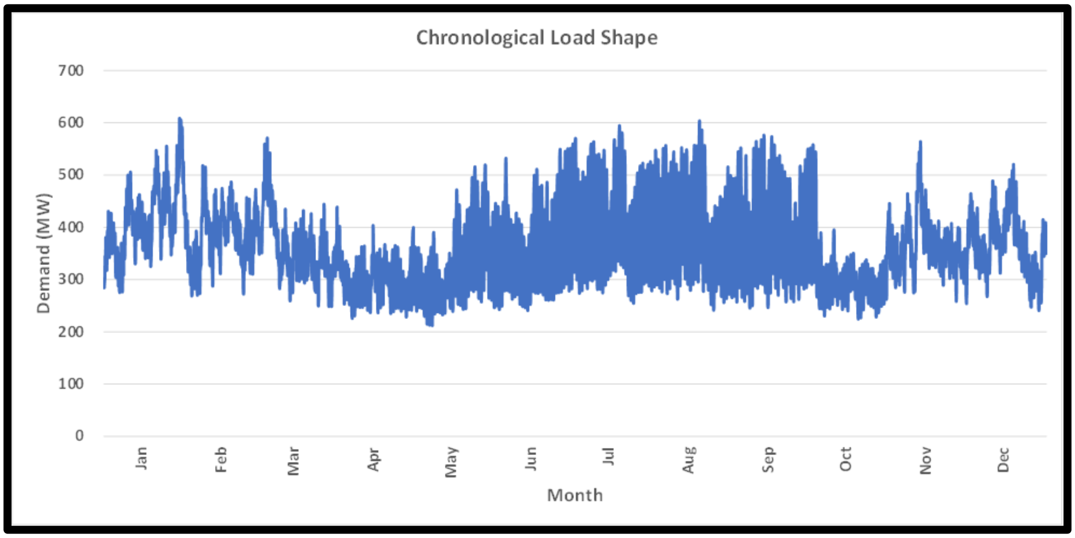
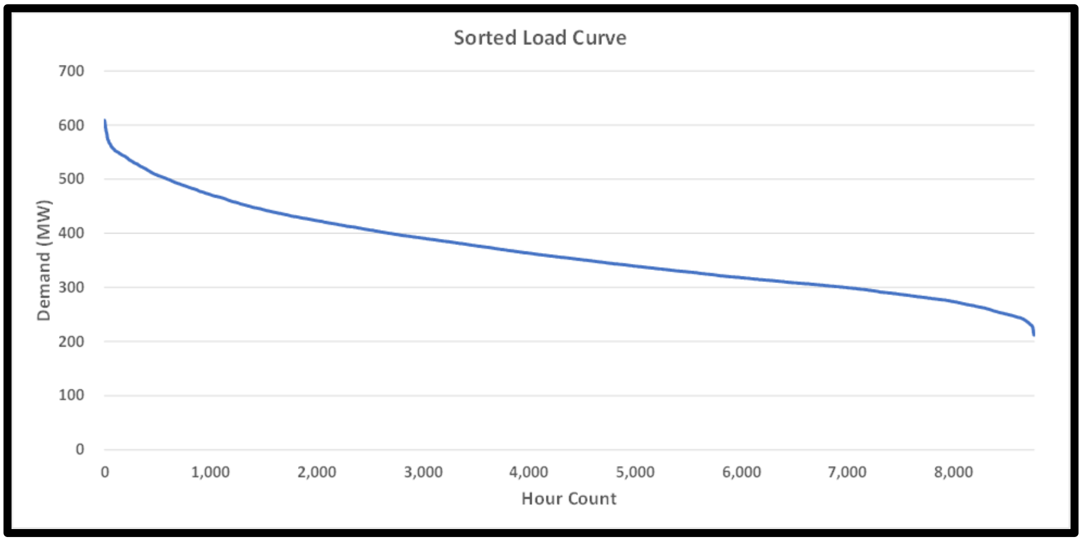


Figure 3.4

Big Rivers Member Load Curve 2019



The following graphs compare historical actual values, the 2017 forecast and the current 2020 forecast.

Figure 3.5

Comparison to Actual and Previous Forecast – Total Consumers

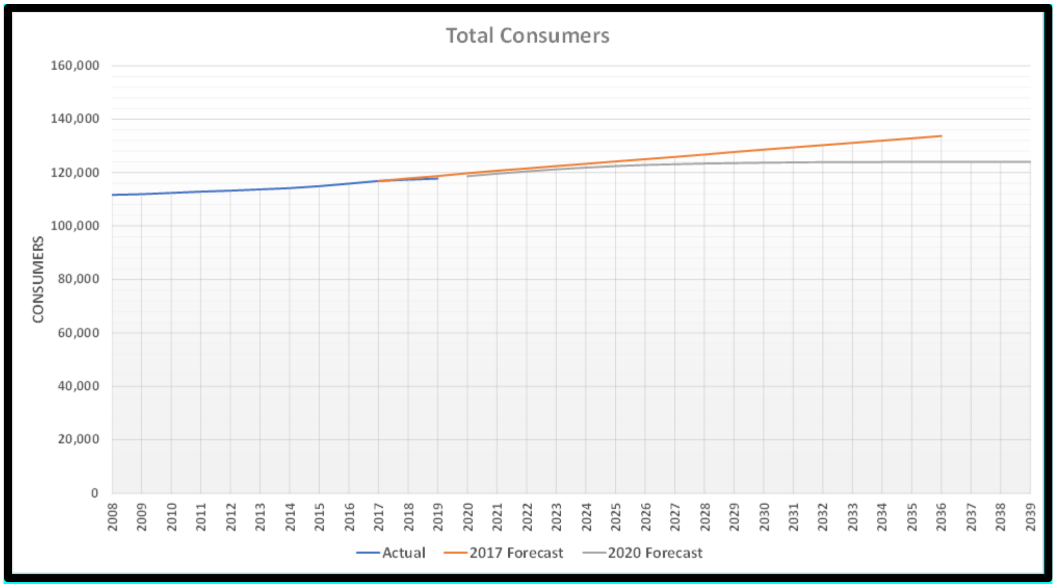


Figure 3.6

Comparison to Actual and Previous Forecast – Member Sales

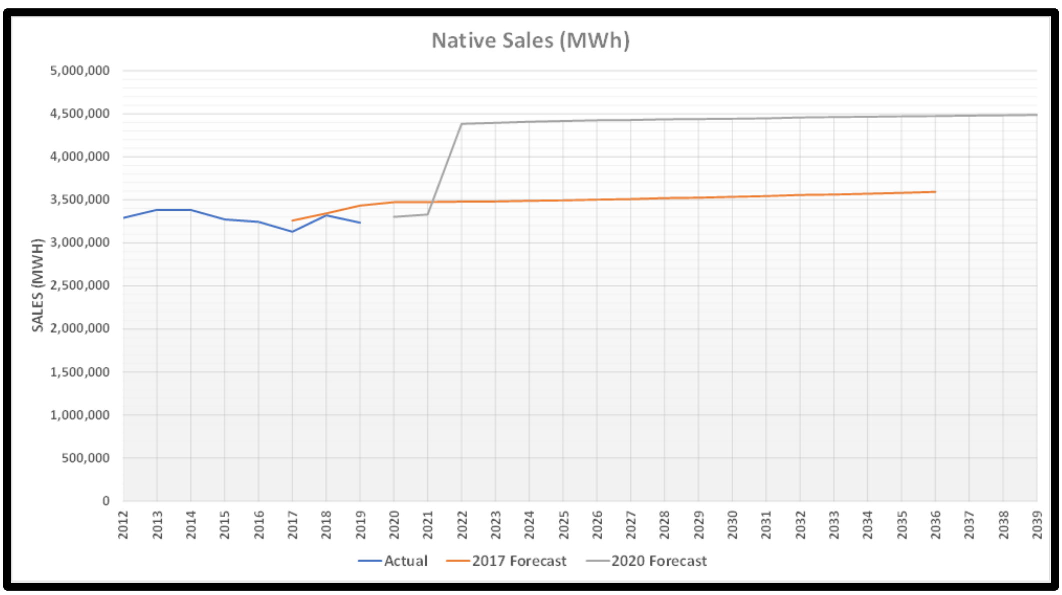


Figure 3.7

Comparison to Actual and Previous Forecast – Member Summer Peak

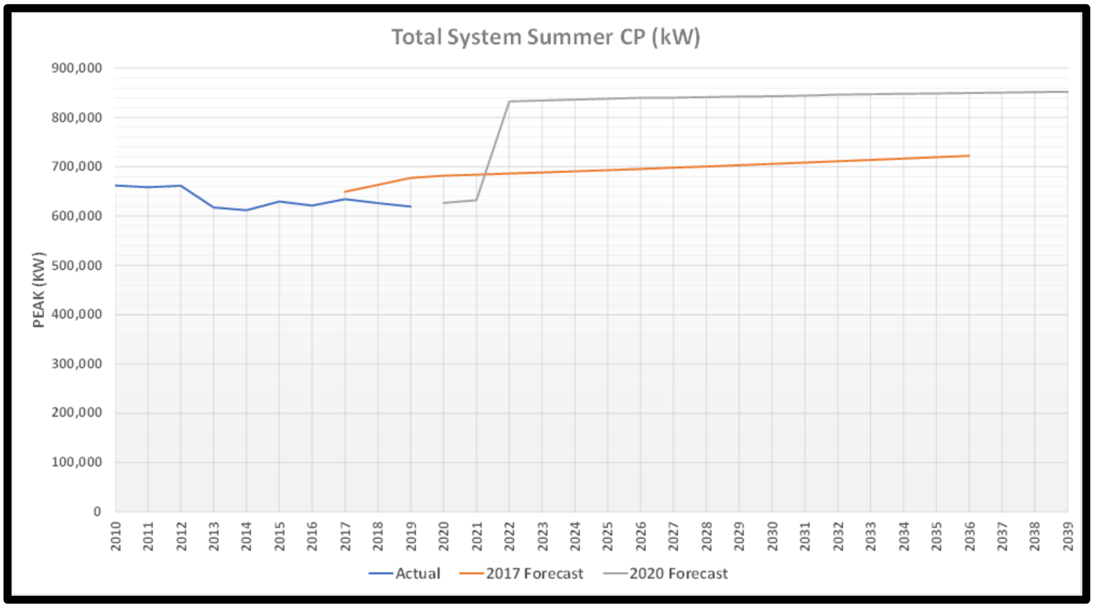


Figure 3.8

Comparison to Actual and Previous Forecast – Member Winter Peak

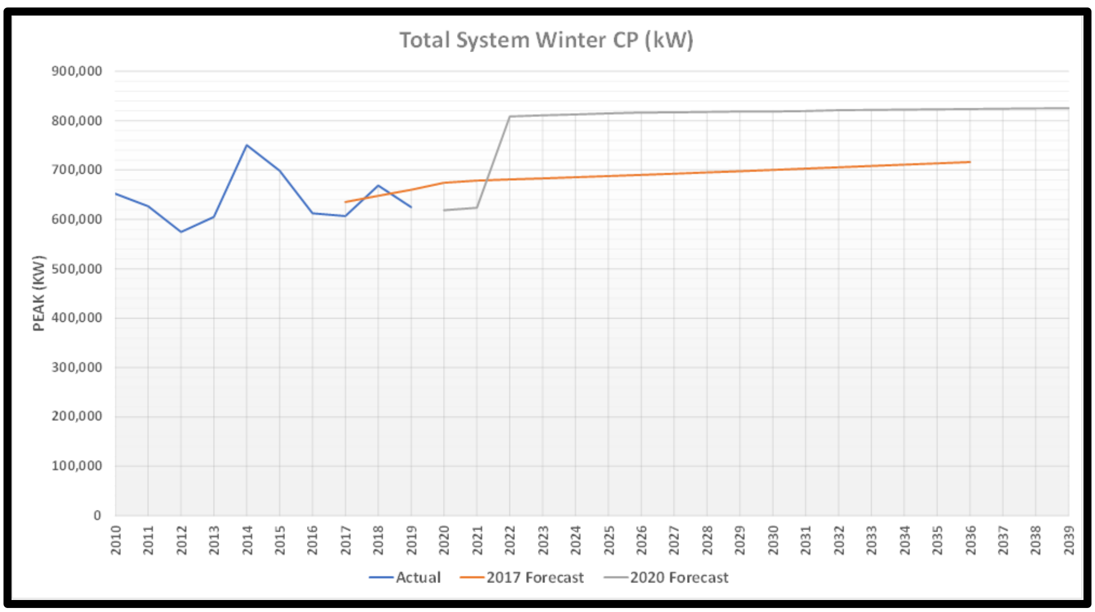


Figure 3.9

Comparison to Actual and Previous Forecast – Rural Summer Coincident Peak

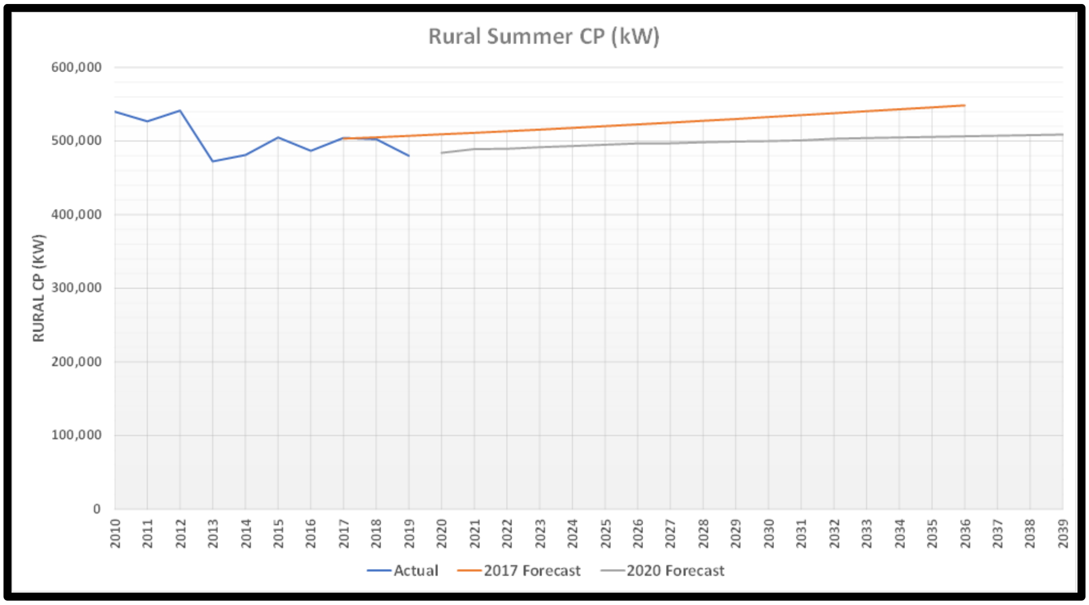
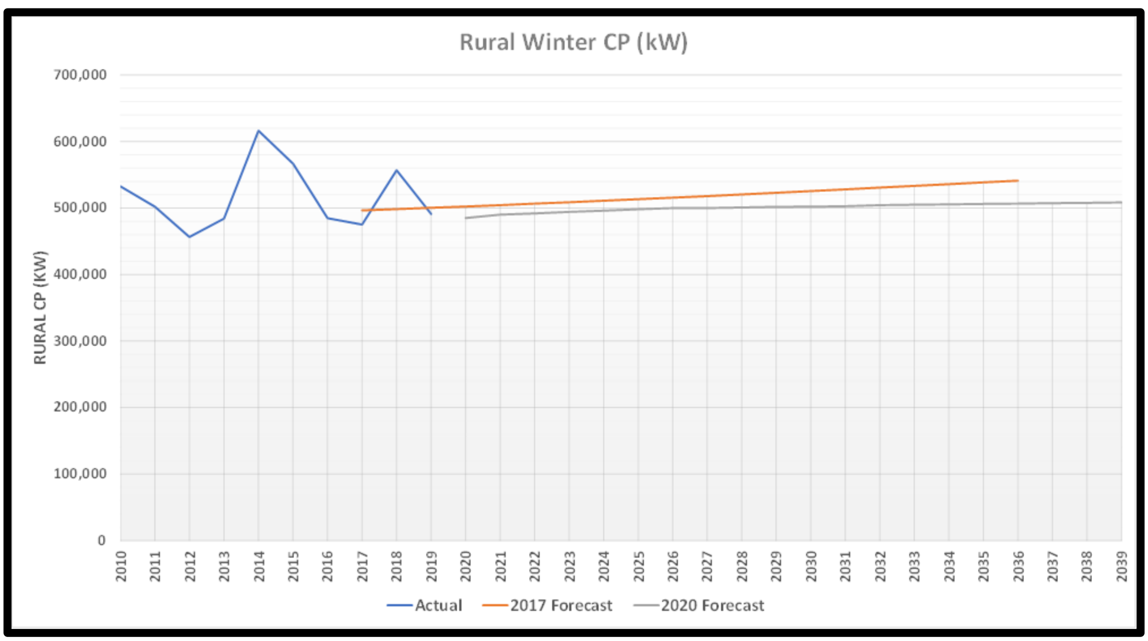


Figure 3.10

Comparison to Actual and Previous Forecast – Rural Winter Coincident Peak



3.7 Load Forecast Methodology

The load forecast process began with Clearspring soliciting feedback from representatives of each Member system as well as Big Rivers. The forecasting team issued an information request to each Member system requesting monthly energy data by rate class, historical or anticipated changes in load on the system, large consumer energy and peak demand data, and retail price forecasts. Big Rivers provided historical demand data used as the basis to forecast load factors and peak demands.

In addition to this data, Clearspring collected a variety of additional data to develop the load forecast. This included county–level historical socioeconomic data from Woods & Poole Economics, Inc., historical alternative fuel price data and energy efficiency indexes from the Energy Information Administration ("EIA"),[30] monthly and daily weather data from the Midwest Regional Climate Center ("MRCC")[31] and High Plains Regional Climate Center ("HPRCC"),[32] and appliance and end-use saturations for each Member's system based off historical end–use surveys conducted by Big Rivers. The most recent such survey was conducted in 2019. See Appendix A Section 7 for more details on the forecasting tools and methods used in developing Big Rivers' 2020 Load Forecast. Below are the key economic and demographic assumptions:

- Households are projected to increase at an average annual growth rate of 0.1% through the forecast period.
- Real residential electricity prices are projected to [redacted] through the forecast period.

[30] https://www.eia.gov/outlooks/aeo/

[31] https://mrcc.illinois.edu/

[32] https://hprcc.unl.edu/

- Air conditioning saturation levels are projected to continue increasing slowly through the forecast period.
- Electrical heating saturation levels are projected to remain flat through the forecast period.
- Major appliance efficiencies are projected to continue increasing through the forecast period, but at a decreasing rate as maximum efficiencies are approached.
- Employment is projected to increase at an average annual rate of 0.6% through the forecast period.
- Real GRP is projected to increase at an average annual rate of 1.2% through the forecast period.
- Real total retail sales is projected to increase at an average annual rate of 0.8% through the forecast period.
- [redacted]
- Cooling degree days, heating degree days, and peak day weather conditions are based on a prior fifteen–year average.

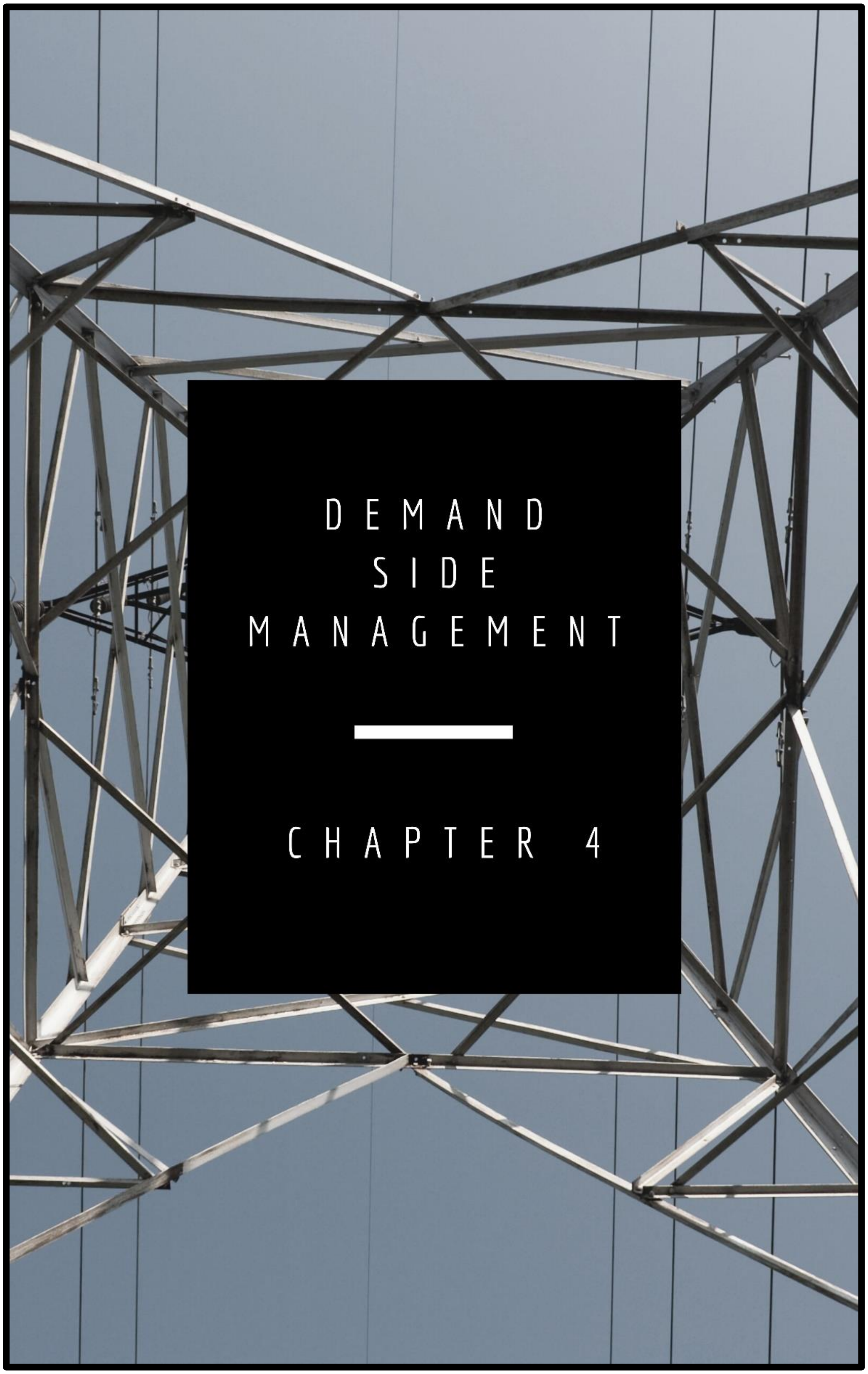
3.8 Research and Development

Big Rivers conducts residential surveys periodically to monitor changes in household major appliances, appliance saturation, and various end–uses. These surveys are 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.

Big Rivers uses the *Plexos* modeling tool and continues to improve its use of these enhanced resources.



DEMAND SIDE MANAGEMENT

CHAPTER 4

DEMAND-SIDE MANAGEMENT

4.1 Demand-Side Management

The 2020 Demand-Side Management Potential Study (the "DSM Study" or the "2020 DSM Study") 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 2021-2030 for the residential and non–residential (commercial/industrial or C&I) sectors. Results from two program potential scenarios are also presented to estimate the portion of the achievable potential that could be realized given specific DSM funding levels.

All results were developed using customized residential and non–residential 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 represent the best available at the time this analysis was developed. Appendix B of this IRP provides the entire 2020 DSM Study.

4.2 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 and non-residential facilities. The study assessed energy efficiency potential and demand response throughout the Big Rivers Members' service territories over ten years, from 2021 through 2030. The study had five primary objectives:

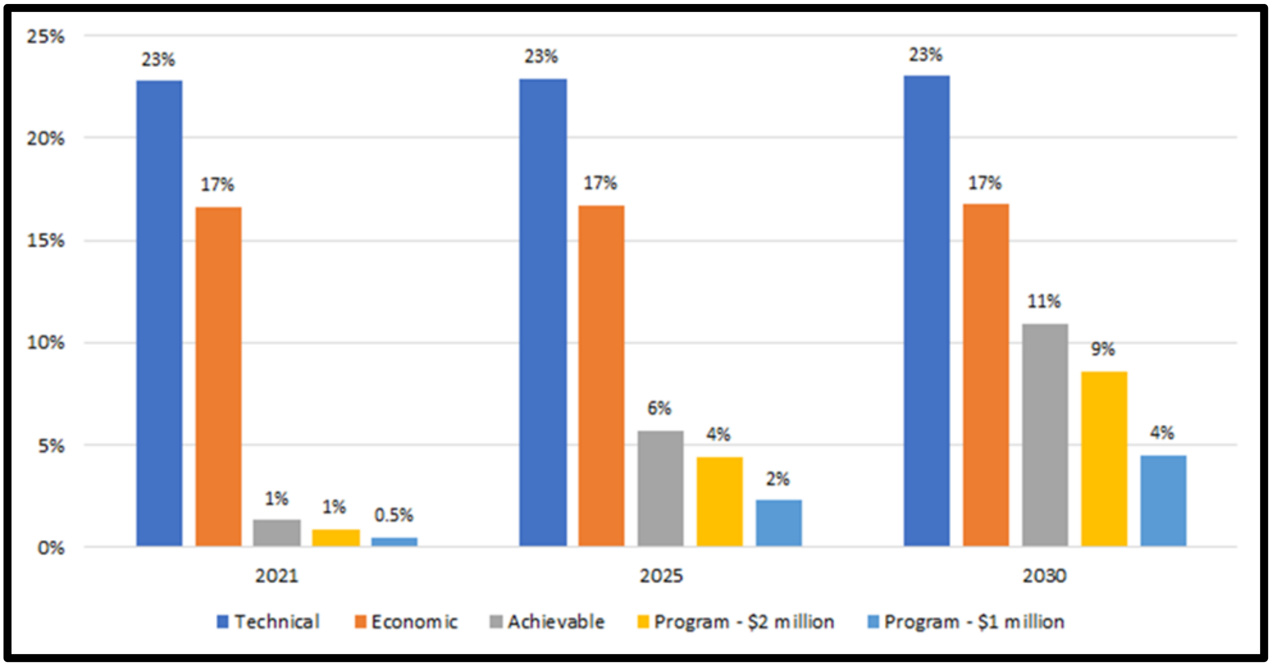
- Develop databases of energy efficiency and demand response measures in the residential and non–residential sectors to reflect current industry knowledge of energy efficiency and demand response measures, account for known codes and standards, and align with the market and demographics of Big Rivers' 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, 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 (2021-2030);
- Estimate the potential savings over that 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 $1.0 million incentive budget and a $2.0 million incentive budget.

Figure 4.1 provides the technical, economic, achievable and program potential (two funding scenarios) for residential and non-residential sectors in the Big Rivers service territory. The economic potential is approximately 17% of forecasted sales by 2030. The program potential at the $1 million incentive scenario is approximately 4% of forecasted sales by 2030. Chapters 3 and 4 of the 2020 DSM Study in Appendix B provide sector level details including program potential details.

Figure 4.1

Electric Efficiency Potential Savings Summary (% of Retail Sales)



Tables 4.1 and 4.2 provide the 10–year energy and demand potential.

Table 4.1

Energy Efficiency Potential (Cumulative Annual) Energy Savings (MWh)

Potential	Residential	Non-Res (C&I)
Technical	290,322	241,646
Economic	217,845	169,463
Achievable	112,308	139,937
Program ($2m)	76,067	122,467
Program ($1m)	39,555	63,683

Table 4.2

Energy Efficiency Potential (Cumulative Annual) Demand Savings (MW)

Potential	Residential	Non-Res (C&I)
Technical	81	72
Economic	45	47
Achievable	17	36
Program ($2m)	12	28
Program ($1m)	6	15

Table 4.3 shows the TRC benefit–cost ratio based on the net present value of benefits and costs of the program scenarios. The cost–effectiveness ratios indicate that the program potential scenarios are cost–effective overall. The program evaluation was based on savings identified in the achievable analysis from key end–use categories rather than specific measure programs.

Table 4.3

Program Potential Cost-Effectiveness (TRC Test)

Potential	TRC Test Ratio
Program - $2 million	2.5
Program - $1 million	2.7

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. 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 incentive scenario and a $1.0 million incentive scenario. In each scenario, the residential sector ended up with 45% of the incentive budget, and the non–residential sector received 55% of the incentive budget. The results for the 1–year, 5–year, and 10–year program potential for each funding scenario were presented previously in Figure 4.1. The $2.0 million funding scenario program potential is 1.0% of forecast sales over the 1–year timeframe, and rises to 9.0% across the 10–year timeframe. The $1.0 million funding scenario program potential is 0.4% of forecast sales over the 1–year timeframe, and rises to 4.0% across the 10–year timeframe.

Table 4.4 provides the 10–year estimates of cumulative annual program potential for energy and summer peak demand. The $2.0 million program potential is 100,000 MWhs by 2025, and the $1.0 million program potential is approximately half that amount at just over 52,000 MWhs. Summer peak demand program potential is 20.3 MWs and 10.5 MWs, respectively, for the $2.0 million and $1.0 million program potential scenarios.

Table 4.4

Program Potential Summary

Annual Energy (MWh)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Program $2 Million	20,049	40,097	60,146	80,194	100,243	120,292	140,340	160,389	179,461	198,534
Program $1 Million	10,425	20,851	31,276	41,701	52,126	62,552	72,977	83,402	93,320	103,238
Demand (MW)	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Program $2 Million	4.1	8.1	12.2	16.2	20.3	24.3	28.4	32.5	36.4	40.3
Program $1 Million	2.1	4.2	6.3	8.4	10.5	12.7	14.8	16.9	18.9	21.0

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 costs of other technologies and efficiency gains will result in the need to shift focus to more effective programs and sectors.

4.3 Residential Energy Efficiency Program Potential Scenarios

The program potential assessment involved estimating potential savings across specific end–use categories. Table 4.5 provides a summary of the program potential for the $1 million incentive scenario for the residential segment. The water heating program opportunities provides the most potential energy savings over the next ten (10) years, followed by Heating, Ventilation, and Air Conditioning (" HVAC").

Table 4.5

$1 Million Scenario – Residential Savings by End-Use

	Category	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Energy (MWh)	HVAC	928	1,857	2,785	3,714	4,642	5,571	6,499	7,428	8,356	9,285
	Water Heating	2,224	4,448	6,672	8,896	11,120	13,344	15,568	17,792	20,017	22,241
	Appliance	752	1,503	2,255	3,007	3,758	4,510	5,262	6,013	6,258	6,502
	Lighting	48	96	144	192	239	287	335	383	431	479
	Other	105	210	315	420	525	629	734	839	944	1,049
	Total	4,057	8,114	12,171	16,228	20,285	24,342	28,399	32,456	36,005	39,555
	Category	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Demand (MW)	HVAC	0.3	0.6	1.0	1.3	1.6	1.9	2.2	2.5	2.9	3.2
	Water Heating	0.2	0.4	0.7	0.9	1.1	1.3	1.6	1.8	2.0	2.2
	Appliance	0.1	0.2	0.3	0.4	0.4	0.5	0.6	0.7	0.7	0.8
	Lighting	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Other	0.0	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.3	0.3
	Total	0.7	1.3	2.0	2.6	3.3	3.9	4.6	5.3	5.9	6.5

Note: MISO Summer Peak
Note: Cumulative Annual Impact

4.4 Non-Residential (C&I) Energy Efficiency Program Potential Scenarios

Table 4.6 provides a summary of the program potential for the $1 million incentive scenario for the non–residential segment. The appliance program opportunities provide the most potential energy savings over the next ten (10) years, followed by lighting and the 'other' category.

Table 4.6

$1 Million Scenario – Non-Residential Savings by End-Use

	Category	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Energy (MWh)	HVAC	844	1,688	2,532	3,376	4,219	5,063	5,907	6,751	7,595	8,439
	Water Heating	146	291	437	583	728	874	1,019	1,165	1,311	1,456
	Lighting	954	1,908	2,862	3,816	4,771	5,725	6,679	7,633	8,587	9,541
	Appliance	3,518	7,036	10,553	14,071	17,589	21,107	24,625	28,142	31,660	35,178
	Other	907	1,814	2,721	3,627	4,534	5,441	6,348	7,255	8,162	9,068
	Total	6,368	12,737	19,105	25,473	31,841	38,210	44,578	50,946	57,315	63,683

	Category	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Demand (MW)	HVAC	0.6	1.2	1.7	2.3	2.9	3.5	4.1	4.6	5.2	5.8
	Water Heating	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1
	Lighting	0.1	0.2	0.3	0.4	0.5	0.7	0.8	0.9	1.0	1.1
	Appliance	0.4	0.8	1.2	1.6	2.0	2.4	2.8	3.2	3.6	4.0
	Other	0.3	0.7	1.0	1.4	1.7	2.1	2.4	2.8	3.1	3.5
	Total	1.5	2.9	4.4	5.8	7.3	8.7	10.2	11.6	13.1	14.5

Note: MISO Summer Peak
Note: Cumulative Annual Impact

4.5 Market Potential Study – Demand Response

The 2020 DSM 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 of the 2020 IRP provides a brief overview of the results of the demand response analysis. Section 5 of the 2020 DSM Study (Appendix B of this IRP) provides a more complete discussion of the demand response analysis. The full study can be found in Appendix B, 2020 DSM Study.

4.6 Current Demand Response Programs

Big Rivers does not currently operate any direct load 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 MWs. There have been no curtailments since 2010. See subsection 3.3.9 for more information.

4.7 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. A total of twelve program categories 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 4.7 provides the results of the evaluations.

Table 4.7

Demand Response Programs Evaluation Results

Program	Sector	Type	Direct Control	TRC	UCT	PCT
Air Conditioner Cycling (25%)	Residential	Load Management	Yes	0.5	0.2	2.2
Air Conditioner Cycling (50%)	Residential	Load Management	Yes	1.0	0.5	2.2
Water Heater Cycling (25%)	Residential	Load Management	Yes	0.1	0.0	2.2
Water Heater Cycling (50%)	Residential	Load Management	Yes	0.2	0.1	2.2
Residential PTR[33]	Residential	Load Management	No	8.1	1.0	5.8
DLC (Customer Ownership)[34]	Non- Residential	Load Management	Yes	0.8	18.7	0.3
DLC (Utility Ownership)	Non- Residential	Load Management	Yes	0.8	0.7	1.3
Residential TOU[35]	Residential	Dynamic Pricing	No	2.9	4.8	4.0
Residential CPP[36]	Residential	Dynamic Pricing	No	7.3	12.2	13.3
Non-Residential TOU	Non- Residential	Dynamic Pricing	No	3.4	20.5	17.6
Non-Residential CPP	Non- Residential	Dynamic Pricing	No	1.3	6.8	6.5
Plug-In EV TOU	All	Dynamic Pricing	No	0.6	1.2	5.9

4.8 Conclusions for Demand Response

Market prices for capacity in MISO have been low for the past decade, therefore, the value of demand response programs is presently low, even lower than in Big Rivers' 2017 DSM Potential Study. Furthermore, there are no benefits associated with avoided transmission facilities (an assumption consistent with the 2017 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.

[33] PTR = Peak Time Rebates

[34] DLC = Direct Load Control.

[35] TOU = Time of Use.

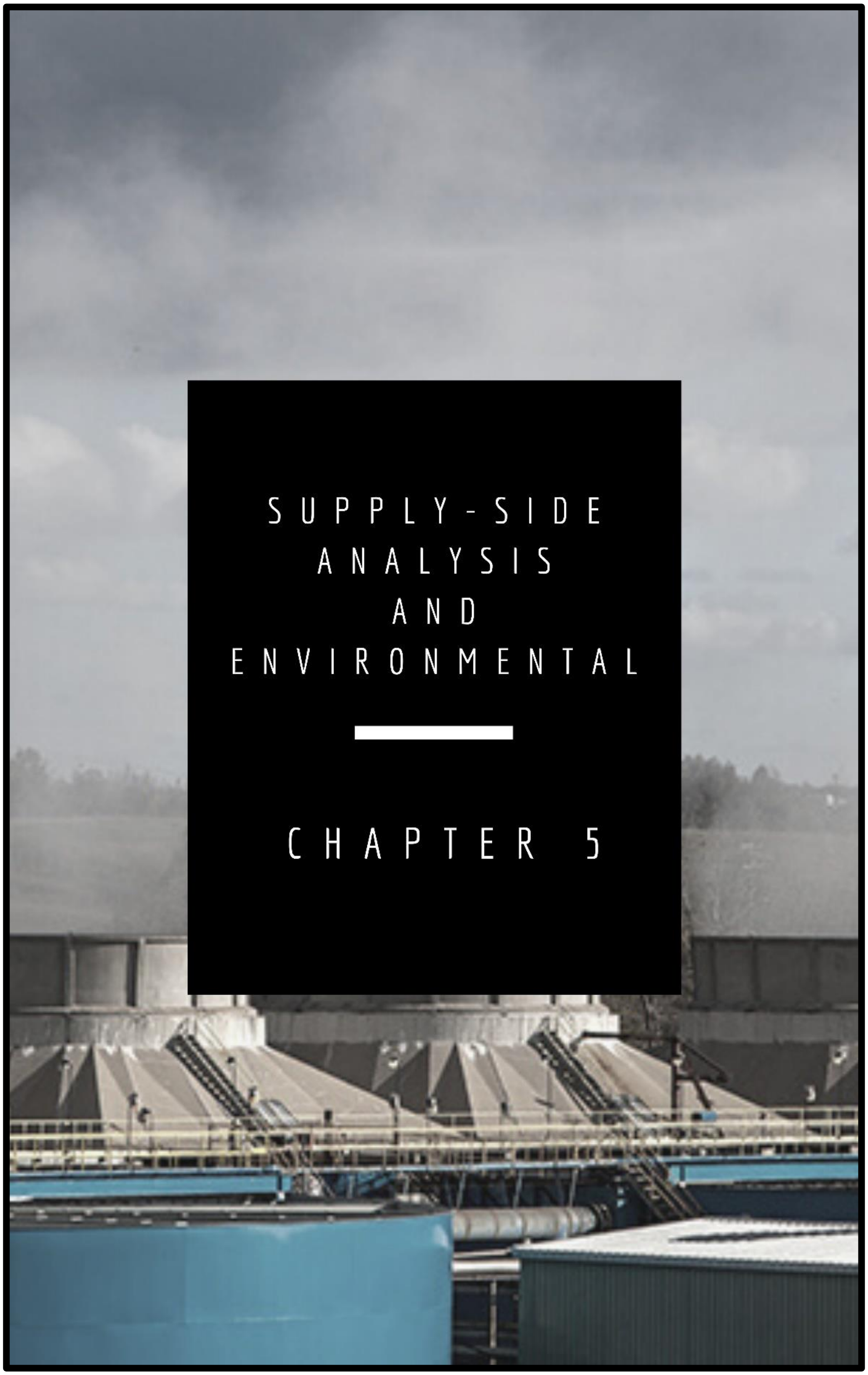
[36] CPP = Critical Peak Pricing.

- **Air Conditioner Cycling (50%)**: The very small margin by which this passes the TRC test (1.0) would not make it a strong candidate as it would be subject to changing drivers which could make it easily fail the test later. The fact that it fails the UCT test also means it would not be recommended for implementation.
- **Residential PTR**: The mass-market, low–cost structure is the reason this passes the TRC test. With no direct control, it does rely on consumer behavior to achieve savings, although there are existing programs around the country that have demonstrated success.
- **Time-of-Use and Critical Peak Pricing**: These dynamic pricing designs pass the TRC for both the residential and non-residential segments. As a program that relies on consumer behavior (in the form of responses to pricing changes) it does rely on properly designed price signals to achieve the desired effects.

4.9 Recommendation

At this time, based on the 2020 DSM Study's conclusions, Big Rivers has no plans to pursue additional energy efficiency or formal demand response programs. Energy efficiency programs will continue to be evaluated to determine if future programs can be designed to be effective at a retail level and effective for both residential and non-residential retail members. 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 will therefore focus its efforts on continuing to evaluate 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, also continue to monitor the cost-effectiveness of DR. Based on Clearspring recommendations in this study, Big Rivers will:

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


SUPPLY-SIDE
ANALYSIS
AND
ENVIRONMENTAL
CHAPTER 5

SUPPLY-SIDE ANALYSIS AND ENVIRONMENTAL

5.1 Generation Operations Update

Big Rivers places an emphasis on generation efficiency, and Big Rivers continues to make strides in generation efficiency improvements and asset value. As wholesale power market prices have dropped over the past few years, Big Rivers has been able to significantly lower the historical minimum generation limits on its generators in order to minimize losses in the MISO power market during off-peak hours, thereby keeping the units running and available for the peak hours in the market. Although operating at lower minimum generation levels negatively impacts heat rate during those hours, it further maximizes the value to Big Rivers' Members by also reducing the number of starts and shutdowns. For the Big Rivers base load units, the heat rate has improved 137 BTU/kWh or 1.2% in the 11-year period from 2009 to 2019. Refer to Figure 5.1 and Table 5.1.

Figure 5.1

System Net Heat Rate

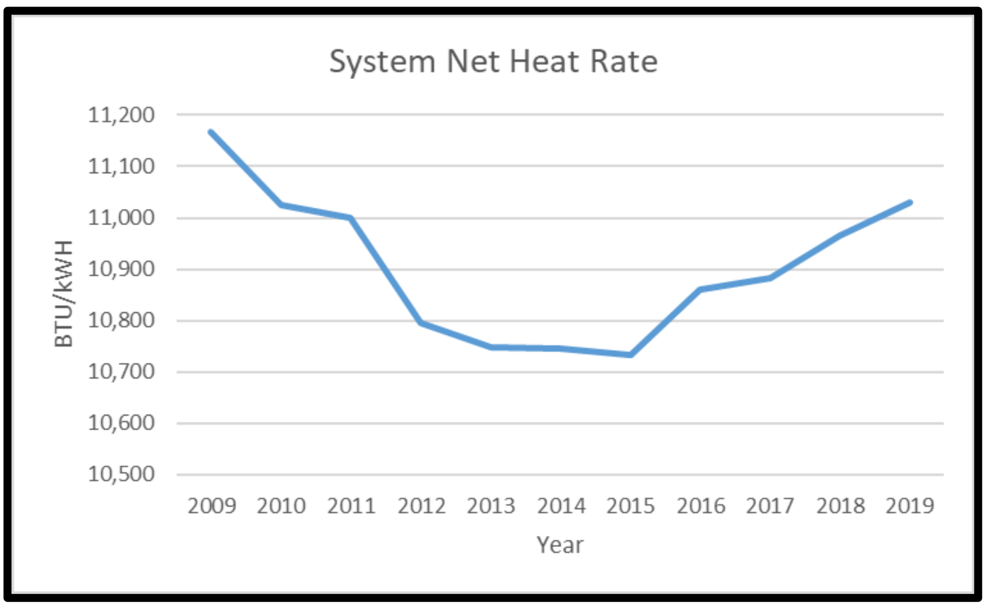


Table 5.1

System Net Heat Rate

<table>
<tr><th colspan="3">System Net Heat Rate</th></tr>
<tr><td>Year</td><td>BTU/kWH</td><td rowspan="12">2009
to
2019
Improvement

137 BTU/kWh

1.2 %</td></tr>
<tr><td>2009</td><td>11,167</td></tr>
<tr><td>2010</td><td>11,025</td></tr>
<tr><td>2011</td><td>11,001</td></tr>
<tr><td>2012</td><td>10,795</td></tr>
<tr><td>2013</td><td>10,747</td></tr>
<tr><td>2014</td><td>10,745</td></tr>
<tr><td>2015</td><td>10,733</td></tr>
<tr><td>2016</td><td>10,861</td></tr>
<tr><td>2017</td><td>10,883</td></tr>
<tr><td>2018</td><td>10,965</td></tr>
<tr><td>2019</td><td>11,030</td></tr>
</table>

Specific generation improvement activities within the last ten (10) years include:

- **High Performance Human Machine Interfaces**: Big Rivers installed High Performance Human Machine Interfaces at Wilson Station in 2019. This gives the Control Room Operators ("CROs") greater awareness, which leads to faster response times and better decisions when issues occur.
- **Operations Training Simulators:** Big Rivers utilizes Operations Training Simulators for training its Wilson and Green CROs. The Simulators provide a realistic reproduction of the generating unit operation in which unit start-ups, shutdowns, and malfunction responses can be taught and practiced by the CRO in a controlled environment without affecting actual unit performance. 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 examples of these maintenance activities include washing air heaters, cleaning condenser tubes, replacing leaking valves and traps, and repairing air/gas leaks.
- **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 Distributed Control System tuners), have continued to optimize the operational 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 5.2 presents the five year averages (2015-2019) of key performance indicators of the Big Rivers generating units.

Table 5.2

Key Performance Indicators per IEEE[37] Standards

Unit	Net Generation (MWHrs)	Net Heat Rate (BTU/kWH)	Gross Capacity Factor (%)	Gross Output Factor (%)	Equivalent Availability Factor (%)	Equivalent Forced Outage Rate (%)
Green 1	1,332,314	11,046	68.1	81.3	88.0	6.9
Green 2	1,293,751	11,270	67.9	80.5	94.2	3.4
Wilson 1	2,782,505	10,683	76.4	90.2	84.6	8.5
SYSTEM	5,408,855	10,913	72.0	85.4	88.9	6.3

Big Rivers continues to utilize the GKS® benchmarking service provided by Navigant Consulting to compare unit performance against its peers. Where possible, experienced employees at idled/retired units were re–deployed to enhance Big Rivers' effectiveness at the remaining generating stations. Wilson Station was awarded Runner-Up in the Medium Plant Category for the Operation Excellence Award in 2015 (five–year period from 2010 – 2014). The awards are based on a detailed analysis of cost, performance and safety data from Navigant's industry–leading GKS® database, which contains data for more than seventy percent (70%) of 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.

5.2 Operating Characteristics of Existing Big Rivers Resources

See Table 5.3, below for the operating characteristics of existing Big Rivers resources.

[37] Institute of Electrical and Electronics Engineers

Table 5.3

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		
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
R.A. Reid	2	Webster	Existing	March-1978	Combustion Turbine	65	65	Gas			2031*
D.B. Wilson	1	Ohio	Existing	November-1986	Steam Turbine	417	417	Coal	Oil	60 days	2045

** The expected Retirement Date of R.A. Reid Unit 2 (Reid CT) will depend greatly on the number of operating hours experienced over the next several years, with relatively low operating houurs and continued maintenance it should provide reasonably available capacity for a number of years into the future.*

5.3 Economics of Adding Solar

The transition from baseload coal resources to solar and other renewables is evident across the country. As recently as May 2020, the EIA touted that U. S. renewable energy consumption surpassed coal for the first time in over 130 years.[38] Utility scale solar growth is evident in that report. Additionally, prices for renewables remain favorable as described by Silvio Marcacci's article, "Renewable Energy Prices Hit Record Lows: How can Utilities Benefit from Unstoppable Solar And Wind"[39] on Forbes' website in January of 2020. This article describes the growth of solar despite federal tax incentives phasing out. Mr. Marcacci describes renewable energy as unstoppable, based on economics, and he states that smart utility policy design will include the economic opportunity that renewables bring. This article describes the cost of renewables falling to date. As evidenced by Big Rivers' recent application for Commission approval of three (3) solar power purchase agreements, Big Rivers concluded that these three agreements provide the lowest–cost resource option, and they also provide the benefits of a diversified generation/power source portfolio.

5.4 Reliability Considerations of Big Rivers' Optimal Plan

Big Rivers' Optimal Plan will not pursue complete abandonment of our valuable existing generation. With a mission to safely and reliably deliver low–cost power to our Member-Owners, Big Rivers considers reliability and other risks along with low cost. According to the testimony of MISO Chief Executive Officer John R. Bear before the House Committee on Energy and Commerce, Subcommittee on Energy on October 30, 2019, MISO has indicated that maintaining grid reliability beyond the 40% renewable penetration level

---

[38] https://www.eia.gov/todayinenergy/detail.php?id=43895.

[39] https://www.forbes.com/sites/energyinnovation/2020/01/21/renewable-energy-prices-hit-record-lows-how-can-utilities-benefit-from-unstoppable-solar-and-wind/#62d4d9db2c84.

becomes significantly more complex. Above that level, advanced technologies would be required to balance the MISO system to reduce renewable curtailments and regional transmission reliability issues and keep the system stable. Mr. Bear identified the path forward to continued reliability, which includes changes in market processes and protocols to adapt to the diverse regional energy and environmental policies. Some states in the MISO footprint have adopted aggressive de–carbonization policies which have prompted utilities within their borders to retire and replace numerous coal and gas resources with intermittent renewables, while other states continue to rely heavily on their legacy fossil resources. Mr. Bear noted declining reserve margins across MISO, divergent state energy policies, and trends that are reshaping the future of the electric industry as drivers of significant change that MISO would need to monitor to ensure reliability of the generation resource mix within the Bulk Electric System. Big Rivers believes that because of all of this change, there remains value in retaining our most efficient baseload resource and in identifying resources that will complement intermittent renewable resources in the future.

5.5 Consideration of Other Renewables and Distributed Generation

Wind power plants require careful planning. According to the EIA,[40] good places for wind turbines are where the annual average wind speed is at least 5.8 meters per second for utility-scale turbines. Wind power in Kentucky has so far exhibited limited potential for development within the state, with the EIA's own study showing average wind speeds between 5 and 5.5 meters per second. The current MISO Interconnection queue[41] contains only one wind project near Kentucky as depicted in Figure 5.2 below,

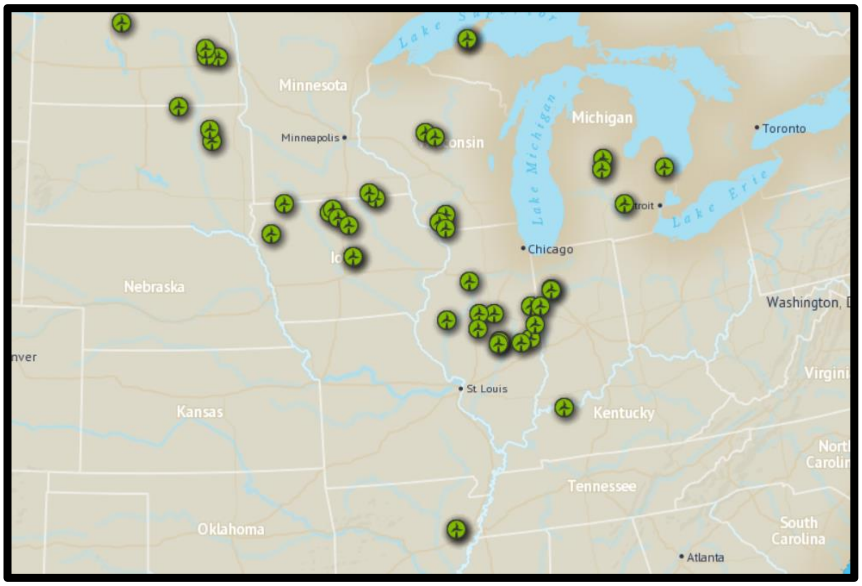
[40] https://www.eia.gov/energyexplained/wind/where-wind-power-is-harnessed.php

[41] https://api.misoenergy.org/PublicGiQueueMap/index.html

demonstrating that others have determined that Kentucky wind power plants are not yet widely viewed as economical.

Figure 5.2

MISO Generator Interconnection Queue – Current Wind Projects



Wind speeds vary with altitude, so depending on the height of the wind turbine, and more advancements in wind power technology, wind might someday be economical in Kentucky, but for development of Big Rivers' 2020 IRP, solar was the more viable alternative as discussed further in section 1.2.2, sections 5.3 and 5.4, above and in Chapter 8 (Base case analysis). The feasibility of solar was made even more evident when Big Rivers' Request for Proposals for solar power in 2019 yielded several respondents for supply of solar resources to be located in Meade, McCracken, Henderson and Webster counties in Big Rivers' service territory, demonstrating the viability and affordability of solar in the Company's service area. While only three were chosen, many more Kentucky projects were submitted.

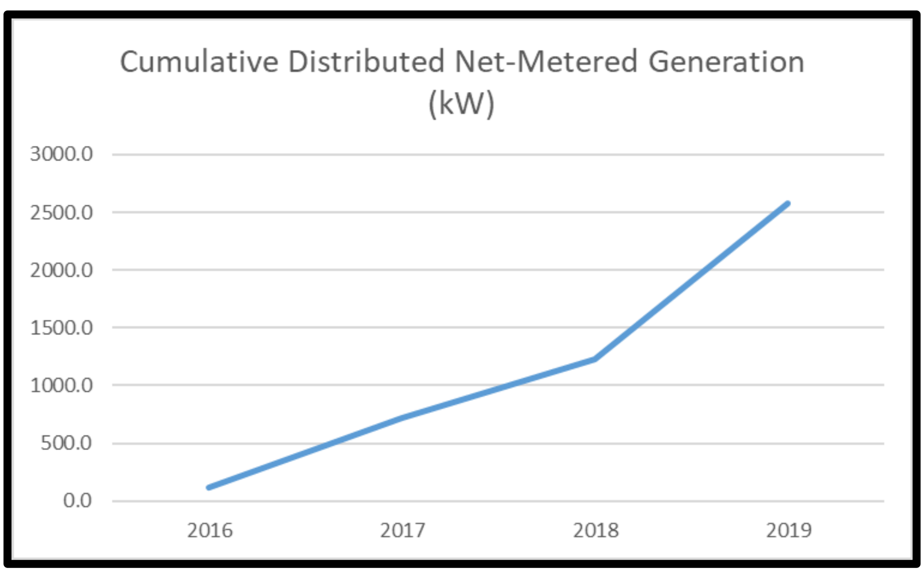
Big Rivers works with MISO transmission planning for proposed generation interconnections within the Big Rivers service territory. Solar or other projects which may be connected to the sub-transmission system or otherwise close to load, along with their costs are considered by Big Rivers when they are included in the proposals from potential suppliers. The MISO transmission expansion planning process allows consideration of non-transmission projects such as distributed generation as alternatives to planned transmission projects. In addition, Big Rivers continues to work with Direct-serve consumers wishing to build generation for co-generation purposes.

5.5.1 Net Metering Statistics

Net-metered distributed generation installations among retail members of the Member-Owners has increased significantly since 2016 to more than 2.5 MW. The impact of federal investment tax credit expiration and changes to net metering regulations in Kentucky have yet to be seen, but it is expected installations will wane beginning in 2020.

Figure 5.3

Cumulative Distributed Net-Metered Generation (kW)



5.6 Environmental

Big Rivers' generation system consists of three active coal–fired units (R.D. Green 1 & 2 and D.B. Wilson), and one natural gas combustion turbine (R.A. Reid CT). Big Rivers has also contracted for 178 MWs of hydroelectric capacity from the Southeastern Power Administration (SEPA). Additionally, Big Rivers recently filed an application with the Kentucky Public Service Commission for approval of three Power Purchase Agreements that, if approved, will give Big Rivers contractual rights to 260 MW of solar capacity from Community Energy (40 MW and 60 MW) and Geronimo Energy (160 MW). Four additional coal-fired units (R.A. Reid 1, K.C. Coleman 1, 2 & 3) are currently idled and set to be retired in 2020. Table 5.4 outlines Big Rivers' current generation portfolio:

Table 5.4

Big Rivers Generation Portfolio[42]

Unit	Net Capacity	Commercialized	Current Status	SO2 Control	Nox Control	MATS
Owned						
R.D. Green 1	231 MW	1979	Active	FGD	Coal re-burn	DSI/Carbon with FGD
R.D. Green 2	233 MW	1981	Active	FGD	Coal re-burn	DSI/Carbon with FGD
D.B. Wilson	417 MW	1986	Active	FGD	SCR Retrofit in 2004	SCR with FGD
R.A. Reid CT	65 MW	1976	Active	Natural Gas	Natural Gas	Natural Gas
Contracted						
SEPA	178 MW	N/A	Active	Hydoelectric	Hydoelectric	Hydoelectric
Community Energy Solar	100 MW	2023 (est.)	Pending KPSC Approval	Solar	Solar	Solar
Geronimo Energy	160 MW	2024 (est)	Pending KPSC Approval	Solar	Solar	Solar

5.6.1 Clean Air Regulations – Cross State Air Pollution Rule

The United States Environmental Protection Agency ("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 fossil fuel-fired Electric Generating Units ("EGU") at coal–, gas–, and oil–fired facilities in twenty–two (22) states to reduce both sulfur dioxide (SO_2) and oxides of nitrogen (NO_X) emissions to help downwind states attain fine particle and/or ozone

[42] This table does not include seven small solar demonstration projects which compose Big Rivers Solar Education Center (https://solar.bigrivers.com/)

compliance with the National Ambient Air Quality Standards ("NAAQS"). EPA sets a pollution limit (emission budget) for each of the states covered by CSAPR. Authorizations to emit pollution, known as allowances, are allocated by EPA to affected sources based on these state emissions budgets. Sources can buy and sell allowances and bank (save) allowances for future use as long as each source holds enough allowances to account for its emissions by the end of the compliance period.

Phase I allowances issued by EPA under CSAPR ran from January 1, 2016, through December 31, 2016, and Phase 2 allowances began January 1, 2017. Phase 2 allowance allocations were reduced by approximately 55 percent (55%) for SO_2, 10 percent (10%) for NO_x annual, and 50 percent (50%) for NO_x seasonal as compared to Phase 1 allocations. 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. Phase 2 SO_2 allowances issued to Big Rivers under CSAPR are presently sufficient to meet the emissions of the operating facilities as a whole. However, due to the age and inefficiency of its flue gas desulphurization ("FGD") system, Wilson Station has operated under an $S0_2$ allocation deficit annually since 2017. As part of its 2020 ECP filed with the Commission, Big Rivers sought approval of a project to replace and upgrade the FGD system by recycling the Coleman Station FGD/absorber system. In its order dated August 6, 2020, the Commission approved that project.[43] That approved project, once implemented, will allow Wilson Station to operate within its annual emission allowance. Additionally, Big Rivers maintains a bank of approximately 42,000 SO_2 allowances as of May 2020.

On September 7, 2016, EPA revised the CSAPR ozone season NO_X program by finalizing an update to CSAPR for the 2008 ozone NAAQS, known as the CSAPR Update. The CSAPR Update ozone season

[43] See *In the Matter of: Electronic Application of Big Rivers Electric Corporation for Approval of its 2020 Environmental Compliance Plan, Authority to Recover Costs Through a Revised Environmental Surcharge and Tariff, the Issuance of a Certificate Of Public Convenience and Necessity for Certain Projects, and Appropriate Accounting and Other Relief* – Case No. 2019-00435. Application filed February 7, 2020; Final Order issued August 6, 2020.

NO_X program largely replaced the original CSAPR ozone season NO_X program as of May 1, 2017. The CSAPR Update further reduced summertime NO_X emissions from power plants in the eastern U.S. On December 6 2018, EPA concluded that the provisions of the CSAPR Update were sufficient to address the "good neighbor" provisions of the Clean Air Act (“CAA”), which require states to tackle interstate movement of air pollution. The CSPAR Update would effectively end the obligation of most states, including Kentucky, to continue to reduce emissions under the rule.

On September 13, 2019, the United States Court of Appeals for the District of Columbia Circuit held that the CSAPR Update unlawfully allows significant contribution to continue beyond downwind attainment deadlines and therefore remanded the rule to EPA to address the court’s holding. EPA is currently considering its options for handling the Court’s remand. Big Rivers is closely monitoring the situation and any impacts it may have on operations.

5.6.2 Mercury and Air Toxics Standards

To meet the Mercury and Air Toxics Standards (“MATS”) requirements, Big Rivers installed Activated Carbon Injection with Dry Sorbent Injection (“DSI”) on Green Units 1 and 2. The system was placed into operation in April 2016. Wilson Station has Selective Catalytic Reduction (“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. However, Wilson Station's existing FGD system has exceeded its expected useful life, represents dated and ineffective technology, and requires significant ongoing investment to operate and maintain. In its 2020 Environmental Compliance plan filed with the Commission, Big Rivers sought and secured the Commission’s approval to replace and upgrade the FGD system by recycling the Coleman Station FGD/absorber system by moving it to the Wilson Station.

The Coleman units were idled in May 2014 and Reid Unit 1 last operated in February, 2015 and therefore, have not operated past the April 2015 compliance date for MATS. These units are set to retire in 2020 and, therefore, will not be subject to ongoing MATS compliance.

On April 16, 2020, EPA completed a reconsideration of the "appropriate and necessary" finding for the MATS rule. EPA stated that the reconsideration was intended to correct flaws in the approach to considering costs and benefits while still ensuring that hazardous air pollutant emissions from power plants continued to be appropriately controlled. However, this reconsideration only related to the cost benefit analysis and did not remove coal– and oil–fired power plants from the list of affected source categories for regulation. Various environmental and civil rights organizations have filed suit against EPA alleging that the agency's reconsideration of the cost–benefit process was unlawful. Additionally, several coal industry related organizations have filed suit claiming that the entire MATS rule should be vacated in its entirety as a result of EPA's reconsideration of the "appropriate and necessary" finding. Until such time as the courts resolve the various challenges to the rule, the MATS standards remain in effect and Big Rivers will continue to operate the control equipment as designed. Given the potential operational impacts, Big Rivers is actively monitoring the ongoing MATS litigation matters.

5.6.3 Coal Combustion Residuals

Coal Combustion Residuals ("CCR") are residues from the combustion of coal and include fly ash, bottom ash, and scrubber waste. EPA published the final rule regulating the disposal of CCR waste in the Federal Register on April 17, 2015 ("CCR Rule"). The rule finalized regulations to provide a comprehensive set of requirements for the safe disposal of CCRs, commonly known as coal ash, from coal-fired power plants. 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. On August 21, 2018, the United States Court of Appeals for the District of Columbia Circuit vacated much of EPA's final rule regulating the disposal of CCRs at coal-fired power plants.

In light of the Court's ruling, and in response to other regulatory developments, in November 2019 and March 2020, EPA issued a new series of proposed rules (referred to as Parts A and B) that it refers to as a "Holistic Approach to Closure." Part A provides the following revisions:

- Establishing a new deadline of April, 2021, for all unlined surface impoundments and those surface impoundments that failed the location restriction for placement above the uppermost aquifer to stop receiving waste and begin closure or retrofit.
- Establishing procedures for facilities to obtain additional time to develop alternate capacity to manage their wastestreams (both coal ash and non–coal ash) before they have to stop receiving waste and initiate closure of their coal ash surface impoundments.
- Changing the classification of compacted–soil–lined or clay–lined surface impoundments from "lined" to "unlined".
- Revising the coal ash regulations to specify that all unlined surface impoundments are required to retrofit or close.

Part B includes the following proposals:

- Procedures to allow facilities to request approval to use an alternate liner for CCR surface impoundments;
- Two co–proposed options to allow the use of CCR during unit closure;
- An additional closure option for CCR units being closed by removal of CCR; and
- Requirements for annual closure progress reports.

EPA published the final version of the Part A rule in the Federal Register on August 28, 2020 and publication of the final version of the Part B rule is expected in the near future. Big Rivers is following the developments closely to determine what impacts they may have on operations and on its closure plans for its CCR facilities listed below.

EPA issued a pre-publication version of the Effluent Limitation Guidelines on August 31, 2020. Among other revisions, it provides for an exemption from the rule for units that cease operation by December 31, 2020. Like the CCR revisions, Big Rivers is determining what impacts these revisions may have on operations of its coal-fired units.

Big Rivers operates, or has operated, three facilities that utilize ash pond (surface impoundments) – Coleman Station, Green Station, and Reid Station/HMP&L Station Two. Initially, Big Rivers installed groundwater monitoring as required by the CCR Rule around the Green and Station Two ash ponds. Under the original CCR Rule, the ash pond at Coleman Station, which Big Rivers idled in May 2014, was considered a "legacy pond" and as such was not subject to the provisions of the CCR Rule. The provisions regarding exemptions for "legacy ponds" were overturned by the August 2018 Court ruling referenced above. EPA is currently evaluating the future treatment of such "legacy ponds." In its 2020 ECP filing with the Commission, Big Rivers sought approval of its plans to close the ash ponds at Coleman Station, Green Station, and Station Two pursuant to the current or expected requirements of the CCR Rule. The Commission's August 6, 2020, Order approved Big Rivers' plan for the Green and Station Two ash ponds and conditionally approved Big Rivers' plan for the Coleman ash pond. All pond closure activities will be conducted in compliance with the revised CCR Rules.

Big Rivers also operates two special waste landfills, one located at the Green Station and one located at Wilson Station. Both landfills had existing groundwater monitoring wells used to comply with the CCR requirement. As a part of its 2020 ECP filing, Big Rivers has also sought approval to install a final cover system for Phase 1 of the Wilson Station landfill. The Commission's August 6, 2020, Order on Big Rivers' 2020 ECP approved this project.

Finally, Big Rivers has established a publicly-accessible web site (http://www.bigrivers.com/environmental-services/big-rivers-electric-corporation-ccr-rule-compliance-and-data-information/) and has populated the site with the reports and studies required to date.

5.6.4 Clean Water Act, Section 316(b)

In order to comply with Section 316(b) of the Clean Water Act, both Big Rivers' Wilson and Green Stations utilize the 'Best Available Control Technology' with a closed cooling water system operating at each facility. As Reid 1 and the Coleman units are currently idled and scheduled to be retired in 2020, they are not subject to Section 316(b).

5.6.5 Affordable Clean Energy Rule

On June 19, 2019, EPA simultaneously repealed the Clean Power Plan rule and issued its replacement, the Affordable Clean Energy ("ACE") rule. The ACE rule establishes emission guidelines for states to use when developing plans to limit carbon dioxide (CO_2) for coal-fired EGUs. The ACE rule establishes heat rate improvement ("HRI"), or efficiency improvement, as the best system of emissions reduction of CO_2 from coal-fired units. The rule lists six HRI "candidate technologies," as well as additional operating and maintenance practices designed to reduce emissions. The candidate technologies include:

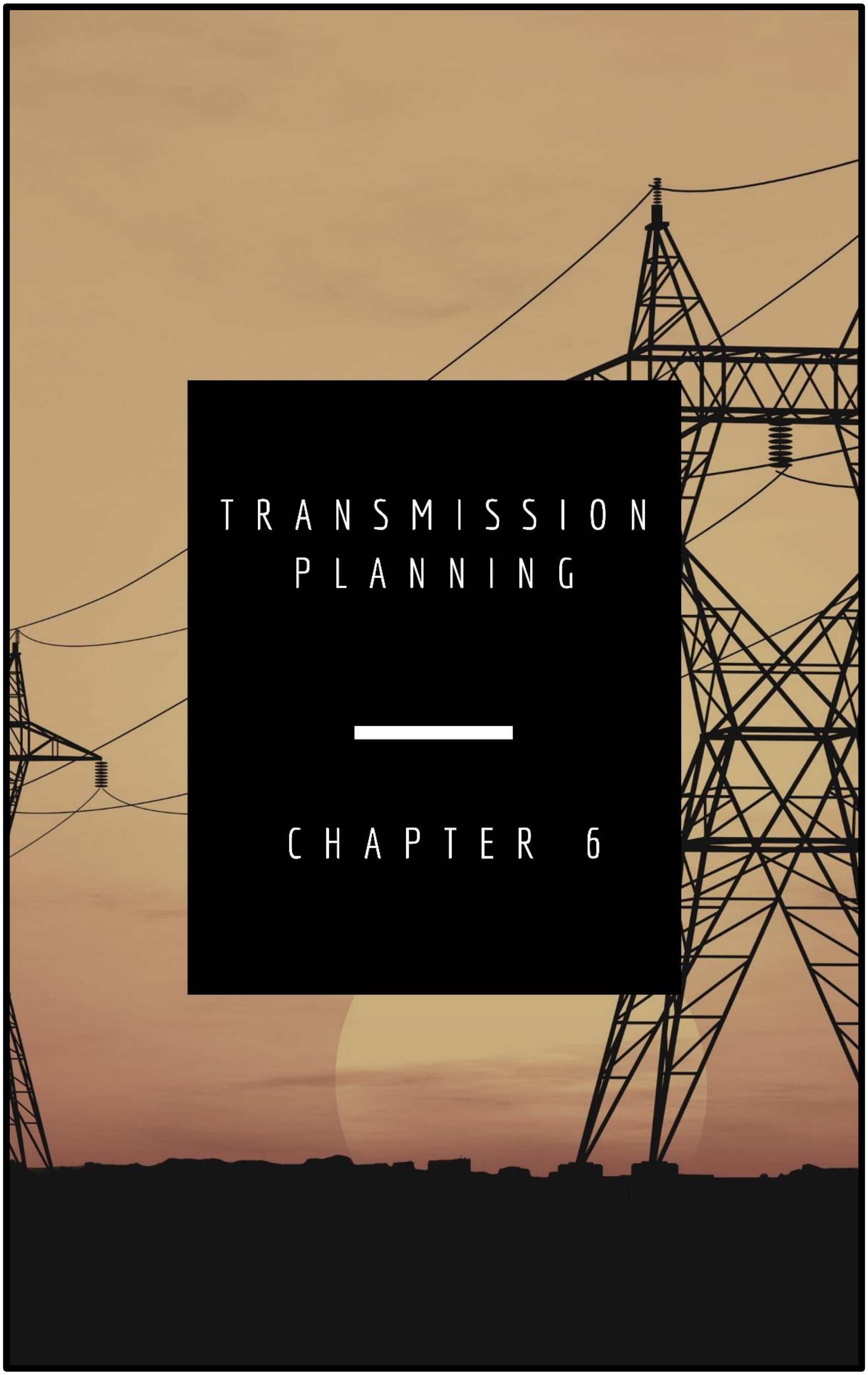
- Neural Network/Intelligent Sootblowers,
- Boiler Feed Pumps,
- Air Heater and Duct Leakage Control,
- Variable Frequency Drives,
- Blade Path Upgrade (Steam Turbine), and

- Redesign/Replace Economizer.

Kentucky is currently in the process of collecting data regarding the EGUs throughout the Commonwealth and developing a proposed plan by which it will evaluate the impact on emissions that each of the candidate technologies would have at the unit level. Upon completion of this process, Kentucky will submit an implementation plan to EPA that establishes CO_2 emission limitation standards for each affected EGU and will include measures that provide for the implementation and enforcement of such standards. State plans must be submitted to EPA by July 8, 2022. Big Rivers is actively involved with several industry groups to provide input to the state on the development of that implementation plan.

5.7 Environmental Study

As outlined above, Big Rivers has closely analyzed all relevant environmental compliance provisions and has outlined plans to achieve compliance within the time allowed by the regulations. These plans may be modified by the outcome of additional litigation against nearly every newly proposed regulation. Big Rivers will continue to monitor the outcome of the litigation or regulatory modifications to the rules and will make any necessary adjustments to meet modified compliance limits or schedules.


TRANSMISSION
PLANNING
CHAPTER 6

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.

6.1 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 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:** Develop a transmission plan 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 the 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 planning processes with neighbors and work to eliminate barriers to reliable and efficient operations.

6.2 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. Transfer capability values can vary significantly due to a number of factors. Based on study results, a simultaneous net import capability of approximately 900 MW is expected. These study results and real-time experiences have demonstrated 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 Member load.

6.3 Transmission System Optimization and Expansion

With respect to the improvement and more efficient utilization of existing Big Rivers transmission facilities during the period from 2015 through July of 2020, Big Rivers constructed and placed in service approximately eight (8) miles of new transmission line to serve three (3) new delivery point substations of its Members. To increase transmission line current ratings, approximately twelve (12) miles of 69 kV and one (1) mile of 161 kV lines were reconductored with higher current capacity conductors. Additionally, Big Rivers reviews facility rating practices on an annual basis. As part of this review, rating assumptions are evaluated for opportunities for increased facility ratings. In 2020, the process used by Big Rivers to provide ambient adjusted ratings to MISO was automated. This ensures that Big Rivers' transmission facilities are efficiently utilized within real-time operations.

A MISO market efficiency project was completed on June 11, 2020. This project consists of a new 345 kV circuit from CenterPoint's Duff Substation in Dubois County, Indiana to Big Rivers' Coleman EHV Substation in Hancock County, Kentucky. The line is thirty-one (31) miles in length and is expected to fully mitigate transmission congestion in the area of Big Rivers' Coleman EHV Substation.

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 2015-2034 time period is presented in Table 6.1 and **CONFIDENTIAL** Table 6.2.

Table 6.1

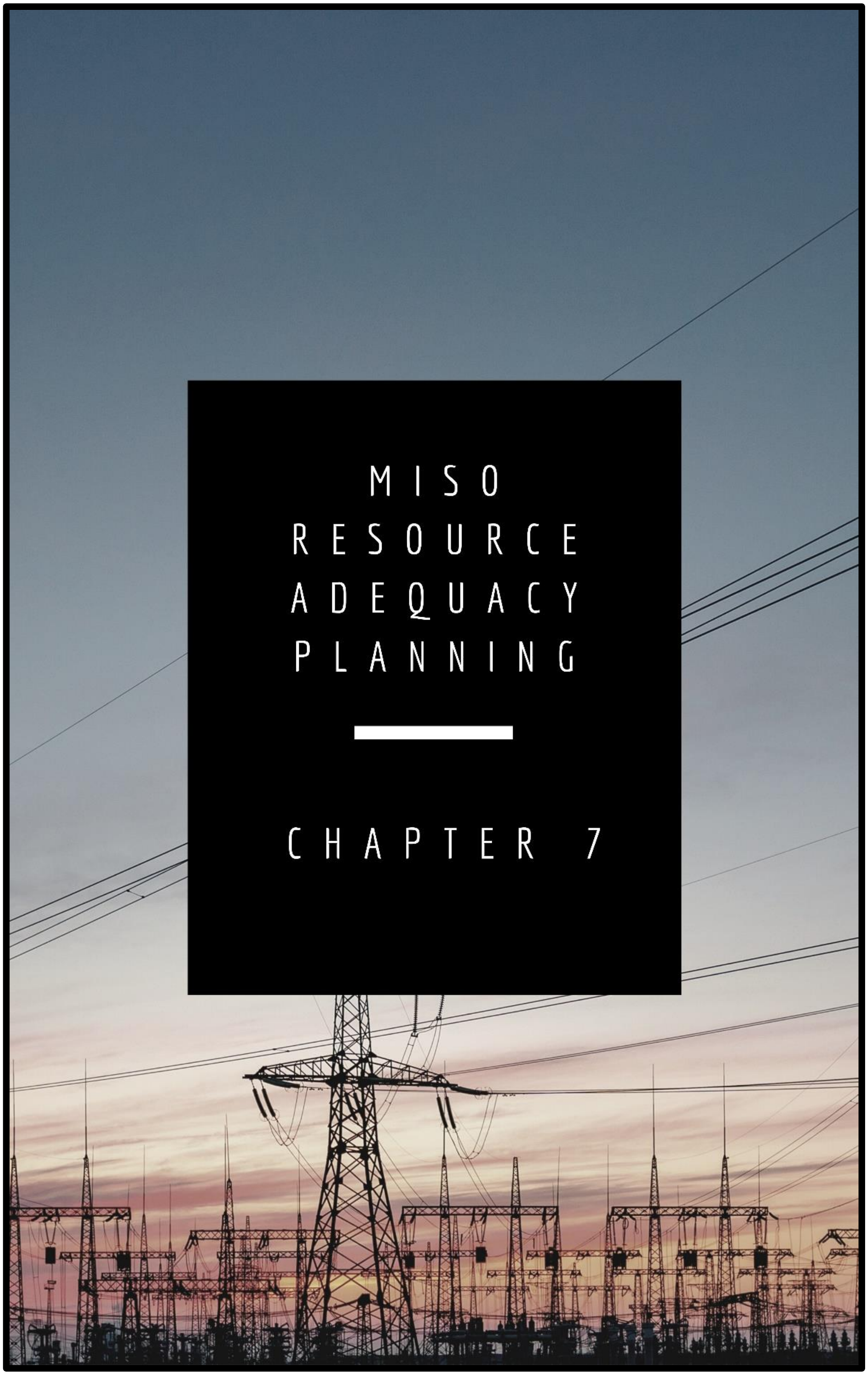
Completed System Additions (2015 – 2020)

Project Description	Year
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
Reid EHV Substation expansion and 69 kV line addition	2018
Meade Co. – Andyville 69 kV line reconductor	2018
Hardinsburg 161/69 kV transformer replacements (2)	2019
Reid EHV-Reid 161 kV Circuit 1 and Circuit 2 reconductor	2019
Coleman – Coleman EHV 161 kV lines 1 and 2 upgrade	2019
Reid EHV and Reid capacitors enlargement and improvement	2020
Fort Avenue 69 kV service	2020
Morganfield – Gallatin 69 kV line reactor	2020
Hardinsburg 1 to Harned 69 kV line reconductor	2020
Coleman EHV – Duff (Vectren) 345 kV line addition	2020
Irvington – Irvington Junction 69 kV line reconductor	2020

Table 6.2

Planned System Additions (2020 – 2034)

Project Description	Year
[redacted]	[redacted]



MISO RESOURCE ADEQUACY PLANNING

CHAPTER 7

MISO RESOURCE ADEQUACY PLANNING

Per the Commission's Order approving Big Rivers' request to join MISO in Case No. 2010-00043,[44] 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, including MISO's Module E-1 Resource Adequacy mechanism. Big Rivers also regularly files its IRPs 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.

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

MISO's module E-1 provides mandatory requirements to ensure access to deliverable, reliable and adequate Planning Resources to meet demand requirements. MISO's mission is to enable reliable delivery of low-cost energy through efficient operations and planning. MISO's resource adequacy mechanism, implemented in 2009, has three primary components: (1) a MISO footprint-wide planning reserve margin, (2) standardized resource qualifications, and (3) 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.

---

[44] See *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. Subsequent to this proceeding, MISO changed its name from Midwest Independent Transmission System Operator, Inc., to Midcontinent Independent System Operator, Inc.

- **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.

7.2 MISO Resource Adequacy Planning

Module E-1 (Resource Adequacy) of MISO's tariff[45] includes an annual Planning Resource Auction ("PRA") to provide a way for Market Participants to meet resource adequacy requirements. This auction is a mechanism for MISO to ensure that LSE's serving load in the MISO region have sufficient Planning Resources to meet their anticipated peak demand requirements plus an appropriate reserve margin.

Some features of the Planning Resource Auction include forward transparent capacity pricing signals, recognizing congestion that limits aggregate deliverability and complementing state resource planning processes. The PRA uses offers of planning resources in conjunction with import and export constraints, local clearing requirements, and other inputs to determine the least cost set of offers that respects those constraints. Each year, MISO performs studies to evaluate current market conditions to forecast future planning environments. The MISO Loss of Load Expectation ("LOLE")[46] 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.

[45] https://www.misoenergy.org/legal/

[46] https://www.misoenergy.org/planning/resource-adequacy/#nt=%2Fplanningdoctype%3APRA%20Document%2Fplanningyear%3APY%2020-21&t=10&p=0&s=&sd=

7.2.1 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 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.

7.2.2 Module E Capacity Tracking Tool

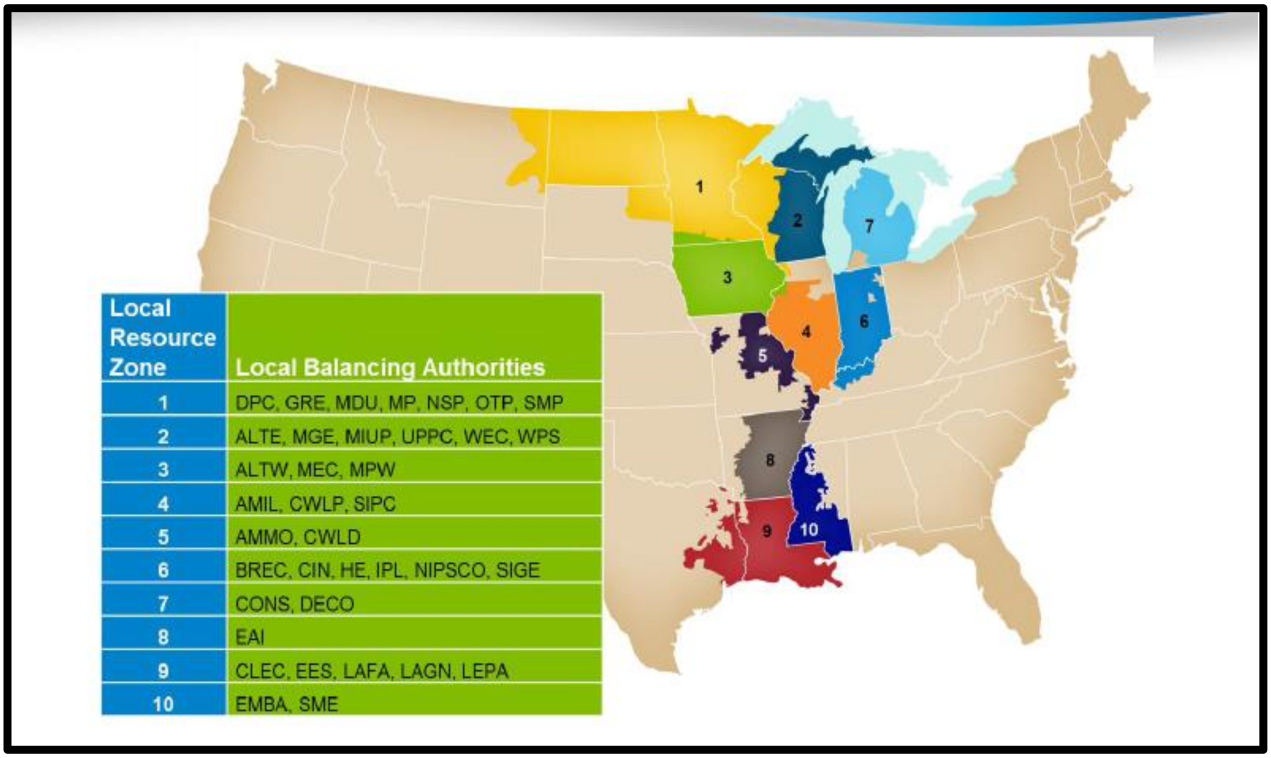
MISO utilizes their Module E Capacity Tracking Tool ("MECT") to collect data from Market Participants including demand forecast, resource qualification, bilateral capacity transaction information, as well as to designate capacity to meet their Planning Reserve Margin requirements in the Planning Resource Auction.

7.2.3 2020 Loss of Load Expectation Study

MISO conducts an annual LOLE study to determine a Planning Reserve Margin, Unforced Capacity ("UCAP"), zonal per-unit Local Reliability Requirements ("LRR"), Zonal Import Ability, Zonal Export Ability, Capacity Import Limits and Capacity Export Limits. The results of the study and its deliverables supply inputs to the MISO Planning Resource Auction.

Figure 7.1

MISO Local Resource Zone Map



Local Resource Zone	Local Balancing Authorities
1	DPC, GRE, MDU, MP, NSP, OTP, SMP
2	ALTE, MGE, MIUP, UPPC, WEC, WPS
3	ALTW, MEC, MPW
4	AMIL, CWLP, SIPC
5	AMMO, CWLD
6	BREC, CIN, HE, IPL, NIPSCO, SIGE
7	CONS, DECO
8	EAI
9	CLEC, EES, LAFA, LAGN, LEPA
10	EMBA, SME

Big Rivers is located in MISO's regional zone 6, along with entities in Indiana, as shown in The MISO Local Resource Zone Map above.

In accordance with the Business Practice Manual BPM011-Resource Adequacy,[47] MISO establishes a Planning Reserve Margin using a LOLE study for the upcoming MISO Planning Year. The LOLE study is consistent with Good Utility Practice, reliability requirements, and applicable states in the MISO Region. The PRM analysis considers factors including, but not limited to: generator forced outage rates of capacity resources, generator planned outages, expected performance of load modifying resources and energy efficiency resources, load forecast uncertainty, and the Transmission System's import and export capability

[47] https://www.misoenergy.org/legal/business-practice-manuals/

with external systems. MISO calculates and publishes the estimated PRM for each of the nine subsequent planning years to provide information for long-term resource planning, without establishing any enforceable specific resource planning reserve requirements beyond the upcoming planning year. The outcome of the LOLE study determines the appropriate PRM for the applicable Planning Year based on the probabilistic analysis of being able to reliably serve MISO's Coincident Peak Demand such that the LOLE is one (1) day in ten (10) years, or 0.1 day per year.

The MISO analysis for 2020 shows that the system would achieve this reliability level when the amount of installed capacity available is 1.18 times that of the MISO system coincident peak. This equates to an 18.0% Planning Reserve Margin requirement for 2020/2021 based on installed capacity ("ICAP") per unit Local Reliability Requirements of Local Resource Zone Peak Demand. The equivalent UCAP PRM is 8.9%.

7.2.4 LOLE Modeling Input Data and Assumptions

MISO uses a program managed by Astrapé Consulting called Strategic Energy and Risk Valuation Model ("SERVM") to calculate the LOLE for the applicable planning year. SERVM uses a sequential Monte Carlo simulation to model a generation system and to assess the system's reliability based on any number of interconnected areas. SERVM calculates the annual LOLE for the MISO system and each Local Resource Zone ("LRZ") 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, weather and economic uncertainty, and external support.

Building the SERVM model is the most time-consuming task of the PRM study. Many scenarios are built in order to determine how certain variables impact the results. The base case models determine the MISO PRM ICAP, PRM UCAP and the LRRs for each LRZ for years one, four and six.

7.2.5 MISO Generation

The 2020-2021 planning year LOLE study used the 2019 PRA converted capacity as a starting point for identifying resources to include in the study. This ensured that only resources eligible as a Planning Resources were included in the LOLE study. An exception was made for resources with a signed Generator Interconnection Agreement (GIA) with an anticipated in-service date for the 2020-2021 Planning Year. These resources were also included. All internal Planning Resources were modeled in the LRZ in which they are physically located. Additionally, Coordinating Owners and Border External Resources were modeled as being internal to the LRZ in which they are committed to serving load.

Forced outage rates and planned maintenance factors were calculated over a five–year period (January 2014 to December 2018) and modeled as one value for each unit. Some units did not have five years of historical data in MISO's Generator Availability Data System (PowerGADS)[48]. However, if they had at least twelve (12) consecutive months of data then unit–specific information was used to calculate their forced outage rates and maintenance factors. Units with fewer than twelve (12) consecutive months of unit–specific data were assigned the corresponding MISO class average forced outage rate and planned maintenance factor based on their fuel type. Any MISO class with fewer than thirty (30) units were assigned the overall MISO weighted class average forced outage rate of 9.24 percent.

Additional data was gathered for Behind-the-Meter Generation and Sales to neighboring capacity markets as well as firm off-system transactions. Generators with approved suspensions or retirements through MISO's Attachment Y process were removed from the analysis. Future thermal generation and upgrades were added to the LOLE model based on unit information in the MISO Generator Interconnection Queue.

[48] Generator Availability Data System

Intermittent Resources such as run–of–river hydro, biomass and wind were explicitly modeled as demand-side resources. Demand Response data came from the MECT tool.

7.2.6 MISO Load Data

The 2020-2021 LOLE analysis used a load training process with neural net software to create a neural–net relationship between historical weather and load data. This relationship was then applied to thirty (30) years of hourly historical weather data to create thirty (30) different load shapes for each LRZ in order to capture both load diversity and seasonal variations. The average monthly loads of the predicted load shapes were adjusted to match each LRZ's Module E 50/50 monthly zonal peak load forecasts for each study year.

Direct Control Load Management and Interruptible Demand types of demand response were explicitly included in the LOLE model as resources. These demand resources are implemented in the LOLE simulation before accumulating LOLE or shedding of firm load.

7.2.6.1 Weather Uncertainty

MISO has adopted a six–step load training process in order to capture the weather uncertainty associated with the 50/50 load forecasts, utilizing thirty (30) years of historical weather data in order to predict/create thirty (30) years' worth of load shapes for each LRZ. By adopting this methodology for capturing weather uncertainty, MISO is able to model multiple load shapes based off a functional relationship with weather. This modeling approach provides a variance in load shapes, as well as the peak loads observed in each load shape. This approach also provides the ability to capture the frequency and duration of severe weather patterns.

7.2.6.2 Economic Load Uncertainty

To account for economic load uncertainty in the 2020–2021 planning year LOLE model, MISO utilized a normal distribution of electric utility forecast error accounting for projected and actual

Gross Domestic Product ("GDP"), as well as electricity usage. The historic projections for GDP growth were taken from the Congressional Budget Office , the actual GDP growth was taken from the Bureau of Economic Analysis, and the electric use was taken from the EIA. Due to lack of statewide projected GDP data MISO relied on United States aggregate level data when calculating the economic uncertainty.

In order to calculate the electric utility forecast error, MISO first calculated the forecast error of GDP between the projected and actual values. The resulting GDP forecast error was then translated into electric utility forecast error by multiplying by the rate at which electric load grows in comparison to the GDP. Finally, a standard deviation was calculated from the electric utility forecast error and used to create a normal distribution representing the probabilities of the load forecast errors ("LFE") as shown in the Economic Uncertainty Table 7.2 below.

Table 7.1

Load Forecast Errors

	LFE Levels				
	-2.0%	-1.0%	0.0%	1.0%	2.0%
Standard Deviation in LFE	Probability assigned to each LFE				
0.95%	5.7%	24.2%	40.1%	24.2%	5.7%

7.2.7 External System

Within the LOLE study, a one (1) MW increase of non-firm support from external areas leads to a one (1) MW decrease in the reserve margin calculation. It is important to account for the benefit of being part of the eastern interconnection while also providing a stable result. Historically, MISO modeled the external system, including non-firm imports, in the LOLE study, which resulted in year–over–year volatility in the

PRM. In order to provide a more stable result and remove the false sense of precision, the external non-firm support was set at an ICAP of 2,987 MW and a UCAP of 2,331 MW.

Firm imports from external areas to MISO are modeled at the individual 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 units are only modeled within the MISO PRM analysis and are not modeled when calculating the LRZ Local Reliability Requirements. Due to the locational Tariff filing,[49] Border and Coordinating Owners' external resources are no longer considered firm imports. Instead, these resources are modeled as internal MISO units and are included in the PRM and LRR analysis. The external resources to include for firm imports were based on the amount offered into the 2019–2020 Planning Year PRA. This is a historically accurate indicator of future imports. For the 2019–2020 Planning Year, this amount was 1,626 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 was removed from the model.

7.2.8 Loss of Load Expectation Analysis and Metric Calculations

Upon completion of the SERVM database, MISO determined the appropriate PRM ICAP and PRM UCAP for the 2020–2021 Planning Year as well as the appropriate Local Reliability Requirement for each of the 10 LRZ's. These metrics were determined by a probabilistic LOLE analysis such that the LOLE for the planning year was one day in 10 years, or 0.1 day per year.

[49] https://www.misoenergy.org/search/#q=locational%20tariff%20filing&t=10&p=0&s=&sd=&f=

7.2.8.1 MISO-Wide LOLE Analysis and PRM Calculation

For the MISO-wide analysis, generating units were modeled as part of their appropriate LRZ as a subset of a larger MISO pool. The MISO system was modeled with no internal transmission limitations. In order to meet the reliability criteria of 0.1 day per year LOLE, capacity is either added or removed from the MISO pool. The minimum amount of capacity above the 50/50 net internal MISO Coincident Peak Demand required to meet the reliability criteria was used to establish the PRM values.

The minimum PRM requirement is determined using the LOLE analysis by either adding or removing capacity until the LOLE reaches 0.1 day per year. If the LOLE is less than 0.1 day per year, a perfect negative unit with zero forced outage rate is added until the LOLE reaches 0.1 day per year. The perfect negative unit adjustment is akin to adding load to the model. If the LOLE is greater than 0.1 day per year, proxy units based on a unit of typical size and forced outage rate were added to the model until the LOLE reaches 0.1 day per year.

For the 2020–2021 Planning Year, the MISO PRM analysis removed capacity (7,950 MW) using the perfect unit adjustment.

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

$$\text{PRM (ICAP)} = \frac{\textbf{[}\text{ (Installed Capacity + Firm External Support ICAP + ICAP Adjustment to meet a LOLE of 0.1 Days per Year) } \textit{minus} \text{ MISO Coincident Peak Demand } \textbf{]}}{\text{MISO Coincident Peak Demand}}$$

$$\text{PRM (UCAP)} = \frac{\textbf{[}\text{ (Unforced Capacity + Firm External Support UCAP + UCAP Adjustment to meet a LOLE of 0.1 Days per Year) } \textit{minus} \text{ MISO Coincident Peak Demand } \textbf{]}}{\text{MISO Coincident Peak Demand}}$$

Where Unforced Capacity (UCAP) = Installed Capacity (ICAP) x (1 – XEFORd).

7.2.8.2 LRZ LOLE Analysis and Local Reliability Requirement Calculation

For the LRZ analysis, each LRZ included only the generating units within the LRZ (including Coordinating Owners and Border External Resources) and was modeled without consideration of the benefit of the LRZ's import capability. Much like the MISO-wide analysis, unforced capacity is either added or removed in each LRZ such that a LOLE of 0.1 day per year is achieved. The minimum amount of unforced capacity above each LRZ's Peak Demand that was required to meet the reliability criteria was used to establish each LRZ's LRR.

The 2020–2021 LRR is determined using the LOLE analysis by either adding or removing capacity until the LOLE reaches 0.1 day per year for the LRZ. If the LOLE is less than 0.1 day per year, a perfect negative unit with zero forced outage rate will be added until the LOLE reaches 0.1 day per year. If the LOLE is greater than 0.1 day per year, proxy units based on a unit of typical size and forced outage rate were be added to the model until the LOLE reaches 0.1 day per year.

For the 2020–2021 Planning Year, only LRZ-3, LRZ-4, and LRZ-8 had sufficient capacity internal to the LRZ to achieve the LOLE of 0.1 day per year as an island. In the seven zones without sufficient capacity as an island, proxy units of typical size (160 MW) and class-average EFORd (4.65 percent) were added to the LRZ. When needed, a fraction of the final proxy unit was added to achieve the exact LOLE of 0.1 day per year for the LRZ.

7.3 Planning Year 2020 – 2021 MISO Planning Reserve Margin Results

For the 2020–2021 Planning Year, the ratio of MISO capacity to forecasted MISO system peak demand yielded a planning ICAP reserve margin of 18.0 percent and a planning UCAP reserve margin of 8.9 percent. These PRM values assume 1,572 MW UCAP of firm and 2,331 MW UCAP of non-firm external support. See Planning Year 2020–2021 MISO System Planning Reserve Margins Table, Table 7.2.

Table 7.2

MISO System Planning Reserve Margin

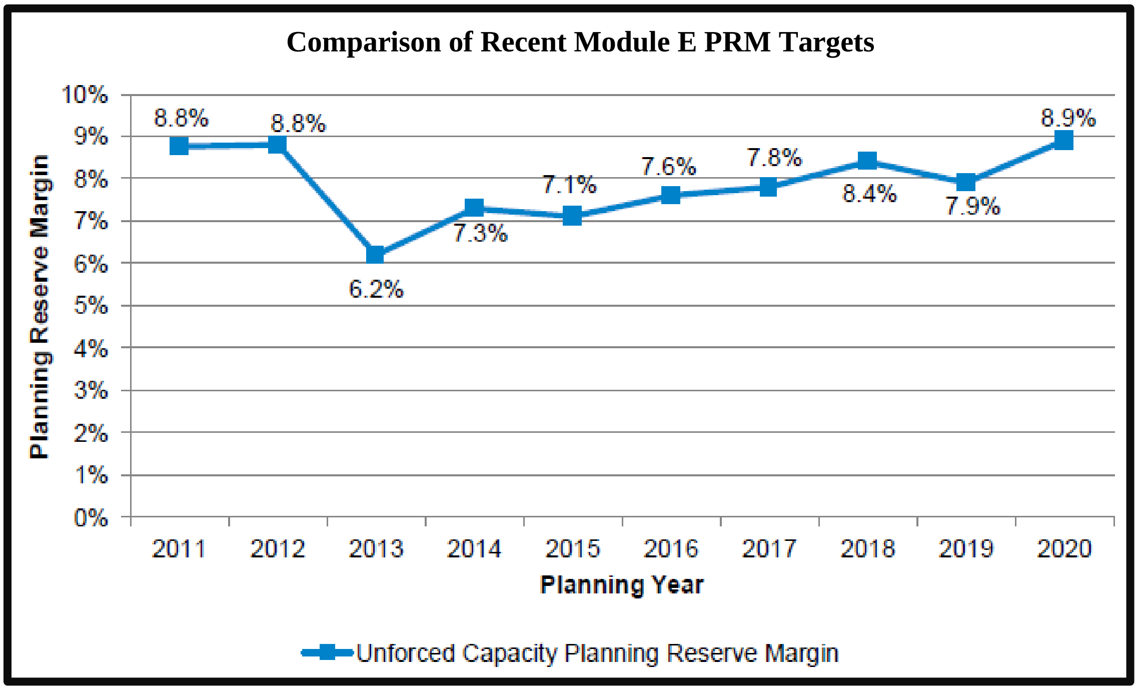
MISO Planning Reserve Margin (PRM)	2020/2021 PY (June 2020 - May 2021)	Formula Key
MISO System Peak Demand (MW)	124,625	[A]
Installed Capacity (ICAP) (MW)	156,426	[B]
Unforced Capacity (UCAP) (MW)	144,456	[C]
Firm External Support (ICAP) (MW)	1,626	[D]
Firm External Support (UCAP) (MW)	1,572	[E]
Adjustment to ICAP {1d in 10yr} (MW)	-7,950	[F]
Adjustment to UCAP {1d in 10yr} (MW)	-7,950	[G]
Non-Firm External Support (ICAP) (MW)	2,987	[H]
Non-Firm External Support (UCAP) (MW)	2,331	[I]
ICAP PRM Requirement (PRMR) (MW)	147,115	[J]=[B]+[D]+[F]-[H]
UCAP PRM Requirement (PRMR) (MW)	135,748	[K]=[C]+[E]+[G]-[I]
MISO PRM ICAP	**18.0%**	[L]=([J]-[A])/[A]
MISO PRM UCAP	**8.9%**	[M]=([K]-[A])/[A]

7.4 Comparison of PRM Targets across 10 Years

Figure 7.2 below compares the PRM UCAP values over the last 10 planning years. The last endpoint shows the Planning Year 2020-2021 PRM value of 8.9%.

Figure 7.2

Recent Planning Year MISO System Planning Reserve Margins



7.5 Future Years 2020 through 2029 Planning Reserve Margins

Beyond the Planning Year 2020–2021 LOLE study analysis, an LOLE analysis was performed for the four–year–out Planning Year of 2023–2024, and the six–year–out Planning Year of 2025-2026. Table 7.3 "Future Planning Year MISO System Planning Reserve Margins" shows all the values and calculations that went into determining the MISO system PRM ICAP and PRM UCAP values for those years. Those results are shown as the underlined values in Table 7.4 "MISO System Planning Reserve Margins 2020 through 2029." The values from the intervening years result from interpolating the 2020, 2023, and 2025 results. Note that the MISO system PRM results assume no limitations on transfers within MISO.

The 2023–2024 Planning Year PRM decreased slightly from the 2020–2021 Planning Year driven mainly by new unit additions and retirements. The forecasts for the 2025–2026 Planning Year PRM increased primarily because of additional new units and retirements.

Table 7.3

Future Planning Year MISO System Planning Reserve Margins

MISO Planning Reserve Margin (PRM)	2023/2024 PY (June 2023 - May 2024)	2025/2026 PY (June 2025 - May 2026)	Formula Key
MISO System Peak Demand (MW)	125,308	125,600	[A]
Installed Capacity (ICAP) (MW)	160,125	161,228	[B]
Unforced Capacity (UCAP) (MW)	148,152	148,922	[C]
Firm External Support (ICAP) (MW)	1,626	1,626	[D]
Firm External Support (UCAP) (MW)	1,572	1,572	[E]
Adjustment to ICAP {1d in 10yr} (MW)	-11,000	-11,360	[F]
Adjustment to UCAP {1d in 10yr} (MW)	-11,000	-11,360	[G]
Non-Firm External Support (ICAP) (MW)	2,987	2,987	[H]
Non-Firm External Support (UCAP) (MW)	2,331	2,331	[I]
ICAP PRM Requirement (PRMR) (MW)	147,764	148,507	[J]=[B]+[D]+[F]-[H]
UCAP PRM Requirement (PRMR) (MW)	136,393	136,804	[K]=[C]+[E]+[G]-[I]
MISO PRM ICAP	17.9%	18.2%	[L]=([J]-[A])/[A]
MISO PRM UCAP	8.8%	8.9%	[M]=([K]-[A])/[A]

Table 7.4

MISO System Planning Reserve Margins 2020 through 2029

Metric	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
ICAP (GW)	158.1	161.4	161.6	161.8	161.8	162.9	162.9	162.9	162.9	162.9
Demand (GW)	124.6	124.8	125.1	125.3	125.3	125.6	125.8	126.0	126.2	126.5
PRM_{ICAP}	**18.0%**	18.0%	17.9%	**17.9%**	18.2%	**18.2%**	18.1%	18.2%	18.2%	18.3%
PRM_{UCAP}	**8.9%**	8.9%	8.8%	**8.8%**	8.8%	**8.9%**	8.9%	8.9%	8.9%	8.9%

In Table 7.4, years without underlined results indicate PRM values that were calculated through interpolation. MISO calculated the per-unit LRR of LRZ Peak Demand (See Table 7.5 "Planning Year 2020-2021 LRZ Local Reliability Requirements"). The UCAP values reflect the UCAP within each LRZ, including Border External Resources and Coordinating Owners. The adjustment to UCAP values are the megawatt adjustments needed in each LRZ so that the reliability criterion of 0.1 days per year LOLE is met. The LRR is the summation of the UCAP and adjustment to UCAP megawatts. The LRR is then divided by each LRZ's Peak Demand to determine the per-unit LRR UCAP. The 2020–2021 per unit LRR UCAP values were multiplied by the updated demand forecasts submitted for the 2020–2021 PRA to determine each LRZ's LRR.

Table 7.5

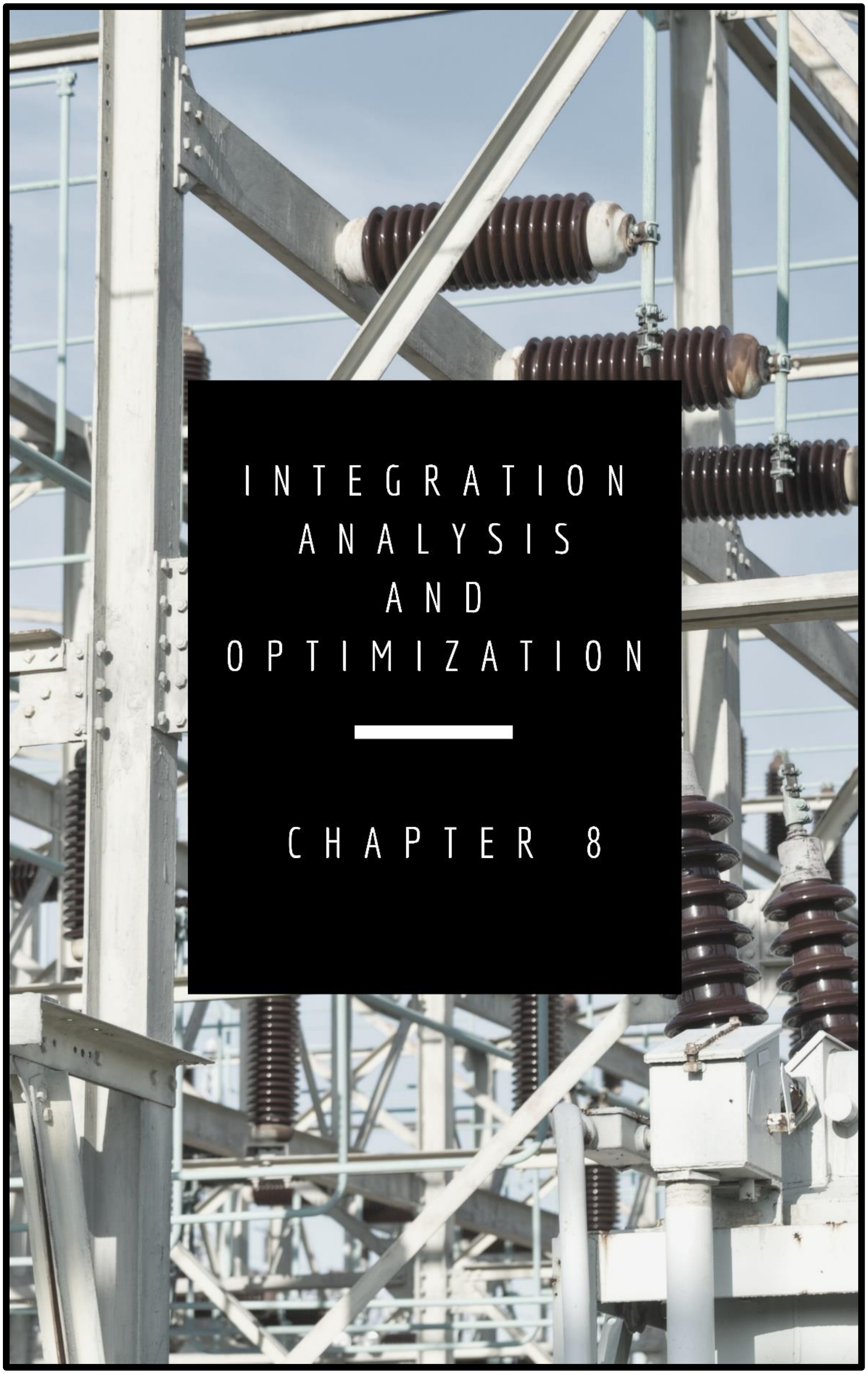
Planning Year 2020-2021 LRC Local Reliability Requirements

Local Resource Zone (LRZ)	LRZ-1 MN/ND	LRZ-2 WI	LRZ-3 IA	LRZ-4 IL	LRZ-5 MO	LRZ-6 IN	LRZ-7 MI	LRZ-8 AR	LRZ-9 LA/TX	LRZ-10 MS	Formula Key
2020-2021 Planning Reserve Margin (PRM) Study											
Installed Capacity (ICAP) (MW)	21,442	15,112	11,957	13,387	8,735	19,249	24,158	11,616	25,248	5,536	[A]
Unforced Capacity (UCAP) (MW)	20,332	14,252	11,371	12,128	7,860	17,846	22,111	10,876	23,091	4,600	[B]
Adjustment to UCAP {1d in 10yr} (MW)	19	610	-380	-260	1,847	2,356	3,258	-655	1,227	2,218	[C]
LRR (UCAP) (MW)	20,352	14,862	10,991	11,868	9,707	20,202	25,370	10,221	24,318	6,818	[D]=[B]+[C]
Peak Demand (MW)	17,815	12,728	9,558	9,185	7,830	17,585	21,226	7,685	20,885	4,673	[E]
LRR UCAP per-unit of LRZ Peak Demand	**114.2%**	**116.8%**	**115.0%**	**129.2%**	**124.0%**	**114.9%**	**119.5%**	**133.0%**	**116.4%**	**145.9%**	[F]=[D]/[E]

7.6 Big Rivers' Consideration of MISO Planning Reserve Margins in this IRP

Big Rivers used the MISO PRM UCAP Planning Reserve Margin of 9%. Analysis supporting this IRP maintained reserve margins between 8% and 10% over the analysis period. The MISO Planning Reserve Margin requirement as determined by the Loss of Load Expectation Study is the appropriate reserve margin for Big Rivers to use in long-term generation planning. LOLE is the industry standard for reserves, and MISO utilizes sophisticated tools and information provided by its members and Market Participants to perform this robust analysis. Big Rivers reviews the results of the MISO Loss of Load Expectation analysis, which determines a minimum Planning Reserve Margin requirement for Big Rivers to meet tariff obligations. This results in the optimal Planning Reserve Margin for Big Rivers by providing 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 an unnecessary and costly utility-specific reserve margin study.

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.


INTEGRATION
ANALYSIS
AND
OPTIMIZATION
CHAPTER 8

INTEGRATION ANALYSIS AND OPTIMIZATION

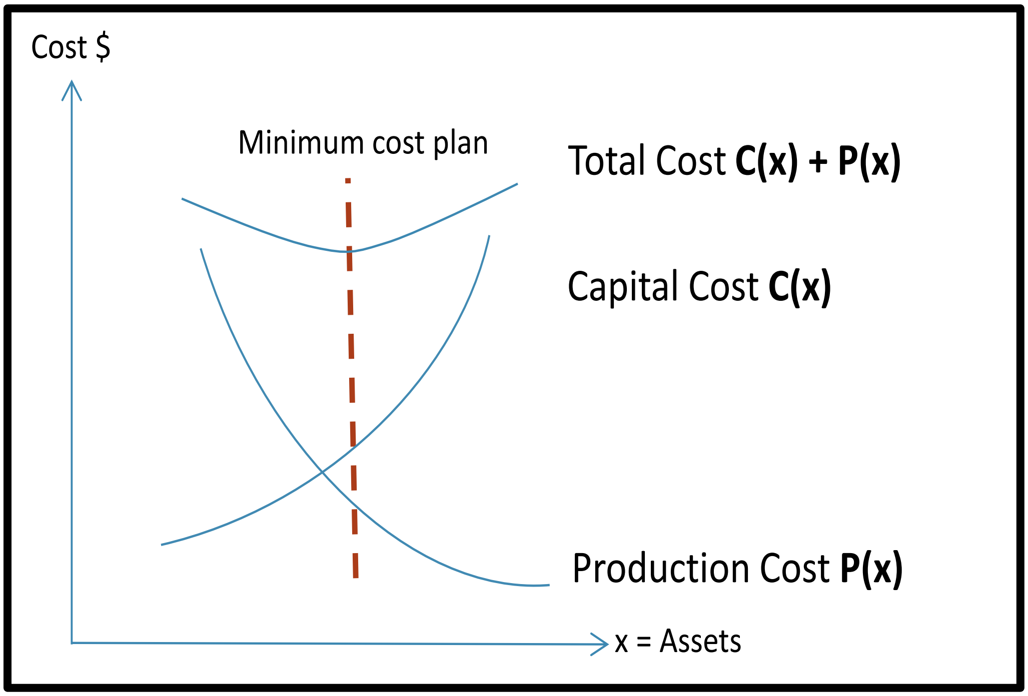
Big Rivers' resource assessment and acquisition plan provides an adequate and reliable supply of electricity to meet forecasted electricity requirements at the lowest reasonable cost while staying within the risk tolerance of the Board. Big Rivers considered the potential impacts of selected, key uncertainties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

8.1 In-House Production Cost Model (Plexos)

Big Rivers has been using Energy Exemplar's *Plexos* production cost modeling software since 2015. With respect to IRP modeling efforts, the *Plexos* LT Plan (long-term capacity expansion planning optimization model) optimizes Big Rivers' fleet of energy and capacity resources over time by determining when to retire existing units and/or acquire new assets. The LT Plan model uses advanced algorithms to analyze a range of possible portfolio options based on the inputs and the constraints entered and provides a solution identifying the optimal investment or retirement decisions to make and when to make them. The LT Plan objective is to minimize the net present value ("NPV") of the capital and production costs formulated as a mixed-integer problem. Capital costs include the expense of building new generation, and compliance costs associated with existing generation. In this 2020 IRP, retirement costs were modeled at zero expense. Production costs include the expense of operating the Big Rivers generation fleet and the market cost of energy not served by native Member generation and the market revenues from energy sold to market. The optimal solution provided by the LT Plan provides the least cost option for the unique set of Big Rivers' input and constraint parameters.

Figure 8.1

PLEXOS LT Plan Optimization



Also, Big Rivers utilized *Plexos* ST Plan aka ST Schedule. The ST Plan does not solve for capacity additions or subtractions but it emulates the economic commit and hourly dispatch of the generation resources being modeled. The ST Plan results provide a more granular view of the portfolio options for evaluation purposes. While the LT Plan solution provides one least-cost alternative, the ST Plan results provide data for all the generation resource options, which can be used to reaffirm the LT Plan's least-cost solution and to evaluate other generation portfolio options.

8.1.1 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. The LT Plan horizon was the 20-year period beginning in 2024 through 2043. The 2024 start was chosen because capacity additions (solar) are not likely to be completed.

Multiple scenarios with multiple input variables were analyzed. The Base Case and the scenarios utilized the Big Rivers 2019-2033 Long-Term Financial Plan with the following updated inputs:

- The 2020 Load Forecast restricted to Big Rivers Member load projections;
- June 2020 market prices for energy, capacity, natural gas and fuel oil;
- The latest unit cost and performance projections for new and existing generation resources, including a conversion of Green Units one and two to natural gas; and
- Market purchases as a resource alternative for both energy and capacity in the model.

The 2019-2033 Long-Term Financial Plan includes environmental compliance with CCR and Effluent Limitation Guidelines (<u>"ELG"</u>) assuming Green Station units remain coal-fired, and it also includes capital costs associated with relocating the Coleman scrubber to Wilson Station. In Big Rivers' 2020 ECP case,[50] Big Rivers did not request funding for Green Station ELG compliance, which would be required for the units to continue to operate as coal-fired generation. Additional costs for ELG compliance at Green may render these units uneconomic, given current market expectations.

[50] See *In the Matter of: Electronic Application of Big Rivers Electric Corporation for Approval of its 2020 Environmental Compliance Plan, Authority to Recover Costs through a Revised Environmental Surcharge and Tariff, the Issuance of a Certificate of Public Convenience and Necessity for Certain Projects, and Appropriate Accounting and Other Relief* - Case No. 2019-00435. Application filed February 7, 2020.

Big Rivers' analysis utilized the following generation resource options for evaluating the 2024-2043 time period utilizing the LT Plan model to determine the least-cost option:

- Wilson remains coal-fired and in operation throughout the period. [redacted]. Also, Wilson remaining coal-fired is consistent with Big Rivers' 2020 ECP case, in which the Commission approved the moving of the Coleman scrubber to Wilson and producing market grade gypsum.

The Green units have the option to remain coal-fired by complying with environmental regulations, convert to natural gas or suspend operations (idle).

- The Reid combustion turbine has the option to remain a natural gas fired unit or suspend operation (idle).
- Big Rivers may continue the status quo with the SEPA contract or exit the agreement.
- The three proposed solar facilities (Henderson Solar Facility, McCracken Solar Facility and Meade Solar Facility) are modeled as being approved by the Commission and all are in operation by 2024.
- A partnership with several other counterparties in a new 592 MW NGCC with participation by Big Rivers available in 10 MW increments is modeled as a new resource option. This new NGCC could be located at Big Rivers' Sebree site (NGCC – Sebree) or Big Rivers' Coleman site (NGCC – Coleman).
- A new 237 natural gas combustion turbine ("NGCT") can be built as a resource.
- Market purchases (PPA – Block) including energy and capacity are available in 10 MW increments.

The LT Plan model constraints are established to meet capacity reserve margin requirements, but there are no constraints on the volume (MWh) being produced from the generation resources. The LT Plan model works exactly the way MISO works. All Big Rivers load is purchased at the market price, and the generation resources are economically dispatched at the market price. Therefore, if the market energy price is higher than the cost to generate, the generator will be dispatched and vice-versa. Also, the LT Plan model for the 2020 IRP has included a resource (PPA – Block) that represents purchasing capacity and energy from the market at the forecasted prices. This enables the model to select the market as a least-cost option capacity resource in order to meet the capacity reserve margin requirements (8%-10%) when the other resource options are not economic. If the LT Plan model selects the PPA-Block as a capacity resource, the model is using the forecasting inputs for capacity and energy and the associated market risk of the forecast inaccuracy was not measured.

Note that the LT Plan model results included in this IRP do not constitute a commitment by Big Rivers to a specific course of action. Note also that changes to the inputs, constraints and assumptions that impact this IRP result can, and do, occur without notice, especially with the current uncertainty around environmental requirements and commodity prices. With that said, Big Rivers has run sensitivities to the Base Case to evaluate the impact that changing the inputs can have on the model determination of the least-cost option. Big Rivers understands that there are relationships between the inputs, e.g. changes in natural gas prices can have an impact on energy prices, but the majority of the sensitivities are designed to focus on the impact of changing one input variable at a time. This single variable sensitivity analysis allows Big Rivers to evaluate the impact of the variability of a single variable without subjecting that analysis to additional uncertainty that would arise from the assumptions utilized to define the relationship between the other inputs or variables. The single variable analysis shows the break points, i.e. the points when the change in a single variable causes a new result for the least cost plan. Big Rivers also ran sensitivities involving multiple variables and sensitivities involving carbon taxes, lowering capacity prices to zero, renewable energy certificates (“REC”), and solar firm capacity allocation. Big Rivers also ran a sensitivity eliminating the NGCC unit as a resource option because of the difficulty and complexity of identifying and obtaining willing partners for the NGCC unit.

8.1.2 Model Generation Resource Options

Table 8.1 shows the generation resources that are currently operating and the options that were made available for those resources in the model. Also, Table 8.1 shows the new generation resources that are being added or available to be added as a least-cost resource. The LT Plan used these generation resources as options for determining the optimal or least-cost plan for the Base Case in each scenario.

Table 8.1

Generation Resources Existing, New, and Potential

Generation Resources			
Existing (Currently Operating) Big Rivers Assets			
Generation Resource	**Capacity, MW**	**Option**	**2024-2043**
Wilson Unit 1	417	Coal-Fired	X
Green Unit 1	231	Coal-Fired	X
		NG Conversion	X
		Idled	X
Green Unit 2	223	Coal-Fired	X
		NG Conversion	X
		Idled	X
Reid CT	65	NG-Fired	X
		Idled	X
SEPA	178	Continue	X
		Exit Contract	X
Total	**1,114**		
New or Potential Big Rivers Assets			
Generation Resource	**Capacity, MW**	**Option**	**2024-2043**
Henderson Solar Facility	160	PSC Approved (Built)	X
McCracken Solar Facility	60	PSC Approved (Built)	X
Meade Solar Facility	40	PSC Approved (Built)	X
Natural Gas Combined Cycle	592	10 MW increment located at Sebree	X
		10 MW increment located at Coleman	X
Natural Gas Combustion Turbine	237	Build asset	X
Market (PPA - Block)	800	10 MW increment up to 800 MW	X

For Big Rivers' existing resources, Wilson Unit 1 was modeled continuing to operate as a coal-fired unit for the duration. Both Green Units were modeled with three options: remaining coal-fired; converting to natural gas firing; or idling. The Reid CT is modeled to remain natural gas fired or idle. Big Rivers' SEPA entitlement was modeled as status quo or exiting the contract. For Big Rivers' new or potential resources, the three proposed solar facilities totaling 260 MW of capacity were modeled as being approved by the Commission and all in operation by 2024. A new natural gas combined cycle unit (592 MW capacity) was modeled with Big Rivers being able to take 10 MW increments of the unit located at either Big Rivers' Sebree site or Coleman site. A new natural gas combustion turbine (237 MW capacity) was included as an option. Also, Big Rivers modeled buying capacity and energy at the current market prices as a generation resource in 10 MW increments up to 800 MW of capacity represented by "PPA – Block" in the models. If the LT Plan selects the PPA – Block as the least cost option, that indicates that the power market forecast is the least cost alternative of all the other generation options.

Big Rivers utilized the 2019-2033 Long-term Financial Plan as the starting point for developing the forecast for the fixed operation and maintenance ("O&M") production costs. Capital costs, including those costs for the anticipated compliance costs for CCR and ELG for the Green units, were included in annual cash flows.

Estimates for the Green natural gas conversion, including natural gas supply lines, were based on budgetary information provided by multiple external sources. Equipment conversion cost information was provided by equipment manufacturers, and pipeline cost information was sourced 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 from those parameters when the units are coal-fired. Only the maximum capacity of the generation units were changed (increased three MW due to lower auxiliary load then reduced by 10%). A detailed engineering study would be required for each Green unit to determine an accurate change to operation parameters resulting from conversion to burn natural gas. Also, the Green natural gas conversion was evaluated both with and without a firm gas supply charge. Firm gas is modeled as a fixed expense and a firm gas supply charge is paid whether the unit operates or not. With firm gas, the unit pays the spot gas price for its variable fuel expense. Non-firm gas is modeled as a variable cost where a delivery charge (gas line and gas transportation charges) is added to the spot natural gas price.

Retirement costs were considered a sunk cost and not explicitly modeled. The Base Case complies with the known current environmental regulations (CCR, ELG) and assumes no carbon regulations for the period. There are two sensitivities (Carbon – ACES[51] and Carbon – IHS[52]) that assume a carbon tax is implemented. Sections 5.6 and 5.7 of this IRP discuss Big Rivers' current and future environmental compliance in more detail. See Table 8.2 for the Fixed O&M costs for Big Rivers existing assets including natural gas conversion that were used in the models.

[51] Alliance for Cooperative Energy Services.

[52] IHS Markit.

Table 8.2

Existing Resource Option Fixed O&M Cost Projections, $M

Existing Unit Fixed O&M (included capital expense) Cost Projections (2024 - 2033), $M

Unit/Station	Option	Costs	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Wilson Station	Coal-Fired	Fixed	[redacted]									
		Plant Capital										
		ECP - Coleman Scrubber (Amortized)	$ 8.58	$ 8.58	$ 8.58	$ 8.58	$ 8.58	$ 8.58	$ 8.58	$ 8.58	$ 8.58	$ 8.58
		Total	[redacted]									
Green Station	Coal-Fired	Fixed - Reduced Capacity Factor										
		Plant Capital - Reduced Capacity Factor										
		Total										
		CCR, ELG & 316b Capital Cost - 2024$	$36.58	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Total	[redacted]									
		Maintenance Adder for Generation, $/MWh										
	Natural Gas Conversion	Fixed										
		Plant Capital										
		Gas Service Cost										
		Total										
		Firm Gas Demand Charge										
		Total with Firm Gas										
Reid CT	Gas-Fired	Fixed										
		Plant Capital										
		Total										

Existing Unit Fixed O&M (included capital expense) Cost Projections (2034 - 2043), $M

Unit/Station	Option	Costs	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Wilson Station	Coal-Fired	Fixed	[redacted]									
		Plant Capital										
		ECP - Coleman Scrubber (Amortized)	$ 8.58	$ 8.58	$ 8.58	$ 8.58	$ 8.58	$ 8.58	$ 8.58	$ 8.58	$ 8.58	$ 8.58
		Total	[redacted]									
Green Station	Coal-Fired	Fixed - Reduced Capacity Factor										
		Plant Capital - Reduced Capacity Factor										
		Total										
		CCR, ELG & 316b Capital Cost - 2024$	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Total	[redacted]									
		Maintenance Adder for Generation, $/MWh										
	Natural Gas Conversion	Fixed										
		Plant Capital										
		Gas Service Cost										
		Total										
		Firm Gas Demand Charge										
		Total with Firm Gas										
Reid CT	Gas-Fired	Fixed										
		Plant Capital										
		Total										

The price and volume forecast for Big Rivers' SEPA entitlement (Big Rivers' allotment of Cumberland River system hydroelectric power) is based on the best information available. The model has the option of continuing the SEPA contract or exiting the contract at any time throughout the horizon (2024 – 2043). 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 8.3 for the SEPA volume and cost projections that were included in the models.

Table 8.3

SEPA Volume and Cost

SEPA			
Year	Price (Includes Transmission) $/MWh	Capacity MWs	Volume MWh
2024	[redacted]	178	267,000
2025		178	267,000
2026		178	267,000
2027		178	267,000
2028		178	267,000
2029		178	267,000
2030		178	267,000
2031		178	267,000
2032		178	267,000
2033		178	267,000
2034		178	267,000
2035		178	267,000
2036		178	267,000
2037		178	267,000
2038		178	267,000
2039		178	267,000
2040		178	267,000
2041		178	267,000
2042		178	267,000
2043		178	267,000

For the new solar resources, Big Rivers utilized the cost and generation profiles for the three solar facilities totaling 260 MW of capacity with whom Big Rivers entered into the PPAs that are the subject of Case No. 2020-00183. In the Base Case, Big Rivers used the current MISO Business Practice Manual for the determination of firm capacity associated with these solar facilities. There is a sensitivity where less firm capacity is forecasted for solar using the MISO effective load carrying capability ("ELCC") projections. In modeling, Big Rivers is assuming that the Commission approves the three solar PPAs and all three solar facilities are in operation by 2024, the start year in the 20 year horizon for the LT Plan (2024-2043).

At the base case inputs and the current proposed solar PPA costs, the model would continue to add solar until reserve margins were met. Big Rivers chose to limit the model's flexibility to add additional solar beyond the proposed facilities until we have more experience with the resource and there is more clarity about the effect of intermittent resources on the transmission system.

Table 8.4

Solar Generation Profiles and Costs

Solar Profile and Cost				
Year	Generation MWh	NCF, %	Cost $M	Cost $/MWh
2024	591,843	25.9%	[redacted]	
2025	587,693	25.8%		
2026	584,724	25.7%		
2027	581,756	25.5%		
2028	579,946	25.4%		
2029	575,820	25.3%		
2030	572,852	25.2%		
2031	569,884	25.0%		
2032	568,050	24.9%		
2033	563,947	24.8%		
2034	560,979	24.6%		
2035	558,011	24.5%		
2036	556,154	24.4%		
2037	552,075	24.2%		
2038	549,107	24.1%		
2039	546,139	24.0%		
2040	544,257	23.8%		
2041	540,202	23.7%		
2042	537,234	23.6%		
2043	534,266	23.5%		

For the new natural gas resources, Big Rivers utilized EIA data for estimated fixed O&M expenses and vendor supplied information for natural gas supply lines and firm gas supply costs. Vendor estimates were used for build costs of the NGCC units at either the Sebree site or Coleman site. Big Rivers used the EIA Capital Cost Estimates for Utility Scale Electricity Generating Plants report dated February 2020 for providing cost for the NGCT unit.[53] Since that February 2020 report did not provide information on the Advanced CC unit, Big Rivers utilized the EIA update from January 2019 for the fixed O&M and variable O&M costs for the Advanced NGCC unit. Please see the table below for the new natural gas costs used in the models.

[53] https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2020.pdf

Table 8.5

New Natural Gas Unit Cost Projections, $M

New Natural Gas Unit Fixed O&M Cost and Build Cost Projections (2024 - 2033), $M												
Unit/Station	Option	Costs	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
NGCC - Sebree (592 MW)	Gas-Fired	Fixed (Outage in VOM Cost)	[redacted]									
		Gas Service Cost	[redacted]									
		Total	[redacted]									
		Firm Gas Demand Charge	[redacted]									
		Total with Firm Gas	[redacted]									
		Build Cost, 2024$	[redacted]									
NGCC - Coleman (592 MW)	Gas-Fired	Fixed (Outage in VOM Cost)	[redacted]									
		Gas Service Cost	[redacted]									
		Total	[redacted]									
		Firm Gas Demand Charge	[redacted]									
		Total with Firm Gas	[redacted]									
		Build Cost, 2024$	[redacted]									
NGCT (237 MW)	Gas-Fired	Fixed (Outage in VOM Cost)	[redacted]									
		Gas Service Cost - Assume in Build Cost	[redacted]									
		Total	[redacted]									
		Firm Gas Demand Charge	[redacted]									
		Total with Firm Gas	[redacted]									
		Build Cost, 2024$	[redacted]									

New Natural Gas Unit Fixed O&M Cost and Build Cost Projections (2034 - 2043), $M												
Unit/Station	Option	Costs	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
NGCC - Sebree (592 MW)	Gas-Fired	Fixed (Outage in VOM Cost)	[redacted]									
		Gas Service Cost	[redacted]									
		Total	[redacted]									
		Firm Gas Demand Charge	[redacted]									
		Total with Firm Gas	[redacted]									
		Build Cost, 2024$	[redacted]									
NGCC - Coleman (592 MW)	Gas-Fired	Fixed (Outage in VOM Cost)	[redacted]									
		Gas Service Cost	[redacted]									
		Total	[redacted]									
		Firm Gas Demand Charge	[redacted]									
		Total with Firm Gas	[redacted]									
		Build Cost, 2024$	[redacted]									
NGCT (237 MW)	Gas-Fired	Fixed (Outage in VOM Cost)	[redacted]									
		Gas Service Cost - Assume in Build Cost	[redacted]									
		Total	[redacted]									
		Firm Gas Demand Charge	[redacted]									
		Total with Firm Gas	[redacted]									
		Build Cost, 2024$	[redacted]									

Big Rivers did not include every option listed in the EIA report in the 2020 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.(see Section 5.5). The Pulverized Coal Conversion to Natural Gas price projections were not used as Big Rivers developed high level cost projections for converting the Green coal-fired units to gas based on information provided by Original Equipment Manufacturers, which will be closer to actual costs than the EIA projections. The EIA data tables can be found in Technical Appendix F.

8.2 Modeling Results

8.2.1 Base Case Inputs/Constraints

Big Rivers developed the Base Case with inputs and constraints using 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.

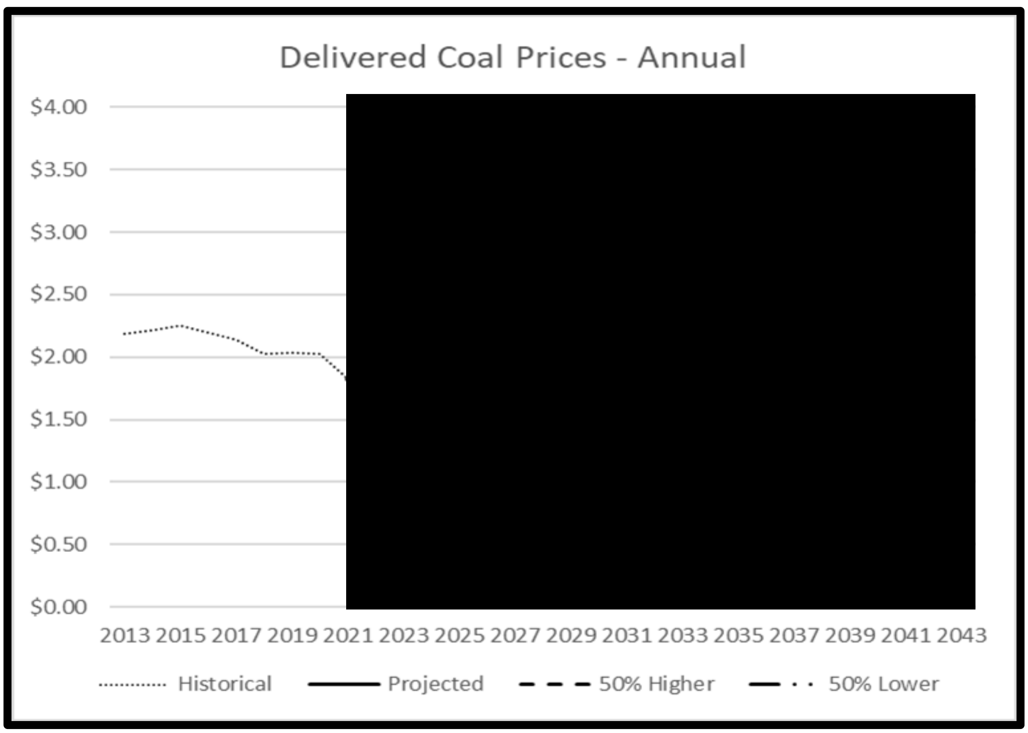
- **Generation Commit:** All coal-fired and natural gas fired generation units are modeled as economic commit according to the startup characteristics of each asset and production variable costs. These characteristics include minimum up-time, minimum down-time, ramp rates and startup costs, and a three day look-ahead (which means the model must recover the startup costs of a unit within three days for the unit to dispatch).
- **Generation Dispatch:** All coal-fired and natural gas-fired generation units are modeled as economic dispatch with the operating parameters provided for each particular unit (max and min capacity, heat rate, unit outage rate, planned outages). The solar units are modeled at a fixed monthly load profile provided by the solar facility owner. The SEPA volumes are modeled per the contract at the monthly maximum and minimum volumes and annual volume take. MISO Business Practice Manual ("BPM") rules require that SEPA currently must be scheduled for four hours across each daily peak at the maximum capacity available.
- **Production Fixed Costs:** The production fixed costs utilized are provided in Table 8.2 for existing resources and Table 8.5 for new or potential resources, and are based on updated projections from

the 2019-2033 long-term financial plan. Also, Big Rivers has consulted with various outside vendors to develop a cost estimate for natural gas conversion for the Green Units and the NGCC unit located at either Sebree or Coleman.

- **<u>Production Non-Fuel Variable Costs and Generator Operating Parameters:</u>** The production non-fuel variable cost and the generator operating parameters (i.e., heat rate, outage rate, etc.) used in models are available in Technical Appendix F.
- **<u>Coal Prices:</u>** Spot coal delivery prices were inflated using JD Energy's long term fuel forecast from September 2019 (see Technical Appendix F). Figure 8.2 below displays annual spot coal prices along with historical prices from 2013 and forecasted prices through 2043.

Figure 8.2

Delivered Coal Prices

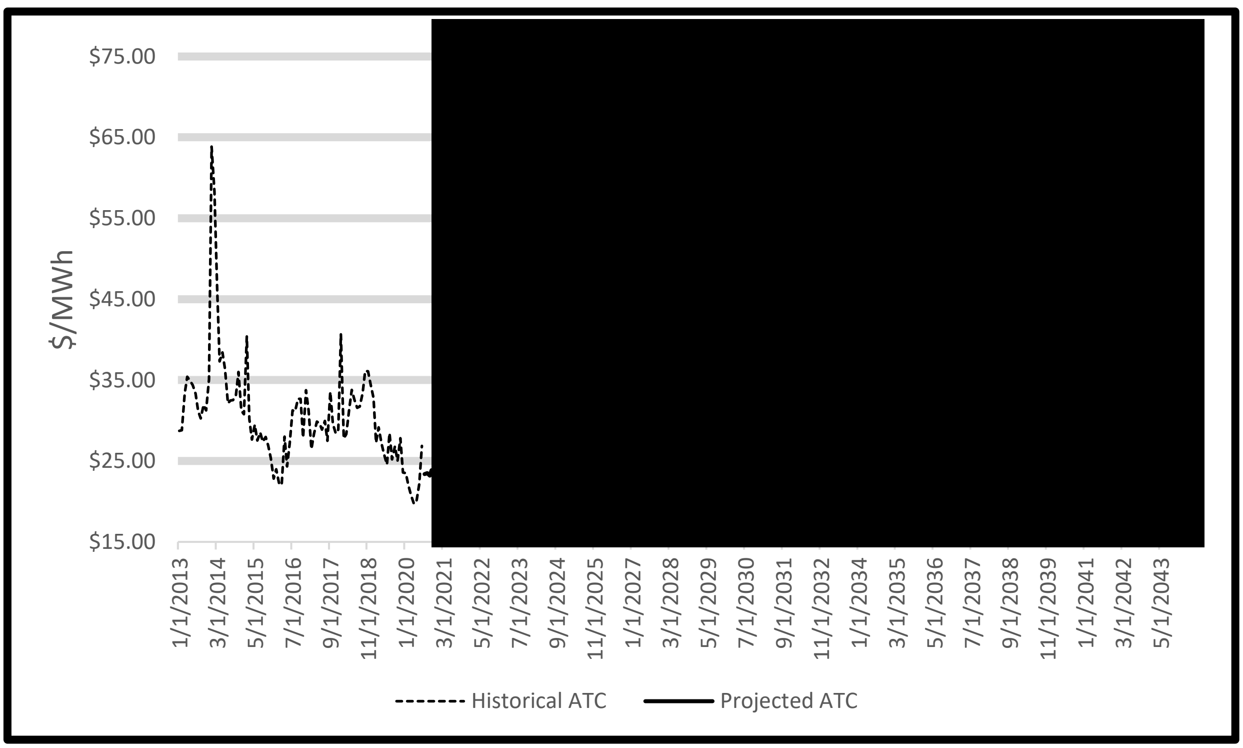


[redacted]

- **<u>Energy Market Prices:</u>** Energy market price forecasts were received from a third party, ACES, whose methodology for energy market price forecasts is provided in Technical Appendix F. An Indiana Hub Day-Ahead Locational Marginal Price (<u>"LMP"</u>) forward curve is the first step in energy market forecasting. Indiana Hub is the most liquid energy trading point in MISO. The Indiana Hub price is then adjusted based upon historical and projected relationships to produced prices in Western Kentucky. Average monthly energy pricing is shown in Figure 8.3. Figure 8.3 shows historical prices for the time period January 2013 to August 2020 and forecasted prices thereafter through December 2043.

Figure 8.3

Indiana Hub Around The Clock Monthly Pricing



- **Capacity Prices:** Capacity price forecasts were based upon internal evaluations of the market and are shown in Table 8.6. Historical MISO capacity auction prices are shown beginning with the 2014/2015 planning year through the 2020/2021 planning year with forecasted prices beginning in the 2021/2022 planning year. Note the large difference between the historical PRA Auction Clearing Prices ("ACP") and the forward bilateral market which is used as the basis for forecasted prices. The PRA ACP only looks forward one year at a time and many participants offer their capacity at zero in order to ensure themselves of some revenue. Those who rely on the PRA won't know the price that they will pay or receive until one month before the start of the new planning year. The forward bilateral market represents terms of one to ten years and is a better indicator of where market participants are willing to buy or sell to hedge their risks several years into the future. However, market information is difficult to obtain.

Table 8.6

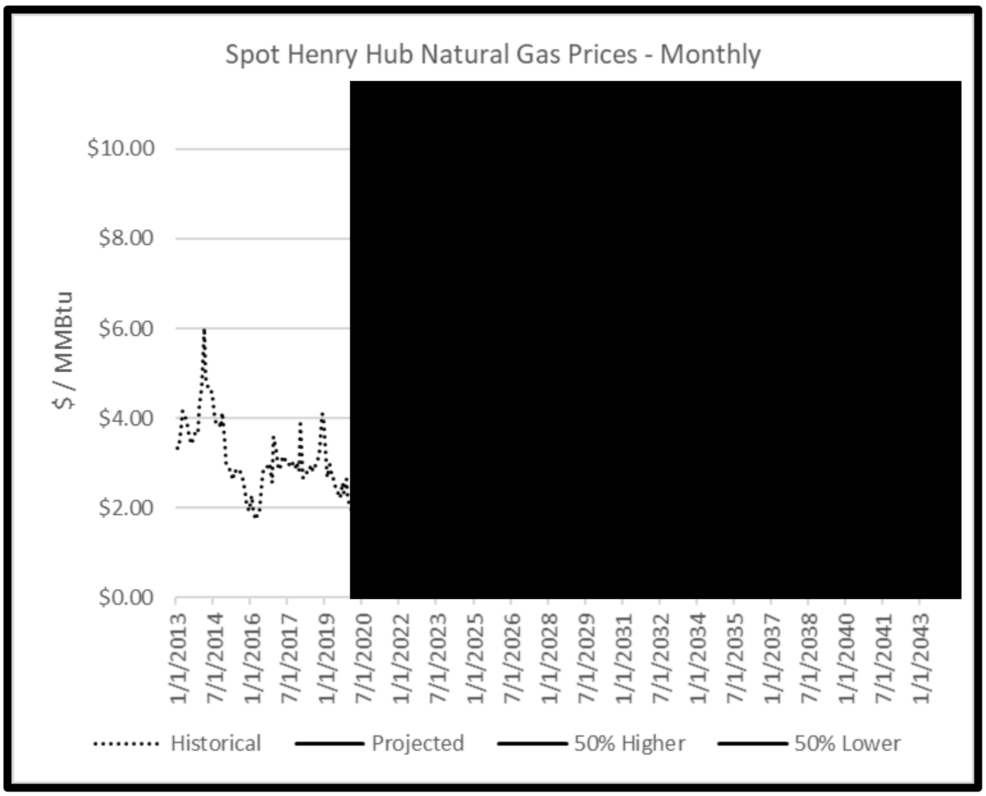
MISO Zone 6 Capacity Prices

MISO Capacity Price	
Planning Year	**$/MW-Day**
14/15	$16.75
15/16	$3.48
16/17	$72.00
17/18	$1.50
18/19	$10.00
19/20	$2.99
20/21	$5.00
21/22	[redacted]
22/23	[redacted]
23/24	[redacted]
24/25	[redacted]
25/26	[redacted]
26/27	[redacted]
27/28	[redacted]
28/29	[redacted]
29/30	[redacted]
30/31	[redacted]
31/32	[redacted]
32/33	[redacted]
33/34	[redacted]
34/35	[redacted]
35/36	[redacted]
36/37	[redacted]
37/38	[redacted]
38/39	[redacted]
39/40	[redacted]
40/41	[redacted]
41/42	[redacted]
42/43	[redacted]

<u>Natural Gas Prices:</u> Spot Henry Hub natural gas price forecasts were provided from a third party, ACES. Please see table below that displays average monthly historical prices from January 2013 to August 2020 and projected spot prices thereafter through December 2043. See Technical Appendix F for forecasting methodology.

Figure 8.4

Spot Henry Hub Natural Gas Prices - Monthly



While not a current requirement a firm gas supply may be required for generation resources to receive capacity payments from MISO in the future. The forecasted firm gas demand charge was provided by vendor estimate and is modeled at [redacted] where the MMBtu amount is the volume of natural gas to be firm. The model is assuming the full load of the resource as the volume of firm natural gas. This rate was set constant for the 20-year horizon (2024-2043). The projected firm gas charge for each resource option can be found in Table 8.2 for the Green natural gas conversion option and Table 8.5 above for the potential new natural gas resources.

- **Load Forecast:** Load forecasts were provided by Clearspring. See Appendix A for the Long Term Load Forecast Report. Big Rivers utilized only Member load in the models for the 2020 IRP evaluation.

Table 8.7

Member Load included in Base Case

Year	Energy, MWh	Peak, MW
2024	4,409,889	815
2025	4,415,339	817
2026	4,425,681	819
2027	4,427,519	819
2028	4,436,200	820
2029	4,439,269	821
2030	4,443,020	822
2031	4,448,003	823
2032	4,462,278	825
2033	4,462,294	826
2034	4,466,493	827
2035	4,470,695	828
2036	4,477,410	829
2037	4,479,154	830
2038	4,482,805	831
2039	4,482,692	832
2040	4,486,504	833
2041	4,482,635	834
2042	4,483,054	835
2043	4,482,822	836

- **<u>Capacity Reserve Margin:</u>** The capacity reserve margin constraints used in the LT Plan® were 8% minimum and 10% maximum.

8.2.2 Base Case Results

The optimal (least cost) plan for the LT Plan Base Case resulted in (i) Big Rivers adding the three solar PPAs totaling 260 MW of new solar capacity, (ii) Big Rivers adding 90 MW of a new 592 MW natural gas combined cycle unit located at Sebree (NGCC – Sebree) in 2024, and (iii) Big Rivers idling both the Green coal units. Big Rivers keeps Wilson unit as a coal-fired station, keeps the Reid CT available as a natural gas peaking unit, and stays in the SEPA contract. Because the NGCC alternative was dependent upon participation by other counterparties, Big Rivers ran a sensitivity where it assumes this coalition of partners is not found and the NGCC unit is not available as a resource option (See Section 8.2.3.3 Other Scenarios).

Big Rivers utilized the results from the LT Plan model and the preliminary least-cost solution (Preliminary LT Plan) had Big Rivers adding 250 MW to 290 MW of the NGCC capacity and exiting the SEPA contract. Big Rivers utilized the Preliminary LT Plan results to develop seven portfolio options using the ST Plan model. The portfolio modeled on the ST Plan included evaluating the current portfolio with and without solar and five potential portfolio options utilizing varying amounts ranging from 0 MW to 330 MW of the NGCC capacity, operating or idling the Reid CT unit, and keeping or exiting the SEPA contract. The five potential options are listed below:

- Green Units idled with the proposed solar added and purchase 80 MW capacity from the market
- Green Units idled and 90 MW of the NGCC – Sebree Unit
- Green Units idled, Reid CT idled and 150 MW of the NGCC – Sebree Unit
- Green Units idled, exiting contract with SEPA and 260 MW of the NGCC – Sebree Unit (Preliminary LT Plan)

- Green Units idled, Reid CT idled, exiting contract with SEPA, and 330 MW of the NGCC - Sebree Unit

Table 8.8 below summarizes the ST Plan results. For the NPV evaluation, Big Rivers utilized a 4.5% discount rate for the 20 year period from 2024 – 2043. The NPV in 2024 dollars shows how close the economics of the NGCC unit, the Reid CT unit, and the SEPA contract are to each other at the base case inputs. There is no clear decision between the four portfolio options where varying amounts of NGCC capacity are added as only $3M in 2024 dollars separate the options for the 20-year period. Also, just $35M in 2024 dollars separate the fifth portfolio option when no NGCC capacity is added and capacity is purchased from the market. As seen in the Section 8.2.3 scenario discussion, all of these portfolio options provide the least cost option when different inputs are varied.

A portfolio that adds 90 MW of NGCC – Sebree capacity, keeps the Reid CT in operation, and retains the SEPA contract status quo as the generation portfolio for its Base Case is the best alternative for keeping Member-Owner rates competitive. The Base Case achieves objectives that Big Rivers is aggressively pursuing by right sizing its generation to Member-Owners' load, diversifying its generation portfolio, and moving toward carbon-free resources when economically feasible. Please see tables and charts below displaying the base case results and see Appendix G Model Results for the complete annual data.

Table 8.8

ST Plan Portfolio Results – Base Case

2024 -2043 ST Plan Portfolio Results - Base Case						
Generation Portfolio	**Cost to Serve Load $M**		**Average Energy Position**	**Average Reserve Capacity Margin**		**Comment**
	NPV, 2024$	**Ranking**	**MWh**	**MW**	**%**	
Status Quo (Wilson, RCT, SEPA, Green)	[redacted]	7	887,309	243.1	29.4%	No Solar Added
+ Solar		6	1,450,055	427.4	51.8%	Current Position
+ Solar, Green Idled		5	(500,458)	(11.8)	-1.4%	Proposed Option
+ Solar, Green and Reid CT Idled, + 150 MW NGCC Sebree		4	606,067	72.2	8.7%	Proposed Option
+ Solar, Green Idled and Exit SEPA, + 260 MW NGCC Sebree		3	1,180,621	57.2	6.9%	Proposed Option
+ Solar, Green and Reid CT idled, Exit SEPA, + 330 NGCC Sebree		2	1,687,738	65.2	7.9%	Proposed Option
+ Solar, Green Idled, + 90 MW NGCC Sebree		**1**	**173,877**	**73.7**	**8.9%**	**Least cost (Base case)**

Table 8.9

Base Case Production Cost 2024 - 2033

	Production Cost (Annual inflation)	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Production Cost (Nominal)	Total Production Cost, $M	[redacted]									
	Total Production Cost, cents/kWh										
	Total Fixed O&M Cost (Incl. New Capital), $M										
	Total Fixed O&M Cost, (Incl. New Capital) $/kW-yr										
	Total Variable Cost, $M										
	Total Variable Cost, cents/kWh										
	Production Cost -(2024$)	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
Production Cost (Real)	Total Production Cost, $M	[redacted]									
	Total Production Cost, cents/kWh										
	Total Fixed O&M Cost (Incl. New Capital), $M										
	Total Fixed O&M Cost, (Incl. New Capital) $/kW-yr										
	Total Variable Cost, $M										
	Total Variable Cost, cents/kWh										
	Market Revenue	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
Nominal	MISO Pool (Energy) Revenue, $M	[redacted]									
	REC Revenue, $M										
	MISO Capacity Revenue, $M										
	Total MISO Revenue, $M										
Real 2024$	MISO Pool (Energy) Revenue, $M										
	REC Revenue, $M										
	MISO Capacity Revenue, $M										
	Total MISO Revenue, $M										
	Operating Performance -KPIs	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
KPIs	Net Capacity (Summer), MW	1,005	1,004	1,002	1,001	1,000	999	997	996	995	993
	Net Capacity (Winter), MW	1,005	1,004	1,002	1,001	1,000	999	997	996	995	993
	Net Generation, GWh	4,628	4,849	4,287	4,845	4,527	4,663	4,465	4,806	4,435	4,835
	Cost to Serve Load (Annual inflation)	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
Nominal	Cost to Serve Load, $M	[redacted]									
	Cost to Serve Load, cents/KWh										
Real 2024$	Cost to Serve Load, $M										
	Cost to Serve Load, cents/KWh										
Nominal	Load Market Cost, $M										
	Generation Market Revenue, $M										
	Net Market, $M										
Real 2024$	Load Market Cost, $M										
	Generation Market Revenue, $M										
	Net Market, $M										
	Load, GWh	4,410	4,415	4,426	4,428	4,436	4,439	4,443	4,448	4,462	4,462

Table 8.9

Base Case Production Cost 2034 - 2043

	Production Cost (Annual inflation)	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Production Cost (Nominal)	Total Production Cost, $M	[redacted]									
	Total Production Cost, cents/kWh										
	Total Fixed O&M Cost (Incl. New Capital), $M										
	Total Fixed O&M Cost, (Incl. New Capital) $/kW-yr										
	Total Variable Cost, $M										
	Total Variable Cost, cents/kWh										
	Production Cost -(2024$)	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Production Cost (Real)	Total Production Cost, $M	[redacted]									
	Total Production Cost, cents/kWh										
	Total Fixed O&M Cost (Incl. New Capital), $M										
	Total Fixed O&M Cost, (Incl. New Capital) $/kW-yr										
	Total Variable Cost, $M										
	Total Variable Cost, cents/kWh										
	Market Revenue	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Nominal	MISO Pool (Energy) Revenue, $M	[redacted]									
	REC Revenue, $M										
	MISO Capacity Revenue, $M										
	Total MISO Revenue, $M										
Real 2024$	MISO Pool (Energy) Revenue, $M										
	REC Revenue, $M										
	MISO Capacity Revenue, $M										
	Total MISO Revenue, $M										
	Operating Performance -KPIs	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
KPIs	Net Capacity (Summer), MW	992	991	989	988	987	986	984	983	982	980
	Net Capacity (Winter), MW	992	991	989	988	987	986	984	983	982	980
	Net Generation, GWh	4,301	4,708	4,667	4,820	4,726	4,787	4,635	4,682	4,229	4,747
	Cost to Serve Load (Annual inflation)	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Nominal	Cost to Serve Load, $M	[redacted]									
	Cost to Serve Load, cents/KWh										
Real 2024$	Cost to Serve Load, $M										
	Cost to Serve Load, cents/KWh										
Nominal	Load Market Cost, $M										
	Generation Market Revenue, $M										
	Net Market, $M										
Real 2024$	Load Market Cost, $M										
	Generation Market Revenue, $M										
	Net Market, $M										
	Load, GWh	4,466	4,471	4,477	4,479	4,483	4,483	4,487	4,483	4,483	4,483

Table 8.10

Generation and Capacity Reserve Margin

Year	Generation Resource Capacity, MW					Native Peak Load	Reserve Capacity Margin	
	Coal	Hydro	Gas	Solar	Total		MW	%
2019	819	154	30	0	1003	631	372	59%
2020	809	178	46	0	1032	650	382	59%
2021	812	178	52	0	1042	662	380	57%
2022	814	178	51	0	1043	863	180	21%
2023	839	178	51	125	1193	864	329	38%
2024	393	178	149	197	917	815	102	12%
2025	393	178	149	195	915	817	98	12%
2026	393	178	149	194	914	819	95	12%
2027	393	178	149	193	913	819	94	11%
2028	393	178	149	191	911	820	91	11%
2029	393	178	149	190	910	821	89	11%
2030	393	178	149	189	909	822	87	11%
2031	393	178	149	188	908	823	85	10%
2032	393	178	149	186	906	825	81	10%
2033	393	178	149	185	905	826	79	10%
2034	393	178	149	184	904	827	77	9%
2035	393	178	149	182	902	828	74	9%
2036	393	178	149	181	901	829	72	9%
2037	393	178	149	180	900	830	70	8%
2038	393	178	149	178	898	831	67	8%
2039	393	178	149	177	897	832	65	8%
2040	393	178	149	176	896	833	63	8%
2041	393	178	149	175	895	834	61	7%
2042	393	178	149	173	893	835	58	7%
2043	393	178	149	172	892	836	56	7%

Table 8.11

Base Case Generation Key Performance Indicators (KPIs)

System - Base Case

Performance	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Generation - GWh	**4,628**	**4,849**	**4,287**	**4,845**	**4,527**	**4,663**	**4,465**	**4,806**	**4,435**	**4,835**
- Coal	3,028	3,244	2,677	3,217	2,933	3,087	2,877	3,240	2,893	3,272
- Hydro	267	267	267	267	267	267	267	267	267	267
- Natural Gas	741	750	758	779	747	733	748	729	706	731
- Solar	592	588	585	582	580	576	573	570	568	564
Winter Capacity, MW	**1,005**	**1,004**	**1,002**	**1,001**	**1,000**	**999**	**997**	**996**	**995**	**993**
- Coal	412	412	412	412	412	412	412	412	412	412
- Hydro	178	178	178	178	178	178	178	178	178	178
- Natural Gas	155	155	155	155	155	155	155	155	155	155
- Solar	260	259	257	256	255	254	252	251	250	248
Summer Capacity, MW	**1,005**	**1,004**	**1,002**	**1,001**	**1,000**	**999**	**997**	**996**	**995**	**993**
- Coal	412	412	412	412	412	412	412	412	412	412
- Hydro	178	178	178	178	178	178	178	178	178	178
- Natural Gas	155	155	155	155	155	155	155	155	155	155
- Solar	260	259	257	256	255	254	252	251	250	248
Firm Capacity, MW	**912**	**911**	**910**	**908**	**907**	**906**	**904**	**903**	**902**	**900**
- Coal	393	393	393	393	393	393	393	393	393	393
- Hydro	178	178	178	178	178	178	178	178	178	178
- Natural Gas	144	144	144	144	144	144	144	144	144	144
- Solar	197	195	194	193	191	190	189	188	186	185
Net Capacity Factor, %	**52.4%**	**55.0%**	**48.7%**	**55.1%**	**51.6%**	**53.2%**	**51.0%**	**54.9%**	**50.8%**	**55.4%**
Fuel Usage (Thermal Units), GBtu	[redacted]									
- Coal										
- Natural Gas										
Heat Rate (Thermal Units), BTU/kWh										
- Coal										
- Natural Gas										

System - Base Case

Performance	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Generation - GWh	**4,301**	**4,708**	**4,667**	**4,820**	**4,726**	**4,787**	**4,635**	**4,682**	**4,229**	**4,747**
- Coal	2,773	3,184	3,133	3,325	3,242	3,328	3,181	3,283	2,863	3,431
- Hydro	267	267	267	267	267	267	267	267	267	267
- Natural Gas	700	699	711	676	667	646	642	592	562	515
- Solar	561	558	556	552	549	546	544	540	537	534
Winter Capacity, MW	**992**	**991**	**989**	**988**	**987**	**986**	**984**	**983**	**982**	**980**
- Coal	412	412	412	412	412	412	412	412	412	412
- Hydro	178	178	178	178	178	178	178	178	178	178
- Natural Gas	155	155	155	155	155	155	155	155	155	155
- Solar	247	246	244	243	242	241	239	238	237	235
Summer Capacity, MW	**992**	**991**	**989**	**988**	**987**	**986**	**984**	**983**	**982**	**980**
- Coal	412	412	412	412	412	412	412	412	412	412
- Hydro	178	178	178	178	178	178	178	178	178	178
- Natural Gas	155	155	155	155	155	155	155	155	155	155
- Solar	247	246	244	243	242	241	239	238	237	235
Firm Capacity, MW	**899**	**898**	**897**	**895**	**894**	**893**	**891**	**890**	**889**	**887**
- Coal	393	393	393	393	393	393	393	393	393	393
- Hydro	178	178	178	178	178	178	178	178	178	178
- Natural Gas	144	144	144	144	144	144	144	144	144	144
- Solar	184	182	181	180	178	177	176	175	173	172
Net Capacity Factor, %	**49.4%**	**54.1%**	**53.7%**	**55.5%**	**54.5%**	**55.3%**	**53.6%**	**54.2%**	**49.0%**	**55.1%**
Fuel Usage (Thermal Units), GBtu	[redacted]									
- Coal										
- Natural Gas										
Heat Rate (Thermal Units), BTU/kWh										
- Coal										
- Natural Gas										

Figure 8.5

Firm Capacity

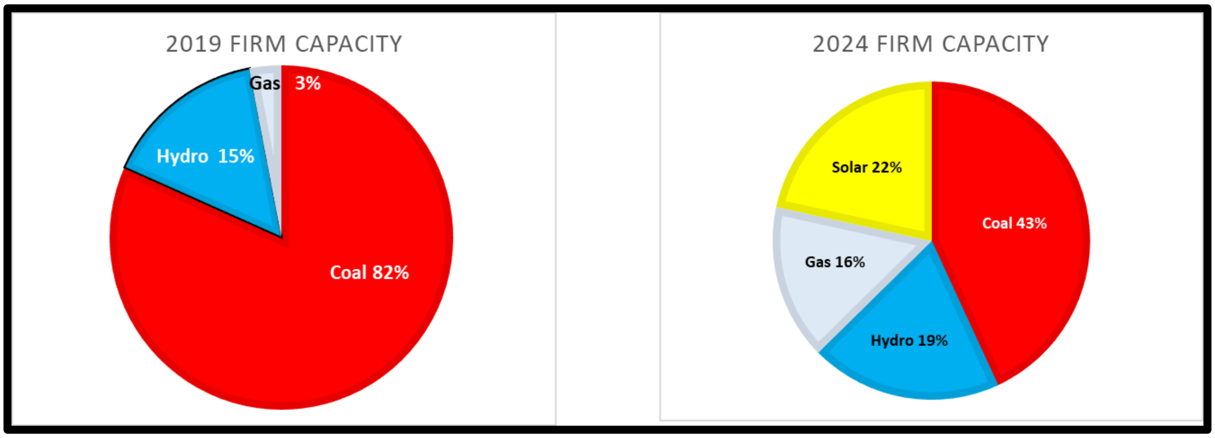
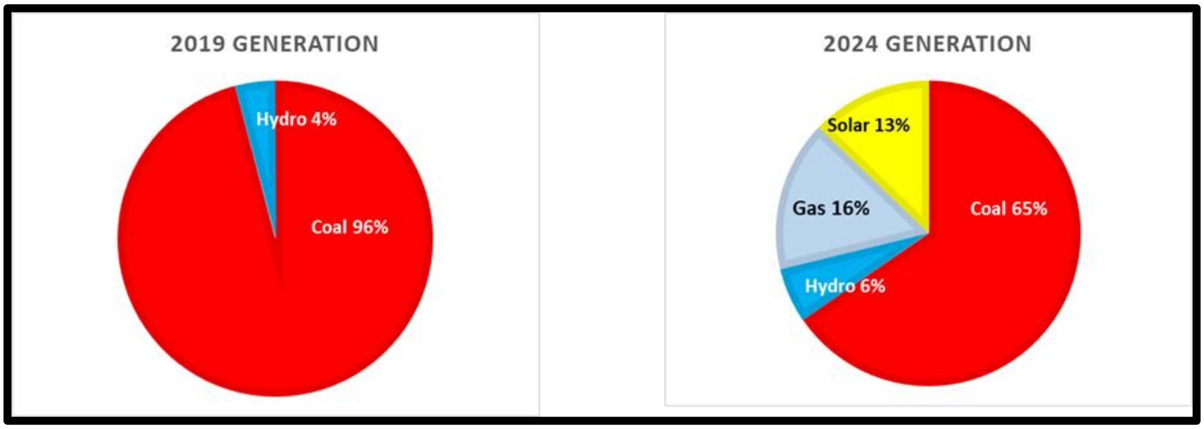


Figure 8.6

Generation



8.2.3 Scenario Evaluation

Forty-nine (49) model sensitivities were performed using the LT Plan model. Please see the description and results of the sensitivity models below.

8.2.3.1 Single Variable Price Scenarios

Thirty single variable price sensitivities were completed using the LT Plan model. The focus of the single variable price scenarios are to find breakpoints where a single variable move results in a different least cost solution from the LT Plan. Ten sensitivities each were run on the market energy prices, delivered coal prices and natural gas spot prices. The ten sensitivities involved varying the base price forecast at 10% increments with the limits being 50% above and 50% below the base forecast.

As discussed in the base case, the economics of the NGCC – Sebree unit, Reid CT and SEPA are close and as inputs are varied, the break points were found for these generation resource options along with determining when it is more economic to purchase from the market (represented by the PPA – Block).

The break points show the NGCC gains advantage over the other options when the market prices are higher and natural gas prices are lower. Only a small change (10% higher market prices or 10% lower natural gas prices) result in adding more NGCC capacity while idling the Reid CT. Also, conversely just a small change the other way (10% lower market prices or 10% lower natural gas prices) result in keeping the Reid CT and adding smaller amounts of the NGCC unit. The NGCC advantage over the Reid CT are lower variable cost from better heat rates resulting in higher capacity factors during higher energy prices and lower natural gas prices. The higher capacity factors result in higher energy margins that offset the Reid CT advantage of lower fixed costs. The NGCC fixed costs include the build cost and the energy margins must offset the difference between the NGCC fixed cost and the lower fixed cost of the Reid CT in order for the NGCC to be built over idling the Reid CT.

The economics between the NGCC unit and SEPA unit are very close at the base case inputs. The ST Plan evaluation was used to establish the least cost. The same break points hold true for the NGCC unit and SEPA as between the NGCC unit and Reid CT for similar reasons. The NGCC advantage over the SEPA are its ability to dispatch at higher capacity factors when profitable during higher energy prices and lower natural gas prices, resulting in higher energy margins. SEPA unit has a fixed contract for generation and costs. The NGCC unit will be least cost when the energy margins offset the difference between the NGCC fixed cost and the SEPA production cost.

Also at the lower energy prices and higher natural gas prices, the market (PPA – Block) is added instead of the NGCC unit at 20% lower energy prices and 30% higher natural gas prices. The production costs (fixed cost including the build cost) of the NGCC are a disadvantage at lower energy price and higher natural gas prices. When the NGCC is not returning a net profit (when market revenue < production costs), then the PPA-Block (market) will be used for the least cost option. The PPA-Block net profit is zero. The table below shows the results of the single variable price scenario results for the 20-year horizon (2024-2043). The full annual data can be seen in Appendix G Model Results.

Table 8.12

2024-2043 Preliminary LT Plan

2024 -2043 LT Plan Portfolio Results - Single Variable Price Scenarios										
Scenario	Generation Portfolio (Max Capacity) for Least Cost Plan						Cost to Serve Load [redacted]	Average Energy Position	Average Capacity Reserve Margin	
	Wilson	Solar	Reid CT	SEPA	NGCC	PPA - Block	[redacted]	MWh	MW	%
Big Rivers Base Case (ST Plan)	**412**	**260**	**65**	**178**	**90**	**-**	[redacted]	**173,877**	**73.7**	**8.9%**
Preliminary LT Plan	412	260	65	-	250 - 290	-	[redacted]	1,158,103	74.8	9.1%
Base 50% Higher LMP	412	260	-	-	320 - 360	-	[redacted]	2,168,192	76.0	9.2%
Base 40% Higher LMP	412	260	-	-	320 - 360	-	[redacted]	2,151,463	76.0	9.2%
Base 30% Higher LMP	412	260	-	-	320 - 360	-	[redacted]	2,107,767	76.0	9.2%
Base 20% Higher LMP	412	260	-	-	320 - 360	-	[redacted]	2,016,990	76.0	9.2%
Base 10% Higher LMP	412	260	-	-	320 - 360	-	[redacted]	1,909,052	76.0	9.2%
Base 10% Lower LMP	412	260	65	178	70 - 80	0 - 20	[redacted]	(701,848)	71.1	8.6%
Base 20% Lower LMP	412	260	65	178	-	60 - 100	[redacted]	(1,948,726)	68.9	8.3%
Base 30% Lower LMP	412	260	65	178	-	60 - 100	[redacted]	(2,725,702)	68.9	8.3%
Base 40% Lower LMP	412	260	65	178	-	60 - 100	[redacted]	(3,296,519)	68.9	8.3%
Base 50% Lower LMP	412	260	65	178	-	60 - 100	[redacted]	(3,551,426)	68.9	8.3%
Base 50% Higher Coal	412	260	65	-	250 - 290	-	[redacted]	(979,590)	74.8	9.1%
Base 40% Higher Coal	412	260	65	-	250 - 290	-	[redacted]	(633,256)	74.8	9.1%
Base 30% Higher Coal	412	260	65	-	250 - 290	-	[redacted]	(215,249)	74.8	9.1%
Base 20% Higher Coal	412	260	65	-	250 - 290	-	[redacted]	270,320	74.8	9.1%
Base 10% Higher Coal	412	260	65	-	250 - 290	-	[redacted]	736,351	74.8	9.1%
Base 10% Lower Coal	412	260	65	-	250 - 290	-	[redacted]	1,322,442	74.8	9.1%
Base 20% Lower Coal	412	260	65	-	250 - 290	-	[redacted]	1,429,019	74.8	9.1%
Base 30% Lower Coal	412	260	65	-	250 - 290	-	[redacted]	1,515,801	74.8	9.1%
Base 40% Lower Coal	412	260	65	-	250 - 290	-	[redacted]	1,540,455	74.8	9.1%
Base 50% Lower Coal	412	260	65	-	250 - 290	-	[redacted]	1,544,179	74.8	9.1%
Base 50% Higher NG	412	260	65	178	-	60 - 100	[redacted]	(759,982)	68.9	8.3%
Base 40% Higher NG	412	260	65	178	-	60 - 100	[redacted]	(759,951)	68.9	8.3%
Base 30% Higher NG	412	260	65	178	-	60 - 100	[redacted]	(759,559)	68.9	8.3%
Base 20% Higher NG	412	260	65	178	70	0 - 30	[redacted]	(307,139)	69.8	8.5%
Base 10% Higher NG	412	260	65	178	70 - 90	0 - 10	[redacted]	(147,464)	72.4	8.8%
Base 10% Lower NG	412	260	-	-	320 - 360	-	[redacted]	1,747,807	76.0	9.2%
Base 20% Lower NG	412	260	-	-	320 - 360	-	[redacted]	1,781,692	76.0	9.2%
Base 30% Lower NG	412	260	-	-	320 - 360	-	[redacted]	1,793,578	76.0	9.2%
Base 40% Lower NG	412	260	-	-	320 - 360	-	[redacted]	1,795,308	76.0	9.2%
Base 50% Lower NG	412	260	-	-	320 - 360	-	[redacted]	1,795,308	76.0	9.2%

8.2.3.2 Multi-Variable Price Scenarios

Twelve multi-variable price sensitivities were run using the LT Plan model. The multi-variable price sensitivities represent a more comprehensive market evaluation as the sensitivities reflect that some prices (energy, natural gas and coal) are correlated and will move together. Six multi-variable sensitivities were run at higher LMP prices and six run at lower prices at 20% intervals. For each 20% interval for the LMP price, three scenarios were run: the natural gag ("NG") price and Coal price were kept the same, increased 10% above the LMP price, and decreased 10% below the LMP price. The table below shows the multi-variable price scenarios that were completed on the LT Plan.

Table 8.13

Multi-Variable Price Scenarios for LT Plan

20% Lower All (LMP, Coal and NG Prices)
20% Lower LMP, 10% Lower Coal and NG Prices
20% Lower LMP, 30% Lower Coal and NG Prices
20% Higher All (LMP, Coal and NG Prices)
20% Higher LMP, 10% Higher Coal and NG Prices
20% Higher LMP, 30% Higher Coal and NG Prices
40% Lower All (LMP, Coal and NG Prices)
40% Lower LMP, 30% Lower Coal and NG Prices
40% Lower LMP, 50% Lower Coal and NG Prices
40% Higher All (LMP, Coal and NG Prices)
40% Higher LMP, 30% Higher Coal and NG Prices
40% Higher LMP, 50% Higher Coal and NG Prices

All of the multi-variable results discussed below were driven by the same factors as the single-variable scenarios. When energy or natural gas prices result in higher output from the NGCC, the resulting margins offset the higher fixed costs of the NGCC when compared to the fixed costs of the Reid CT or the contractual demand charges of the SEPA contract and vice-versa.

The multi-variable scenario results display that the Reid CT is idled in favor of adding more NGCC capacity at the higher price scenarios and the Reid CT is kept in operation at the lower priced scenarios.

At the higher price scenarios, the SEPA contract is exited when the prices move together or NG and coal prices gain a 10% advantage in favor of adding more NGCC capacity. However, SEPA is kept when the NG and coal prices have a 10% disadvantage.

At the lower LMP scenarios, SEPA is kept when prices move together and when the NG and coal prices have a 10% disadvantage and SEPA is exited when the NG and coal prices have a 10% advantage.

Less NGCC capacity is added and market purchases are needed at the end of the horizon at the 20% lower LMP scenarios when prices are moved together and when NG and coal prices have a 10% disadvantage.

NGCC capacity replaces the SEPA contract at the 20% lower LMP scenarios when NG and coal prices have a 10% advantage.

For the 40% lower LMP scenarios, no NGCC capacity is taken in favor of the market when prices move together and when NG and coal prices have a 10% disadvantage. NGCC capacity is still added at the 40% lower LMP when NG and coal prices have a 10% advantage.

Please see the table below displaying the multi-variable price scenarios.

Table 8.14

2024-2043 Preliminary LT Plan Multi-Variable Price Scenarios

2024 -2043 LT Plan Portfolio Results - Multi-Variable Price Scenarios										
Scenario	Generation Portfolio (Max Capacity) for Least Cost Plan						Cost to Serve Load [redacted]	Average Energy Position	Average Reserve Capacity Margin	
	Wilson	Solar	Reid CT	SEPA	NGCC	PPA - Block		MWh	MW	%
Big Rivers Base Case (ST Plan)	**412**	**260**	**65**	**178**	**90**	**-**	[redacted]	**173,877**	**73.7**	**8.9%**
Preliminary LT Plan	412	260	65	-	250 - 290	-	[redacted]	1,158,103	74.8	9.1%
LT Plan - 40% Higher All	412	260	-	-	320 - 360	-	[redacted]	1,722,754	76.0	9.2%
LT Plan - 40% Higher LMP - Coal&NG 30% Higher	412	260	-	-	320 - 360	-	[redacted]	1,900,586	76.0	9.2%
LT Plan - 40% Higher LMP - Coal&NG 50% Higher	412	260	-	178	130 - 170	-	[redacted]	168,534	76.1	9.2%
LT Plan - 20% Higher All	412	260	-	-	320 - 360	-	[redacted]	1,685,165	76.0	9.2%
LT Plan - 20% Higher LMP - Coal&NG 10% Higher	412	260	-	-	320 - 360	-	[redacted]	1,906,117	76.0	9.2%
LT Plan - 20% Higher LMP - Coal&NG 30% Higher	412	260	-	178	130 - 170	-	[redacted]	60,458	74.5	9.0%
LT Plan - 20% Lower All	412	260	65	178	70 - 90	0 - 10	[redacted]	(133,646)	72.4	8.8%
LT Plan - 20% Lower LMP - Coal&NG 10% Lower	412	260	65	178	60	0 - 40	[redacted]	(937,142)	69.2	8.4%
LT Plan - 20% Lower LMP - Coal&NG 30% Lower	412	260	65	-	260 - 300	-	[redacted]	1,449,759	75.4	9.1%
LT Plan - 40% Lower All	412	260	65	178	-	60 - 100	[redacted]	(845,039)	68.9	8.3%
LT Plan - 40% Lower LMP - Coal&NG 30% Lower	412	260	65	178	-	60 - 100	[redacted]	(1,625,698)	68.9	8.3%
LT Plan - 40% Lower LMP - Coal&NG 50% Lower	412	260	65	-	250 - 290	-	[redacted]	1,473,128	74.8	9.1%

8.2.3.3 Other Scenarios

Seven other model scenarios were run on the LT Plan model and the results are shown below.

Table 8.15

LT Plan Other Scenarios

2024 -2043 LT Plan Portfolio Results - Other Scenarios										
Scenario	Generation Portfolio (Max Capacity) for Least Cost Plan							Average Energy Position	Average Reserve Capacity Margin	
	Wilson	Solar	Reid CT	SEPA	NGCC	PPA - Block	[redacted]	MWh	MW	%
Big Rivers Base Case (ST Plan)	**412**	**260**	**65**	**178**	**90**	**-**	[redacted]	**173,877**	**73.7**	**8.9%**
Preliminary LT Plan	412	260	65	-	250 - 290	-	[redacted]	1,158,103	74.8	9.1%
LT Plan - Carbon ACES	412	260	-	-	320 - 360	-	[redacted]	1,397,356	76.0	9.2%
LT Plan - Carbon IHS	412	260	65	178	70	0 - 30	[redacted]	(2,138,244)	71.5	8.7%
LT Plan - No Capacity Price	412	260	-	-	-	290 - 330	[redacted]	(1,027,079)	67.9	8.2%
LT Plan - REC None	412	260	65	-	250 - 290	-	[redacted]	1,158,103	74.8	9.1%
LT Plan - REC Ohio Solar	412	260	65	-	250 - 290	-	[redacted]	1,158,103	74.8	9.1%
LT Plan - Solar Capacity ELCC	412	260	65	-	380 - 420	-	[redacted]	2,167,400	75.3	9.1%
LT Plan - No NGCC Option	412	260	65	178	-	60 - 100	[redacted]	(723,091)	68.7	8.3%

- The NGCC Unit not available as an alternative due to inability to acquire partners: This scenario removes the NGCC Unit at both the Sebree or Coleman sites as a resource option. The least cost option results in idling the Green Units and purchasing the needed capacity from the market.
- Two carbon tax scenarios (ACES and IHS) – The carbon tax scenarios utilized a carbon tax price for the carbon dioxide (CO_2) tons emitted and a resultant change in market energy prices. The same market energy prices with carbon were used for both scenarios. The ACES carbon tax projections assumed implementation in 2034 and at lower rates than the IHS projections, which implemented the tax in 2030. Only one market energy projection that included carbon was used for both scenarios so the ACES scenario most likely has too high market energy prices in the early years due to carbon tax being implemented later (2034). For this reason, the IHS scenario is more representative of a portfolio if the carbon tax regulations are implemented.

- The NPV impact in 2024 dollars of the IHS carbon tax scenario is [redacted] from the Base Case, and in that scenario, the portfolio is short on energy by over [redacted] as the Wilson coal unit is not economic to generate when the carbon tax is implemented.
- Two REC prices (Ohio Solar Prices and None) – The base analysis assumes REC prices based upon the Green-E Wind REC forward curve. These scenarios show variations of the value of the RECs for the proposed solar facilities. The REC None scenario assumes zero value for RECs and the REC Ohio Solar scenario assumes RECs credit at the higher Ohio Solar price. The value of the RECs in 2024 dollars for the 20 year period in the Base Case is [redacted] as that is the amount the NPV is higher than the REC none scenario. If Big Rivers receives the Ohio Solar REC price, the NPV in 2024 dollars is [redacted] higher than the base case.
- No Capacity Price – This scenario represents no value for capacity. While zero value is unrealistic, it can be seen as a proxy for an extremely low value close to the current annual PRA ACPs. The least cost portfolio changes to idling both Green and the Reid CT, and Big Rivers exiting the SEPA contract. The shortfall if made up with market purchases (290 MW – 330 MW PPA-Block). In addition, when the generation portfolio is right-sized to load requirements, then the capacity price becomes immaterial as the capacity revenue for generation equals the capacity cost for load.
- Solar Firm Capacity at ELCC – This scenario uses the ELCC firm capacity for the proposed solar facilities, which is lower than the Base Case (which uses the current MISO BPM solar firm capacity projections). The least-cost option under this scenario has Big Rivers adding 130 MW more NGCC capacity than the Base Case.

8.3 Summary Scenarios

Big Rivers' mission remains unchanged: to safely deliver low-cost, reliable wholesale power and the cost-effective shared services desired by its Member-Owners. 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 LT Plan results were used to formulate and evaluate five portfolio options using the ST Plan results. The Base Case inputs and constraints were modeled using the best information available at the time this IRP was prepared. The capacity reserve margin requirements utilized in the model were 8% minimum (which represents the minimum MISO UCAP capacity reserve requirement) and 10% maximum (which represents Big Rivers' desire to right-size the generation portfolio for its' Member load). Big Rivers opted not to include any existing or projected Non-Member sales as part of this resource assessment.

The Electrical Integration Analysis determined that the least cost option under the Base Case is to continue operation of Wilson Unit as a coal-fired generator, continue the contract with SEPA, continue the Reid CT unit as a peaking gas unit, idle the Green Units, add the proposed three Solar Facilities and find partners to add 90 MW of a 592 MW natural gas combined cycle generator located at its Sebree site.

Several alternative scenarios and five alternative generation portfolios were evaluated. Thirty single variable scenarios were analyzed varying LMP prices, natural gas prices and coal prices. In the single variable price scenarios, break points were found for the least-cost plan for varying market power prices and natural gas prices. Twelve multi-variable price scenarios that are more representative of market moves and eight other scenarios were completed showing the Big Rivers Optimal portfolio with the least cost option.

The economics between the NGCC unit, Reid CT, SEPA contract and market warrant continued analysis. The Base Case achieves Big Rivers' objectives to both right-size its generation portfolio to its native load and diversify the portfolio between coal, natural gas, hydro and solar resources to give Big Rivers the best opportunity to keep its Member-Owners rates stable and competitive in light of the uncertainty in environmental regulation and changing market conditions.

Big Rivers' last Board-approved financial plan (approved in November 2019) projected Member-Owner rates as shown in Table 8.23 below.

Table 8.16

Projected Member-Owner Rates[54]

Big Rivers Electric Corporation Projected Member Wholesale Rates ($/MWh)*			
2019	$ 75.09	**2027**	[redacted]
2020	[redacted]	**2028**	
2021		**2029**	
2022		**2030**	
2023		**2031**	
2024		**2032**	
2025		**2033**	
2026			

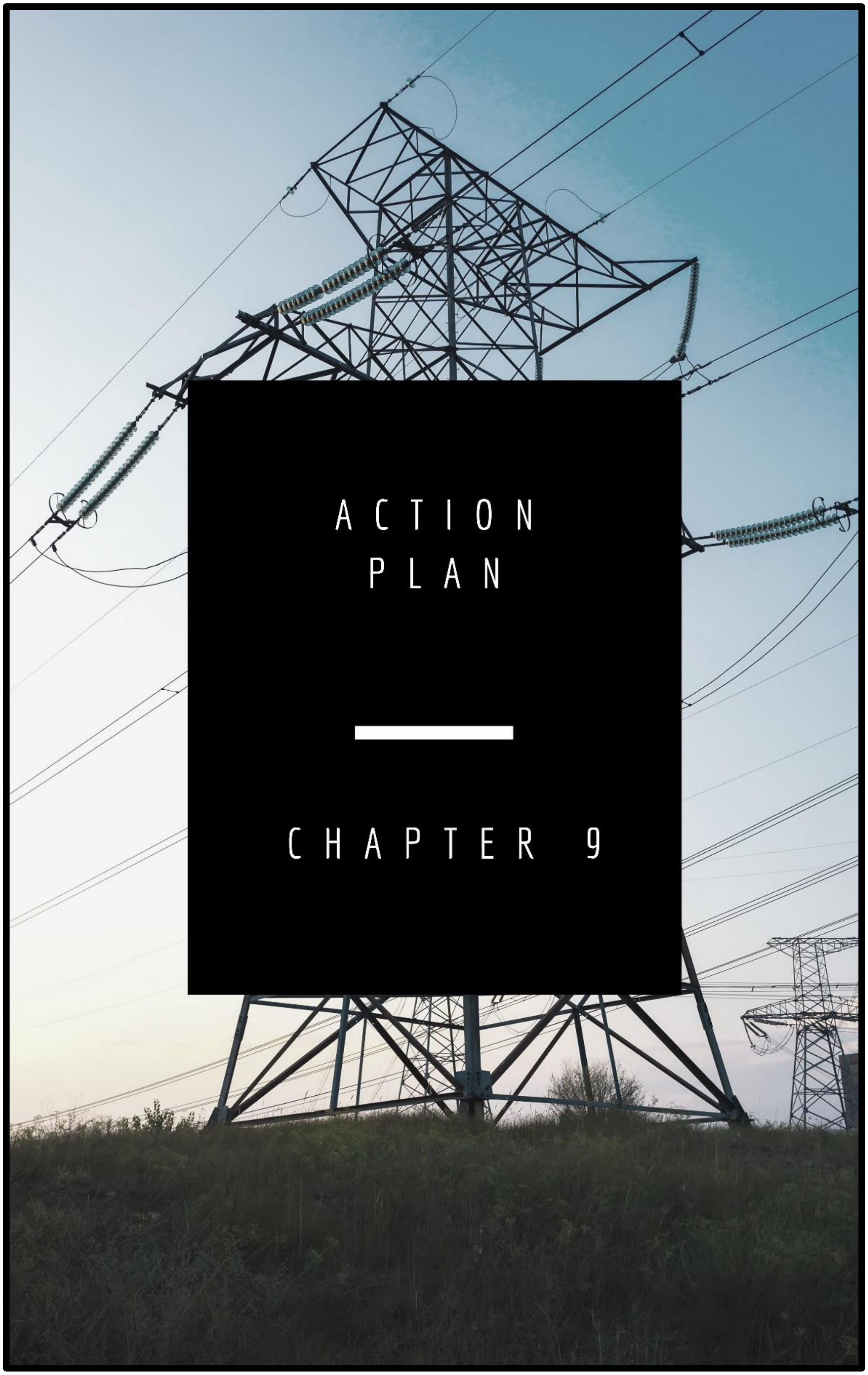
* 2019 actuals and 2020-2033 forecast amounts per Big Rivers Electric Corporation's 2020-2033 Financial Forecast approved by its Board of Directors December 2019.

The variables impacting Big Rivers' future rates are complex, and much has happened since December 2019, when the 2020 through 2033 Financial Plan was approved. The 2020 through 2033 Financial Plan did include a projection for adding 250 MW of solar capacity (very similar to the current 260 MW of proposed solar capacity) and included adding Nucor as a new large industrial load.

[54] Combined Rural and LIC rates

However, these rates do not include the impacts of recent modifications to Big Rivers' MRSM and related "TIER Credit" (approved by the Commission in June 2020 in Case No. 2020-00064), which will impact Members' effective rates beginning in 2021. Big Rivers' optimal plan (least cost option) for meeting its Member -Owners' native load requirements under the base case scenario is to idle the Green Units, add the three proposed solar facilities, and find partners to add the optimum amount of a natural gas combined cycle generation at Big Rivers' Sebree site. Additionally, changes in commodity prices, market prices, environmental regulations, Non-Member sales volumes, and many other variables can impact Big Rivers' Member-Owners' rates.

As noted above, significant analysis has occurred surrounding the optimum use of Big Rivers' assets in the future. Having a more diversified generation portfolio provides Big Rivers the optimum case for stabilizing Member-Owners' rates and keeping those rates competitive. With the uncertainty surrounding future market prices for energy and commodities, upcoming political elections and environmental regulations, the best option for Big Rivers is to remain vigilant in finding partners for the NGCC unit and make a final decision on the future of the Green Units if they remain uneconomic. 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. Big Rivers exists solely to safely and reliably serve its Member-Owners at the lowest reasonable cost, and management will continue to focus on the best options for the Member-Owners in the years to come.


ACTION
PLAN
CHAPTER 9

ACTION PLAN

Following the analysis required to prepare this IRP, as well as ongoing business plans, Big Rivers' Optimal Resource Portfolio will include the existing Wilson (417 MW), Reid CT (65 MW), SEPA Hydropower allocation (178 MW), Solar PPAs (260 MW), and suspension of Green (454 MW). Following the planned retirement of Coleman (443 MW) and Reid 1 (65 MW) in 2020, Big Rivers' existing load and Non-Member sales obligations will require additional resources. Analysis supporting this IRP indicates the least cost resource addition, likely around 2026, will be a Natural Gas Combined Cycle (NGCC) unit, and to achieve sufficient economies of construction, *etc.*, that resource will likely need to exceed the volume Big Rivers requires. Neighboring entities may also have need for additional resources that are short of the efficient size (600-800 MW), so pursuing a purchase of a portion of a NGCC resource is the logical approach. In order to proceed with the addition of a NGCC resource, Big Rivers needs to collaborate with neighboring entities with a need for a substantial portion of the NGCC output. Big Rivers is uncertain at this time if those neighboring entities' future resource needs include a NGCC.

Big Rivers has access to the wholesale power markets to buy and sell energy to maximize Member value and meet fluctuations in its owned–generation resource availability. Sufficient resources should be available to purchase to meet short–term capacity needs until construction of an adequate NGCC occurs, likely around 2024. See Section 8.2.2 Base Case Results for details of changes in projected capacity.

9.1 Big Rivers Robert D. Green Plant

In the base plan, the Green Units will be suspended by June of 2022 in order to comply with EPA regulations. Converting the units to natural gas as a capacity-only resource is currently uneconomic and would involve regulatory risk, but Big Rivers will continue to examine the feasibility of that approach. A recent (August 2020) EPA order may create an opportunity to extend the life of the Green units through December 31, 2028. Analysis of that opportunity is ongoing at the deadline for submitting this IRP.

9.2 Big Rivers Optimal Plan

Over the past several years, Big Rivers worked to adapt to changing requirements while keeping costs affordable for its Members. Considering fuel diversity and reliability, it is unlikely that nationwide long–term energy and environmental objectives will be met without retaining high–capacity–factor electric generation sources *(i.e.*, generation available 24 hours a day, 365 days a year). Since most generation from renewable sources is weather and time–of–day dependent and thus intermittent in output, there must be sufficient generation sources to support this variability. Reliable and flexible generation sources like Big Rivers' Wilson Station will still be needed to react to customer electricity needs as intermittent solar and wind generation fluctuates. Failing to keep baseload resources available and online would not only lead to much higher costs, but may have serious reliability consequences. In order to retain a supply of safe, reliable and cost–effective resources for our Members, a diverse portfolio is optimal in order to meet future energy needs.

Consistent with Big Rivers' business plan and mission to safely deliver competitive and reliable wholesale power to our Member-Owners, the Optimal Plan to meet annual and seasonal peak demands and total energy requirements identified in the base load forecast at the lowest reasonable costs includes:

- Continue to operate existing efficient generating units;
- Continue to monitor the energy and capacity market to efficiently meet the needs of Member load and fixed-term non-member sales, purchasing as necessary to meet those needs and to reduce risk;
- Constantly evaluate off-system sales activity to ensure that it continues to provide low-risk value to our Members, but only to the degree that it supports Big Rivers' mission and core business.

- Continue to monitor the political landscape for changes that may impact the nature and/or timing of environmental requirements;
- Complete the required approvals and purchase of 260 MW solar generation to be constructed within the Big Rivers footprint;
- Initiate outreach to similarly situated utilities who seek economies of scale that larger combined–cycle generators provide but do not require the full output of those generators. Big Rivers' goal is to either construct a facility, or purchase partial output of a facility constructed by another utility, in an amount to meet Member load needs at least through 2039; and
- Idle inefficient units.

Big Rivers' existing Wilson, Green, and Reid CT units are currently economic and remain efficient. Under expected conditions as described in the Base Case, the Green units become uneconomic, especially with upcoming environmental regulations that require significant expenditures, and thus the expectation is to idle the Green units. The November 2020 presidential election may bring additional risk of changes in future environmental and market requirements. Incremental changes in costs and/or markets may alter the Optimum Plan at a future date, and this IRP and Optimal Plan considers the best information and analysis available at this time. Big Rivers is in position to defer additional investment in "steel in the ground" by leveraging the economical capacity and energy markets for the next few years while at the same time finding partners, negotiating the agreements, monitoring technology developments, and developing a plan to jointly build new generation. Currently, that new generation would be a natural gas combined cycle unit located at Big Rivers' Sebree site. This IRP presents an appropriate time to build and optimum amount of that generation for Big Rivers. That time and quantity represent placeholders while Big Rivers monitors developments in technology, economy, and the political landscape.

LOAD FORECAST

2020

Big Rivers
ELECTRIC CORPORATION

2020 Big Rivers Electric Corporation
Load Forecast Study

August 10, 2020

Prepared By:

Clearspring Energy Advisors LLC

1050 Regent St., Suite L3

Madison, WI 53715

608.442.8668

Confidentiality Statement

TABLE OF CONTENTS

1 Introduction and System Summary

1.1 Project Overview

The 2020 Big Rivers Electric Corporation ("Big Rivers") electric load forecast has been created from the bottom up. That is, forecast models have been developed for each of the three distribution systems served by Big Rivers and then integrated into Big Rivers' forecast. Each distribution Member forecast is conducted separately, and each distribution Member has reviewed and approved the load forecast applicable to its system.

Clearspring Energy Advisors, LLC (Clearspring) was selected by Big Rivers and its Members to prepare this 2020 electric load forecast. The forecasting process relies on internal system data, third-party demographic and economic data, and insight from cooperative staff that are most familiar with the end-uses and trends in the service territory. An emphasis has been placed on strong coordination between Big Rivers, the three Member systems, and Clearspring in preparing this study to ensure accurate and useful load forecast results. The Big Rivers forecast team members include the following individuals.

Project Team

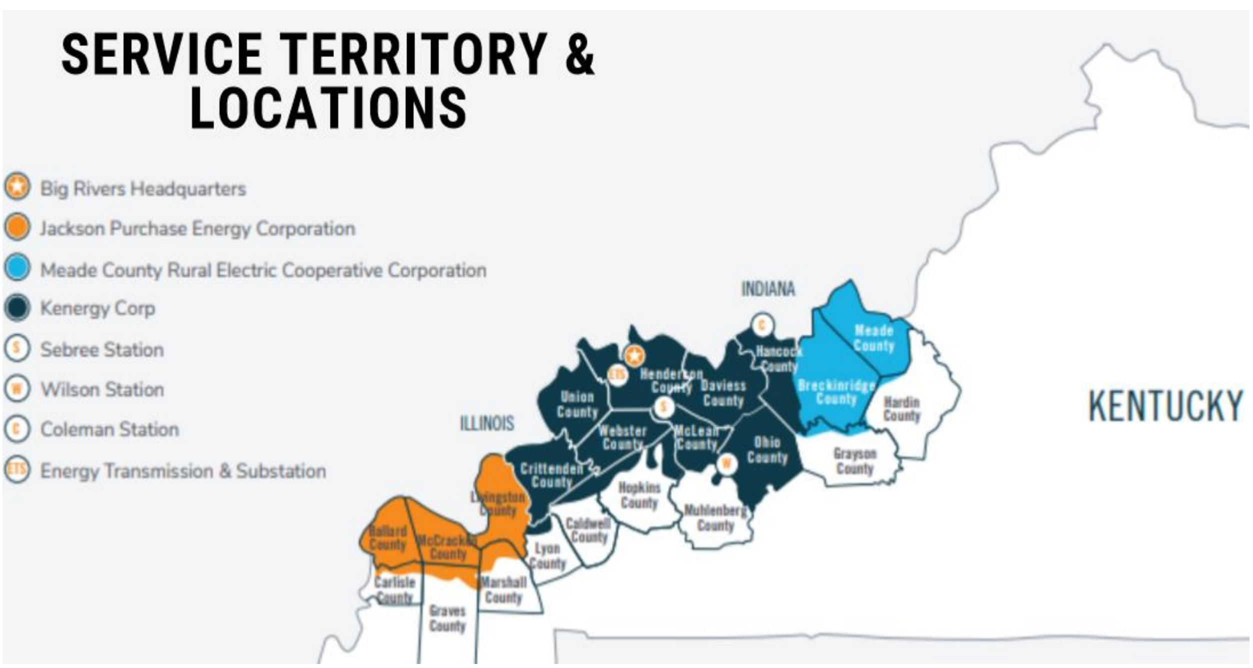
Name	Company	Role
Marlene Parsley	Big Rivers Electric Corporation	Project Manager
Russ Pogue	Big Rivers Electric Corporation	DSM Study
Jeff Williams	Jackson Purchase Energy Corporation	Load Forecast Representative
Scott Ribble	Jackson Purchase Energy Corporation	Load Forecast Representative
Steve Thompson	Kenergy Corporation	Load Forecast Representative
Travis Siewert	Kenergy Corporation	Load Forecast Representative
Anna Swanson	Meade County RECC	Load Forecast Representative
David Poe	Meade County RECC	Load Forecast Representative
Mike French	Meade County RECC	Load Forecast Representative
Matt Sekeres	Clearspring Energy Advisors	Lead Consultant
Steve Fenrick	Clearspring Energy Advisors	Model Development
Josh Hoyt	Clearspring Energy Advisors	DSM Study
Doug Carlson	Clearspring Energy Advisors	MISO Peak Forecast

The forecast results meet the requirements of and will be used in United States Department of Agriculture ("USDA") Rural Utilities Service ("RUS") loan applications. The forecast will be used by Big Rivers as a key input into an Integrated Resource Plan ("IRP") being completed to satisfy Kentucky Public Service Commission ("Commission") statutory requirements, and the forecast will be used for other internal uses such as planning and financial projections. This forecast may also be used externally to meet state and federal regulatory requirements and participating in reliability council and independent transmission organization activities. This forecast was developed using methods and procedures in general use by the electric utility industry.

1.2 Big Rivers' Member Information

The three distribution cooperatives are Jackson Purchase Energy Corporation ("JPEC"), Kenergy Corporation ("Kenergy"), and Meade County Rural Electric Cooperative Corporation ("MCRECC"). These three Big Rivers Members serve more than 118,000 residential households, businesses, and farms in western Kentucky. This report details the load forecast for the total Big Rivers system. The service territories of the three Big Rivers distribution Members are shown below.

Service Territory



1.3 Native Forecast Summary

The forecast study develops a forecast for individual retail classes. The forecasted retail classes are:

- Residential,
- General Commercial and Industrial ("GCI"),
- Large Commercial and Industrial ("LCI"),
- Irrigation,
- Street & Highway, and
- Direct Serve sales.

The Residential, GCI, LCI, Irrigation, and Street and Highway classes along with own use and distribution losses make up the Rural system requirements. Direct Serve sales and transmission losses are aggregated with the Rural system to provide total system ("Native") requirements. The total Rural forecast is the sum of the forecasts for each of the three distribution Members. Each Member's retail class sales forecast is the product of the consumer forecast and the use per consumer forecast for each class. The Member's total sales forecast is constructed by summing the individual retail class sales forecasts.

The table below provides the total Rural energy requirements, Direct Serve energy requirements, Rural peak demand coincident to Big Rivers, Direct Serve peak demand coincident to Big Rivers, Rural system load factor, and Native system load factor for the last five historical years (2015-2019) and the forecasts for the next 20 years. Throughout this load forecast study, 2019 is considered a historical data year even though due to timeline considerations November and December of 2019 often contain estimated data.

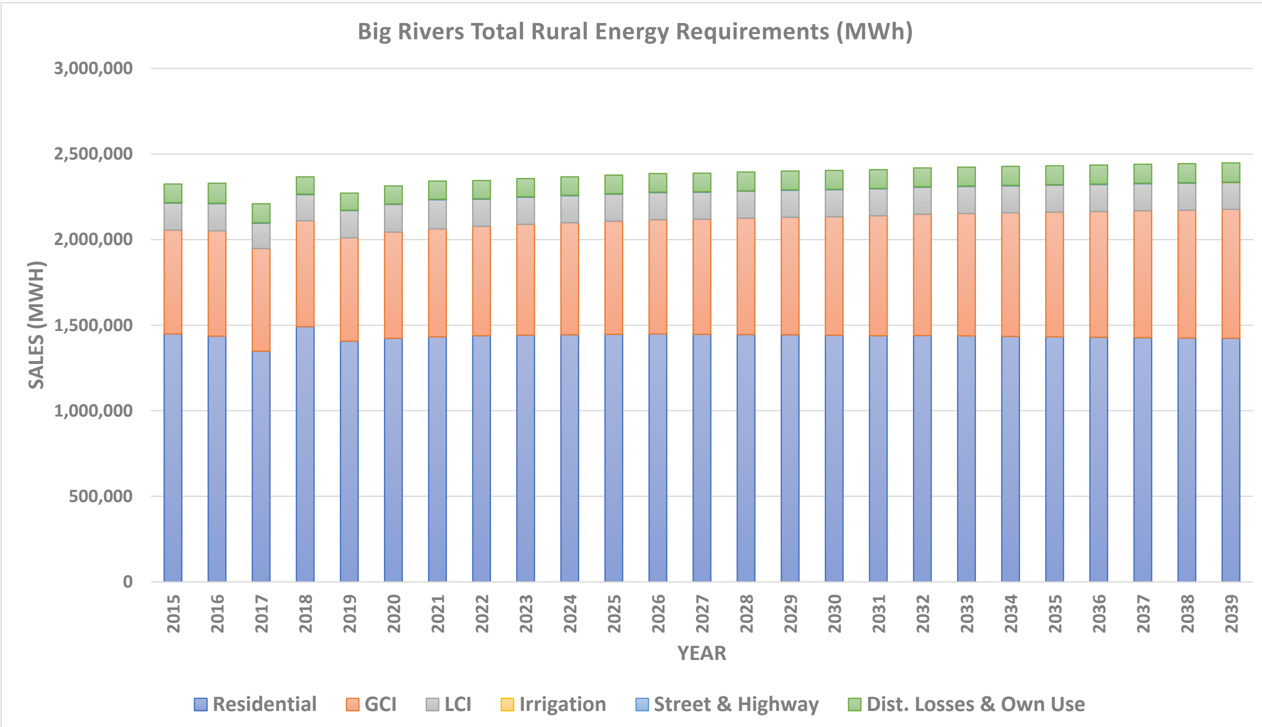
***Native System Summary*[1]**

Big Rivers Native System Totals						
Year	Total Rural Energy Requirements (MWh)	Direct Serve Energy Requirements (MWh)	Rural System Coincident Peak Demand (MW)	Direct Serve Coincident Peak Demand (MW)	Rural System Coincident Peak Load Factor	Native System Coincident Peak Load Factor
2015	2,325,204	946,873	566.6	121.1	46.9%	54.5%
2016	2,330,037	915,310	486.7	120.8	54.5%	60.8%
2017	2,209,837	919,895	504.3	114.4	50.0%	57.7%
2018	2,366,988	953,822	556.7	95.5	48.5%	58.2%
2019	2,271,772	957,994	490.9	117.9	52.8%	60.6%
2020	2,313,997	987,552	483.9	127.1	54.4%	61.5%
2021	2,342,004	987,552	489.2	127.1	54.6%	61.7%
2022	2,345,137	2,038,752	489.6	322.0	54.7%	61.7%
2023	2,357,028	2,038,752	491.6	322.0	54.7%	61.7%
2024	2,366,988	2,041,632	493.4	322.0	54.6%	61.6%
2025	2,376,885	2,038,752	495.1	322.0	54.8%	61.7%
2026	2,386,410	2,038,752	496.9	322.0	54.8%	61.7%
2027	2,388,504	2,038,752	497.1	322.0	54.8%	61.7%
2028	2,394,976	2,041,632	498.4	322.0	54.7%	61.6%
2029	2,400,628	2,038,752	499.4	322.0	54.9%	61.7%
2030	2,403,821	2,038,752	500.0	322.0	54.9%	61.7%
2031	2,409,248	2,038,752	501.1	322.0	54.9%	61.7%
2032	2,419,240	2,038,752	503.1	322.0	54.7%	61.5%
2033	2,424,117	2,038,752	504.1	322.0	54.9%	61.7%
2034	2,427,766	2,038,752	504.8	322.0	54.9%	61.7%
2035	2,431,849	2,038,752	505.7	322.0	54.9%	61.7%
2036	2,435,950	2,038,752	506.5	322.0	54.8%	61.5%
2037	2,440,157	2,038,752	507.3	322.0	54.9%	61.6%
2038	2,444,021	2,038,752	508.1	322.0	54.9%	61.6%
2039	2,448,197	2,038,752	509.0	322.0	54.9%	61.6%
Average Annual Growth Rates						
Previous 10 Years	0.15%	-2.27%	-1.32%	0.98%	1.49%	0.29%
Previous 5 Years	-1.22%	-0.17%	-4.44%	-1.03%	3.37%	3.01%
Next 5 Years	0.82%	16.34%	0.10%	22.25%	0.67%	0.31%
Next 10 Years	0.55%	7.85%	0.17%	10.57%	0.38%	0.18%
Next 20 Years	0.37%	3.85%	0.18%	5.15%	0.19%	0.08%

[1] Big Rivers has no current non-pilot Demand Side Management (DSM) or Energy Efficiency (EE) programs and is not projected to have any new programs in the base forecast. Alternate forecasts with projected DSM impacts are discussed in section 4.

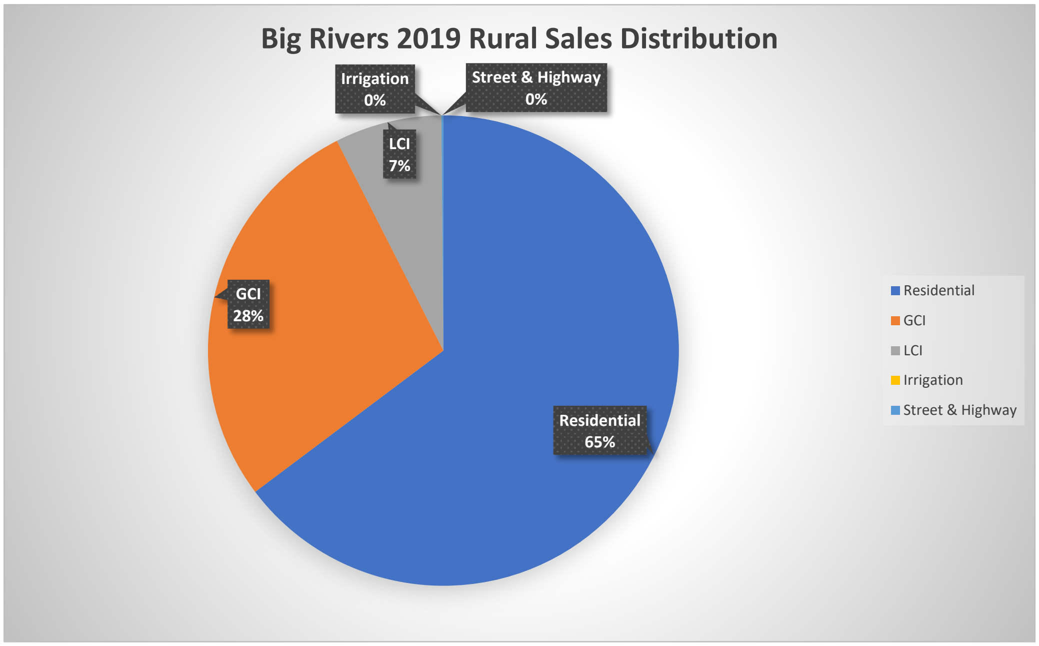
The following graph provides the Native system Rural energy requirements forecast.

Rural Energy Requirements



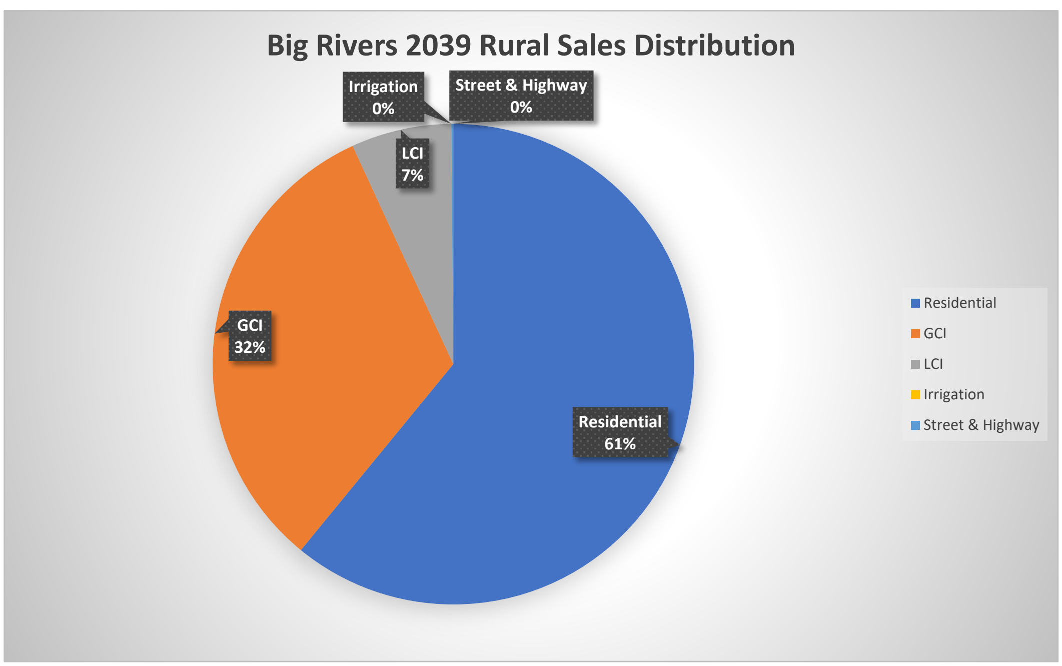
The figure below provides the Native system Rural sales distribution by class for 2019.

2019 Rural Sales by Class Distribution



The figure below provides the Native system Rural sales forecasted distribution by class for 2039.

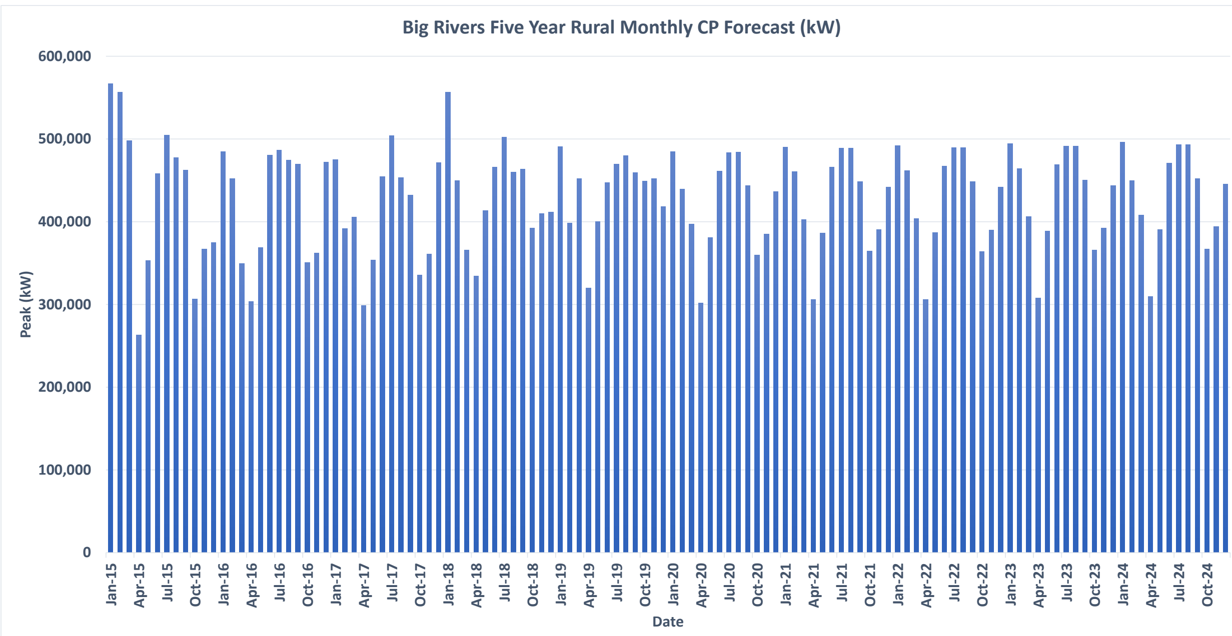
2039 Rural Sales by Class Distribution



1.3.1 Monthly Peak Forecast

Monthly load factors have been econometrically modeled for each Member system. The load factor models are used in conjunction with the energy forecasts to calculate monthly peak demands. The monthly Rural peak demand forecast (coincident with Big Rivers) for the prior and next five years is presented in the following figure.

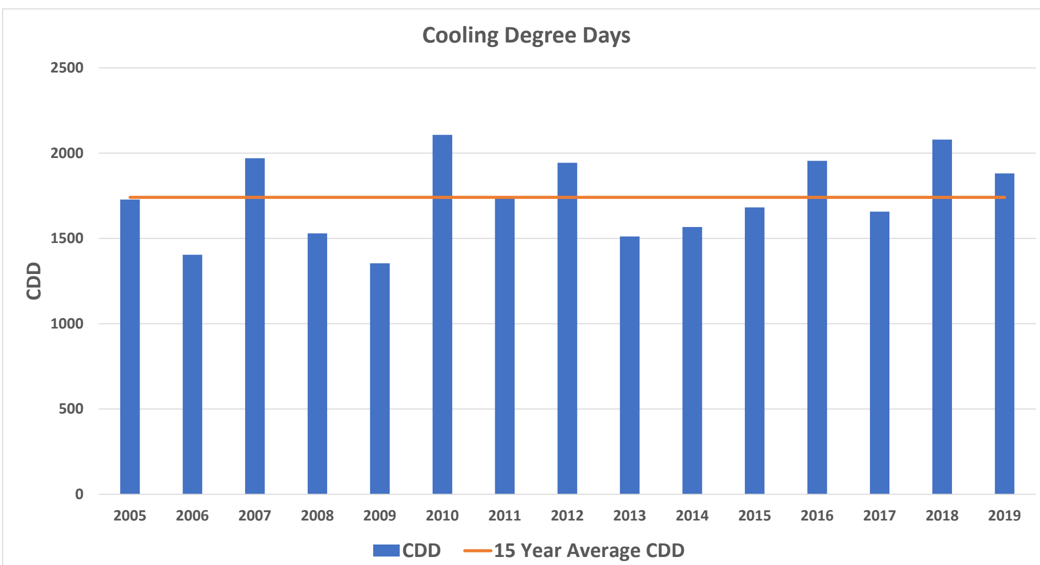
Monthly Rural Peak Forecast



1.4 2019 Weather Conditions

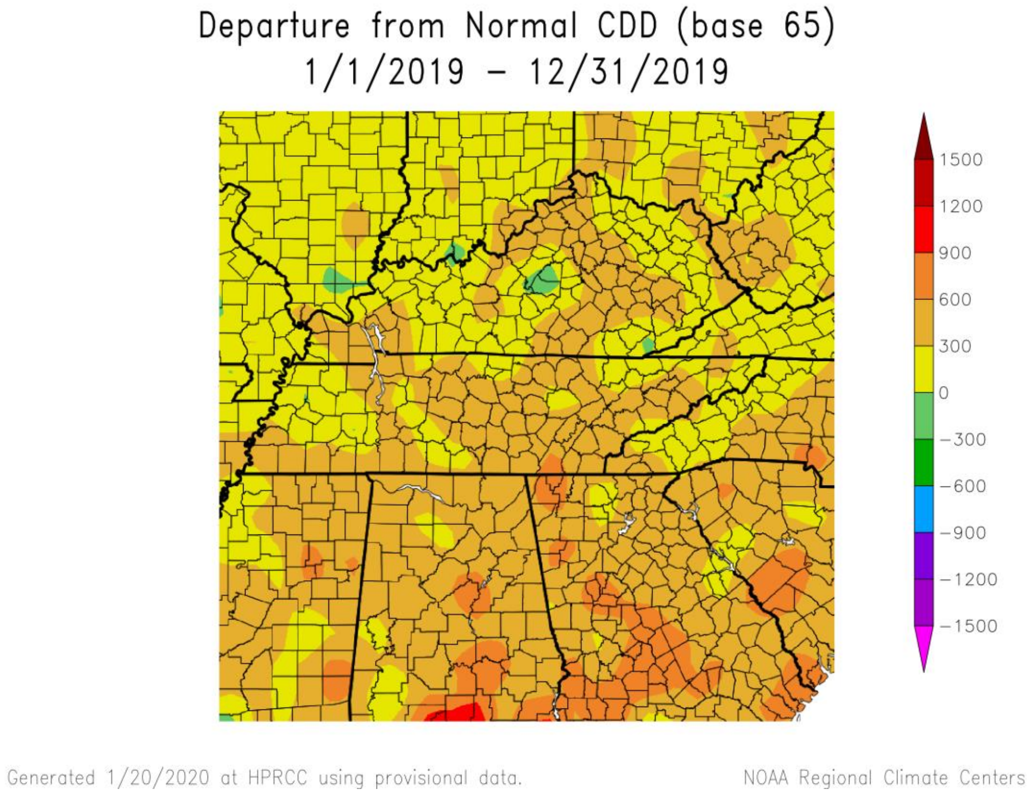
There contains an assumption of a "normal" weather scenario for the forecasts for each class. Clearspring Energy compiled historical weather observations to enable the estimation of weather impacts onto sales and peak loads. Weather variables such as cooling degree days (CDD), heating degree days (HDD), and peak temperatures were gathered using weather stations within each service territory. Paducah, KY was used as the primary weather station to gather data for JPEC. Owensboro, KY was used as the primary weather station to gather data for Kenergy. Louisville, KY was used as the primary weather station to gather data for MCRECC. In the cases of missing historical data, a variety of backup stations were used to fill in missing data. The figure below displays the last fifteen years of CDDs for Big Rivers along with the 15-year average CDD.

Cooling Degree Days for Last 15 Years



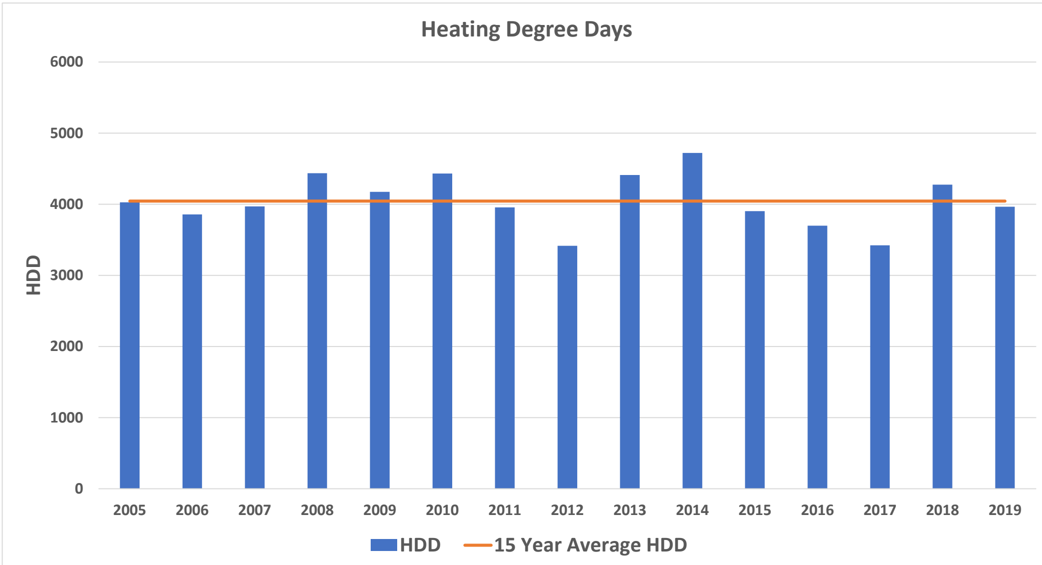
The figure below provides the CDD deviation in 2019 from a 30-year normal amount for the entire state of Kentucky, showing the distribution of weather conditions across the full service territory. The map shows an isolated pocket of mild summer CDD amounts in the northern portion of the service territory. However, most of the service territory experienced a hotter-than-normal summer season with the most extreme areas occurring in the southwest area of the service territory.

Kentucky 2019 CDD Deviations



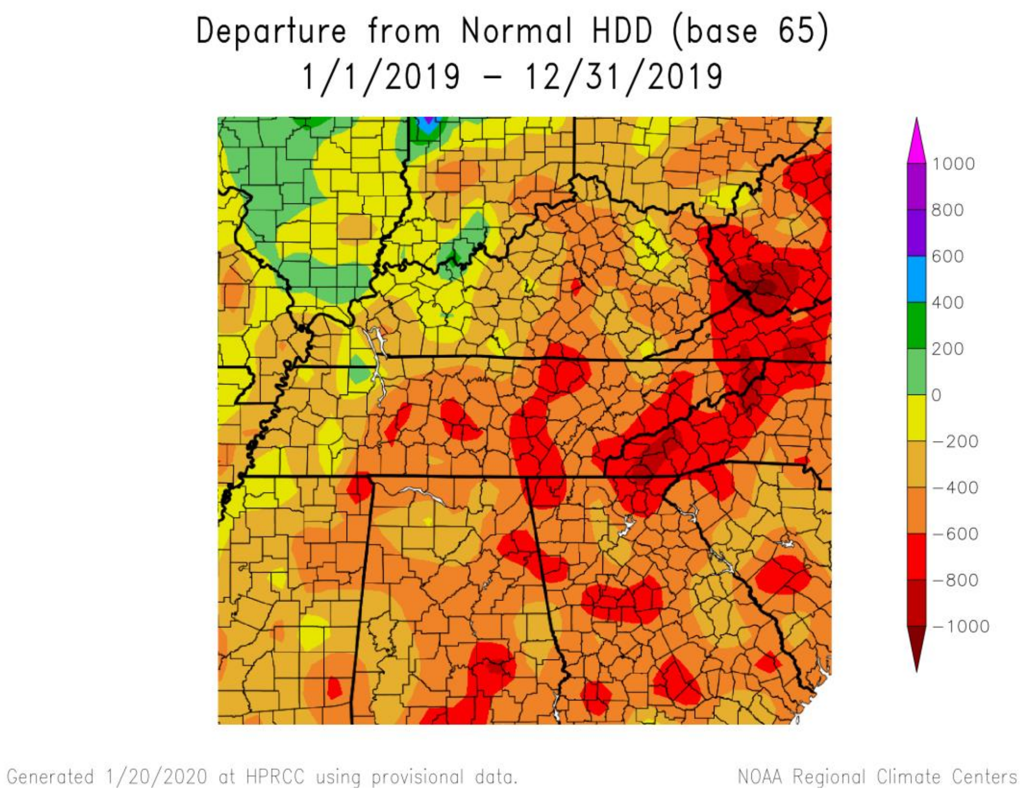
The figure below displays the last fifteen years of HDDs for Big Rivers along with the 15-year average HDD.

Heating Degree Days for Last 15 Years



The figure below provides the HDD deviation in 2019 from a 30-year normal amount for the entire state of Kentucky. The map shows mostly average winter HDD amounts, with some slightly more mild areas in the southwest portion of the service territory.

Kentucky 2019 HDD Deviations



1.5 Forecast Process Summary

Clearspring developed econometric models in order to forecast Residential energy per consumer, General C&I (GCI) consumers, GCI use per consumer, and the Rural system's monthly load factors. A growth index using projections for the number of households was used to forecast Residential consumers. Historical weather and economic data were gathered from various sources to estimate the impacts of variables onto the corresponding category. Normalized weather and forecasted economic variables are then combined with the parameter estimates of the models to calculate forecasted values.

Forecasts for the LCI and Direct Serve commercial loads have been prepared based on input from the cooperatives and historical value. Judgment and trend analysis are used to project Irrigation, Street and Highway, own use, and distribution losses. The forecasts have been provided to Big Rivers and the Member systems and have been approved by each.

2 ENERGY FORECAST RESULTS

2.1 Residential Class

The Residential sales forecast is comprised of a forecast for Residential use per consumer and a forecast for Residential retail members. The product of the two disaggregated forecasts equals the Residential sales forecast.

The following table provides the last five years of historical data and the next 20 years of forecasted data for the number of Residential customers, Residential use per consumer, and Residential energy sales. Growth rates for the prior 5 and 10 years and projected growth rates for the next 5, 10, and 20 years are also provided.

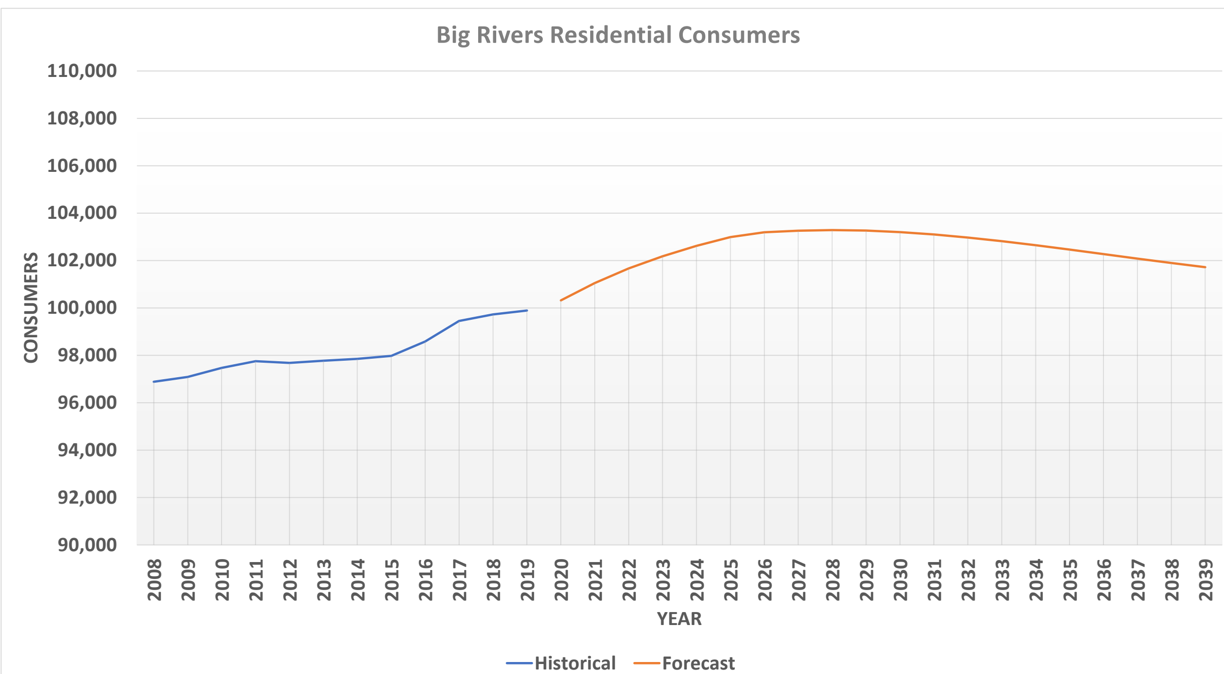
Historical and Projected Residential Consumers, Use per Consumer, and Sales

Big Rivers Residential Class						
Year	Number of Consumers	% Change per Year in Consumers	Use Per Consumer (kWh)	% Change per Year in Use Per Consumer	Energy Sales (MWh)	% Change per Year in Energy Sales
2015	97,971		14,783		1,448,343	
2016	98,583	0.62%	14,565	-1.48%	1,435,874	-0.86%
2017	99,451	0.88%	13,553	-6.95%	1,347,867	-6.13%
2018	99,724	0.27%	14,955	10.34%	1,491,338	10.64%
2019	99,891	0.17%	14,083	-5.83%	1,406,754	-5.67%
2020	100,314	0.42%	14,195	0.79%	1,423,914	1.22%
2021	101,044	0.73%	14,170	-0.17%	1,431,787	0.55%
2022	101,667	0.62%	14,153	-0.12%	1,438,903	0.50%
2023	102,180	0.50%	14,114	-0.28%	1,442,148	0.23%
2024	102,616	0.43%	14,073	-0.29%	1,444,122	0.14%
2025	102,990	0.36%	14,047	-0.18%	1,446,702	0.18%
2026	103,193	0.20%	14,040	-0.05%	1,448,868	0.15%
2027	103,256	0.06%	14,006	-0.25%	1,446,170	-0.19%
2028	103,282	0.03%	13,996	-0.07%	1,445,528	-0.04%
2029	103,263	-0.02%	13,985	-0.08%	1,444,108	-0.10%
2030	103,200	-0.06%	13,963	-0.16%	1,440,938	-0.22%
2031	103,101	-0.10%	13,955	-0.05%	1,438,824	-0.15%
2032	102,970	-0.13%	13,977	0.16%	1,439,236	0.03%
2033	102,815	-0.15%	13,978	0.01%	1,437,166	-0.14%
2034	102,644	-0.17%	13,975	-0.02%	1,434,434	-0.19%
2035	102,460	-0.18%	13,976	0.01%	1,431,962	-0.17%
2036	102,269	-0.19%	13,979	0.02%	1,429,572	-0.17%
2037	102,079	-0.19%	13,985	0.04%	1,427,550	-0.14%
2038	101,894	-0.18%	13,989	0.03%	1,425,414	-0.15%
2039	101,718	-0.17%	13,994	0.04%	1,423,491	-0.13%
Average Annual Growth Rates						
Previous 10 Years	0.29%		-0.43%		-0.14%	
Previous 5 Years	0.41%		-2.09%		-1.69%	
Next 5 Years	0.54%		-0.01%		0.53%	
Next 10 Years	0.33%		-0.07%		0.26%	
Next 20 Years	0.09%		-0.03%		0.06%	

2.1.1 Residential Consumer Forecast

Third party household growth projections are gathered from Woods & Poole Economics, Inc. The projections are based at the county level and weighted up for each county within the distribution Member's service territories using the current distribution of Residential consumers across each county. These household growth estimates are used to project the number of Residential members in future years with additional adjustments made based on cooperative staff recommendations. The following figure provides the historical and projected Residential consumers on the Big Rivers system. Residential consumers are projected to increase over the next five years at an average annual rate of 0.5% driven mostly by increased large C&I activity creating a demand for new housing in the service territory. After the first five years of the forecast the housing growth is expected to slow and decline slightly in the later years of the forecast.

Residential Consumers

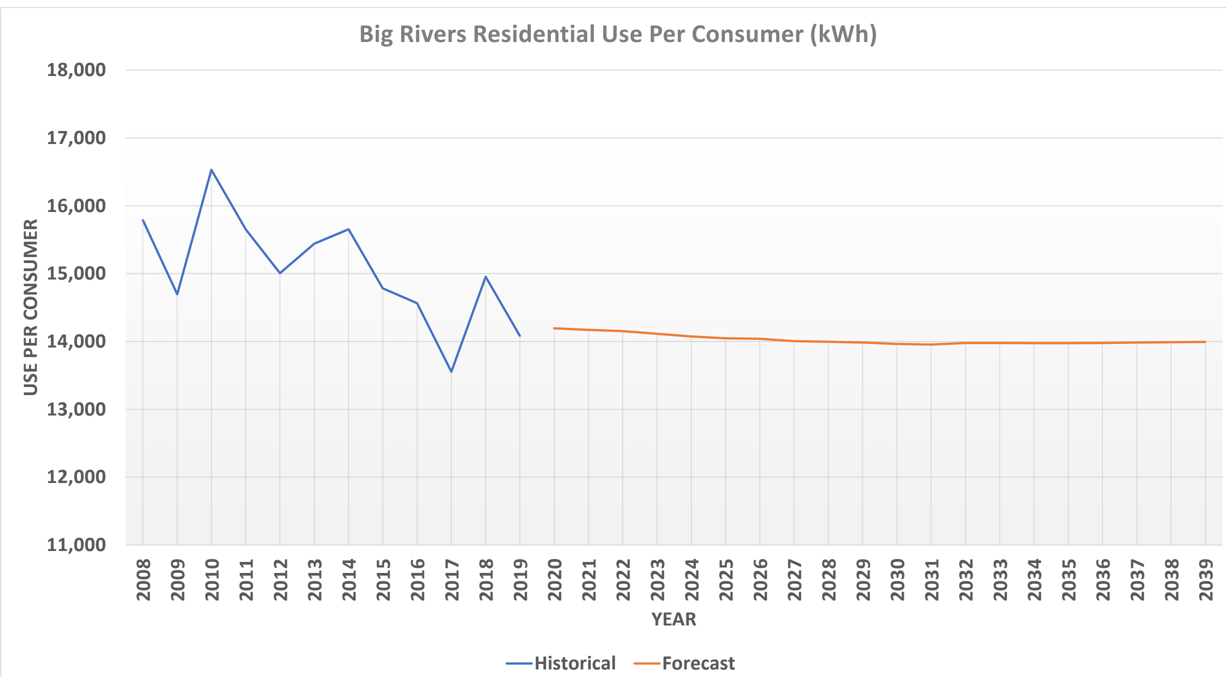


2.1.2 Residential Use per Consumer Forecast

The Residential use per consumer forecast is estimated using econometric models for each distribution Member that relates certain explanatory variables to Residential use per consumer. The models employ a monthly dataset with 154 observations from January 2007 to October 2019.

The models use price of electricity, alternate fuel prices, cooling and heating degree days, appliance saturation levels, and appliance efficiencies. Explanatory variable values are projected in future years using demographic and economic projections and weather normalized values. Preliminary model results were reviewed by cooperative staff and modifications were made if necessary where staff had specific knowledge of the service territory and conditions. Use per consumer values are projected to fall slightly through the first ten years of the forecast at an average annual rate of -0.1%. The reduction is due to continuing efficiency gains in appliance stocks as older, less efficient, appliances are replaced with more efficient ones. During the last ten years of the forecast additional efficiency gains are slower and the effect on use per consumer is balanced by the continuing decreasing real cost of electricity resulting in flat growth in the final years of the forecast period. The Residential use per consumer models are provided in the Appendix. The following figure provides the historical and projected Residential use per consumer for the Big Rivers Native system.

Residential Use Per Consumer



2.2 Commercial and Industrial Class

The total commercial and industrial class is divided into three distinct sub classes. The majority of the commercial and industrial retail members are placed and forecasted within the General C&I (GCI) class. This class consists of the relatively smaller C&I consumers at each distribution Member. The second commercial and industrial class is the Large C&I (LCI) class. This class consists of the largest commercial and industrial customers that are not served under Big Rivers' Large Industrial Customer tariff (LIC) and therefore do not qualify as Direct Serve consumers. The third class are Direct Serve consumers. The consumers that fall under this class are served under Big Rivers' LIC. These Direct Serve customers are individually forecasted based on input from the member system, Big Rivers, or the Direct Serve consumer itself. The Direct Serve sales are aggregated to the Native system requirements separately from the Rural system load.

2.2.1 General Commercial and Industrial (GCI) Class

The GCI class is defined as the total commercial and industrial loads minus the Direct Serve and LCI loads. Given the importance of the GCI class, Clearspring used econometric modeling to project both the GCI consumer counts and the GCI use per consumer for the Big Rivers distribution Members.

The following table provides the last five years of historical data and the next 20 years of forecasted data for the number of GCI customers, GCI use per consumer, and GCI energy sales. Growth rates for the prior 5 and 10 years and projected growth rates for the next 5, 10, and 20 years are provided in the table for GCI consumers, use per consumer, and sales.

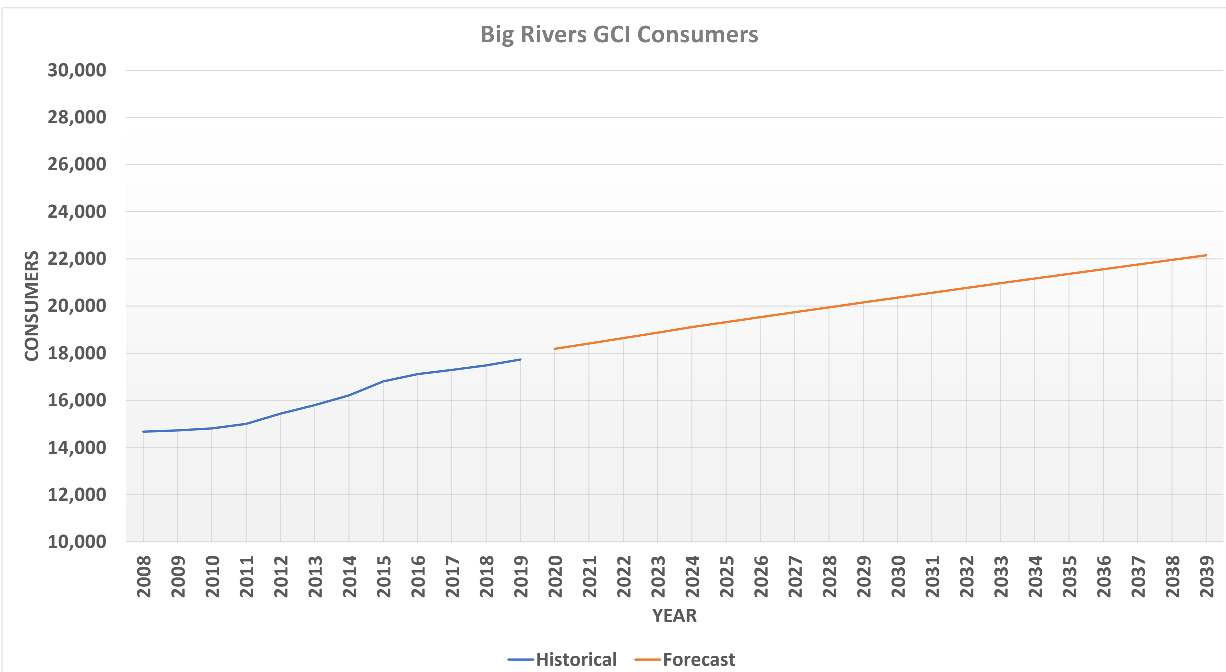
Historical and Projected GCI Consumers, Use per Consumer, and Sales

Big Rivers General C&I Class						
Year	Number of Consumers	% Change per Year in Consumers	Use Per Consumer (kWh)	% Change per Year in Use Per Consumer	Energy Sales (MWh)	% Change per Year in Energy Sales
2015	16,805		36,121		607,011	
2016	17,110	1.81%	35,949	-0.48%	615,083	1.33%
2017	17,290	1.05%	34,721	-3.42%	600,334	-2.40%
2018	17,483	1.12%	35,398	1.95%	618,866	3.09%
2019	17,732	1.42%	34,050	-3.81%	603,764	-2.44%
2020	18,188	2.57%	34,138	0.26%	620,892	2.84%
2021	18,406	1.20%	34,237	0.29%	630,164	1.49%
2022	18,641	1.28%	34,283	0.14%	639,079	1.41%
2023	18,872	1.24%	34,293	0.03%	647,167	1.27%
2024	19,104	1.23%	34,270	-0.07%	654,681	1.16%
2025	19,314	1.10%	34,251	-0.05%	661,534	1.05%
2026	19,524	1.09%	34,238	-0.04%	668,455	1.05%
2027	19,734	1.08%	34,110	-0.37%	673,141	0.70%
2028	19,942	1.06%	34,096	-0.04%	679,960	1.01%
2029	20,150	1.04%	34,082	-0.04%	686,774	1.00%
2030	20,357	1.03%	34,041	-0.12%	692,988	0.90%
2031	20,562	1.01%	34,056	0.04%	700,284	1.05%
2032	20,765	0.99%	34,164	0.32%	709,422	1.30%
2033	20,966	0.97%	34,157	-0.02%	716,148	0.95%
2034	21,166	0.95%	34,128	-0.08%	722,361	0.87%
2035	21,365	0.94%	34,109	-0.06%	728,729	0.88%
2036	21,562	0.92%	34,089	-0.06%	735,033	0.87%
2037	21,759	0.91%	34,059	-0.09%	741,068	0.82%
2038	21,954	0.90%	34,020	-0.11%	746,889	0.79%
2039	22,149	0.89%	33,988	-0.10%	752,795	0.79%
Average Annual Growth Rates						
Previous 10 Years	1.88%		-1.26%		0.59%	
Previous 5 Years	1.81%		-1.97%		-0.20%	
Next 5 Years	1.50%		0.13%		1.63%	
Next 10 Years	1.29%		0.01%		1.30%	
Next 20 Years	1.12%		-0.01%		1.11%	

2.2.1.1 GCI Consumer Forecast

The GCI consumer forecast is estimated using econometric models for each Big Rivers distribution Member that relates explanatory variables to the GCI consumer count. The models use gross regional product (GRP) and total retail sales within the counties served and are aligned with each distribution cooperatives 2019 GCI consumer values. Explanatory variable values are projected in future years using economic projections. Preliminary model results were reviewed by cooperative staff and modifications were made if necessary where staff had specific knowledge of the service territory and conditions. The GCI consumer models are provided in the Appendix. The following figure provides the historical and projected GCI consumers for the Big Rivers Native system.

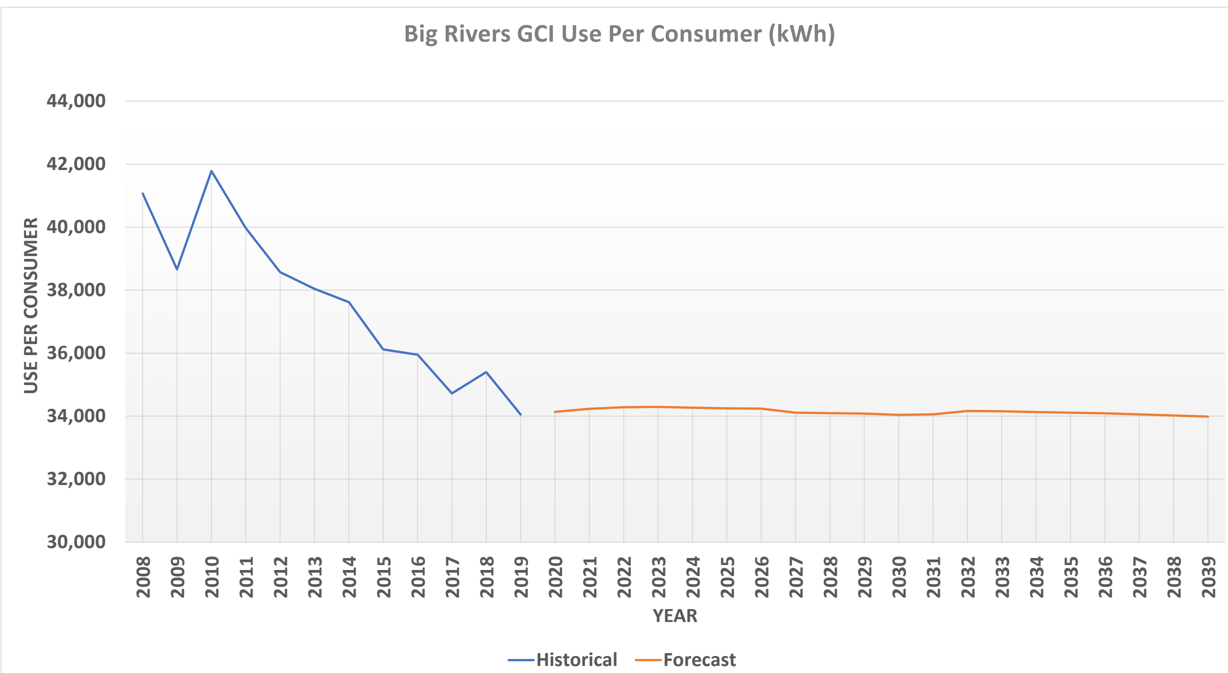
GCI Consumers



2.2.1.2 GCI Use per Consumer Forecast

The GCI use per consumer forecast is estimated using econometric models for each of the Big Rivers distribution Members that relates certain explanatory variables to the GCI use per consumer. The models use electricity price, employment per consumer, cooling degree days, and heating degree days within the counties served. Explanatory variable values are projected in future years using demographic and economic projections and weather normalized values. Preliminary model results were reviewed by cooperative staff and modifications were made if necessary where staff had specific knowledge of the service territory and conditions. The GCI use per consumer models are provided in the Appendix. The following figure provides the historical and projected GCI use per consumer for the Big Rivers Native system.

GCI Use per Consumer



2.2.2 Large Commercial and Industrial (LCI) Class

The Large C&I (LCI) class consists of the largest commercial and industrial customers at each distribution Member that do not qualify as Direct Serve consumers. In 2019 the Big Rivers LCI class contained 31 consumers. The sales forecasts are based on staff knowledge and judgement with input from each cooperative. The following table provides the last five years of historical data and the next 20 years of forecasted data for the number of LCI consumers, LCI use per consumer, and LCI energy sales. Growth rates for the prior 5 and 10 years and projected growth rates for the next 5, 10, and 20 years are provided in the table for LCI consumers, use per consumer, and sales.

Historical and Projected LCI Consumers, Use per Consumer, and Sales

Big Rivers Large C&I Class						
Year	Number of Consumers	% Change per Year in Consumers	Use Per Consumer (MWh)	% Change per Year in Use Per Consumer	Energy Sales (MWh)	% Change per Year in Energy Sales
2015	33		4,778		157,680	
2016	32	-3.28%	4,982	4.26%	158,999	0.84%
2017	29	-10.18%	5,143	3.24%	147,433	-7.27%
2018	29	1.16%	5,266	2.39%	152,708	3.58%
2019	31	5.46%	5,203	-1.20%	159,111	4.19%
2020	32	3.81%	5,064	-2.67%	160,778	1.05%
2021	32	0.79%	5,323	5.12%	170,333	5.94%
2022	31	-3.13%	5,075	-4.67%	157,311	-7.64%
2023	31	0.00%	5,075	0.00%	157,311	0.00%
2024	31	0.00%	5,075	0.00%	157,311	0.00%
2025	31	0.00%	5,075	0.00%	157,311	0.00%
2026	31	0.00%	5,075	0.00%	157,311	0.00%
2027	31	0.00%	5,075	0.00%	157,311	0.00%
2028	31	0.00%	5,075	0.00%	157,311	0.00%
2029	31	0.00%	5,075	0.00%	157,311	0.00%
2030	31	0.00%	5,075	0.00%	157,311	0.00%
2031	31	0.00%	5,075	0.00%	157,311	0.00%
2032	31	0.00%	5,075	0.00%	157,311	0.00%
2033	31	0.00%	5,075	0.00%	157,311	0.00%
2034	31	0.00%	5,075	0.00%	157,311	0.00%
2035	31	0.00%	5,075	0.00%	157,311	0.00%
2036	31	0.00%	5,075	0.00%	157,311	0.00%
2037	31	0.00%	5,075	0.00%	157,311	0.00%
2038	31	0.00%	5,075	0.00%	157,311	0.00%
2039	31	0.00%	5,075	0.00%	157,311	0.00%
Average Annual Growth Rates						
Previous 10 Years	5.49%		-2.79%		2.55%	
Previous 5 Years	-0.32%		0.86%		0.53%	
Next 5 Years	0.27%		-0.50%		-0.23%	
Next 10 Years	0.14%		-0.25%		-0.11%	
Next 20 Years	0.07%		-0.12%		-0.06%	

2.2.3 Direct Serve Class

The Direct Serve class contains consumers that are directly served from the transmission system. The sales forecasts are based on manager and staff knowledge and input from each cooperative. Big Rivers Direct Serve class contained twenty-one[2] consumers in 2019. The Direct Serve class is expected to add one additional consumer in 2022.

The following table provides the last five years of historical data and the next 20 years of forecasted data for the number of Direct Serve customers, Direct Serve use per consumer, and Direct Serve energy sales. Growth rates for the prior 5 and 10 years and projected growth rates for the next 5, 10, and 20 years are provided in the table for Direct Serve consumers, use per consumer, and sales.

[2] The Kenergy load forecast contains projections for two additional Direct Serve smelter load consumers that are not included in this report because they do not contribute to the Big Rivers energy or peak requirements. Including those two consumers the Direct Serve consumer count in 2019 would be twenty-three.

Historical and Projected Direct Serve Consumers, Use per Consumer, and Sales

Big Rivers Direct Serve Class						
Year	Number of Consumers	% Change per Year in Consumers	Use Per Consumer (MWh)	% Change per Year in Use Per Consumer	Energy Sales (MWh)	% Change per Year in Energy Sales
2015	20		47,344		946,873	
2016	20	0.00%	45,765	-3.33%	915,310	-3.33%
2017	20	0.00%	45,995	0.50%	919,895	0.50%
2018	21	4.17%	45,783	-0.46%	953,822	3.69%
2019	21	0.80%	45,619	-0.36%	957,994	0.44%
2020	21	0.00%	47,026	3.09%	987,552	3.09%
2021	21	0.00%	47,026	0.00%	987,552	0.00%
2022	22	4.76%	92,671	97.06%	2,038,752	106.45%
2023	22	0.00%	92,671	0.00%	2,038,752	0.00%
2024	22	0.00%	92,801	0.14%	2,041,632	0.14%
2025	22	0.00%	92,671	-0.14%	2,038,752	-0.14%
2026	22	0.00%	92,671	0.00%	2,038,752	0.00%
2027	22	0.00%	92,671	0.00%	2,038,752	0.00%
2028	22	0.00%	92,801	0.14%	2,041,632	0.14%
2029	22	0.00%	92,671	-0.14%	2,038,752	-0.14%
2030	22	0.00%	92,671	0.00%	2,038,752	0.00%
2031	22	0.00%	92,671	0.00%	2,038,752	0.00%
2032	22	0.00%	92,671	0.00%	2,038,752	0.00%
2033	22	0.00%	92,671	0.00%	2,038,752	0.00%
2034	22	0.00%	92,671	0.00%	2,038,752	0.00%
2035	22	0.00%	92,671	0.00%	2,038,752	0.00%
2036	22	0.00%	92,671	0.00%	2,038,752	0.00%
2037	22	0.00%	92,671	0.00%	2,038,752	0.00%
2038	22	0.00%	92,671	0.00%	2,038,752	0.00%
2039	22	0.00%	92,671	0.00%	2,038,752	0.00%
Average Annual Growth Rates						
Previous 10 Years	0.49%		-2.74%		-2.27%	
Previous 5 Years	0.98%		-1.14%		-0.17%	
Next 5 Years	0.93%		15.26%		16.34%	
Next 10 Years	0.47%		7.34%		7.85%	
Next 20 Years	0.23%		3.61%		3.85%	

2.3 Street and Highway Class

Given the small proportion of the Street and Highway class in total sales, the forecast for this class was calculated manually rather than through econometric modeling. The most recent consumer values were held constant through the forecast and the prior twelve months of usage were used to derive monthly energy forecasts for the forecast period.

The following table provides the last five years of historical data and the next 20 years of forecasted data for the number of Street and Highway consumers, Street and Highway use per consumer, and Street and Highway energy sales. Growth rates for the prior 5 and 10 years and projected growth rates for the next 5, 10, and 20 years are provided in the table for Street and Highway consumers, use per consumer, and sales.

Historical and Projected Street & Highway Consumers, Use per Consumer, and Sales

Big Rivers Street & Highway Class						
Year	Number of Consumers	% Change per Year in Consumers	Use Per Consumer (kWh)	% Change per Year in Use Per Consumer	Energy Sales (MWh)	% Change per Year in Energy Sales
2015	100		34,234		3,429	
2016	103	3.16%	32,049	-6.38%	3,312	-3.43%
2017	104	0.73%	31,223	-2.58%	3,250	-1.87%
2018	107	3.20%	28,965	-7.23%	3,111	-4.26%
2019	106	-1.01%	28,914	-0.18%	3,074	-1.18%
2020	108	1.57%	28,892	-0.07%	3,120	1.49%
2021	108	0.00%	28,892	0.00%	3,120	0.00%
2022	108	0.00%	28,892	0.00%	3,120	0.00%
2023	108	0.00%	28,892	0.00%	3,120	0.00%
2024	108	0.00%	28,892	0.00%	3,120	0.00%
2025	108	0.00%	28,892	0.00%	3,120	0.00%
2026	108	0.00%	28,892	0.00%	3,120	0.00%
2027	108	0.00%	28,892	0.00%	3,120	0.00%
2028	108	0.00%	28,892	0.00%	3,120	0.00%
2029	108	0.00%	28,892	0.00%	3,120	0.00%
2030	108	0.00%	28,892	0.00%	3,120	0.00%
2031	108	0.00%	28,892	0.00%	3,120	0.00%
2032	108	0.00%	28,892	0.00%	3,120	0.00%
2033	108	0.00%	28,892	0.00%	3,120	0.00%
2034	108	0.00%	28,892	0.00%	3,120	0.00%
2035	108	0.00%	28,892	0.00%	3,120	0.00%
2036	108	0.00%	28,892	0.00%	3,120	0.00%
2037	108	0.00%	28,892	0.00%	3,120	0.00%
2038	108	0.00%	28,892	0.00%	3,120	0.00%
2039	108	0.00%	28,892	0.00%	3,120	0.00%
Average Annual Growth Rates						
Previous 10 Years	2.24%		-2.73%		-0.54%	
Previous 5 Years	3.16%		-5.34%		-2.34%	
Next 5 Years	0.31%		-0.01%		0.30%	
Next 10 Years	0.16%		-0.01%		0.15%	
Next 20 Years	0.08%		0.00%		0.07%	

2.4 Irrigation Class

Given the small proportion of the Irrigation class in total sales, the forecast for this class was calculated manually rather than through econometric modeling. The most recent consumer values were held constant through the forecast and the prior twelve months of usage were used to derive monthly energy forecasts for the forecast period

The following table provides the last five years of historical data and the next 20 years of forecasted data for the number of Irrigation customers, Irrigation use per consumer, and Irrigation energy sales. Growth rates for the prior 5 and 10 years and projected growth rates for the next 5, 10, and 20 years are provided in the table for Irrigation consumers, use per consumer, and sales.

Historical and Projected Irrigation Consumers, Use per Consumer, and Sales

Big Rivers Irrigation Class						
Year	Number of Consumers	% Change per Year in Consumers	Use Per Consumer (kWh)	% Change per Year in Use Per Consumer	Energy Sales (MWh)	% Change per Year in Energy Sales
2015	4		15,428		62	
2016	4	0.00%	12,760	-17.29%	51	-17.29%
2017	4	0.00%	25,437	99.35%	102	99.35%
2018	5	12.50%	15,618	-38.60%	70	-30.93%
2019	5	11.11%	21,652	38.63%	108	54.04%
2020	5	0.00%	21,652	0.00%	108	0.00%
2021	5	0.00%	21,652	0.00%	108	0.00%
2022	5	0.00%	21,652	0.00%	108	0.00%
2023	5	0.00%	21,652	0.00%	108	0.00%
2024	5	0.00%	21,652	0.00%	108	0.00%
2025	5	0.00%	21,652	0.00%	108	0.00%
2026	5	0.00%	21,652	0.00%	108	0.00%
2027	5	0.00%	21,652	0.00%	108	0.00%
2028	5	0.00%	21,652	0.00%	108	0.00%
2029	5	0.00%	21,652	0.00%	108	0.00%
2030	5	0.00%	21,652	0.00%	108	0.00%
2031	5	0.00%	21,652	0.00%	108	0.00%
2032	5	0.00%	21,652	0.00%	108	0.00%
2033	5	0.00%	21,652	0.00%	108	0.00%
2034	5	0.00%	21,652	0.00%	108	0.00%
2035	5	0.00%	21,652	0.00%	108	0.00%
2036	5	0.00%	21,652	0.00%	108	0.00%
2037	5	0.00%	21,652	0.00%	108	0.00%
2038	5	0.00%	21,652	0.00%	108	0.00%
2039	5	0.00%	21,652	0.00%	108	0.00%
Average Annual Growth Rates						
Previous 10 Years	-5.17%		-7.62%		-12.39%	
Previous 5 Years	4.56%		-8.69%		-4.52%	
Next 5 Years	0.00%		0.00%		0.00%	
Next 10 Years	0.00%		0.00%		0.00%	
Next 20 Years	0.00%		0.00%		0.00%	

2.5 TOTAL RURAL ENERGY

The total Rural energy requirements are calculated by taking the sales forecasts for each class, detailed in the previous sections of this report, and adding distribution losses and own use. Distribution losses are estimated using a three-year historical average percent. This percent is computed after any Direct Sale loads are removed since these loads are no loss loads.

The following table provides the historical and forecast components of total Rural energy requirements. The last five historical years are provided (2015 to 2019) along with the next twenty years of forecasts for each component.

Rural System Energy Summary

Big Rivers Rural Energy Summary (MWh)								
Year	Residential Energy Sales	General C&I Energy Sales	Large C&I Energy Sales	Irrigation Energy Sales	Street & Highway Energy Sales	Distribution Losses	Own Use	**Total Rural Energy Requirements**
2015	1,448,343	607,011	157,680	62	3,429	107,766	913	**2,325,204**
2016	1,435,874	615,083	158,999	51	3,312	115,265	1,454	**2,330,037**
2017	1,347,867	600,334	147,433	102	3,250	107,908	2,944	**2,209,837**
2018	1,491,338	618,866	152,708	70	3,111	97,684	3,211	**2,366,988**
2019	1,406,754	603,764	159,111	108	3,074	95,907	3,053	**2,271,772**
2020	1,423,914	620,892	160,778	108	3,120	102,077	3,108	**2,313,997**
2021	1,431,787	630,164	170,333	108	3,120	103,358	3,132	**2,342,004**
2022	1,438,903	639,079	157,311	108	3,120	103,460	3,154	**2,345,137**
2023	1,442,148	647,167	157,311	108	3,120	104,000	3,173	**2,357,028**
2024	1,444,122	654,681	157,311	108	3,120	104,455	3,190	**2,366,988**
2025	1,446,702	661,534	157,311	108	3,120	104,904	3,205	**2,376,885**
2026	1,448,868	668,455	157,311	108	3,120	105,330	3,216	**2,386,410**
2027	1,446,170	673,141	157,311	108	3,120	105,429	3,225	**2,388,504**
2028	1,445,528	679,960	157,311	108	3,120	105,716	3,232	**2,394,976**
2029	1,444,108	686,774	157,311	108	3,120	105,968	3,238	**2,400,628**
2030	1,440,938	692,988	157,311	108	3,120	106,112	3,243	**2,403,821**
2031	1,438,824	700,284	157,311	108	3,120	106,354	3,247	**2,409,248**
2032	1,439,236	709,422	157,311	108	3,120	106,793	3,249	**2,419,240**
2033	1,437,166	716,148	157,311	108	3,120	107,012	3,252	**2,424,117**
2034	1,434,434	722,361	157,311	108	3,120	107,178	3,254	**2,427,766**
2035	1,431,962	728,729	157,311	108	3,120	107,363	3,255	**2,431,849**
2036	1,429,572	735,033	157,311	108	3,120	107,549	3,256	**2,435,950**
2037	1,427,550	741,068	157,311	108	3,120	107,742	3,257	**2,440,157**
2038	1,425,414	746,889	157,311	108	3,120	107,919	3,259	**2,444,021**
2039	1,423,491	752,795	157,311	108	3,120	108,111	3,260	**2,448,197**
Average Annual Growth Rates								
Previous 10 Years	-0.14%	0.59%	2.55%	-12.39%	-0.54%	-1.65%	7.43%	**0.15%**
Previous 5 Years	-1.69%	-0.20%	0.53%	-4.52%	-2.34%	-3.46%	22.98%	**-1.22%**
Next 5 Years	0.53%	1.63%	-0.23%	0.00%	0.30%	1.72%	0.88%	**0.82%**
Next 10 Years	0.26%	1.30%	-0.11%	0.00%	0.15%	1.00%	0.59%	**0.55%**
Next 20 Years	0.06%	1.11%	-0.06%	0.00%	0.07%	0.60%	0.33%	**0.37%**

2.6 TOTAL NATIVE SYSTEM ENERGY

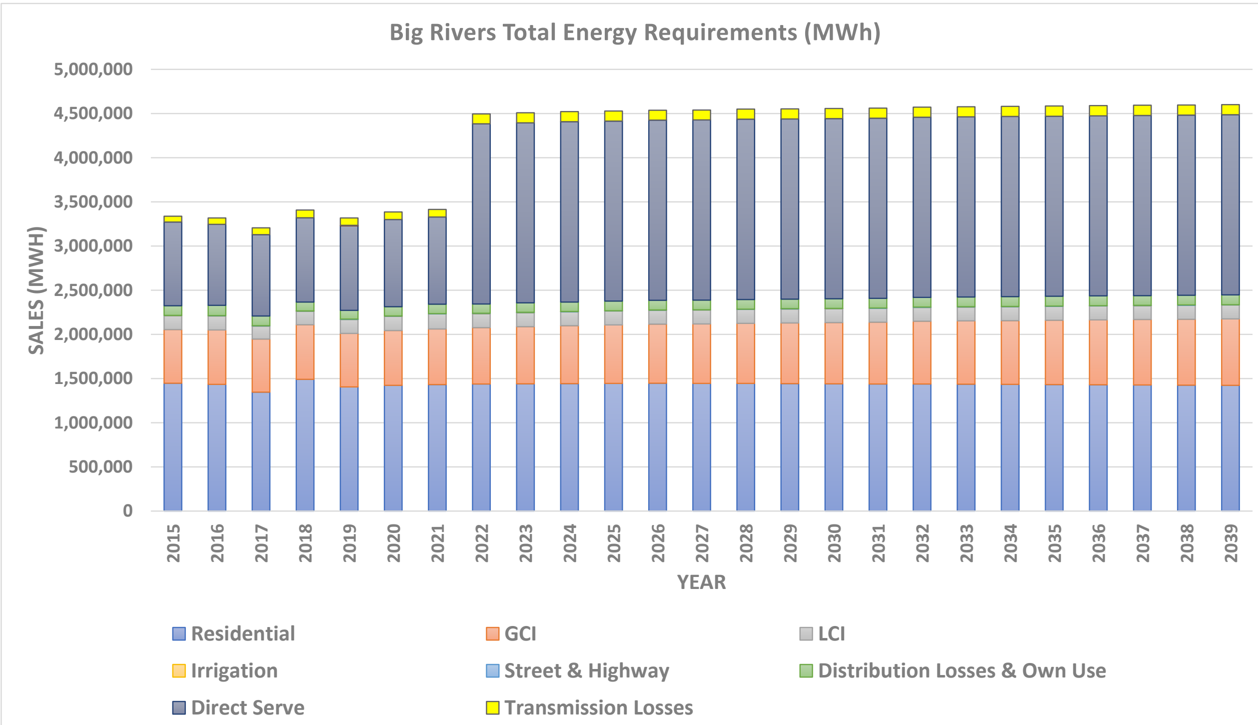
The total system Native energy requirements consist of the Rural system requirements, Direct Serve energy, and transmission losses. Transmission losses were 2.51% in 2019 and are forecasted at 2.50% beginning in February 2020 for the remainder of the forecast. The table below shows each component of the total system energy requirements. While Domtar is a Direct Serve consumer, only a partial amount of the energy use contributes to the Big Rivers energy requirements.

Total Native System Energy Summary

Big Rivers Total Native System Energy Summary (MWh)				
Year	Total Rural Requirements	Direct Serve	Transmission Losses	**Total System Energy Requirements**
2015	2,325,204	946,873	66,970	**3,339,047**
2016	2,330,037	915,310	73,420	**3,318,766**
2017	2,209,837	919,895	77,928	**3,207,660**
2018	2,366,988	953,822	86,858	**3,407,668**
2019	2,271,772	957,994	83,431	**3,317,632**
2020	2,313,997	987,552	84,688	**3,386,237**
2021	2,342,004	987,552	85,373	**3,414,929**
2022	2,345,137	2,038,752	112,407	**4,496,296**
2023	2,357,028	2,038,752	112,712	**4,508,492**
2024	2,366,988	2,041,632	113,042	**4,521,662**
2025	2,376,885	2,038,752	113,221	**4,528,859**
2026	2,386,410	2,038,752	113,466	**4,538,628**
2027	2,388,504	2,038,752	113,519	**4,540,776**
2028	2,394,976	2,041,632	113,759	**4,550,367**
2029	2,400,628	2,038,752	113,830	**4,553,210**
2030	2,403,821	2,038,752	113,912	**4,556,486**
2031	2,409,248	2,038,752	114,051	**4,562,051**
2032	2,419,240	2,038,752	114,307	**4,572,299**
2033	2,424,117	2,038,752	114,433	**4,577,302**
2034	2,427,766	2,038,752	114,526	**4,581,044**
2035	2,431,849	2,038,752	114,631	**4,585,232**
2036	2,435,950	2,038,752	114,736	**4,589,439**
2037	2,440,157	2,038,752	114,844	**4,593,753**
2038	2,444,021	2,038,752	114,943	**4,597,716**
2039	2,448,197	2,038,752	115,050	**4,601,999**
Average Annual Growth Rates				
Previous 10 Years	0.15%	-2.27%	11.89%	**-0.45%**
Previous 5 Years	-1.22%	-0.17%	8.91%	**-0.70%**
Next 5 Years	0.82%	16.34%	6.26%	**6.39%**
Next 10 Years	0.55%	7.85%	3.16%	**3.22%**
Next 20 Years	0.37%	3.85%	1.62%	**1.65%**

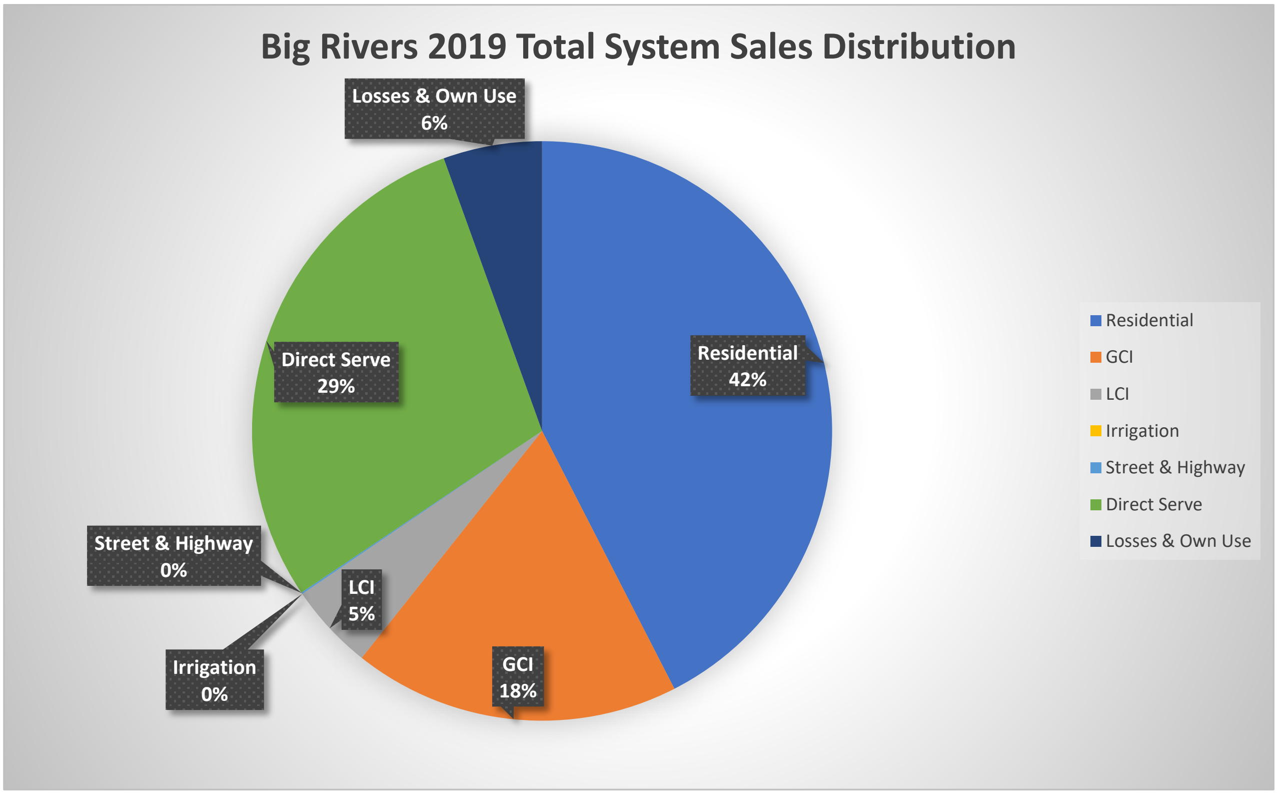
The following graph provides the class components that comprise the total energy requirements for the Big Rivers Native system.

Total Native Energy Forecast



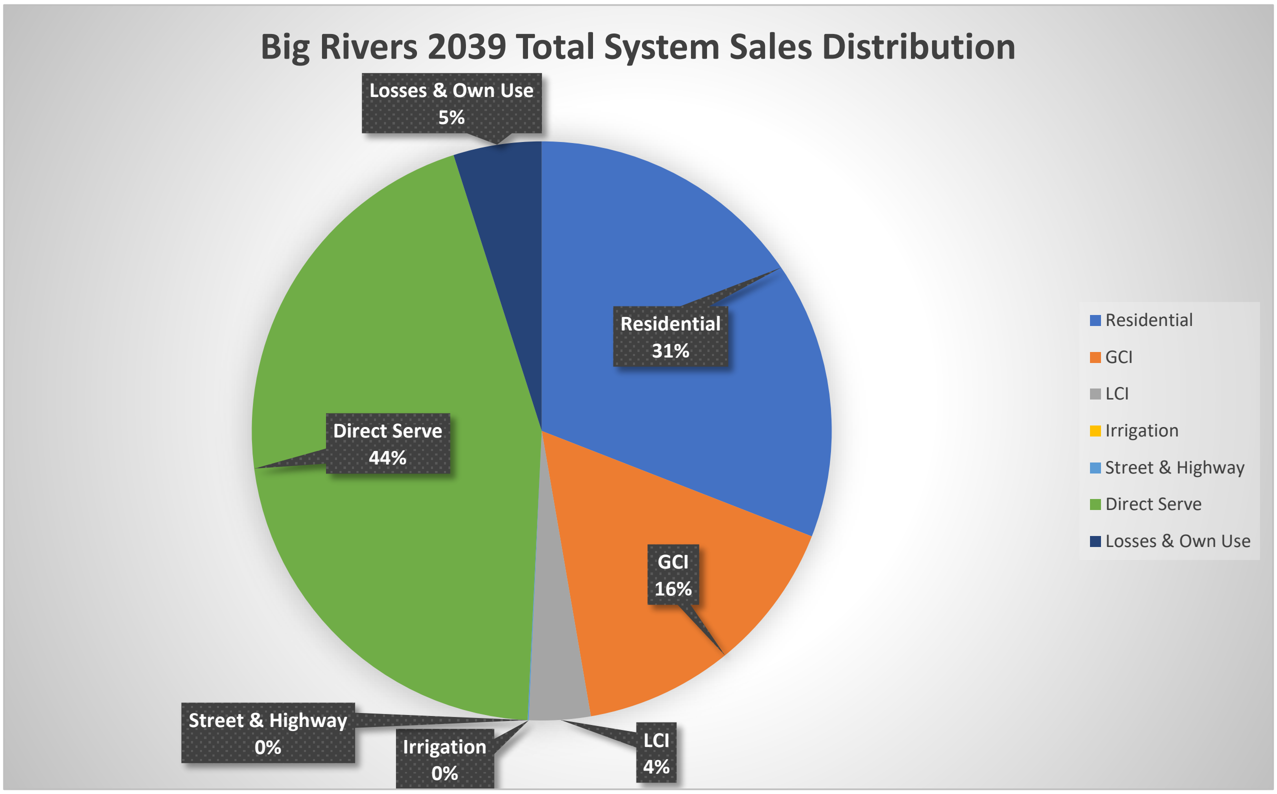
The figure below provides the Native sales distribution by each contributing component for 2019.

2019 Native System Sales by Class Distribution



The figure below provides the Native sales distribution by each contributing component for 2039. The largest change in the class distribution is within the Direct Serve class. The Direct Serve class contributed 29% of sales in 2019 and is projected to contribute 44% in 2039.

2039 Native System Sales by Class Distribution



2.7 Non-Member Energy Sales

In addition to the Native system loads described in the previous sections, Big Rivers engages in buying or selling any available excess resources where those transactions derive value for the Big Rivers Members. These capacity and energy transactions are made bilaterally or through participation in the regional transmission organization day ahead and real time markets. Optimization of these transactions involve evaluating the costs to deliver Big Rivers' generation versus buying on the market, and when the costs of purchasing capacity or energy are more economical than the comparable generation and transmission costs, those purchases are made to drive the most value for the Member owners. The table below shows anticipated net Non-Member energy sales. Capacity sales for Non-Member loads are discussed in section 3.2. The projections in the table below and the projections for the non-Member capacity in section 3.2 include sales or purchases for the following entities, and only include projections for the period of the current contracts:

- Owensboro Municipal Utilities (OMU)[3],
- Kentucky Municipal Energy Agency (KYMEA)[4],
- Nebraska Entities[5], and
- Short Term Bilateral Capacity[6].

Non-Member Energy Sales

Non-Member Sales Under Contract as of 2020	
Calendar Year	MWH
2020	1,466,620
2021	1,750,832
2022	1,784,986
2023	1,713,663
2024	1,722,453
2025	1,726,630
2026	1,732,865
2027	613,200
2028	613,200
2029	255,500

[3] OMU load is net of their allocation of Southeastern Power Administration Cumberland system hydropower and a future purchase of renewable power.

[4] KYMEA is a block sale of power and the volume will vary based on economic conditions.

[5] Nebraska entities' load is net of their allocation of Western Area Power Administration hydropower, renewables purchases, and a small amount of purchase power from their former supplier.

[6] Short Term bilateral capacity with no associated energy

Big Rivers total system energy requirements include the Native system energy requirements described in section 2.6 plus the Non-Member energy requirements described in this section. The following table provides the total system energy requirements.

Total System Energy Forecast

Big Rivers Total System Energy Summary (MWh)					
Year	Total Rural Requirements	Direct Serve	Transmission Losses	Non-Member Requirements	**Total System Energy Requirements**
2015	2,325,204	946,873	66,970		**3,339,047**
2016	2,330,037	915,310	73,420		**3,318,766**
2017	2,209,837	919,895	77,928		**3,207,660**
2018	2,366,988	953,822	86,858	75,404	**3,483,072**
2019	2,271,772	957,994	83,431	578,276	**3,891,473**
2020	2,313,997	987,552	84,688	1,466,620	**4,852,857**
2021	2,342,004	987,552	85,373	1,750,832	**5,165,761**
2022	2,345,137	2,038,752	112,407	1,784,986	**6,281,282**
2023	2,357,028	2,038,752	112,712	1,713,663	**6,222,155**
2024	2,366,988	2,041,632	113,042	1,722,453	**6,244,114**
2025	2,376,885	2,038,752	113,221	1,726,630	**6,255,489**
2026	2,386,410	2,038,752	113,466	1,732,865	**6,271,493**
2027	2,388,504	2,038,752	113,519	613,200	**5,153,976**
2028	2,394,976	2,041,632	113,759	613,200	**5,163,567**
2029	2,400,628	2,038,752	113,830	255,500	**4,808,710**
2030	2,403,821	2,038,752	113,912		**4,556,486**
2031	2,409,248	2,038,752	114,051		**4,562,051**
2032	2,419,240	2,038,752	114,307		**4,572,299**
2033	2,424,117	2,038,752	114,433		**4,577,302**
2034	2,427,766	2,038,752	114,526		**4,581,044**
2035	2,431,849	2,038,752	114,631		**4,585,232**
2036	2,435,950	2,038,752	114,736		**4,589,439**
2037	2,440,157	2,038,752	114,844		**4,593,753**
2038	2,444,021	2,038,752	114,943		**4,597,716**
2039	2,448,197	2,038,752	115,050		**4,601,999**
Average Annual Growth Rates					
Previous 10 Years	0.15%	-2.27%	11.89%	-	**1.15%**
Previous 5 Years	-1.22%	-0.17%	8.91%	-	**2.52%**
Next 5 Years	0.82%	16.34%	6.26%	-	**9.92%**
Next 10 Years	0.55%	7.85%	3.16%	-	**2.14%**
Next 20 Years	0.37%	3.85%	1.62%	-	**0.84%**

3 PEAK DEMAND

3.1 COINCIDENT PEAK DEMAND

The Rural system coincident peak demand (Rural CP) is measured based on the demand coincident with the total Big Rivers system. Clearspring econometrically modeled the Rural coincident load factor for each distribution Member using a monthly dataset. The predicted load factor is combined with the Rural energy forecast to forecast the Rural coincident peak demand. The Rural load factor models use temperature on the peak day each month, cooling degree days, heating degree days, appliance saturations, and appliance efficiencies. The Rural CP load factor models are provided in the Appendix.

Seasonal and annual Rural CP values were set to the maximum monthly Rural CP value for each applicable timeframe. The following table provides the last five years of historical data and the next 20 years of forecasted data for the winter, summer, and annual peaks for the Big Rivers Rural system. The table also provides the annual coincident peak contribution for the Direct Serve class, transmission losses at the annual peak, and the total Big Rivers coincident peak. The Direct Serve coincident peak contribution was forecasted using an average of historical load factors for that class. Growth rates for the prior 5 and 10 years and projected growth rates for the next 5, 10, and 20 years are provided in the table below.

Historical and Projected CP Demands

Big Rivers Coincident Peak (kW)						
Year	Rural Summer CP	Rural Winter CP	Rural Annual CP	Direct Serve Annual CP	Transmission Losses	**Total Annual CP**
2015	504,990	566,553	566,553	121,143	11,253	**698,949**
2016	486,690	484,768	486,690	120,750	13,855	**621,295**
2017	504,269	474,971	504,269	114,378	15,538	**634,184**
2018	502,549	556,742	556,742	95,530	16,382	**668,654**
2019	480,171	490,895	490,895	117,931	15,995	**624,821**
2020	483,946	484,817	483,946	127,101	15,668	**626,715**
2021	489,218	489,893	489,218	127,101	15,803	**632,122**
2022	489,558	491,914	489,558	322,043	20,810	**832,412**
2023	491,639	494,177	491,639	322,043	20,864	**834,546**
2024	493,376	495,970	493,376	322,043	20,908	**836,327**
2025	495,136	497,935	495,136	322,043	20,953	**838,132**
2026	496,879	499,794	496,879	322,043	20,998	**839,920**
2027	497,133	499,957	497,133	322,043	21,005	**840,180**
2028	498,359	500,820	498,359	322,043	21,036	**841,438**
2029	499,422	501,685	499,422	322,043	21,063	**842,528**
2030	500,004	501,900	500,004	322,043	21,078	**843,125**
2031	501,074	502,687	501,074	322,043	21,106	**844,223**
2032	503,128	504,331	503,128	322,043	21,158	**846,330**
2033	504,103	505,032	504,103	322,043	21,183	**847,329**
2034	504,841	505,432	504,841	322,043	21,202	**848,086**
2035	505,663	506,010	505,663	322,043	21,223	**848,929**
2036	506,495	506,574	506,495	322,043	21,245	**849,782**
2037	507,349	507,238	507,349	322,043	21,266	**850,659**
2038	508,129	507,810	508,129	322,043	21,286	**851,459**
2039	508,968	508,470	508,968	322,043	21,308	**852,319**
Average Annual Growth Rates						
Previous 10 Years	-0.34%	-1.32%	-1.32%	0.98%	11.50%	**-0.74%**
Previous 5 Years	-0.04%	-4.44%	-4.44%	-1.03%	9.24%	**-3.60%**
Next 5 Years	0.54%	0.21%	0.10%	22.25%	5.50%	**6.00%**
Next 10 Years	0.39%	0.22%	0.17%	10.57%	2.79%	**3.03%**
Next 20 Years	0.29%	0.18%	0.18%	5.15%	1.44%	**1.56%**

3.2 Non-Member Capacity Sales

Non-Member energy sales have been previously discussed in section 2.7. In addition to the Non-Member energy sales, the Non-Member entities contribute to capacity sales. These capacity sales are aggregated with the Native CP totals in section 3.3 to provide the total Big River non-coincident (NCP) peak. The following table provides the net Non-Member capacity forecast. The table includes projections for the period of the current contracts

Non-Member Capacity Sales

Non-Member Sales Under Contract as of 2020	
Calendar Year	MW
2020	422
2021	422
2022	422
2023	306
2024	210
2025	311
2026	311
2027	100
2028	100

3.3 NON-COINCIDENT PEAK DEMAND

The Big Rivers non-coincident peak is defined as the Big Rivers Native CP demand summarized in section 3.1 plus Non-Member sales at their peak load values shown in section 3.2. The table below displays the peak NCP forecast for the total system.

Total System NCP

Total System NCP (kW)			
Year	Total Annual CP	Non-Member Sales	Total NCP
2015	698,949	513,000	1,211,949
2016	621,295	450,000	1,071,295
2017	634,184	487,000	1,121,184
2018	668,654	314,200	982,854
2019	624,821	376,200	1,001,021
2020	626,715	421,500	1,048,215
2021	632,122	421,900	1,054,022
2022	832,412	421,500	1,253,912
2023	834,546	305,900	1,140,446
2024	836,327	210,300	1,046,627
2025	838,132	310,700	1,148,832
2026	839,920	311,100	1,151,020
2027	840,180	100,000	940,180
2028	841,438	100,000	941,438
2029	842,528		842,528
2030	843,125		843,125
2031	844,223		844,223
2032	846,330		846,330
2033	847,329		847,329
2034	848,086		848,086
2035	848,929		848,929
2036	849,782		849,782
2037	850,659		850,659
2038	851,459		851,459
2039	852,319		852,319

4 DSM IMPACTS

Clearspring was selected by Big Rivers to complete a Demand-Side Management ("DSM") potential study in 2020 that quantified the impact of additional DSM spending on future energy and peak requirements. For the base case forecast it is assumed that any impacts of prior DSM programs are captured indirectly through the historical energy and peak data used as an input to the modeling process. The base case forecast assumes no additional DSM spending in the future and additional future DSM impacts are set to zero.

Two alternate load forecast scenarios have been developed that are derived from the Big Rivers DSM potential study that outline the projected impacts of $1,000,000 and $2,000,000 DSM spending scenarios. The DSM study provides the impact at each appliance end-use. The DSM impacts were then scaled up to capture additional decreases in distribution and transmission losses. The table below outlines the anticipated annual impact of these two spending scenarios on total energy requirements.

DSM Scenario Impacts on Energy

Big Rivers DSM Spending Scenarios (MWh)					
Year	Total Energy Requirements (Base Forecast)	Impact of $1,000,000 Spending Scenario on Energy	Total Energy Requirements ($1,000,000 Spending Scenario)	Impact of $2,000,000 Spending Scenario on Energy	Total Energy Requirements ($2,000,000 Spending Scenario)
2015	3,339,047	0	3,339,047	0	3,339,047
2016	3,318,766	0	3,318,766	0	3,318,766
2017	3,207,660	0	3,207,660	0	3,207,660
2018	3,407,668	0	3,407,668	0	3,407,668
2019	3,317,632	0	3,317,632	0	3,317,632
2020	3,386,237	0	3,386,237	0	3,386,237
2021	3,414,929	11,186	3,403,743	21,512	3,393,417
2022	4,496,296	22,372	4,473,924	43,023	4,453,273
2023	4,508,492	33,558	4,474,934	64,535	4,443,957
2024	4,521,662	44,745	4,476,917	86,048	4,435,614
2025	4,528,859	55,931	4,472,927	107,560	4,421,298
2026	4,538,628	67,118	4,471,510	129,073	4,409,555
2027	4,540,776	78,304	4,462,472	150,585	4,390,191
2028	4,550,367	89,491	4,460,877	172,098	4,378,270
2029	4,553,210	100,133	4,453,077	192,563	4,360,647
2030	4,556,486	110,775	4,445,711	213,028	4,343,457
2031	4,562,051	110,775	4,451,276	213,029	4,349,023
2032	4,572,299	110,775	4,461,525	213,028	4,359,271
2033	4,577,302	110,775	4,466,527	213,029	4,364,273
2034	4,581,044	110,775	4,470,269	213,029	4,368,015
2035	4,585,232	110,775	4,474,456	213,030	4,372,202
2036	4,589,439	110,776	4,478,663	213,030	4,376,408
2037	4,593,753	110,776	4,482,978	213,031	4,380,723
2038	4,597,716	110,776	4,486,940	213,031	4,384,685
2039	4,601,999	110,777	4,491,222	213,032	4,388,967
Average Annual Growth Rates					
Previous 10 Years	-0.45%		-0.45%		-0.45%
Previous 5 Years	-0.70%		-0.70%		-0.70%
Next 5 Years	6.39%		6.18%		5.98%
Next 10 Years	3.22%		2.99%		2.77%
Next 20 Years	1.65%		1.53%		1.41%

The table below provides the anticipated annual impact of the two spending scenarios on total Big Rivers CP.

DSM Scenario Impacts on CP

Big Rivers DSM Spending Scenarios (kW)					
Year	Total Big Rivers CP (Base Forecast)	Impact of $1,000,000 Spending Scenario on CP	Total Big Rivers CP ($1,000,000 Spending Scenario)	Impact of $2,000,000 Spending Scenario on CP	Total Big Rivers CP ($2,000,000 Spending Scenario)
2015	698,949	0	698,949	0	698,949
2016	621,295	0	621,295	0	621,295
2017	634,184	0	634,184	0	634,184
2018	668,654	0	668,654	0	668,654
2019	624,821	0	624,821	0	624,821
2020	626,715	0	626,715	0	626,715
2021	632,122	2,264	629,858	4,353	627,769
2022	832,412	4,527	827,885	8,706	823,706
2023	834,546	6,791	827,755	13,059	821,487
2024	836,327	9,054	827,273	17,412	818,915
2025	838,132	11,318	826,815	21,765	816,368
2026	839,920	13,581	826,339	26,118	813,802
2027	840,180	15,845	824,336	30,471	809,710
2028	841,438	18,108	823,330	34,824	806,614
2029	842,528	20,310	822,218	39,057	803,471
2030	843,125	22,511	820,614	43,291	799,834
2031	844,223	22,511	821,712	43,291	800,932
2032	846,330	22,511	823,818	43,291	803,039
2033	847,329	22,511	824,818	43,291	804,038
2034	848,086	22,511	825,575	43,291	804,795
2035	848,929	22,511	826,417	43,291	805,638
2036	849,782	22,511	827,271	43,291	806,491
2037	850,659	22,511	828,147	43,291	807,368
2038	851,459	22,512	828,947	43,291	808,167
2039	852,319	22,512	829,807	43,292	809,027
Average Annual Growth Rates					
Previous 10 Years	-0.74%		-0.74%		-0.74%
Previous 5 Years	-3.60%		-3.60%		-3.60%
Next 5 Years	6.00%		5.77%		5.56%
Next 10 Years	3.03%		2.78%		2.55%
Next 20 Years	1.56%		1.43%		1.30%

5 Alternative System Forecasts and Uncertainty Analysis

While the projections summarized in previous sections are considered the most probable outcome, it is important to remember that energy loads can be influenced by factors that are inherently difficult to predict, such as weather and the economy. Forecasting attempts to model reality and identify the primary drivers of growth and change. However, due to the unpredictable nature of these drivers, the base case forecast is unlikely to be fully accurate. Therefore, it is important to develop flexible plans for meeting future energy needs based on a range of forecast outcomes.

The study includes scenario analyses that show how the forecasts change under assumed variations in future weather and economic growth paths. The alternate growth scenarios that have been explored are:

1. Extreme weather with normal economic growth
2. Mild weather with normal economic growth
3. High economic growth with normal weather
4. Low economic growth with normal weather

5.1 Weather Scenarios

Weather is one of the critical components to explain year-to-year variation in load. Because of this, extreme and mild weather scenarios were developed for the forecast period. The Residential use per consumer and GCI use per consumer monthly energy models use cooling degree days and heating degree days. For the creation of the mild and extreme energy scenarios these two variables were altered to a fifteen-year historical annual maximum and minimum value. These annual extremes were then redistributed across each month based on an average monthly distribution of cooling degree days and heating degree days.

The Rural peak load factor model also contains cooling degree days and heating degree days for the month. Additionally, the load factor model captures peak day weather conditions. The extreme and mild weather scenarios alter the load factor model to use monthly weather conditions consistent with the energy models and change the peak day conditions to the most extreme or mild found in the last fifteen years of history for each given month. The peak values displayed are a maximum of each monthly scenario value for the given season and therefore can occur in a different month than the base case forecast. The following table provides the last five years of historical data and the next 20 years of forecasted data for the mild, base, and extreme weather scenarios. The forecasts are for the Rural system.

Rural System Weather Scenarios

Big Rivers Rural System Weather Scenarios									
Year	Energy (MWh)			Winter CP Demand (kW)			Summer CP Demand (kW)		
	Mild	Base	Extreme	Mild	Base	Extreme	Mild	Base	Extreme
2015		2,325,204			566,553			504,990	
2016		2,330,037			484,768			486,690	
2017		2,209,837			474,971			504,269	
2018		2,366,988			556,742			502,549	
2019		2,271,772			490,895			480,171	
2020	2,179,148	2,313,997	2,466,208	424,802	484,817	550,097	448,471	483,946	555,294
2021	2,206,842	2,342,004	2,494,467	429,655	489,893	555,362	453,741	489,218	560,678
2022	2,209,714	2,345,137	2,497,785	431,444	491,914	557,580	447,277	489,558	560,857
2023	2,221,974	2,357,028	2,509,121	433,755	494,177	559,713	449,590	491,639	562,368
2024	2,232,330	2,366,988	2,518,504	435,624	495,970	561,350	451,550	493,376	563,568
2025	2,242,531	2,376,885	2,527,949	437,624	497,935	563,207	453,497	495,136	564,870
2026	2,252,321	2,386,410	2,537,093	439,514	499,794	564,978	455,404	496,879	566,215
2027	2,255,046	2,388,504	2,538,406	439,917	499,957	564,829	455,915	497,133	565,929
2028	2,261,847	2,394,976	2,544,447	440,930	500,820	565,489	457,292	498,359	566,812
2029	2,267,819	2,400,628	2,549,684	441,925	501,685	566,171	458,491	499,422	567,563
2030	2,271,413	2,403,821	2,552,376	442,326	501,900	566,146	459,221	500,004	567,826
2031	2,277,065	2,409,248	2,557,507	443,218	502,687	566,781	460,376	501,074	568,694
2032	2,286,983	2,419,240	2,567,548	444,859	504,331	568,400	462,416	503,128	570,721
2033	2,292,000	2,424,117	2,572,233	445,630	505,032	568,995	463,437	504,103	571,571
2034	2,295,802	2,427,766	2,575,677	446,113	505,432	569,279	464,219	504,841	572,195
2035	2,299,963	2,431,849	2,579,641	446,731	506,010	569,790	465,059	505,663	572,952
2036	2,304,085	2,435,950	2,583,693	447,312	506,574	570,317	465,889	506,495	573,762
2037	2,308,239	2,440,157	2,587,936	447,951	507,238	570,992	466,716	507,349	574,642
2038	2,312,062	2,444,021	2,591,822	448,503	507,810	571,570	467,473	508,129	575,441
2039	2,316,171	2,448,197	2,596,047	449,128	508,470	572,251	468,281	508,968	576,310

Direct Serve load is assumed to not be influenced by weather and is held constant to the base case forecast for the weather ranges. The extreme and mild ranges with the Direct Serve class included are shown below.

Native System Weather Scenarios

Big Rivers Total System Weather Scenarios									
Year	Energy (MWh)			Winter CP Demand (kW)			Summer CP Demand (kW)		
	Mild	Base	Extreme	Mild	Base	Extreme	Mild	Base	Extreme
2015		3,339,047			698,949			629,640	
2016		3,318,766			612,568			621,295	
2017		3,207,660			606,671			634,184	
2018		3,407,668			668,654			626,212	
2019		3,317,632			624,821			619,296	
2020	3,247,929	3,386,237	3,542,354	556,932	618,492	685,453	590,330	626,715	696,756
2021	3,276,302	3,414,929	3,571,301	561,852	623,635	690,783	595,735	632,122	702,278
2022	4,357,402	4,496,296	4,652,858	746,457	808,477	875,826	789,046	832,412	905,538
2023	4,369,975	4,508,492	4,664,485	748,827	810,798	878,015	791,419	834,546	907,089
2024	4,383,551	4,521,662	4,677,063	750,744	812,637	879,694	793,429	836,327	908,319
2025	4,391,060	4,528,859	4,683,797	752,795	814,652	881,598	795,425	838,132	909,654
2026	4,401,100	4,538,628	4,693,175	754,733	816,559	883,415	797,381	839,920	911,033
2027	4,403,895	4,540,776	4,694,521	755,147	816,726	883,262	797,906	840,180	910,740
2028	4,413,825	4,550,367	4,703,670	756,186	817,611	883,938	799,318	841,438	911,646
2029	4,416,996	4,553,210	4,706,088	757,206	818,499	884,638	800,548	842,528	912,417
2030	4,420,682	4,556,486	4,708,850	757,618	818,719	884,613	801,296	843,125	912,686
2031	4,426,479	4,562,051	4,714,112	758,533	819,526	885,264	802,481	844,223	913,576
2032	4,436,652	4,572,299	4,724,411	760,215	821,212	886,925	804,573	846,330	915,655
2033	4,441,797	4,577,302	4,729,216	761,007	821,931	887,534	805,621	847,329	916,527
2034	4,445,696	4,581,044	4,732,748	761,502	822,341	887,826	806,422	848,086	917,167
2035	4,449,964	4,585,232	4,736,814	762,136	822,934	888,350	807,284	848,929	917,944
2036	4,454,192	4,589,439	4,740,970	762,732	823,513	888,890	808,135	849,782	918,774
2037	4,458,453	4,593,753	4,745,321	763,387	824,194	889,583	808,984	850,659	919,677
2038	4,462,373	4,597,716	4,749,306	763,953	824,780	890,175	809,760	851,459	920,496
2039	4,466,588	4,601,999	4,753,640	764,593	825,457	890,874	810,589	852,319	921,388

5.2 Economic Scenarios

Another critical component of a long-term load forecast is the underlying economic variables within the service territory. Two scenarios have been developed: low economic growth and high economic growth. To create the economic scenarios, economic variables within each econometrically modeled class are altered by an additional plus or minus 1.0% in 2020. As the forecast is projected further into the future, the variable values deviate by an additional 1.0% each additional year relative to the base case forecast (variable values in 2039 are +/- 20% of the base case forecast values). The altered variables include electricity price, GRP, employment, and total retail sales.

The forecast for Residential consumers, LCI, Irrigation, and Street and Highway are not modeled econometrically and are therefore directly modified by 1.0% per year relative to the base case forecast to create the high and low economic ranges. The following table provides the last five years of historical data and the next 20 years of forecasted data for the low, base, and high economic scenarios.

Rural System Economic Scenarios

Big Rivers Rural System Economic Scenarios									
Year	Energy (MWh)			Winter CP Demand (kW)			Summer CP Demand (kW)		
	Low	Base	High	Low	Base	High	Low	Base	High
2015		2,325,204			566,553			504,990	
2016		2,330,037			484,768			486,690	
2017		2,209,837			474,971			504,269	
2018		2,366,988			556,742			502,549	
2019		2,271,772			490,895			480,171	
2020	2,300,509	2,313,997	2,327,505	484,384	484,817	485,251	480,458	483,946	487,440
2021	2,303,123	2,342,004	2,381,023	484,183	489,893	495,617	480,419	489,218	498,050
2022	2,280,873	2,345,137	2,409,772	480,882	491,914	502,995	475,905	489,558	503,292
2023	2,267,151	2,357,028	2,447,627	477,800	494,177	510,664	472,651	491,639	510,783
2024	2,251,422	2,366,988	2,483,746	474,236	495,970	517,898	469,042	493,376	517,965
2025	2,235,453	2,376,885	2,520,102	470,811	497,935	525,360	465,425	495,136	525,228
2026	2,218,993	2,386,410	2,556,329	467,245	499,794	532,776	461,768	496,879	532,523
2027	2,195,568	2,388,504	2,584,771	462,098	499,957	538,404	456,720	497,133	538,254
2028	2,176,136	2,394,976	2,618,112	457,587	500,820	544,824	452,564	498,359	545,067
2029	2,155,897	2,400,628	2,650,747	453,085	501,685	551,264	448,247	499,422	551,740
2030	2,133,428	2,403,821	2,680,818	447,985	501,900	557,024	443,498	500,004	557,911
2031	2,112,915	2,409,248	2,713,542	443,409	502,687	563,433	439,177	501,074	564,660
2032	2,096,302	2,419,240	2,751,662	439,565	504,331	570,856	435,698	503,128	572,568
2033	2,075,191	2,424,117	2,784,160	434,900	505,032	577,235	431,271	504,103	579,289
2034	2,053,019	2,427,766	2,815,392	429,972	505,432	583,301	426,641	504,841	585,767
2035	2,031,207	2,431,849	2,847,276	425,207	506,010	589,589	422,080	505,663	592,374
2036	2,009,404	2,435,950	2,879,332	420,427	506,574	595,893	417,528	506,495	599,024
2037	1,987,683	2,440,157	2,911,659	415,738	507,238	602,333	412,993	507,349	605,730
2038	1,965,680	2,444,021	2,943,723	410,971	507,810	608,693	408,398	508,129	612,378
2039	1,943,925	2,448,197	2,976,318	406,282	508,470	615,182	403,849	508,968	619,128

The Direct Serve class is not modeled using econometric modeling. The forecast for the Direct Serve class is increased by an additional 1.0% per year relative to the base case in the high scenario. In the low scenario the Direct Serve class is decreased by 1.0% per year relative to the base case. The high and low ranges with the Direct Serve class included are shown below.

Native System Economic Scenarios

Big Rivers Total System Economic Scenarios									
Year	Energy (MWh)			Winter CP Demand (kW)			Summer CP Demand (kW)		
	Low	Base	High	Low	Base	High	Low	Base	High
2015		3,339,047			698,949			629,640	
2016		3,318,766			612,568			621,295	
2017		3,207,660			606,671			634,184	
2018		3,407,668			668,654			626,212	
2019		3,317,632			624,821			619,296	
2020	3,367,634	3,386,237	3,404,861	617,960	618,492	619,025	622,371	626,715	631,064
2021	3,361,494	3,414,929	3,468,506	616,632	623,635	630,652	621,181	632,122	643,096
2022	4,380,613	4,496,296	4,612,361	791,151	808,477	825,854	810,273	832,412	854,633
2023	4,346,970	4,508,492	4,670,756	785,103	810,798	836,606	803,786	834,546	865,465
2024	4,314,099	4,521,662	4,730,448	778,563	812,637	846,911	796,936	836,327	875,980
2025	4,275,319	4,528,859	4,784,229	772,164	814,652	857,449	790,076	838,132	886,579
2026	4,238,868	4,538,628	4,840,954	765,621	816,559	867,942	783,177	839,920	897,210
2027	4,195,273	4,540,776	4,889,695	757,457	816,726	876,599	774,851	840,180	906,237
2028	4,158,485	4,550,367	4,946,655	749,944	817,611	886,069	767,438	841,438	916,374
2029	4,115,445	4,553,210	4,996,502	742,441	818,499	895,561	759,862	842,528	926,367
2030	4,072,831	4,556,486	5,046,913	734,325	818,719	904,354	751,841	843,125	935,845
2031	4,032,222	4,562,051	5,100,046	726,745	819,526	913,812	744,261	844,223	945,916
2032	3,995,613	4,572,299	5,158,713	719,918	821,212	924,311	737,544	846,330	957,177
2033	3,954,392	4,577,302	5,211,613	712,248	821,931	933,740	729,854	847,329	967,219
2034	3,912,081	4,581,044	5,263,217	704,308	822,341	942,847	721,956	848,086	977,013
2035	3,870,140	4,585,232	5,315,488	696,534	822,934	952,182	714,129	848,929	986,938
2036	3,828,209	4,589,439	5,367,935	688,746	823,513	961,533	706,311	849,782	996,907
2037	3,786,361	4,593,753	5,420,660	681,051	824,194	971,024	698,511	850,659	1,006,935
2038	3,744,225	4,597,716	5,473,117	673,276	824,780	980,433	690,648	851,459	1,016,902
2039	3,702,342	4,601,999	5,526,116	665,581	825,457	989,974	682,834	852,319	1,026,975

6 WEATHER NORMALIZED VALUES

Weather-sensitive electricity loads comprise a large portion of electricity end-uses. Weather conditions vary and will cause electricity sales and peak demands to increase during more extreme periods or decrease during milder periods. In this section, we provide estimates of energy and peak demands for Big Rivers during the last ten years with the assumption that temperatures had been at their 15-year normal amounts in each year.

The weather normalized values are calculated using the econometric models that identified weather as a driver of electricity sales. These are the Residential use per consumer and the GCI use per consumer models. Additionally, the load factor model (used to project peak demands) also includes temperature variables. The weather impacts of the deviation from the actual weather to the weather normalized weather are estimated using these models. The weather impacts are then added (or subtracted) to the actual load in that year to determine the weather normalized energy or peak demand.

The following table provides the last ten years of historical data for the Big Rivers Rural system. The normalized peak values displayed are a maximum of each monthly normalized value for the given season and therefore frequently occur in a different month than the actual value.

Rural System Weather Normalized

Big Rivers Rural System Weather Normalization						
Year	Energy (MWh)		Winter CP Demand (kW)		Summer CP Demand (kW)	
	Actual	Normalized	Actual	Normalized	Actual	Normalized
2010	2,481,391	2,340,195	532,501	499,474	539,955	487,416
2011	2,371,105	2,364,681	501,923	481,872	526,815	521,536
2012	2,321,477	2,349,809	456,468	504,888	541,370	478,313
2013	2,374,921	2,378,459	484,077	487,948	472,452	495,755
2014	2,415,564	2,357,913	616,023	537,661	481,155	483,895
2015	2,325,204	2,339,796	566,553	532,134	504,990	495,380
2016	2,330,037	2,321,049	484,768	474,701	486,690	487,892
2017	2,209,837	2,288,904	474,971	503,621	504,269	492,879
2018	2,366,988	2,296,588	556,742	508,279	502,549	492,212
2019	2,271,772	2,264,292	490,895	476,628	480,171	486,620

The following table provides the last ten years of historical data for the Big Rivers total system.

Native System Weather Normalized

Big Rivers Total System Weather Normalization						
Year	Energy (MWh)		Winter CP Demand (kW)		Summer CP Demand (kW)	
	Actual	Normalized	Actual	Normalized	Actual	Normalized
2010	4,214,187	4,071,823	652,163	621,367	662,129	613,470
2011	3,757,727	3,751,272	626,666	609,848	658,514	653,183
2012	3,326,245	3,354,869	574,579	623,473	661,427	606,020
2013	3,431,215	3,434,768	605,121	603,822	617,356	640,983
2014	3,436,352	3,377,837	750,485	671,034	611,785	621,847
2015	3,339,047	3,353,970	698,949	663,967	629,640	626,956
2016	3,318,766	3,309,582	612,568	607,623	621,295	622,525
2017	3,207,660	3,288,655	606,671	635,975	634,184	622,509
2018	3,407,668	3,335,436	668,654	618,974	626,212	615,604
2019	3,317,632	3,309,960	624,821	610,180	619,296	625,911

7 FORECAST METHODOLOGY

The load forecast process began by discussions with Clearspring Energy to solicit feedback from representatives of each Member system as well as Big Rivers. The forecasting team issued an information request to each Member system requesting monthly energy data by rate class, historical or anticipated changes in load on the system, large consumer energy and peak demand data, and retail price forecasts. Big Rivers provided historical demand data used as the basis to forecast load factors and peak demands.

In addition to this data, Clearspring Energy collected a variety of additional data to develop the load forecast. This included county-level historical socioeconomic data from Woods & Poole Economics, Inc., historical alternative fuel price data and energy efficiency indexes from the Energy Information Administration (EIA)[7], monthly and daily weather data from the Midwest Regional Climate Center (MRCC)[8] and High Plains Regional Climate Center (HPRCC)[9], and appliance and end-use saturations for each member system based off historical end-use surveys conducted by Big Rivers. The most recent survey was conducted in 2019.

7.1 DATABASE SETUP AND ANALYSES

Upon receipt of the associated Member systems' data, Big Rivers' data and data obtained from external sources, Clearspring Energy reviewed the data for accuracy and adequacy for use in the study. An electronic database with consumer and energy sales by rate class and demand data was developed using Microsoft Excel.

County-level economic and demographic data was gathered and added to the energy database. Any financial forecasts gathered that were not provided in real terms were converted to real dollars using an inflation adjustment from the Congressional Budget Office (CBO)[10]. Weighted averages were calculated using customized member system county weights based on the service territory of

---

[7] https://www.eia.gov/outlooks/aeo/

[8] https://mrcc.illinois.edu/

[9] https://hprcc.unl.edu/

[10] https://www.cbo.gov/system/files/2020-01/56020-CBO-Outlook.pdf

each Member system. The appropriate weights were calculated using the number of Residential consumers served for each Member system by county.

Weather variables were also calculated and added to the database. Appropriate customized weather station data was used based on the service territory location of each Member system. Historical fifteen-year averages of the selected weather variables were calculated and used as the basis for the normal weather expectation in future years and in the weather normalization results.

Big Rivers conducts residential end-use appliance surveys for residential consumers every few years and plans to continue this process in the future. The surveys provide data on major appliance saturations, fuel types, housing characteristics, as well as adoption rates for new equipment and technologies. This information provides valuable insight into the makeup of the Residential class and the Big Rivers load forecasting effort will continue to make enhancements to the forecasting process as the market penetration of new technologies and equipment continues. The various data elements and sources are displayed in the table below.

Data Sources

Data Category	Data Source
Energy, Demand, Customers, and Electricity Price	Big Rivers and its three member systems
Economic & Demographic	Woods & Poole Economics, Inc.
Weather	Midwest Regional Climate Center High Plains Regional Climate Center
Alternative Fuel Prices and Appliance Energy Efficiency	Energy Information Administration
End-Use Appliance Saturations	Big Rivers Survey Reports

7.2 Key Economic and Demographic Assumptions

Various economic and demographic variables are used in the econometric models developed for the 2020 load forecast. The key economic and demographic assumptions for these variables are listed below.

- Households are projected to increase at an average annual growth rate of 0.1% through the forecast period.
- Real residential electricity prices are projected to [redacted].
- Air conditioning saturation levels are projected to continue increasing slowly through the forecast period.
- Electrical heating saturation levels are projected to remain flat through the forecast period.
- Major appliance efficiencies are projected to continue increasing through the forecast period, but at a decreasing rate as maximum efficiencies are approached.
- Employment is projected to increase at an average annual rate of 0.6% through the forecast period.
- Real GRP is projected to increase at an average annual rate of 1.2% through the forecast period.
- Real total retail sales is projected to increase at an average annual rate of 0.8% through the forecast period.
- [redacted].
- Cooling degree days, heating degree days, and peak day weather conditions are based on a prior fifteen-year average.

7.3 MODEL DEVELOPMENT

Clearspring estimated econometric models to forecast Residential use per consumer, GCI consumers, GCI use per consumer, and the Rural load factor. A separate model was developed for each Member system and for each component. A growth index using household forecasts was used to escalate Residential consumers.

Forecasts for the LCI and Direct Serve commercial consumers were prepared judgmentally based on input from the cooperatives. Due to their relatively small size, trend analysis was used to project the Street and Highway and Irrigation classes.

Econometric parameters were estimated using the ordinary least squares (OLS) approach to regression analysis employed by the EViews™ version 10 econometric software package. Heteroskedasticity adjusted standard errors were calculated for statistical significance testing of the included variables. The models were selected based on theoretical and statistical validity as well as the reasonableness of the forecast results generated.

The statistical validity of each variable included in the model needed to pass two key criterion to be included in the model. A simple but important standard is that the coefficient of each explanatory variable must have a logical sign. For example, energy sales will generally increase during periods of colder or hotter weather (i.e., these variables should have positive coefficients). Conversely, energy sales generally decrease with increasing electricity prices (i.e., the coefficient of this variable should be negative).

The second criterion is the fact that each explanatory variable has a statistically significant influence on the dependent variable. The statistical significance of an explanatory variable is measured by the t-statistic. The specific value of a particular t-statistic required for statistical significance depends on both the degrees of freedom (the number of data points less the number of variables) of the equations and desired level of confidence in the estimated coefficients. In general, however, the t-statistic should have a magnitude of at least 1.645 for a 90 percent level of confidence.

Another validity criterion that we took into consideration are examinations of the equation residuals (the difference between the actual historical and estimated historical values). In a good equation, the residuals are randomly distributed and of approximately constant magnitude, in absolute terms.

This indicates that there is no obvious pattern in the data that has not been explained by the equation.

The models developed must also pass a test of reasonableness. Models must make intuitive sense to the Members of the forecasting team and the forecasts that result must be plausible given reasonable assumptions of growth factors. All models created in the load forecast pass these criteria.

7.4 FORECAST DEVELOPMENT

Using the econometric equations developed as part of the modeling process, monthly forecasts were created for each of the Member systems. The modeled classes are calculated using the estimated equations along with forecasted values for those variables that enter into the estimated equation.

The amount of energy required by each system (the total energy ultimately generated by Big Rivers) is greater than the sum of the retail energy sales. System own-use and energy losses are forecast for each Member system. Energy losses are forecasted as a percentage of total system energy requirements based on historical loss data.

Three monthly demand values are determined for each of the Member distribution cooperatives. The individual Direct Serve consumer non-coincident peaks, the distribution cooperative's Rural non-coincident peak demand, and its contribution to the Big Rivers monthly coincident peak (CP). Clearspring developed a load factor econometric model to forecast the Rural coincident peak load factor which we then use to calculate the peak demand forecasts for each of the three Member systems.

Preliminary forecasts were distributed to the respective Member systems and Big Rivers for their review and input. The Member systems offered suggestions for revisions to the forecasts and these revisions were incorporated.

7.5 Changes in Methodology From 2017 Load Forecast

The 2020 research was conducted by Clearspring Energy Advisors, LLC whereas the 2017 research was conducted by GDS Associates, Inc ("GDS"). Clearspring has reviewed the past load forecast report and other documents and lists the known methodological changes that we are aware of based on this review of the prior consultants' research. We note that it is often difficult to assume what the exact research of another consultant consisted of. We offer the list, acknowledging that we may be incorrect in interpreting the exact methodological approach used by GDS.

1. Clearspring uses "weighted" economic and demographic variables that are weighted based on the calculated consumer counts in each county served by each Member system. We believe that GDS did not calculate the variables based on weighted consumer counts but used unweighted variables.
2. GDS used a Statistical Adjusted End-Use (SAE) modeling approach. Clearspring uses econometric modeling to directly estimate the impacts of variables that influence use per consumer or consumer counts.
3. Clearspring directly models the electricity price in relationship to an alternative price fuel index (comprised of natural gas and propane prices). We are not aware of GDS directly inserting alternative fuel prices into the analysis.
4. Clearspring calculates the price elasticity based on the relative impact of the electricity price and the alternative fuel index. This price elasticity is estimated directly in the econometric model. Conversely, GDS did not use their SAE modeling but, rather, estimated the price elasticity with a separate econometric model that did not account for other possible drivers of electricity use.
5. Clearspring uses a 15-year weather normal for the base case load forecasts, whereas GDS used a 20-year weather normal.
6. Different weather station mappings were used compared to the previous load forecast. Owensboro, KY was used for Kenergy rather than Evansville, IN due to being a better geographic representation. Additionally there are likely different secondary stations used to fill in historical readings across all Members resulting in slight historical differences from the previous forecast.

7. Clearspring uses daily high/low temperature values for the load factor econometric model used to forecast peak demands. GDS appears to use hourly values to forecast peak demands.
8. GDS makes some references to using trended energy amounts in the forecast. Annual energy and peak amounts were set to specific monthly distributions and fixed to those relative percentages for the full forecast. As the relative composition percentages of these classes change over time due to different class growth rates it is only reasonable to assume the distribution of energy and peak across each season will shift as well. The 2020 load forecast directly forecasts energy and peak monthly creating a more complete monthly weather normalization process and allowing for anticipated shifts in the monthly load shape to occur as class compositions change through the forecast.

8 TRACKING ANALYSIS

8.1 TRACKING 2013 THROUGH 2017 FORECASTS TO ACTUAL VALUES

The following section provides a tracking analysis comparing portions of the 2013, 2015, and 2017 load forecasts to actual values. The table below shows the total consumer forecast from each of the prior three forecasts. The forecasted consumer values have been consistently over-projected in the past. The three forecasts over-projected 2017 actual consumer counts by an average of 0.1%. 2018 actual values were over-projected by an average of 0.6% across the forecasts and 2019 values were over-projected by an average of 1.1%.

Total Consumer Tracking Analysis

Comparison of Consumer Forecasts								
Year	Actual	2013 Load Forecast	2013 Forecast Compared to Actual	2015 Load Forecast	2015 Forecast Compared to Actual	2017 Load Forecast	2017 Forecast Compared to Actual	2020 Load Forecast
2008	111,691							
2009	111,940							
2010	112,410							
2011	112,885							
2012	113,250							
2013	113,717	113,562	-0.1%					
2014	114,208	114,545	0.3%					
2015	114,934	115,658	0.6%	114,864	-0.1%			
2016	115,852	116,753	0.8%	115,694	-0.1%			
2017	116,898	117,815	0.8%	116,511	-0.3%	116,843	0.0%	
2018	117,369	118,818	1.2%	117,529	0.1%	117,809	0.4%	
2019	117,785	119,796	1.7%	118,538	0.6%	118,737	0.8%	
2020		120,784		119,523		119,781		118,667
2021		121,772		120,465		120,701		119,616
2022		122,734		121,386		121,568		120,474
2023		123,678		122,313		122,434		121,218
2024		124,582		123,206		123,299		121,886
2025		125,473		124,067		124,197		122,470
2026		126,366		124,910		125,044		122,883
2027				125,712		125,882		123,157
2028				126,511		126,786		123,391
2029						127,688		123,579
2030						128,589		123,723
2031						129,438		123,830
2032						130,286		123,901
2033						131,134		123,947
2034						131,983		123,976
2035						132,831		123,991
2036						133,680		123,997
2037								124,003
2038								124,014
2039								124,033

The following table provides a breakdown of the 2017 forecasted consumer values by Residential and GCI class. The majority of the high consumer forecast can be traced back to the Residential class. The 2017 forecast projected the 2019 Residential consumer count at 915 consumers above actual. Historically, the short-term Residential consumer forecasts were done using a simple trend that did not reflect the typical number of Residential consumers added on the service territory over the prior decade. The 2020 Residential consumer forecast is considerably lower than previous forecasts.

Consumer Tracking Analysis by Class

Comparison of Consumer Forecasts by Class								
Year	Residential Actual	2017 Residential Load Forecast	2017 Forecast Compared to Actual	2020 Residential Load Forecast	GCI Actual	2017 GCI Load Forecast	2017 Forecast Compared to Actual	2020 GCI Load Forecast
2008	96,886				14,672			
2009	97,084				14,725			
2010	97,467				14,808			
2011	97,750				14,999			
2012	97,675				15,435			
2013	97,773				15,797			
2014	97,851				16,210			
2015	97,971				16,805			
2016	98,583				17,110			
2017	99,451	99,290	-0.2%		17,290	17,398	0.6%	
2018	99,724	100,046	0.3%		17,483	17,607	0.7%	
2019	99,891	100,806	0.9%		17,732	17,774	0.2%	
2020		101,619		100,314		18,005		18,188
2021		102,311		101,044		18,234		18,406
2022		102,952		101,667		18,460		18,641
2023		103,594		102,180		18,684		18,872
2024		104,236		102,616		18,907		19,104
2025		104,913		102,990		19,128		19,314
2026		105,542		103,193		19,346		19,524
2027		106,162		103,256		19,563		19,734
2028		106,852		103,282		19,777		19,942
2029		107,542		103,263		19,990		20,150
2030		108,233		103,200		20,199		20,357
2031		108,874		103,101		20,407		20,562
2032		109,514		102,970		20,615		20,765
2033		110,155		102,815		20,823		20,966
2034		110,795		102,644		21,031		21,166
2035		111,436		102,460		21,239		21,365
2036		112,077		102,269		21,447		21,562
2037				102,079				21,759
2038				101,894				21,954
2039				101,718				22,149

The following table compares the 2013, 2015 and 2017 forecasts to actual energy values for the Native system. The three forecasts over-projected 2017 energy values by an average of 7.6%. 2018 actual values were over-projected by an average of 2.7% across the forecasts, and 2019 values were over-projected by an average of 6.7%. Comparing the prior forecasts to weather normalized energy values explains some of the fluctuation in the comparisons of these three years, making the comparisons for 2017 and 2018 much more consistent. When the forecasts are compared to weather normalized values 2017 was over-projected by an average of 5.0%, 2018 was over-projected by 4.9%, and 2019 was over-projected by 7.0%. The 2020 forecast shows a much higher long-range energy forecast. This is attributable to an additional large consumer expected in 2022.

Total Native Energy Tracking Analysis

Comparison of Native Energy Forecasts (GWh)									
Year	Actual	Weather Normalization	2013 Load Forecast	2013 Forecast Compared to Actual	2015 Load Forecast	2015 Forecast Compared to Actual	2017 Load Forecast	2017 Forecast Compared to Actual	2020 Load Forecast
2008									
2009									
2010									
2011									
2012	3,290	3,319							
2013	3,385	3,389	3,350	-1.0%					
2014	3,382	3,324	3,408	0.8%					
2015	3,272	3,287	3,384	3.4%	3,318	1.4%			
2016	3,245	3,236	3,373	3.9%	3,413	5.2%			
2017	3,130	3,209	3,394	8.4%	3,452	10.3%	3,259	4.1%	
2018	3,321	3,250	3,416	2.9%	3,469	4.5%	3,343	0.7%	
2019	3,234	3,227	3,437	6.3%	3,486	7.8%	3,433	6.1%	
2020			3,460		3,496		3,473		3,302
2021			3,485		3,514		3,475		3,330
2022			3,511		3,536		3,479		4,384
2023			3,537		3,560		3,481		4,396
2024			3,562		3,581		3,490		4,409
2025			3,589		3,602		3,495		4,416
2026			3,616		3,624		3,502		4,425
2027			3,644		3,642		3,509		4,427
2028					3,669		3,521		4,437
2029					3,691		3,526		4,439
2030					3,714		3,535		4,443
2031					3,737		3,544		4,448
2032					3,760		3,557		4,458
2033					3,782		3,562		4,463
2034					3,805		3,572		4,467
2035							3,581		4,471
2036							3,593		4,475
2037									4,479
2038									4,483
2039									4,487

The following table provides a breakdown of the 2017 forecasted energy values by Residential and GCI class. When the prior forecast is compared to weather normalized values the Residential forecast was an average of 1.6% high during the 2017-2019 forecast period. The GCI forecast was an average of 3.8% high during the 2017-2019 forecast period compared to weather normalized actual values. In addition to the high consumer forecasts being a contributing factor, possible factors that could have led to high use per consumer forecasts in the past forecasts include:

- Higher than actual household income projections,
- Lower than actual electric price projections,
- Higher than actual appliance saturation projections,
- Lower than actual appliance efficiency projections,
- Omission of alternate fuel prices, price of electricity in the commercial modeling, or any economic variables in the GCI use per consumer modeling,
- Additional unknown factors that influence electrical usage per consumer that were omitted from prior modeling.

The 2020 forecast projects lower Residential energy values. This is directly attributable to the lower Residential consumer forecast. GCI forecasted values in the 2020 forecast are comparable to the previous forecast iteration.

Energy Tracking Analysis by Class

Comparison of Class Energy Forecasts (GWh)												
Year	Residential Actual	Residential Weather Normalization	2017 Residential Load Forecast	2017 Forecast Compared to Actual	2017 Forecast Compared to Weather Norm	2020 Residential Load Forecast	GCI Actual	GCI Weather Normalization	2017 GCI Load Forecast	2017 Forecast Compared to Actual	2017 Forecast Compared to Weather Norm	2020 GCI Load Forecast
2008												
2009												
2010												
2011												
2012	1,466	1,491					595	596				
2013	1,510	1,511					601	604				
2014	1,532	1,484					610	604				
2015	1,448	1,457					607	612				
2016	1,436	1,432					615	611				
2017	1,348	1,409	1,425	5.7%	1.1%		600	615	623	3.8%	1.4%	
2018	1,491	1,441	1,440	-3.4%	-0.1%		619	602	629	1.6%	4.5%	
2019	1,407	1,402	1,452	3.2%	3.6%		604	602	634	5.0%	5.4%	
2020			1,458			1,424			640			621
2021			1,457			1,432			646			630
2022			1,463			1,439			652			639
2023			1,467			1,442			658			647
2024			1,475			1,444			664			655
2025			1,485			1,447			670			662
2026			1,492			1,449			675			668
2027			1,500			1,446			681			673
2028			1,509			1,446			687			680
2029			1,518			1,444			693			687
2030			1,528			1,441			698			693
2031			1,537			1,439			704			700
2032			1,546			1,439			709			709
2033			1,556			1,437			715			716
2034			1,565			1,434			720			722
2035			1,574			1,432			726			729
2036			1,583			1,430			731			735
2037						1,428						741
2038						1,425						747
2039						1,423						753

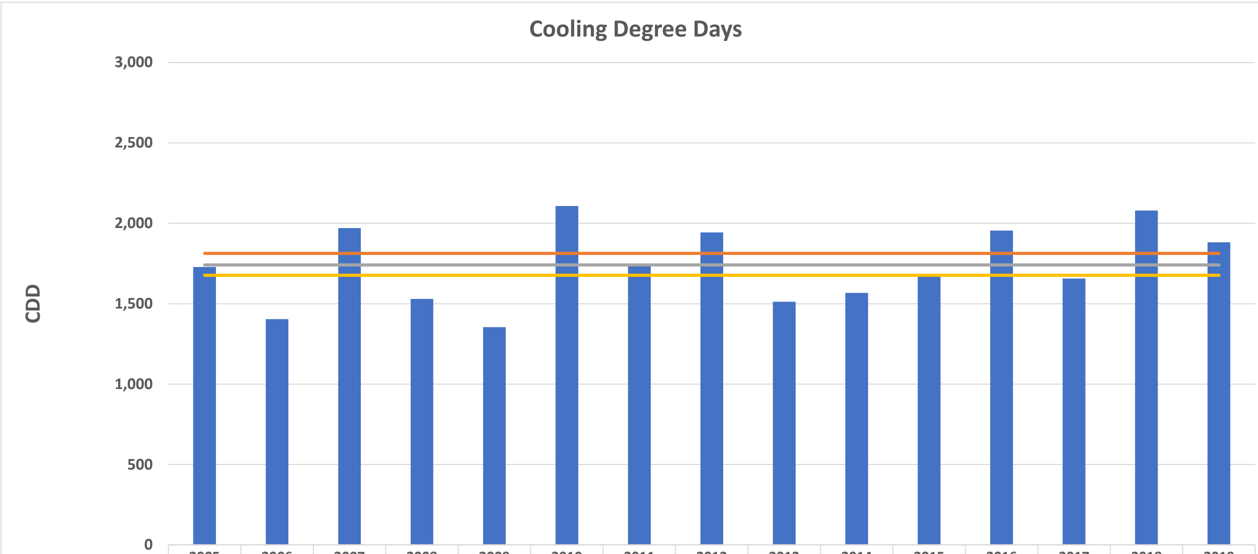
The following table compares the 2013, 2015 and 2017 forecasts to actual peak values for the Native system. The three forecasts over-projected 2017 peak values by an average of 4.1%. 2018 actual values were under-projected by an average of -0.4% across the forecasts, and 2019 values were over-projected by an average of 7.6%. Comparing the prior forecasts to weather normalized energy values explains some of the fluctuation in the comparisons of these three years. When the forecasts are compared to weather normalized values 2017 was over-projected by an average of 3.8%, 2018 was over-projected by 7.6%, and 2019 was over-projected by 7.4%. The over-projection of peak on prior forecasts is attributable to the higher than actual energy forecast.

Native Peak Tracking Analysis

Comparison of Native Peak Forecasts (MW)									
Year	Actual	Weather Normalization	2013 Load Forecast	2013 Forecast Compared to Actual	2015 Load Forecast	2015 Forecast Compared to Actual	2017 Load Forecast	2017 Forecast Compared to Actual	2020 Load Forecast
2008	618	626							
2009	673	627							
2010	662	621							
2011	659	653							
2012	661	623							
2013	617	641	632	2.4%					
2014	750	671	635	-15.4%					
2015	699	664	635	-9.1%	661	-5.4%			
2016	621	623	637	2.5%	683	9.9%			
2017	634	636	642	1.2%	691	9.0%	648	2.2%	
2018	669	619	645	-3.5%	693	3.6%	660	-1.3%	
2019	625	626	649	3.9%	695	11.2%	673	7.7%	
2020			653		697		676		627
2021			658		701		678		632
2022			663		704		679		832
2023			668		707		680		835
2024			673		711		681		836
2025			678		715		682		838
2026			683		720		683		840
2027					724		685		840
2028					729		686		841
2029					734		688		843
2030					740		689		843
2031					745		691		844
2032					750		693		846
2033					755		695		847
2034					761		696		848
2035							698		849
2036							700		850
2037									851
2038									851
2039									852

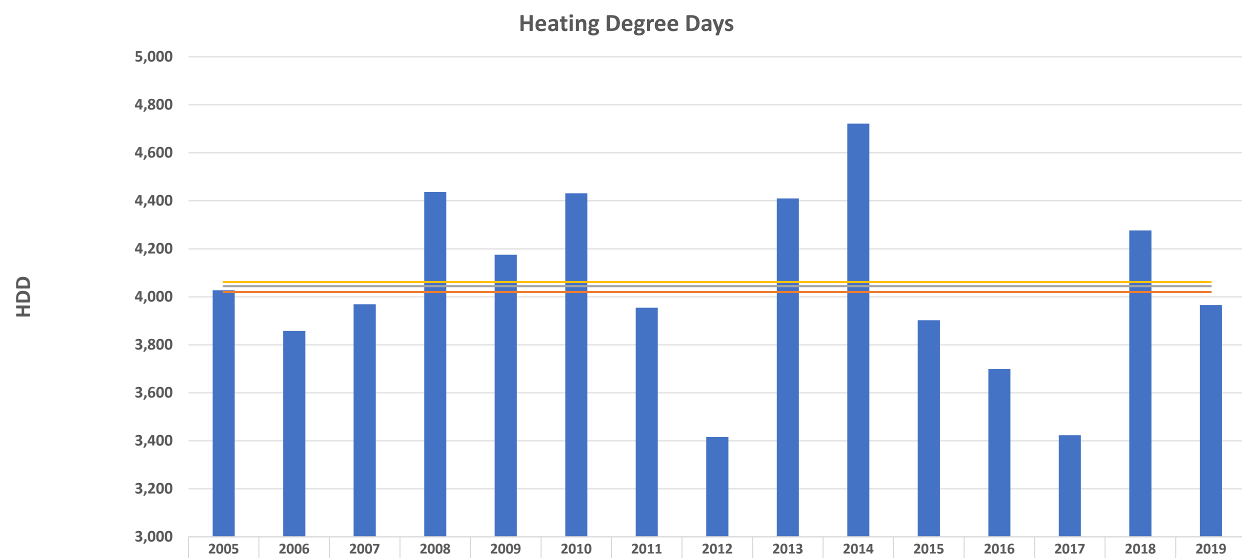
The historical weather normalized values in this section were completed using fifteen-year average values as the definition for normal weather. This is consistent with the normal weather definition used throughout the forecast. If the time span used to define normal weather is shortened to a ten-year average, the normal CDD values would be slightly higher and the normal HDD values would be slightly lower. Conversely, if a twenty-year average is used, the normal CDD values would be slightly lower and the HDD values slightly higher. Altering the time span used to define normal weather to either ten or twenty years would cause one season to go up slightly and the other season to fall slightly. This creates a balancing effect resulting in very little overall annual impact in normalized sales figures by changing the normalization period. The following figures show CDD and HDD values for the last fifteen years as well as the ten, fifteen, and twenty-year averages.

Cooling Degree Day Normal Values



	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
CDD	1,728	1,404	1,970	1,530	1,354	2,107	1,748	1,943	1,512	1,567	1,682	1,955	1,657	2,079	1,882
10 Year Avg CDD	1,813	1,813	1,813	1,813	1,813	1,813	1,813	1,813	1,813	1,813	1,813	1,813	1,813	1,813	1,813
15 Year Avg CDD	1,741	1,741	1,741	1,741	1,741	1,741	1,741	1,741	1,741	1,741	1,741	1,741	1,741	1,741	1,741
20 Year Avg CDD	1,676	1,676	1,676	1,676	1,676	1,676	1,676	1,676	1,676	1,676	1,676	1,676	1,676	1,676	1,676

Heating Degree Day Normal Values

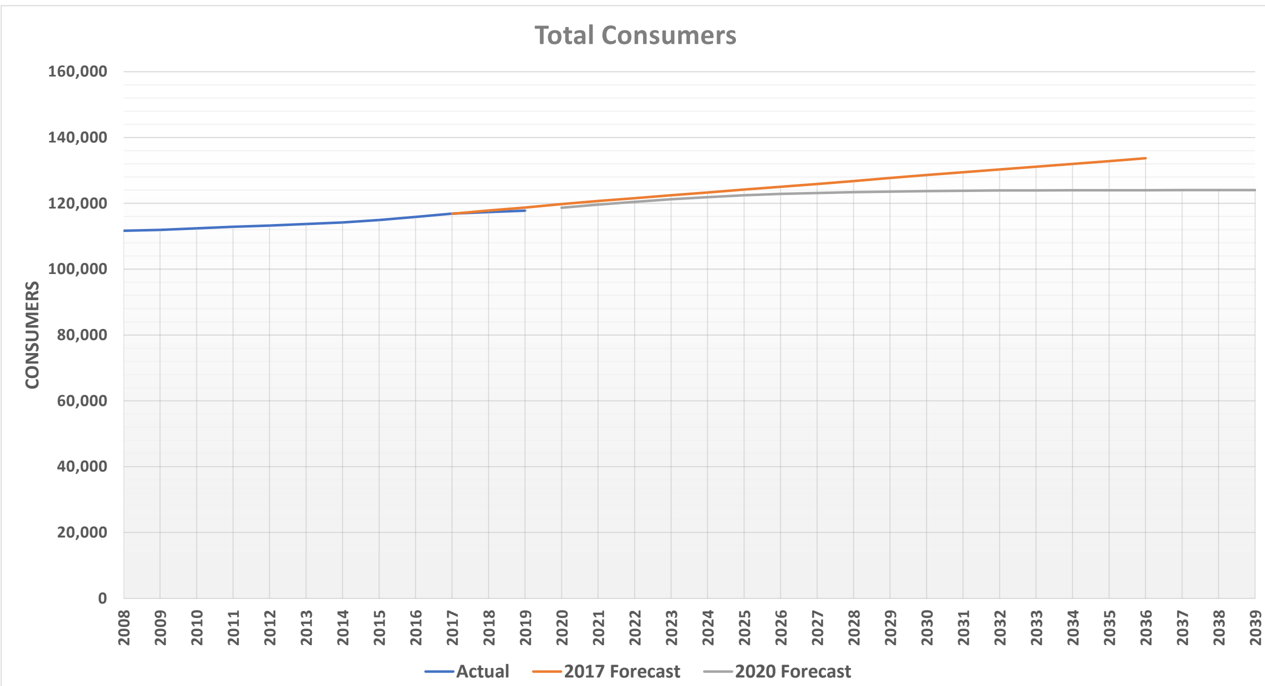


	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
HDD	4,027	3,858	3,970	4,437	4,175	4,432	3,955	3,416	4,410	4,722	3,903	3,699	3,423	4,277	3,966
10 Year Average HDD	4,020	4,020	4,020	4,020	4,020	4,020	4,020	4,020	4,020	4,020	4,020	4,020	4,020	4,020	4,020
15 Year Average HDD	4,045	4,045	4,045	4,045	4,045	4,045	4,045	4,045	4,045	4,045	4,045	4,045	4,045	4,045	4,045
20 Year Average HDD	4,062	4,062	4,062	4,062	4,062	4,062	4,062	4,062	4,062	4,062	4,062	4,062	4,062	4,062	4,062

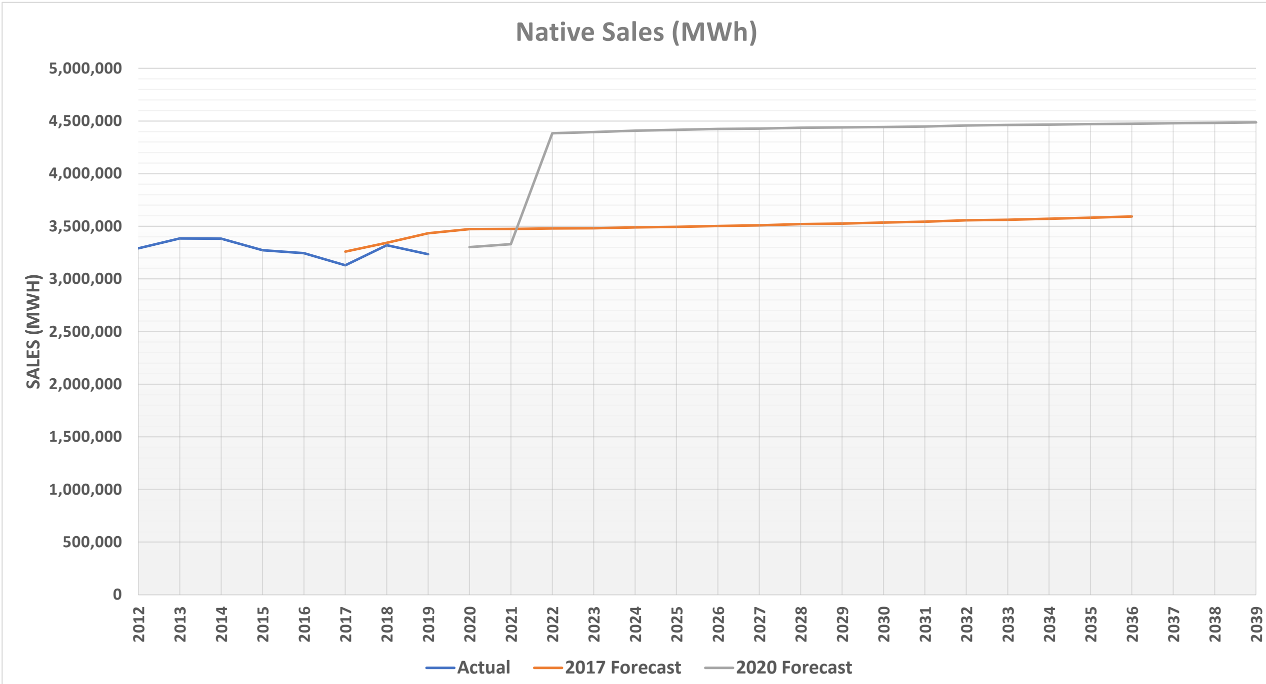
8.2 Comparisons to the 2017 Forecast By Class

The following figures display comparisons to the 2017 Load Forecast results. Comparisons are shown for Rural totals, total system load, and comparisons for each separate class.

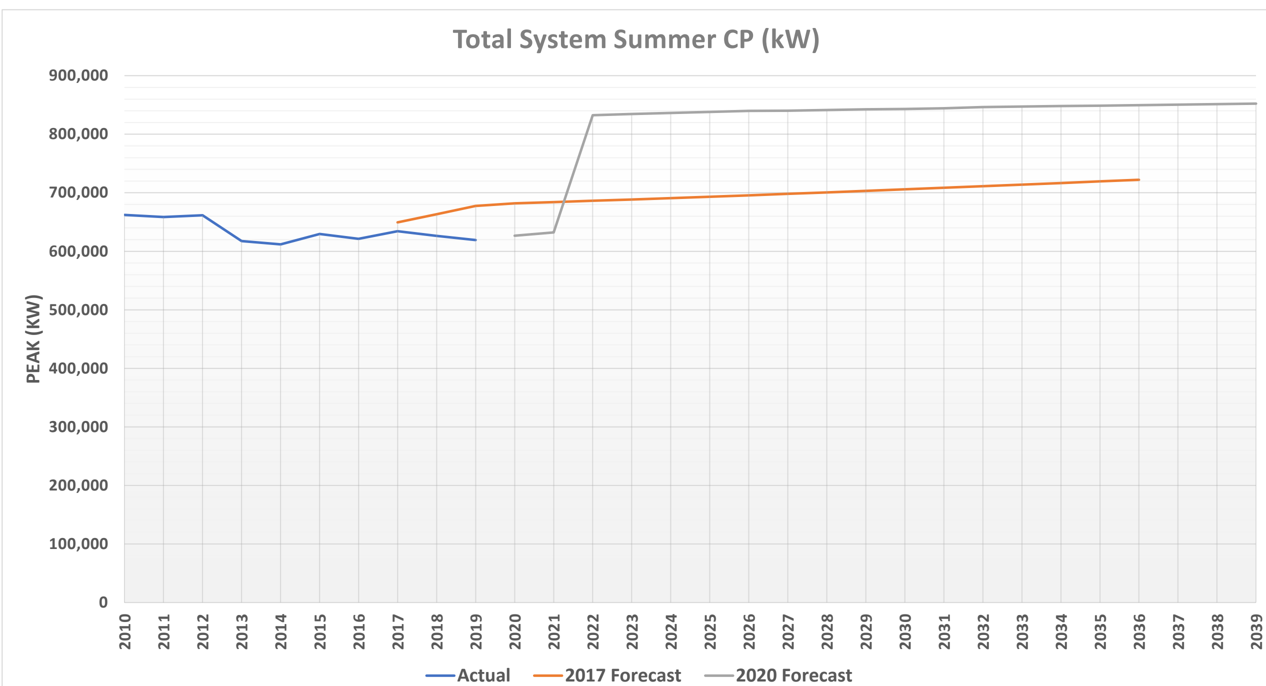
2017 Forecast Total Consumers Comparison



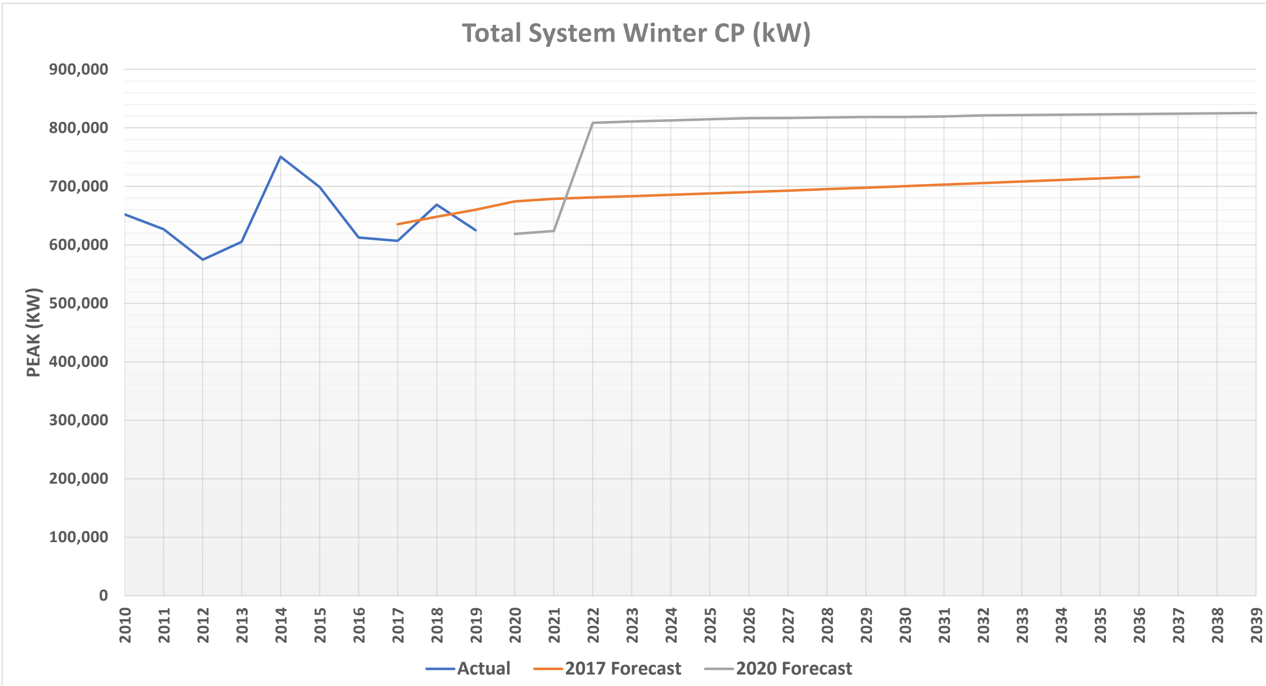
2017 Forecast Native Sales Comparison



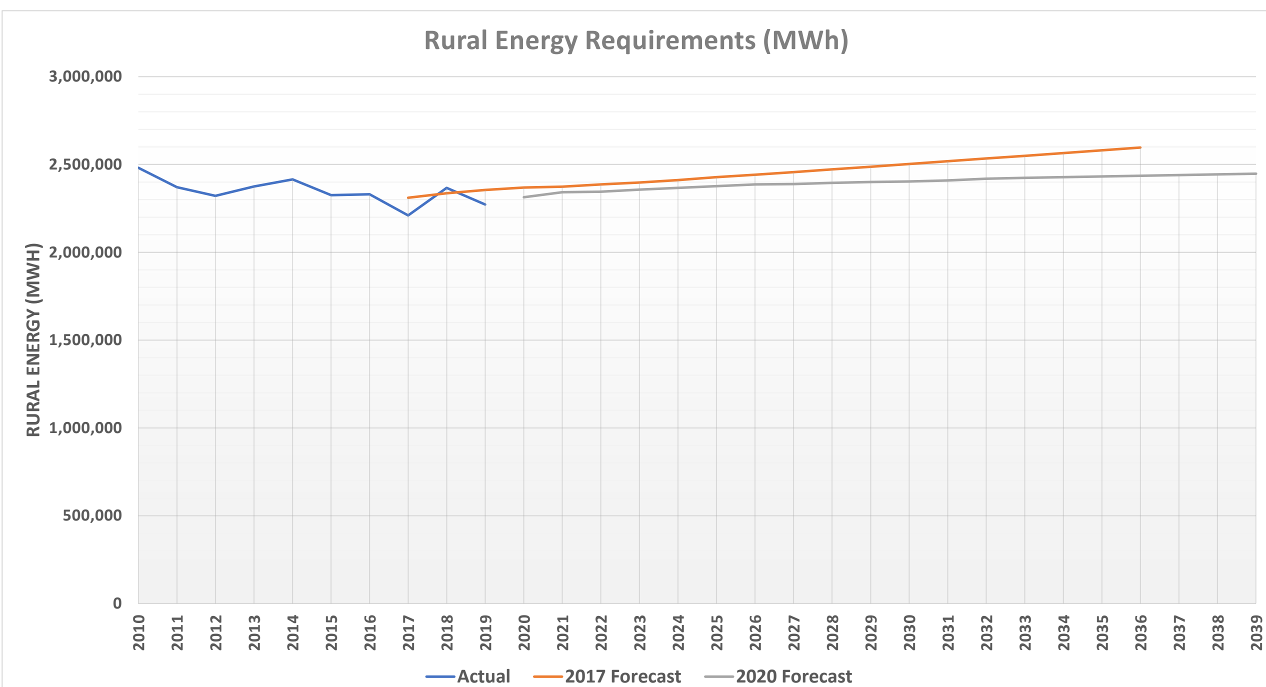
2017 Forecast Summer CP Comparison



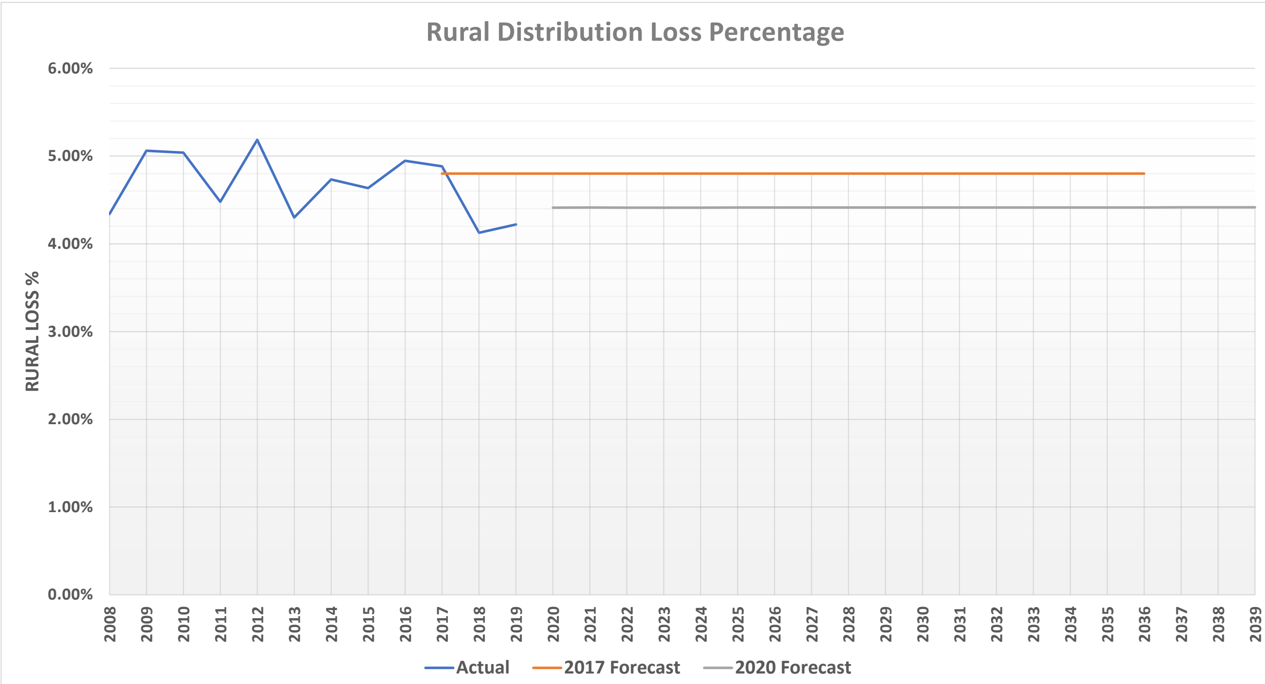
2017 Forecast Winter CP Comparison



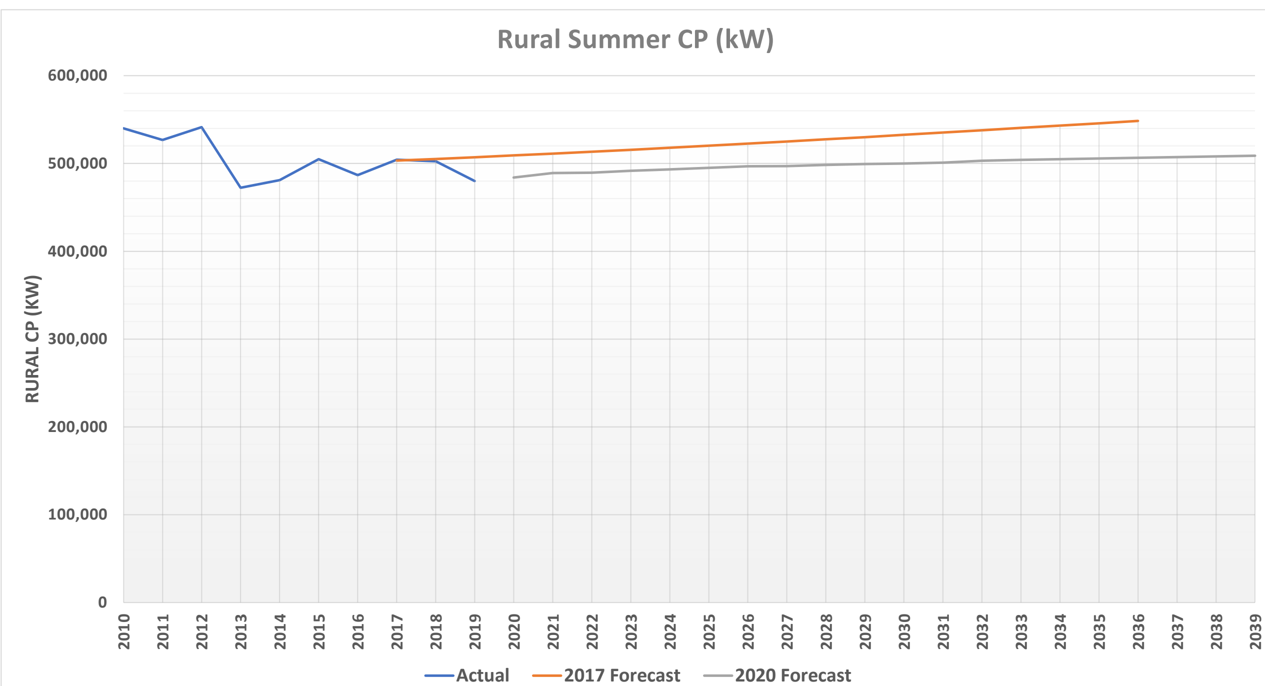
2017 Forecast Rural Energy Requirements Comparison



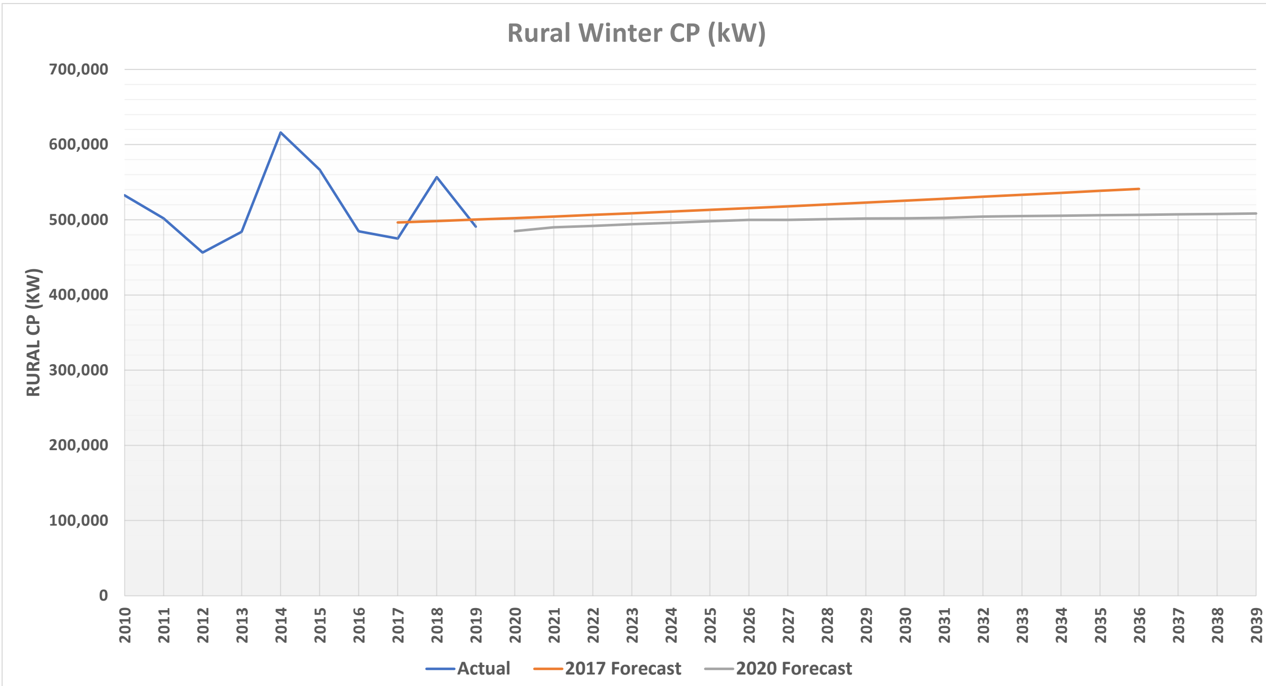
2017 Forecast Distribution Loss Comparison



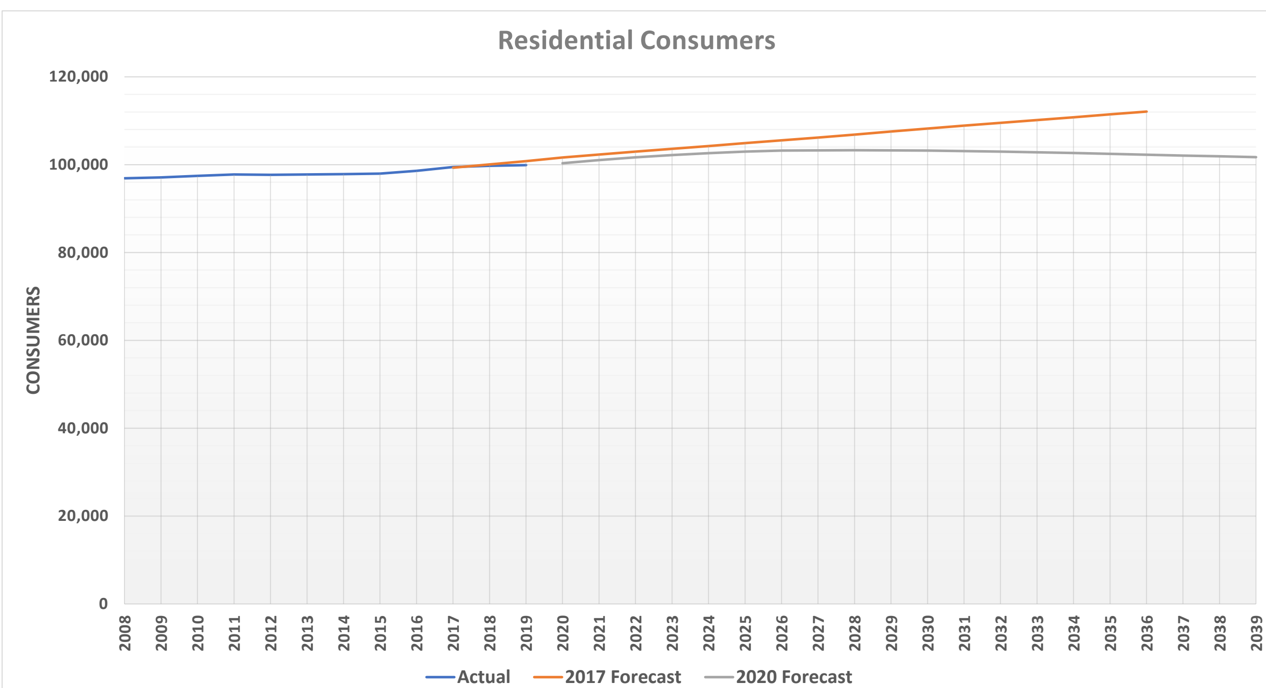
2017 Forecast Rural Summer CP Comparison



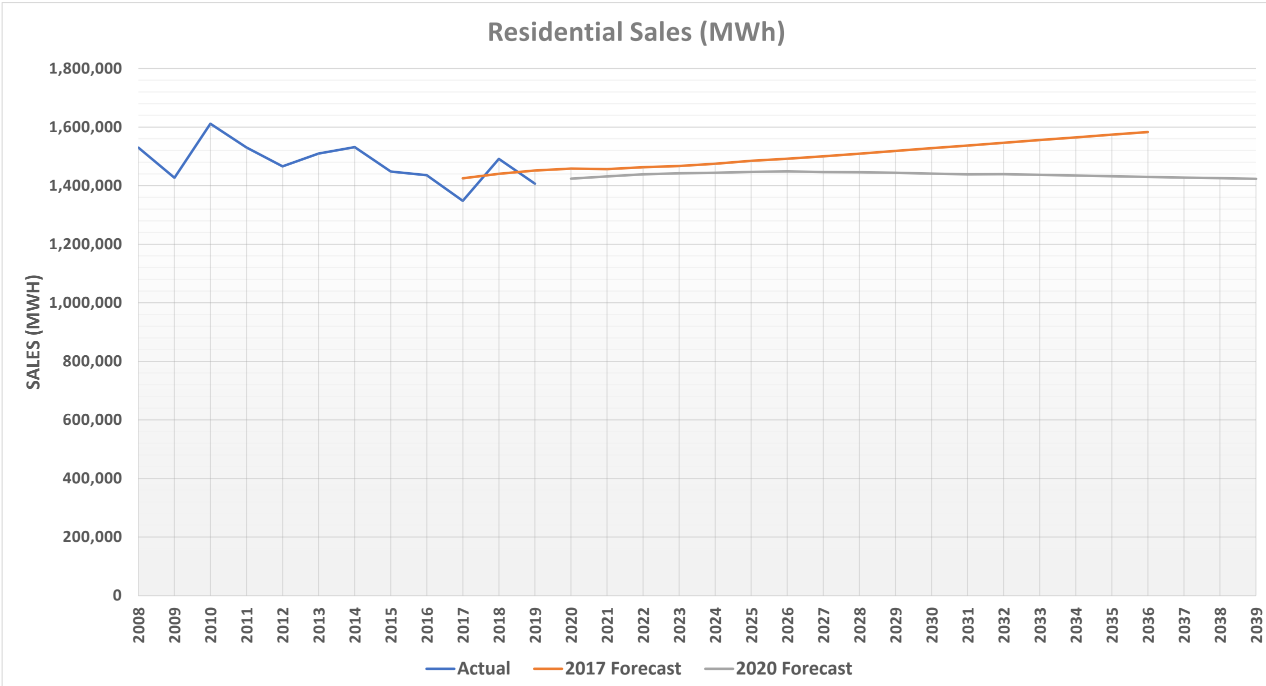
2017 Forecast Rural Winter CP Comparison



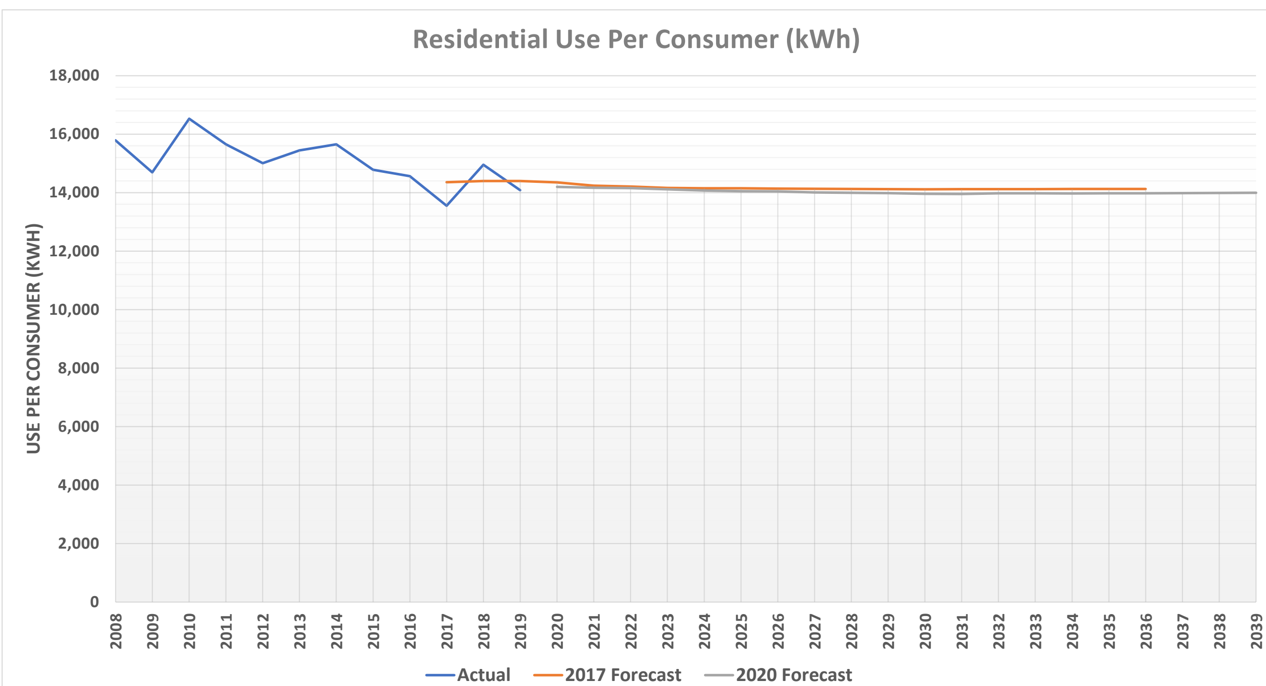
2017 Forecast Residential Consumers Comparison



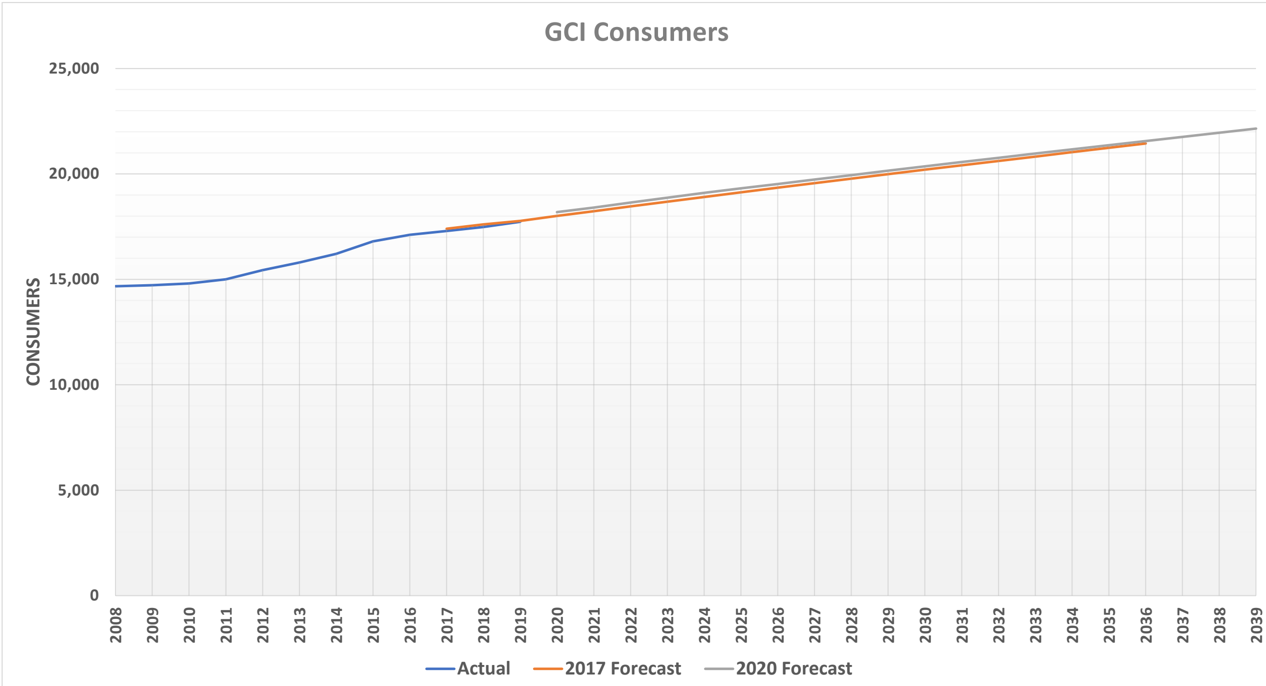
2017 Forecast Residential Sales Comparison



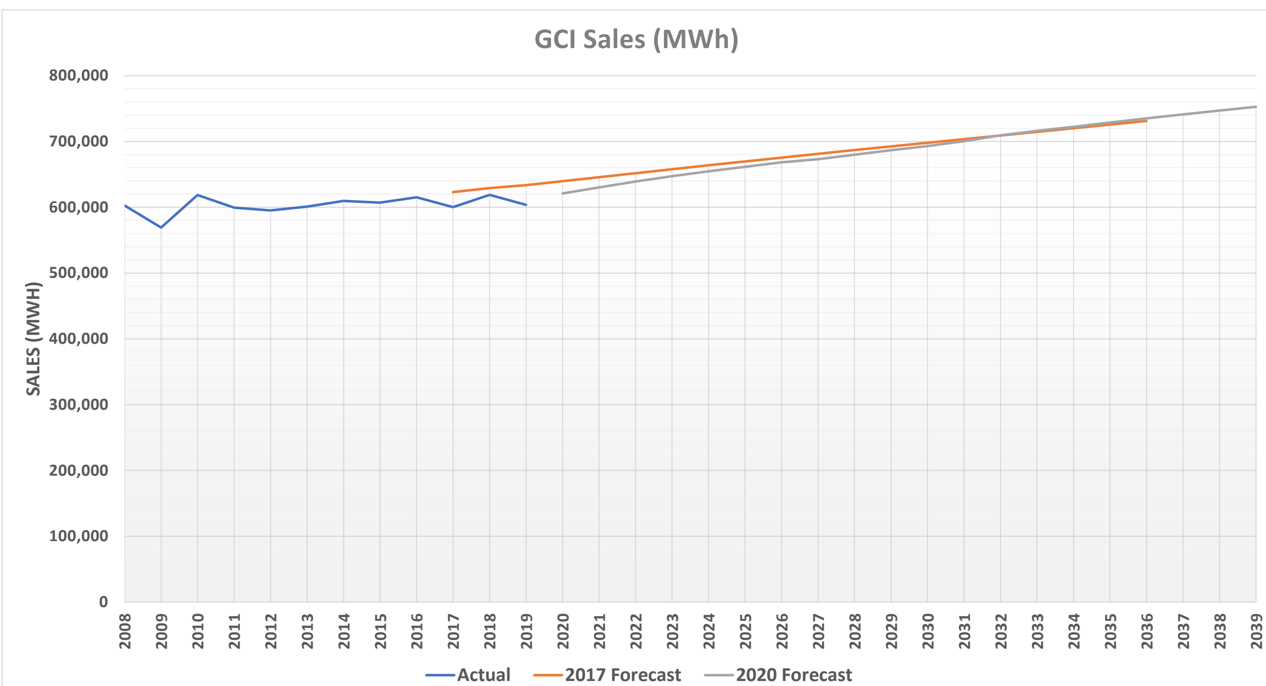
2017 Forecast Residential Use Per Consumer Comparison



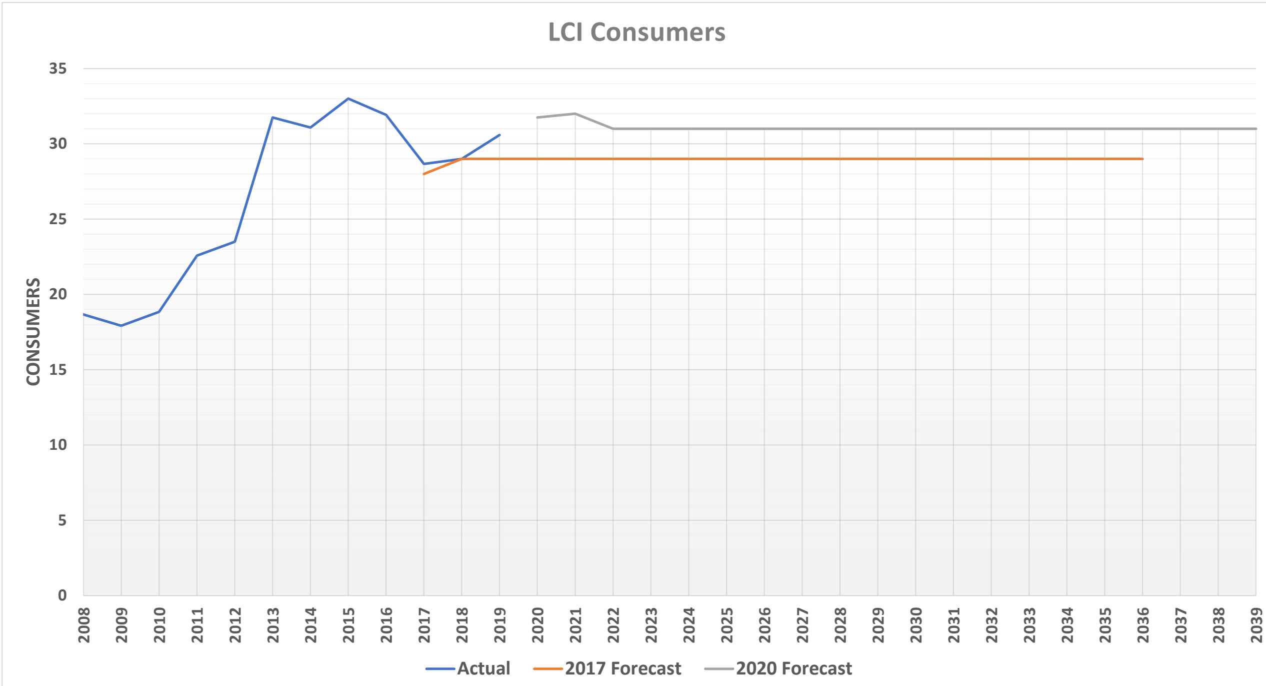
2017 Forecast GCI Consumer Comparison



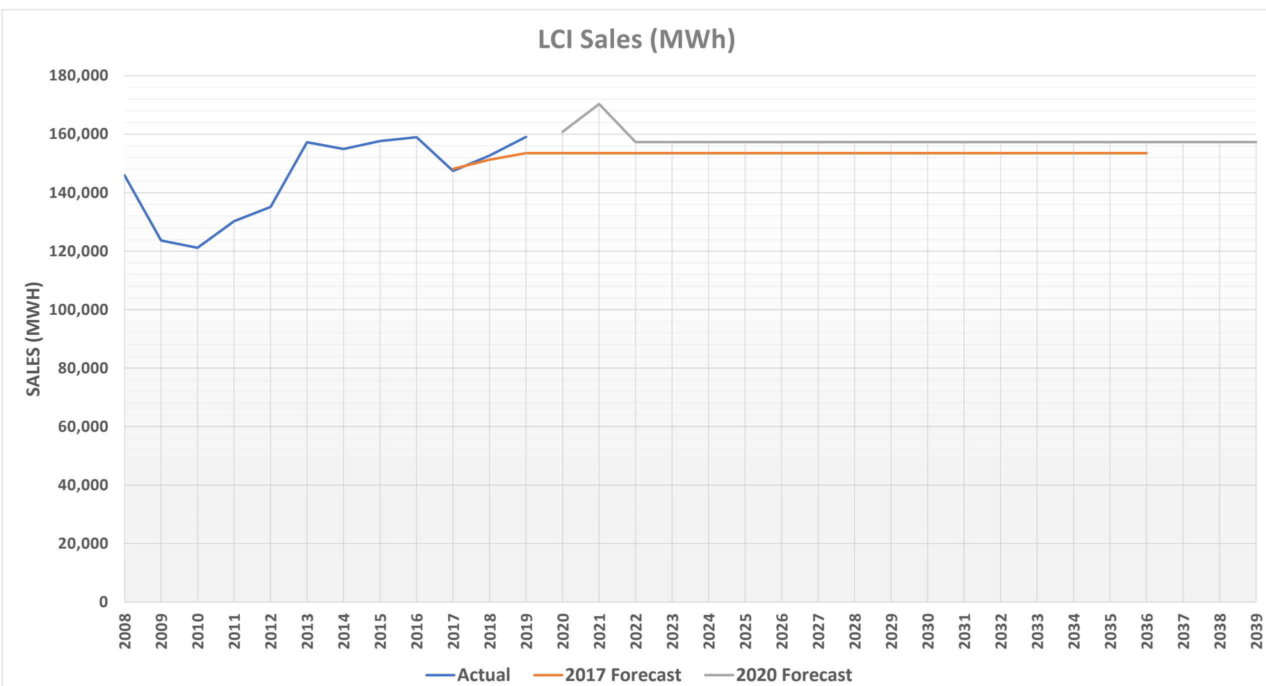
2017 Forecast GCI Sales Comparison



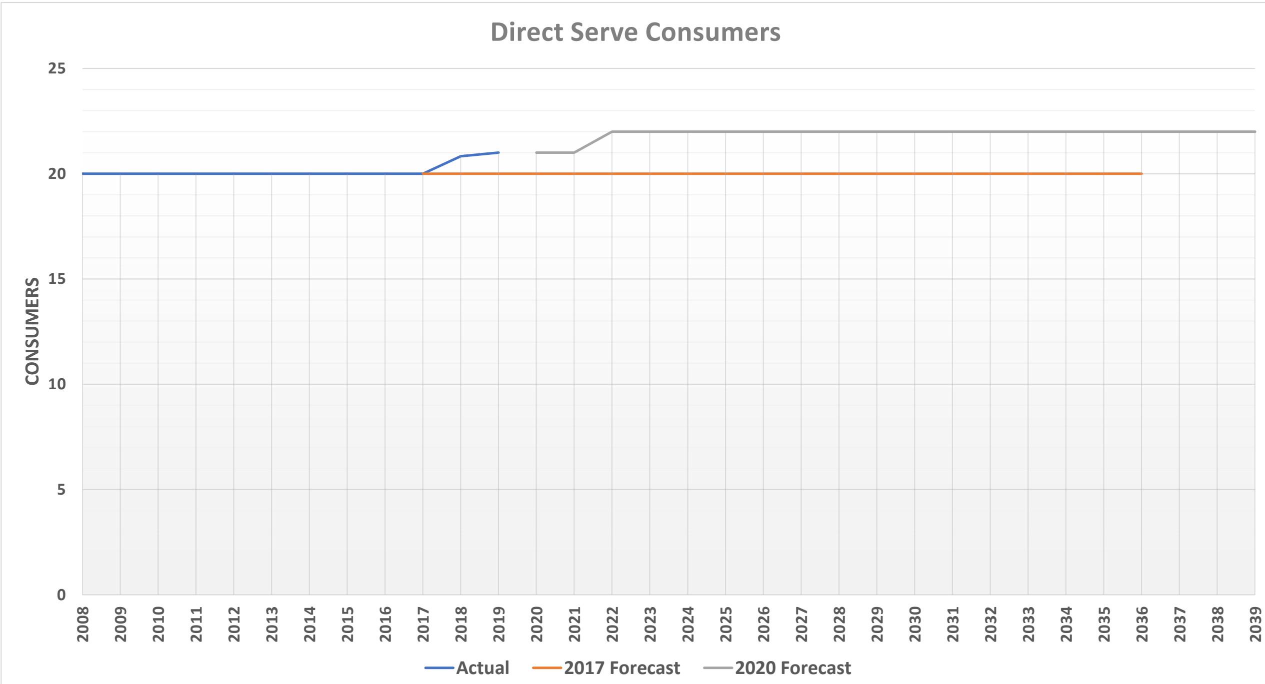
2017 Forecast LCI Consumer Comparison



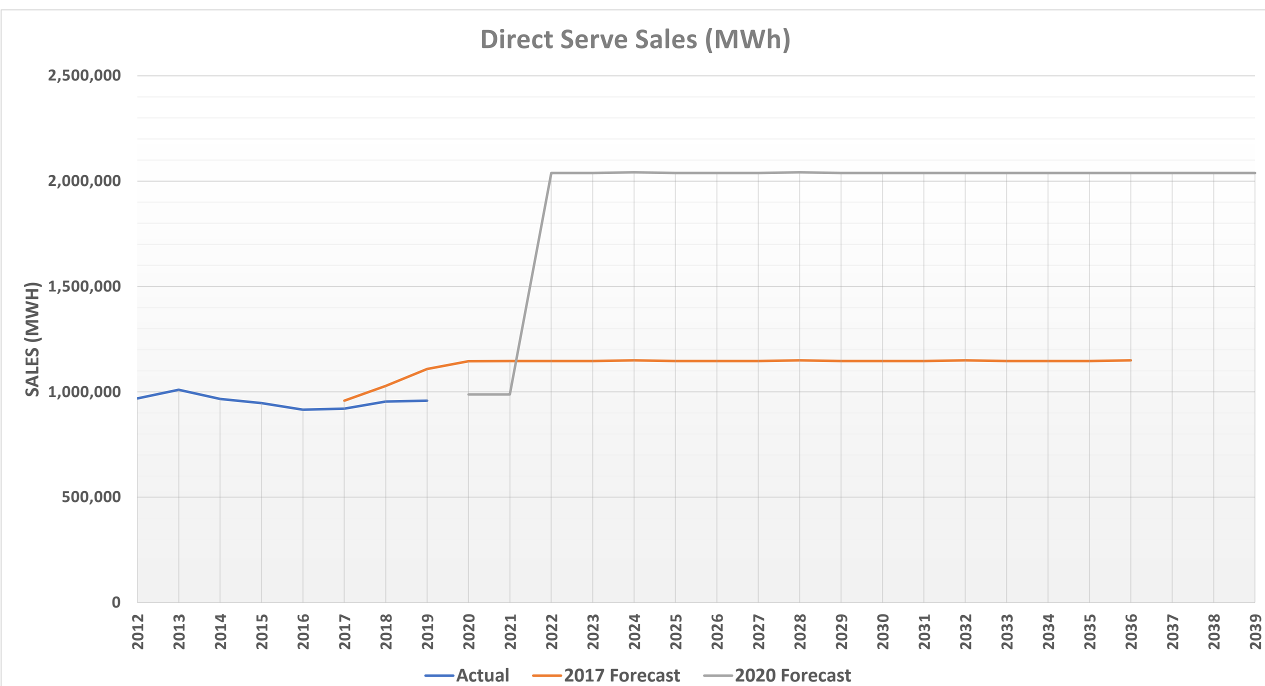
2017 Forecast LCI Sales Comparison



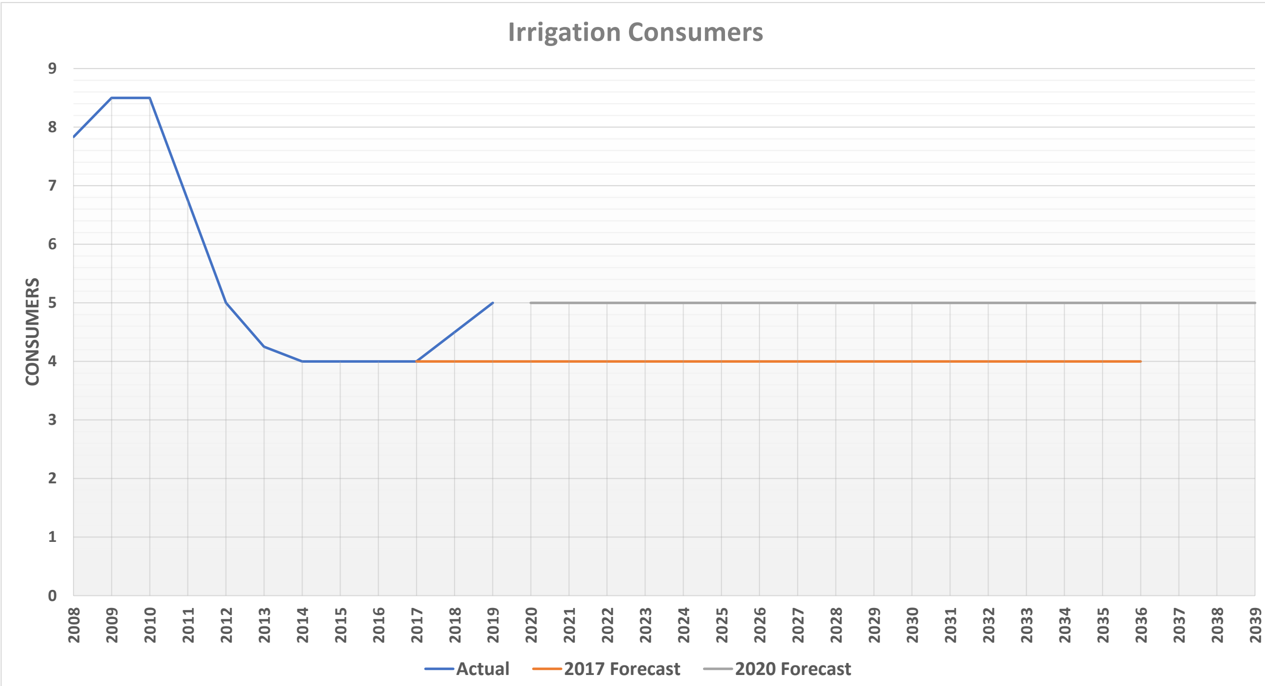
2017 Forecast Direct Serve Consumer Comparison



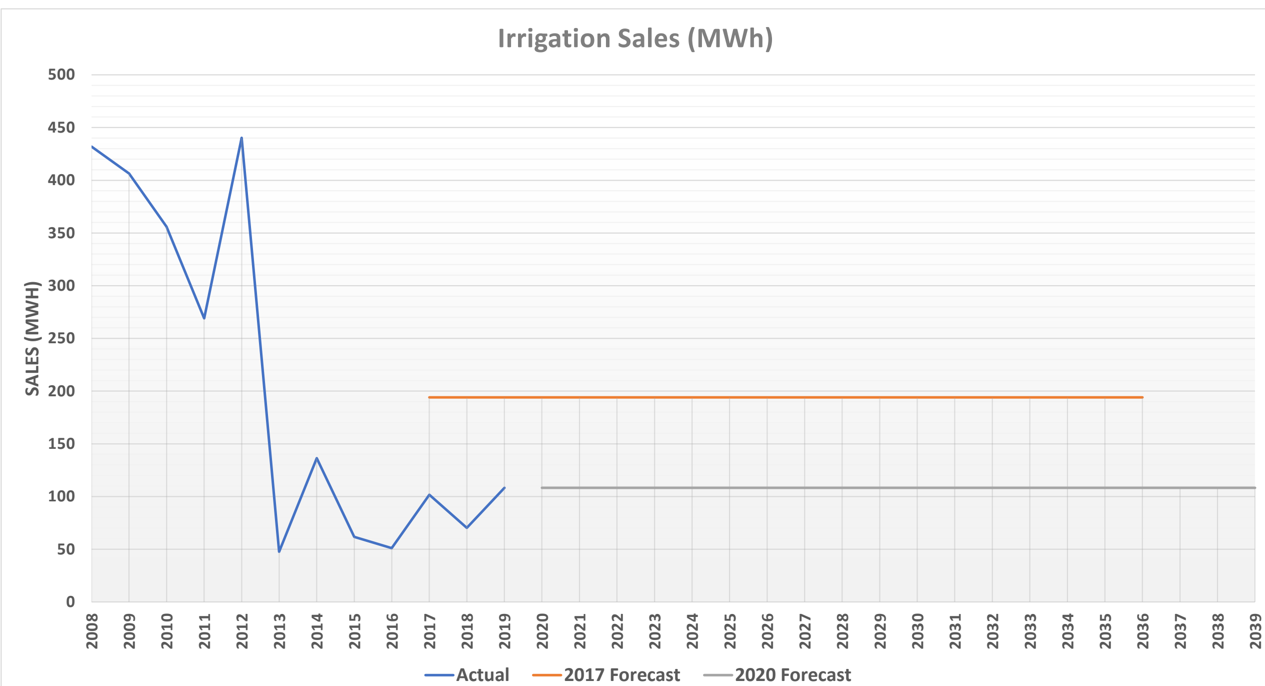
2017 Forecast Direct Serve Sales Comparison



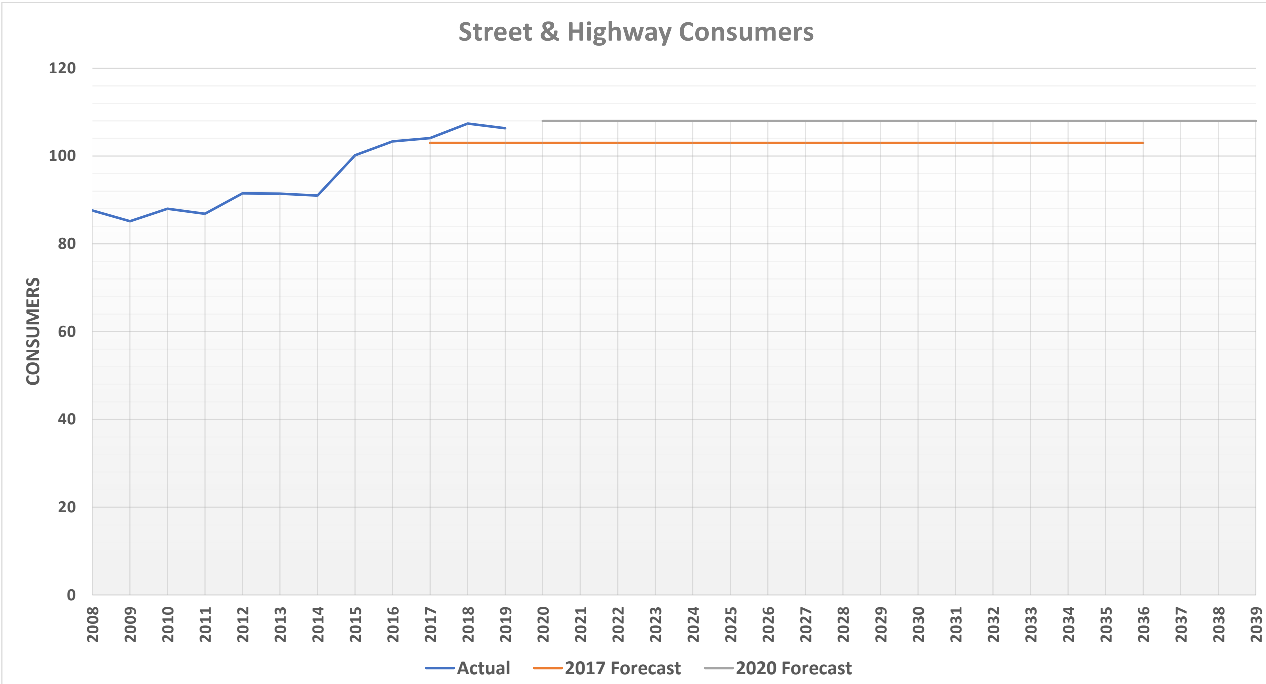
2017 Forecast Irrigation Consumer Comparison



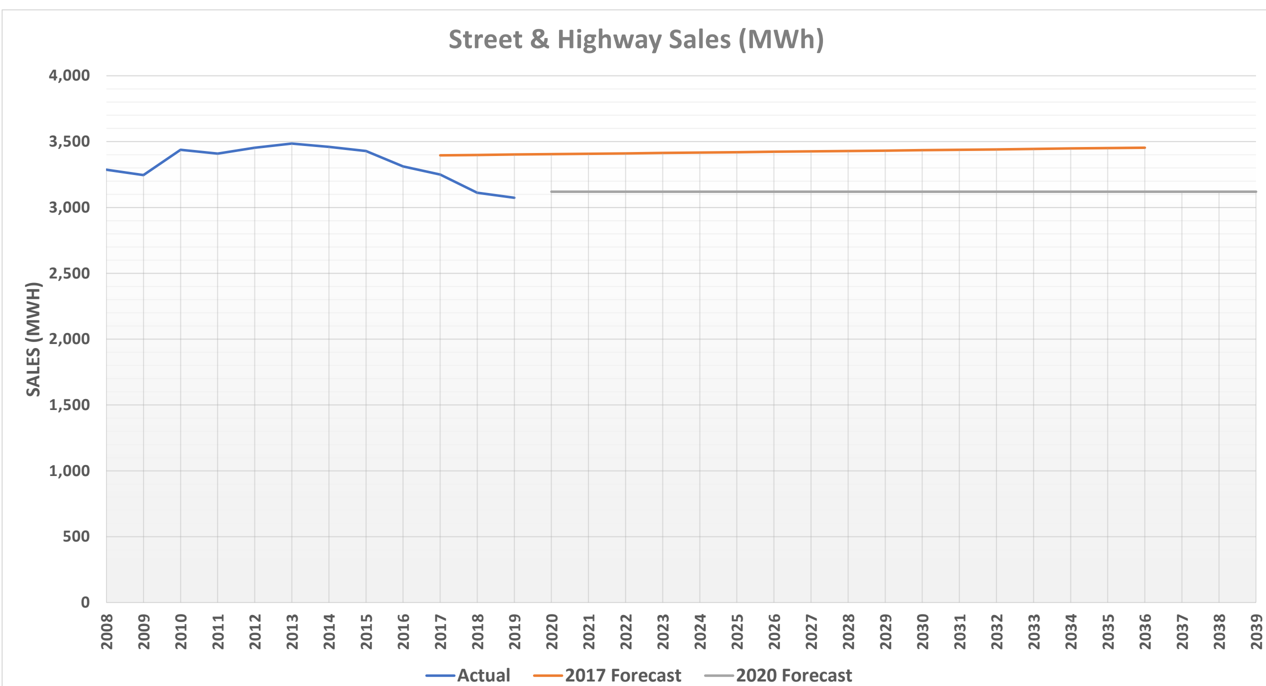
2017 Forecast Irrigation Sales Comparison



2017 Forecast Street & Highway Consumer Comparison



2017 Forecast Street & Highway Sales Comparison



9 APPENDIX

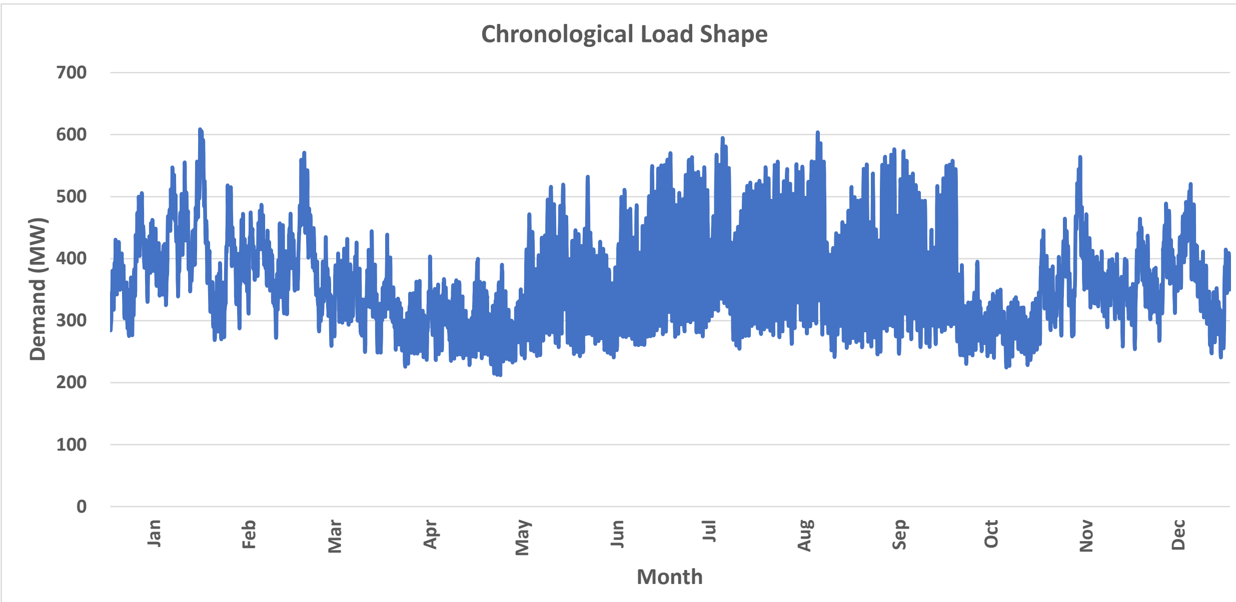
The following table provides the details on the consumers, sales, and use per consumer for each class for the Big Rivers Native system. The prior five years and the forecasted year values are provided in the table. Both historical and forecasted growth rates for each class are also provided.

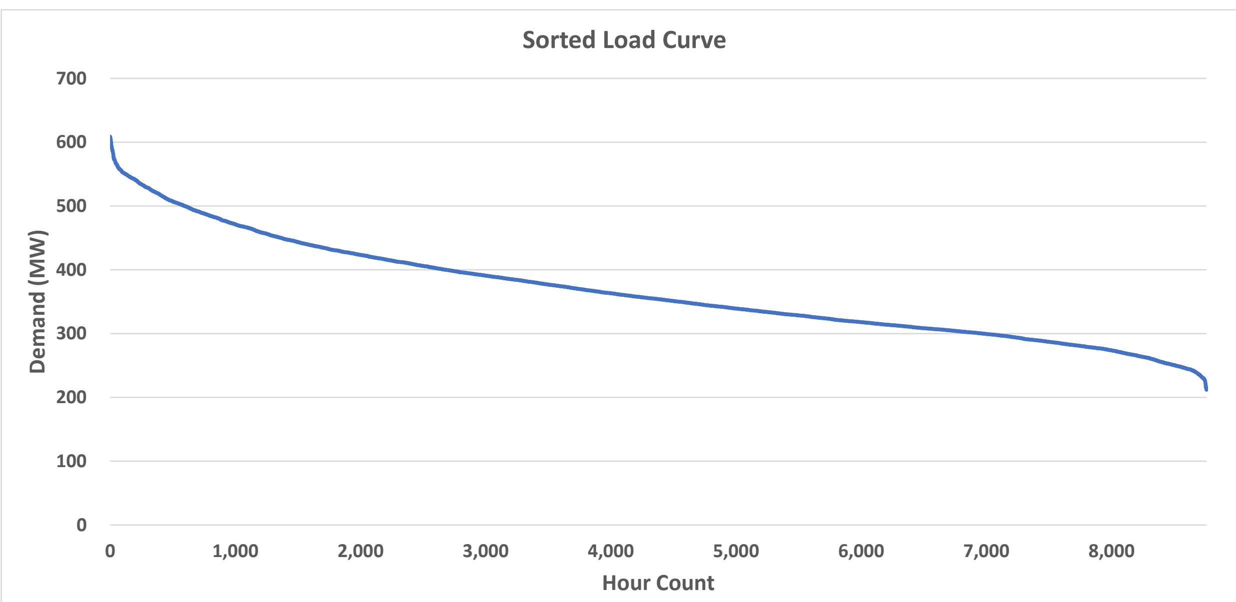
BIG RIVERS TOTAL FORECAST										
RESIDENTIAL	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
CONSUMERS	97,971	98,583	99,451	99,724	99,891	100,314	101,044	101,667	102,180	102,616
SALES-MWH	1,448,343	1,435,874	1,347,867	1,491,338	1,406,754	1,423,914	1,431,787	1,438,903	1,442,148	1,444,122
USE PER CONSUMER-kWH	14,783	14,565	13,553	14,955	14,083	14,195	14,170	14,153	14,114	14,073
GENERAL C&I	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
CONSUMERS	16,805	17,110	17,290	17,483	17,732	18,188	18,406	18,641	18,872	19,104
SALES-MWH	607,011	615,083	600,334	618,866	603,764	620,892	630,164	639,079	647,167	654,681
USE PER CONSUMER-kWH	36,121	35,949	34,721	35,398	34,050	34,138	34,237	34,283	34,293	34,270
LARGE C&I	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
CONSUMERS	33	32	29	29	31	32	32	31	31	31
SALES-MWH	157,680	158,999	147,433	152,708	159,111	160,778	170,333	157,311	157,311	157,311
USE PER CONSUMER-kWH	4,778,175	4,981,686	5,143,005	5,265,808	5,202,541	5,063,866	5,322,904	5,074,561	5,074,561	5,074,561
IRRIGATION	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
CONSUMERS	4	4	4	5	5	5	5	5	5	5
SALES-MWH	62	51	102	70	108	108	108	108	108	108
USE PER CONSUMER-kWH	15,428	12,760	25,437	15,618	21,652	21,652	21,652	21,652	21,652	21,652
STREET & HIGHWAY	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
CONSUMERS	100	103	104	107	106	108	108	108	108	108
SALES-MWH	3,429	3,312	3,250	3,111	3,074	3,120	3,120	3,120	3,120	3,120
USE PER CONSUMER-kWH	34,234	32,049	31,223	28,965	28,914	28,892	28,892	28,892	28,892	28,892
RURAL TOTAL	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
CONSUMERS	114,914	115,832	116,878	117,348	117,764	118,646	119,595	120,452	121,196	121,864
SALES-MWH	2,216,525	2,213,318	2,098,985	2,266,093	2,172,812	2,208,812	2,235,513	2,238,522	2,249,855	2,259,342
USE PER CONSUMER-kWH	19,289	19,108	17,959	19,311	18,451	18,617	18,692	18,584	18,564	18,540
OWNUSE-MWH	913	1,454	2,944	3,211	3,053	3,108	3,132	3,154	3,173	3,190
PURCHASES-MWH	2,325,204	2,330,037	2,209,837	2,366,988	2,271,772	2,313,997	2,342,004	2,345,137	2,357,028	2,366,988
DISTRIBUTION LOSSES-MWH	107,766	115,265	107,908	97,684	95,907	102,077	103,358	103,460	104,000	104,455
LOSSES (%)	4.6%	4.9%	4.9%	4.1%	4.2%	4.4%	4.4%	4.4%	4.4%	4.4%
DIRECT SERVE	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
CONSUMERS	20	20	20	21	21	21	21	22	22	22
SALES-MWH	946,873	915,310	919,895	953,822	957,994	987,552	987,552	2,038,752	2,038,752	2,041,632
USE PER CONSUMER-MWH	47,344	45,765	45,995	45,783	45,619	47,026	47,026	92,671	92,671	92,801
SYSTEM TOTAL WITH DIRECT SERVE	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
CONSUMERS	114,934	115,852	116,898	117,369	117,785	118,667	119,616	120,474	121,218	121,886
SALES-MWH	3,163,398	3,128,628	3,018,880	3,219,916	3,135,240	3,196,364	3,223,065	4,277,274	4,288,607	4,300,974
USE PER CONSUMER-kWH	27,524	27,005	25,825	27,434	26,618	26,936	26,945	35,504	35,379	35,287
OWNUSE-MWH	913	1,454	2,944	3,211	3,053	3,108	3,132	3,154	3,173	3,190
TOTAL ENERGY REQUIREMENTS-MWH (NO TRANS. LOSSES)	3,272,077	3,245,346	3,129,732	3,320,811	3,234,200	3,301,549	3,329,556	4,383,889	4,395,780	4,408,620
DISTRIBUTION LOSSES-MWH	107,766	115,265	107,908	97,684	95,907	102,077	103,358	103,460	104,000	104,455
DISTRIBUTION LOSS (%)	3.3%	3.6%	3.4%	2.9%	3.0%	3.1%	3.1%	2.4%	2.4%	2.4%
TRANSMISSION LOSSES-MWH	66,970	73,420	77,928	86,858	83,431	84,688	85,373	112,407	112,712	113,042
TRANSMISSION LOSS (%)	2.0%	2.2%	2.4%	2.6%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%
TOTAL ENERGY REQUIREMENTS-MWH	**3,339,047**	**3,318,766**	**3,207,660**	**3,407,668**	**3,317,632**	**3,386,237**	**3,414,929**	**4,496,296**	**4,508,492**	**4,521,662**
ANNUAL PEAK	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
RURAL CP - kW	566,553	486,690	504,269	556,742	490,895	483,946	489,218	489,558	491,639	493,376
DIRECT SERVE CP - kW	121,143	120,750	114,378	95,530	117,931	127,101	127,101	322,043	322,043	322,043
TOTAL CP - kW	687,696	607,440	618,647	652,272	608,826	611,047	616,319	811,601	813,682	815,419
TRANSMISSION LOSSES - kW	11,253	13,855	15,538	16,382	15,995	15,668	15,803	20,810	20,864	20,908
TRANSMISSION LOSS (%)	2.0%	2.2%	2.4%	2.6%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%
TOTAL CP - kW (WITH TRANSMISSION LOSSES)	**698,949**	**621,295**	**634,184**	**668,654**	**624,821**	**626,715**	**632,122**	**832,412**	**834,546**	**836,327**

BIG RIVERS TOTAL FORECAST										
RESIDENTIAL	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
CONSUMERS	102,990	103,193	103,256	103,282	103,263	103,200	103,101	102,970	102,815	102,644
SALES-MWH	1,446,702	1,448,868	1,446,170	1,445,528	1,444,108	1,440,938	1,438,824	1,439,236	1,437,166	1,434,434
USE PER CONSUMER-kWH	14,047	14,040	14,006	13,996	13,985	13,963	13,955	13,977	13,978	13,975
GENERAL C&I	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
CONSUMERS	19,314	19,524	19,734	19,942	20,150	20,357	20,562	20,765	20,966	21,166
SALES-MWH	661,534	668,455	673,141	679,960	686,774	692,988	700,284	709,422	716,148	722,361
USE PER CONSUMER-kWH	34,251	34,238	34,110	34,096	34,082	34,041	34,056	34,164	34,157	34,128
LARGE C&I	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
CONSUMERS	31	31	31	31	31	31	31	31	31	31
SALES-MWH	157,311	157,311	157,311	157,311	157,311	157,311	157,311	157,311	157,311	157,311
USE PER CONSUMER-kWH	5,074,561	5,074,561	5,074,561	5,074,561	5,074,561	5,074,561	5,074,561	5,074,561	5,074,561	5,074,561
IRRIGATION	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
CONSUMERS	5	5	5	5	5	5	5	5	5	5
SALES-MWH	108	108	108	108	108	108	108	108	108	108
USE PER CONSUMER-kWH	21,652	21,652	21,652	21,652	21,652	21,652	21,652	21,652	21,652	21,652
STREET & HIGHWAY	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
CONSUMERS	108	108	108	108	108	108	108	108	108	108
SALES-MWH	3,120	3,120	3,120	3,120	3,120	3,120	3,120	3,120	3,120	3,120
USE PER CONSUMER-kWH	28,892	28,892	28,892	28,892	28,892	28,892	28,892	28,892	28,892	28,892
RURAL TOTAL	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
CONSUMERS	122,448	122,861	123,135	123,369	123,557	123,701	123,808	123,879	123,925	123,954
SALES-MWH	2,268,776	2,277,864	2,279,851	2,286,028	2,291,422	2,294,466	2,299,648	2,309,197	2,313,854	2,317,335
USE PER CONSUMER-kWH	18,529	18,540	18,515	18,530	18,545	18,548	18,574	18,641	18,671	18,695
OWNUSE-MWH	3,205	3,216	3,225	3,232	3,238	3,243	3,247	3,249	3,252	3,254
PURCHASES-MWH	2,376,885	2,386,410	2,388,504	2,394,976	2,400,628	2,403,821	2,409,248	2,419,240	2,424,117	2,427,766
DISTRIBUTION LOSSES-MWH	104,904	105,330	105,429	105,716	105,968	106,112	106,354	106,793	107,012	107,178
LOSSES (%)	4.4%	4.4%	4.4%	4.4%	4.4%	4.4%	4.4%	4.4%	4.4%	4.4%
DIRECT SERVE	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
CONSUMERS	22	22	22	22	22	22	22	22	22	22
SALES-MWH	2,038,752	2,038,752	2,038,752	2,041,632	2,038,752	2,038,752	2,038,752	2,038,752	2,038,752	2,038,752
USE PER CONSUMER-MWH	92,671	92,671	92,671	92,801	92,671	92,671	92,671	92,671	92,671	92,671
SYSTEM TOTAL WITH DIRECT SERVE	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
CONSUMERS	122,470	122,883	123,157	123,391	123,579	123,723	123,830	123,901	123,947	123,976
SALES-MWH	4,307,528	4,316,616	4,318,603	4,327,660	4,330,175	4,333,218	4,338,400	4,347,950	4,352,606	4,356,087
USE PER CONSUMER-kWH	35,172	35,128	35,066	35,073	35,040	35,023	35,035	35,092	35,117	35,136
OWNUSE-MWH	3,205	3,216	3,225	3,232	3,238	3,243	3,247	3,249	3,252	3,254
TOTAL ENERGY REQUIREMENTS-MWH (NO TRANS. LOSSES)	4,415,637	4,425,162	4,427,257	4,436,608	4,439,380	4,442,574	4,448,000	4,457,992	4,462,869	4,466,518
DISTRIBUTION LOSSES-MWH	104,904	105,330	105,429	105,716	105,968	106,112	106,354	106,793	107,012	107,178
DISTRIBUTION LOSS (%)	2.4%	2.4%	2.4%	2.4%	2.4%	2.4%	2.4%	2.4%	2.4%	2.4%
TRANSMISSION LOSSES-MWH	113,221	113,466	113,519	113,759	113,830	113,912	114,051	114,307	114,433	114,526
TRANSMISSION LOSS (%)	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%
TOTAL ENERGY REQUIREMENTS-MWH	**4,528,859**	**4,538,628**	**4,540,776**	**4,550,367**	**4,553,210**	**4,556,486**	**4,562,051**	**4,572,299**	**4,577,302**	**4,581,044**
ANNUAL PEAK	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
RURAL CP - kW	495,136	496,879	497,133	498,359	499,422	500,004	501,074	503,128	504,103	504,841
DIRECT SERVE CP - kW	322,043	322,043	322,043	322,043	322,043	322,043	322,043	322,043	322,043	322,043
TOTAL CP - kW	817,179	818,922	819,176	820,402	821,465	822,047	823,117	825,171	826,146	826,884
TRANSMISSION LOSSES - kW	20,953	20,998	21,005	21,036	21,063	21,078	21,106	21,158	21,183	21,202
TRANSMISSION LOSS (%)	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%
TOTAL CP - kW (WITH TRANSMISSION LOSSES)	**838,132**	**839,920**	**840,180**	**841,438**	**842,528**	**843,125**	**844,223**	**846,330**	**847,329**	**848,086**

BIG RIVERS TOTAL FORECAST						Last 10 Yrs	Last 5 Yrs	Next 5 Yrs	Next 10 Yrs	Next 20 Yrs
RESIDENTIAL	2035	2036	2037	2038	2039	2009 - 2019	2014 - 2019	2019 - 2024	2019 - 2029	2019 - 2039
CONSUMERS	102,460	102,269	102,079	101,894	101,718	0.3%	0.4%	0.5%	0.3%	0.1%
SALES-MWH	1,431,962	1,429,572	1,427,550	1,425,414	1,423,491	-0.1%	-1.7%	0.5%	0.3%	0.1%
USE PER CONSUMER-kWH	13,976	13,979	13,985	13,989	13,994	-0.4%	-2.1%	0.0%	-0.1%	0.0%
GENERAL C&I	2035	2036	2037	2038	2039	2009 - 2019	2014 - 2019	2019 - 2024	2019 - 2029	2019 - 2039
CONSUMERS	21,365	21,562	21,759	21,954	22,149	1.9%	1.8%	1.5%	1.3%	1.1%
SALES-MWH	728,729	735,033	741,068	746,889	752,795	0.6%	-0.2%	1.6%	1.3%	1.1%
USE PER CONSUMER-kWH	34,109	34,089	34,059	34,020	33,988	-1.3%	-2.0%	0.1%	0.0%	0.0%
LARGE C&I	2035	2036	2037	2038	2039	2009 - 2019	2014 - 2019	2019 - 2024	2019 - 2029	2019 - 2039
CONSUMERS	31	31	31	31	31	5.5%	-0.3%	0.3%	0.1%	0.1%
SALES-MWH	157,311	157,311	157,311	157,311	157,311	2.6%	0.5%	-0.2%	-0.1%	-0.1%
USE PER CONSUMER-kWH	5,074,561	5,074,561	5,074,561	5,074,561	5,074,561	-2.8%	0.9%	-0.5%	-0.2%	-0.1%
IRRIGATION	2035	2036	2037	2038	2039	2009 - 2019	2014 - 2019	2019 - 2024	2019 - 2029	2019 - 2039
CONSUMERS	5	5	5	5	5	-5.2%	4.6%	0.0%	0.0%	0.0%
SALES-MWH	108	108	108	108	108	-12.4%	-4.5%	0.0%	0.0%	0.0%
USE PER CONSUMER-kWH	21,652	21,652	21,652	21,652	21,652	-7.6%	-8.7%	0.0%	0.0%	0.0%
STREET & HIGHWAY	2035	2036	2037	2038	2039	2009 - 2019	2014 - 2019	2019 - 2024	2019 - 2029	2019 - 2039
CONSUMERS	108	108	108	108	108	2.2%	3.2%	0.3%	0.2%	0.1%
SALES-MWH	3,120	3,120	3,120	3,120	3,120	-0.5%	-2.3%	0.3%	0.1%	0.1%
USE PER CONSUMER-kWH	28,892	28,892	28,892	28,892	28,892	-2.7%	-5.3%	0.0%	0.0%	0.0%
RURAL TOTAL	2035	2036	2037	2038	2039	2009 - 2019	2014 - 2019	2019 - 2024	2019 - 2029	2019 - 2039
CONSUMERS	123,969	123,975	123,981	123,992	124,011	0.5%	0.6%	0.7%	0.5%	0.3%
SALES-MWH	2,321,231	2,325,145	2,329,158	2,332,843	2,336,825	0.2%	-1.1%	0.8%	0.5%	0.4%
USE PER CONSUMER-kWH	18,724	18,755	18,786	18,814	18,844	-0.3%	-1.7%	0.1%	0.1%	0.1%
OWNUSE-MWH	3,255	3,256	3,257	3,259	3,260	7.4%	23.0%	0.9%	0.6%	0.3%
PURCHASES-MWH	2,431,849	2,435,950	2,440,157	2,444,021	2,448,197	0.1%	-1.2%	0.8%	0.6%	0.4%
DISTRIBUTION LOSSES-MWH	107,363	107,549	107,742	107,919	108,111	-1.6%	-3.5%	1.7%	1.0%	0.6%
LOSSES (%)	4.4%	4.4%	4.4%	4.4%	4.4%	-1.8%	-2.3%	0.9%	0.4%	0.2%
DIRECT SERVE	2035	2036	2037	2038	2039	2009 - 2019	2014 - 2019	2019 - 2024	2019 - 2029	2019 - 2039
CONSUMERS	22	22	22	22	22	0.5%	1.0%	0.9%	0.5%	0.2%
SALES-MWH	2,038,752	2,038,752	2,038,752	2,038,752	2,038,752	-2.3%	-0.2%	16.3%	7.8%	3.8%
USE PER CONSUMER-MWH	92,671	92,671	92,671	92,671	92,671	-2.7%	-1.1%	15.3%	7.3%	3.6%
SYSTEM TOTAL WITH DIRECT SERVE	2035	2036	2037	2038	2039	2009 - 2019	2014 - 2019	2019 - 2024	2019 - 2029	2019 - 2039
CONSUMERS	123,991	123,997	124,003	124,014	124,033	0.5%	0.6%	0.7%	0.5%	0.3%
SALES-MWH	4,359,983	4,363,897	4,367,911	4,371,595	4,375,578	-0.6%	-0.8%	6.5%	3.3%	1.7%
USE PER CONSUMER-kWH	35,164	35,194	35,224	35,251	35,277	-1.1%	-1.4%	5.8%	2.8%	1.4%
OWNUSE-MWH	3,255	3,256	3,257	3,259	3,260	7.4%	23.0%	0.9%	0.6%	0.3%
TOTAL ENERGY REQUIREMENTS-MWH (NO TRANS. LOSSES)	4,470,601	4,474,703	4,478,910	4,482,773	4,486,949	-0.6%	-0.9%	6.4%	3.2%	1.7%
DISTRIBUTION LOSSES-MWH	107,363	107,549	107,742	107,919	108,111	-1.6%	-3.5%	1.7%	1.0%	0.6%
DISTRIBUTION LOSS (%)	2.4%	2.4%	2.4%	2.4%	2.4%	-1.0%	-2.6%	-4.4%	-2.1%	-1.0%
TRANSMISSION LOSSES-MWH	114,631	114,736	114,844	114,943	115,050	11.9%	8.9%	6.3%	3.2%	1.6%
TRANSMISSION LOSS (%)	2.5%	2.5%	2.5%	2.5%	2.5%	12.4%	9.6%	-0.1%	-0.1%	0.0%
TOTAL ENERGY REQUIREMENTS-MWH	**4,585,232**	**4,589,439**	**4,593,753**	**4,597,716**	**4,601,999**	**-0.4%**	**-0.7%**	**6.4%**	**3.2%**	**1.6%**
ANNUAL PEAK	2035	2036	2037	2038	2039	2009 - 2019	2014 - 2019	2019 - 2024	2019 - 2029	2019 - 2039
RURAL CP - kW	505,663	506,495	507,349	508,129	508,968	-1.3%	-4.4%	0.1%	0.2%	0.2%
DIRECT SERVE CP - kW	322,043	322,043	322,043	322,043	322,043	1.0%	-1.0%	22.3%	10.6%	5.2%
TOTAL CP - kW	827,706	828,538	829,392	830,172	831,011	-0.9%	-3.8%	6.0%	3.0%	1.6%
TRANSMISSION LOSSES - kW	21,223	21,245	21,266	21,286	21,308	11.5%	9.2%	5.5%	2.8%	1.4%
TRANSMISSION LOSS (%)	2.5%	2.5%	2.5%	2.5%	2.5%	12.4%	9.6%	-0.1%	-0.1%	0.0%
TOTAL CP - kW (WITH TRANSMISSION LOSSES)	**848,929**	**849,782**	**850,659**	**851,459**	**852,319**	**-0.7%**	**-3.6%**	**6.0%**	**3.0%**	**1.6%**

The following figures display the 2019 annual load shape and descending load curve for the Big Rivers Native system. The five-year monthly forecast is also shown on the following page.





Big Rivers Monthly Forecast

		Rural Energy Sales (MWh)						Rural Energy Requirements (MWh)			Native Energy Sales (MWh)		Native Energy Requirements (MWh)		Peak Forecast (kW)				
Year	Month	Residential	Small C&I	Large C&I	Irrigation	Street & Highway	Total Rural Sales	Distribution Losses	Own Use	Total Rural Energy Requirements	Direct Serve	Total Energy Requirements	Transmission Losses	Total Energy Requirements with Losses	Rural CP	Direct Serve CP	Total CP	Transmission Losses	Total CP with losses
2020	January	154,330	53,296	12,149	0	267	220,041	10,194	397	230,633	83,883	314,516	8,098	322,614	484,817	118,151	602,968	15,524	618,492
2020	February	130,702	46,029	12,743	1	241	189,716	8,789	348	198,853	79,500	278,352	7,137	285,490	439,272	118,626	557,898	14,305	572,203
2020	March	115,979	44,254	12,350	5	275	172,864	7,999	277	181,139	81,969	263,108	6,746	269,854	397,360	115,445	512,806	13,149	525,954
2020	April	88,631	40,972	12,612	4	258	142,476	6,580	221	149,278	81,479	230,757	5,917	236,673	301,528	122,462	423,990	10,872	434,861
2020	May	96,850	48,753	12,915	4	239	158,761	7,325	193	166,279	81,014	247,293	6,341	253,633	381,148	119,476	500,624	12,837	513,461
2020	June	119,804	58,559	13,219	2	258	191,842	8,847	215	200,905	81,469	282,373	7,240	289,614	460,932	123,651	584,583	14,989	599,573
2020	July	138,998	62,168	14,174	16	264	215,620	9,943	223	225,786	84,078	309,864	7,945	317,809	483,719	124,043	607,762	15,584	623,346
2020	August	136,533	59,884	14,353	33	257	211,059	9,735	236	221,030	86,130	307,160	7,876	315,036	483,946	127,101	611,047	15,668	626,715
2020	September	108,348	51,034	14,645	33	262	174,322	8,042	217	182,581	82,110	264,691	6,787	271,478	443,529	124,639	568,168	14,568	582,737
2020	October	90,809	47,910	14,228	8	262	153,217	7,079	199	160,496	83,068	243,564	6,245	249,809	359,898	121,345	481,243	12,340	493,583
2020	November	104,669	51,389	14,187	3	293	170,540	7,894	253	178,687	80,219	258,907	6,639	265,546	385,238	116,231	501,469	12,858	514,327
2020	December	138,262	56,643	13,203	-1	245	208,353	9,649	329	218,330	82,634	300,964	7,717	308,681	436,705	116,386	553,091	14,182	567,273
2021	January	155,161	54,083	12,807	0	267	222,318	10,303	400	233,021	83,883	316,905	8,126	325,030	489,893	118,151	608,044	15,591	623,635
2021	February	131,470	46,723	13,536	1	241	191,971	8,897	350	201,219	79,500	280,718	7,198	287,916	460,424	122,318	582,742	14,942	597,684
2021	March	116,732	44,923	13,272	5	275	175,208	8,112	279	183,598	81,969	265,567	6,809	272,376	402,714	115,445	518,159	13,286	531,445
2021	April	89,256	41,598	13,462	4	258	144,577	6,681	223	151,481	81,479	232,960	5,973	238,933	306,022	122,462	428,483	10,987	439,470
2021	May	97,458	49,486	13,837	4	239	161,025	7,433	195	168,653	81,014	249,666	6,402	256,068	386,312	119,476	505,788	12,969	518,757
2021	June	120,356	59,419	14,026	2	258	194,061	8,954	217	203,232	81,469	284,701	7,300	292,001	466,280	123,651	589,931	15,126	605,057
2021	July	139,540	63,085	15,052	16	264	217,956	10,055	225	228,236	84,078	312,314	8,008	320,322	489,221	124,043	613,264	15,725	628,989
2021	August	137,080	60,779	15,143	33	257	213,292	9,842	238	223,372	86,130	309,502	7,936	317,437	489,218	127,101	616,319	15,803	632,122
2021	September	108,953	51,804	15,410	33	262	176,461	8,145	219	184,825	82,110	266,935	6,844	273,780	448,605	124,639	573,244	14,699	587,943
2021	October	91,415	48,638	14,974	8	262	155,297	7,179	201	162,677	83,068	245,746	6,301	252,047	364,376	121,345	485,721	12,454	498,176
2021	November	105,334	52,154	14,909	3	293	172,693	7,997	255	180,945	80,219	261,165	6,697	267,861	390,171	116,231	506,402	12,985	519,386
2021	December	139,032	57,473	13,906	-1	245	210,654	9,759	331	220,745	82,634	303,379	7,779	311,158	441,720	116,386	558,105	14,310	572,416
2022	January	156,019	54,834	12,149	0	267	223,268	10,346	404	234,017	173,163	407,180	10,441	417,621	491,914	296,351	788,265	20,212	808,477
2022	February	132,239	47,386	12,743	1	241	192,610	8,925	353	201,888	160,140	362,027	9,283	371,310	461,760	300,518	762,278	19,546	781,823
2022	March	117,466	45,565	12,350	5	275	175,661	8,130	281	184,072	171,249	355,321	9,111	364,431	403,686	293,645	697,331	17,880	715,212
2022	April	89,849	42,201	12,527	4	258	144,839	6,691	224	151,754	167,879	319,633	8,196	327,829	306,153	300,662	606,815	15,559	622,374
2022	May	98,019	50,196	12,740	4	239	161,198	7,438	196	168,832	170,294	339,125	8,696	347,821	386,618	277,876	664,495	17,038	681,533
2022	June	120,838	60,254	12,964	2	258	194,316	8,963	218	203,497	167,869	371,365	9,522	380,888	466,914	301,851	768,765	19,712	788,477
2022	July	139,980	63,978	13,823	16	264	218,061	10,057	226	228,343	173,358	401,701	10,300	412,001	489,558	322,043	811,601	20,810	832,412
2022	August	137,522	61,647	13,914	33	257	213,373	9,842	239	223,454	175,410	398,864	10,227	409,092	489,501	305,301	794,801	20,380	815,181
2022	September	109,467	52,545	14,178	33	262	176,485	8,142	220	184,847	168,510	353,357	9,060	362,418	448,580	302,839	751,419	19,267	770,687
2022	October	91,940	49,336	13,702	8	262	155,247	7,173	202	162,622	172,348	334,970	8,589	343,559	363,924	299,545	663,470	17,012	680,482
2022	November	105,902	52,881	13,635	3	293	172,713	7,994	257	180,965	166,619	347,584	8,912	356,497	390,014	294,431	684,445	17,550	701,995
2022	December	139,664	58,255	12,589	-1	245	210,752	9,760	333	220,846	171,914	392,760	10,071	402,830	441,673	294,586	736,258	18,878	755,137
2023	January	156,349	55,536	12,149	0	267	224,300	10,395	406	235,102	173,163	408,265	10,468	418,733	494,177	296,351	790,528	20,270	810,798
2023	February	132,605	48,004	12,743	1	241	193,593	8,972	355	202,920	160,140	363,060	9,309	372,369	464,008	300,518	764,526	19,603	784,129
2023	March	117,891	46,158	12,350	5	275	176,678	8,178	283	185,139	171,249	356,388	9,138	365,526	405,933	293,645	699,578	17,938	717,516
2023	April	90,246	42,752	12,527	4	258	145,788	6,736	226	152,749	167,879	320,628	8,221	328,849	307,933	300,662	608,594	15,605	624,199
2023	May	98,350	50,840	12,740	4	239	162,173	7,484	197	169,854	170,294	340,148	8,722	348,869	388,693	277,876	666,569	17,092	683,661
2023	June	120,972	61,002	12,964	2	258	195,199	9,005	219	204,423	167,869	372,292	9,546	381,838	469,062	301,851	770,913	19,767	790,680
2023	July	139,994	64,772	13,823	16	264	218,868	10,095	227	229,190	173,358	402,548	10,322	412,870	491,639	322,043	813,682	20,864	834,546
2023	August	137,558	62,422	13,914	33	257	214,184	9,881	241	224,306	175,410	399,716	10,249	409,965	491,543	305,301	796,844	20,432	817,276
2023	September	109,729	53,210	14,178	33	262	177,412	8,186	222	185,820	168,510	354,330	9,085	363,415	450,581	302,839	753,420	19,318	772,738
2023	October	92,285	49,966	13,702	8	262	156,223	7,219	203	163,645	172,348	335,993	8,615	344,608	365,716	299,545	665,261	17,058	682,319
2023	November	106,234	53,541	13,635	3	293	173,704	8,042	259	182,005	166,619	348,624	8,939	357,563	392,193	294,431	686,624	17,606	704,230
2023	December	139,935	58,965	12,589	-1	245	211,732	9,807	335	221,874	171,914	393,788	10,097	403,886	443,762	294,586	738,347	18,932	757,279
2024	January	156,533	56,167	12,149	0	267	225,116	10,434	409	235,959	173,163	409,122	10,490	419,612	495,970	296,351	792,322	20,316	812,637
2024	February	132,841	48,564	12,743	1	241	194,390	9,010	357	203,758	163,020	366,777	9,405	376,182	449,760	296,826	746,586	19,143	765,729
2024	March	118,193	46,699	12,350	5	275	177,523	8,219	284	186,026	171,249	357,274	9,161	366,435	407,797	293,645	701,442	17,986	719,428
2024	April	90,544	43,260	12,527	4	258	146,594	6,774	227	153,594	167,879	321,473	8,243	329,716	309,422	300,662	610,084	15,643	625,727
2024	May	98,585	51,436	12,740	4	239	163,003	7,524	198	170,725	170,294	341,018	8,744	349,763	390,439	277,876	668,315	17,136	685,451
2024	June	121,014	61,699	12,964	2	258	195,937	9,041	221	205,198	167,869	373,067	9,566	382,633	470,860	301,851	772,711	19,813	792,524
2024	July	139,914	65,515	13,823	16	264	219,532	10,128	228	229,888	173,358	403,246	10,340	413,586	493,376	322,043	815,419	20,908	836,327
2024	August	137,501	63,150	13,914	33	257	214,855	9,914	242	225,011	175,410	400,421	10,267	410,688	493,247	305,301	798,547	20,476	819,023
2024	September	109,896	53,835	14,178	33	262	178,204	8,224	223	186,650	168,510	355,160	9,107	364,267	452,268	302,839	755,107	19,362	774,469
2024	October	92,539	50,561	13,702	8	262	157,072	7,259	204	164,535	172,348	336,883	8,638	345,521	367,250	299,545	666,795	17,097	683,892
2024	November	106,469	54,162	13,635	3	293	174,561	8,083	260	182,903	166,619	349,523	8,962	358,485	394,079	294,431	688,510	17,654	706,164
2024	December	140,092	59,631	12,589	-1	245	212,556	9,847	337	222,740	171,914	394,654	10,119	404,774	445,530	294,586	740,115	18,977	759,093

The following tables provide the econometric models for Jackson Purchase Energy Corporation (JPEC).

JPEC Residential Use Per Consumer Model				
Sample: 2007 - 2019 Total Observations: 154				
Variable	Coefficient	Std. Error	t-Statistic	Prob.
January	6.555083	0.051571	127.1073	0
February	6.471421	0.0465	139.1691	0
March	6.494198	0.037785	171.8732	0
April	6.395643	0.030825	207.4807	0
May	6.52232	0.034815	187.3398	0
June	6.629714	0.042908	154.5117	0
July	6.692348	0.04857	137.7881	0
August	6.689342	0.046313	144.4377	0
September	6.605444	0.037123	177.9347	0
October	6.422282	0.029883	214.9132	0
November	6.438005	0.038993	165.1081	0
December	6.556474	0.044827	146.261	0
Log(Residential Price/Alternate Fuel Price)	-0.066133	0.011283	-5.861178	0
Cooling Degree Days*(AC Saturation)*(1/AC Efficiency)	0.014177	0.000883	16.0548	0
Heating Degree Days*Electric Heat Saturation*(1/Heating Efficiency)	0.015707	0.001259	12.47104	0
Weighted Statistics				
Adjusted R-squared: 0.9412				

JPEC General C&I Consumer Model				
Sample: 1999 - 2019 Total Observations: 250				
Variable	Coefficient	Std. Error	t-Statistic	Prob.
GRP	2.262405	0.009413	240.3562	0
January 1999 - July 2015	-1180.094	21.57386	-54.70017	0
Weighted Statistics				
Adjusted R-squared: 0.926993				

JPEC General C&I Use Per Consumer Model

Sample: 1999 - 2019

Total Observations: 250

Variable	Coefficient	Std. Error	t-Statistic	Prob.
January	8.600848	0.281849	30.5158	0
February	8.522346	0.280138	30.42194	0
March	8.546241	0.276151	30.94766	0
April	8.560973	0.269839	31.72619	0
May	8.626614	0.270179	31.9293	0
June	8.614929	0.268555	32.07879	0
July	8.649323	0.269833	32.05432	0
August	8.660487	0.269027	32.19186	0
September	8.644216	0.266897	32.38786	0
October	8.617445	0.274983	31.33808	0
November	8.563895	0.277375	30.87484	0
December	8.586087	0.281162	30.53791	0
Log(C&I Electricity Price)	-0.183357	0.054165	-3.385128	0.0008
Cooling Degree Days	0.00061	0.0000953	6.401003	0
Heating Degree Days	0.000201	0.000052	3.856308	0.0001
Log(Total Employment/C&I Consumers)	0.178616	0.036983	4.829628	0
January 1999 - July 2015	0.102737	0.02041	5.033621	0

Weighted Statistics

Adjusted R-squared: 0.796959

JPEC Load Factor Model

Sample: 2007 - 2019
Total Observations: 154

Variable	Coefficient	Std. Error	t-Statistic	Prob.
January	0.657717	0.029229	22.50207	0
February	0.690955	0.024563	28.13002	0
March	0.668066	0.021476	31.10736	0
April Cold Peaking	0.701504	0.017757	39.50476	0
April Hot Peaking	0.659123	0.021667	30.42063	0
May	0.591251	0.015673	37.72414	0
June	0.609293	0.021739	28.02783	0
July	0.60305	0.024117	25.00528	0
August	0.600394	0.022935	26.17772	0
September	0.606743	0.021043	28.83319	0
October Cold Peaking	0.732852	0.015114	48.48963	0
October Hot Peaking	0.626334	0.025267	24.78835	0
November	0.680741	0.020149	33.78508	0
December	0.695933	0.027604	25.21132	0
Cooling Degree Days on Peak Day*(AC Saturation)*(1/AC Efficiency)	-0.086523	0.015833	-5.464825	0
Heating Degree Days on Peak Day*Electric Heating Saturation*(1/Heating Efficiency)	-0.085747	0.014716	-5.826914	0
Cooling Degree During Remainder of Month*(AC Saturation)*(1/AC Efficiency)	0.004952	0.000601	8.240219	0
Heating Degree During Remainder of Month*Electric Heating Saturation*(1/Heating Efficiency)	0.004441	0.000788	5.636105	0

Weighted Statistics

Adjusted R-squared: 0.711106

The following tables provide the econometric models for Kenergy Corporation.

Kenergy Residential Use Per Consumer Model

Sample: 2007 - 2019
Total Observations: 154

Variable	Coefficient	Std. Error	t-Statistic	Prob.
January	6.614538	0.051025	129.6343	0
February	6.585116	0.053226	123.7206	0
March	6.631454	0.045352	146.2217	0
April	6.555139	0.047973	136.642	0
May	6.618776	0.038003	174.1632	0
June	6.680367	0.043713	152.8245	0
July	6.784962	0.044501	152.4661	0
August	6.801286	0.043024	158.0823	0
September	6.728907	0.044558	151.013	0
October	6.544728	0.042725	153.1825	0
November	6.450676	0.041616	155.0059	0
December	6.558418	0.049587	132.26	0
Log(Residential Price/Alternate Fuel Price)	-0.070507	0.013307	-5.298569	0
Cooling Degree Days*(AC Saturation)*(1/AC Efficiency)	0.010761	0.000612	17.574	0
Heating Degree Days*Electric Heat Saturation*(1/Heating Efficiency)	0.011193	0.000849	13.18324	0

Weighted Statistics

Adjusted R-squared: 0.922044

Kenergy General C&I Consumer Model				
Sample: 1999 - 2019 Total Observations: 250				
Variable	Coefficient	Std. Error	t-Statistic	Prob.
GRP	1.363354	0.23916	5.700593	0
Total Retail Sales	2.918014	0.739225	3.947394	0.0001
Weighted Statistics				
Adjusted R-squared: 0.559381				

Kenergy General C&I Use Per Consumer Model

Sample: 1999 - 2019
Total Observations: 250

Variable	Coefficient	Std. Error	t-Statistic	Prob.
January	11.05862	0.206038	53.67269	0
February	10.95246	0.202846	53.99397	0
March	11.01351	0.201787	54.57994	0
April	11.01615	0.201731	54.60801	0
May	11.21571	0.19844	56.51943	0
June	11.33681	0.198407	57.13918	0
July	11.32223	0.20008	56.58848	0
August	11.26737	0.200495	56.19772	0
September	11.22473	0.199892	56.15399	0
October	11.21241	0.199678	56.15239	0
November	11.2425	0.20106	55.91619	0
December	11.24374	0.205601	54.68706	0
Log(C&I Electricity Price)	-0.080253	0.036195	-2.217223	0.0276
Cooling Degree Days	0.000892	0.0000848	10.51386	0
Heating Degree Days	0.000511	0.0000577	8.843284	0
Log(Total Employment/C&I Consumers)	0.727082	0.030415	23.90546	0

Weighted Statistics

Adjusted R-squared: 0.895253

Kenergy Load Factor Model

Sample: 2007 - 2019
Total Observations: 154

Variable	Coefficient	Std. Error	t-Statistic	Prob.
January	0.652034	0.023963	27.20968	0
February	0.679921	0.022638	30.03493	0
March	0.648822	0.01715	37.83232	0
April Cold Peaking	0.680085	0.015563	43.69874	0
April Hot Peaking	0.687651	0.019987	34.40458	0
May	0.60156	0.013883	43.33197	0
June	0.594472	0.016098	36.92744	0
July	0.59567	0.01599	37.2529	0
August	0.590477	0.016007	36.88807	0
September	0.598327	0.016549	36.15449	0
October Cold Peaking	0.725742	0.016679	43.51174	0
October Hot Peaking	0.62122	0.020181	30.78215	0
November	0.67773	0.016807	40.325	0
December	0.683866	0.02341	29.21206	0
Cooling Degree Days on Peak Day*(AC Saturation)*(1/AC Efficiency)	-0.082488	0.013899	-5.935027	0
Heating Degree Days on Peak Day*Electric Heating Saturation*(1/Heating Efficiency)	-0.068364	0.008904	-7.677592	0
Cooling Degree During Remainder of Month*(AC Saturation)*(1/AC Efficiency)	0.00506	0.000622	8.129419	0
Heating Degree During Remainder of Month*Electric Heating Saturation*(1/Heating Efficiency)	0.003299	0.000433	7.62205	0

Weighted Statistics

Adjusted R-squared: 0.691088

The following tables provide the econometric models for Meade County Rural Electric Cooperative Corporation (MCRECC).

MCRECC Residential Use Per Consumer Model				
Sample: 2007 - 2019 Total Observations: 154				
Variable	**Coefficient**	**Std. Error**	**t-Statistic**	**Prob.**
January	6.502017	0.032406	200.6445	0
February	6.442692	0.029824	216.0239	0
March	6.463045	0.025399	254.4629	0
April	6.344359	0.021936	289.2233	0
May	6.403802	0.021567	296.9234	0
June	6.477804	0.028175	229.9153	0
July	6.53239	0.028028	233.0685	0
August	6.501135	0.029804	218.1295	0
September	6.418795	0.023509	273.0325	0
October	6.356149	0.02102	302.3865	0
November	6.425176	0.024297	264.4417	0
December	6.511993	0.028191	230.9937	0
Log(Residential Price/Alternate Fuel Price)	-0.037951	0.006605	-5.745857	0
Cooling Degree Days*(AC Saturation)*(1/AC Efficiency)	0.012035	0.000577	20.86585	0
Heating Degree Days*Electric Heat Saturation*(1/Heating Efficiency)	0.010624	0.00039	27.22624	0
Weighted Statistics				
Adjusted R-squared: 0.977587				

MCRECC General C&I Consumer Model				
Sample: 1999 - 2019 Total Observations: 250				
Variable	Coefficient	Std. Error	t-Statistic	Prob.
GRP	2.015144	0.225529	8.935168	0
Total Retail Sales	1.943915	0.398097	4.883025	0
Weighted Statistics				
Adjusted R-squared: 0.259195				

MCRECC General C&I Use Per Consumer Model				
Sample: 1999 - 2019 Total Observations: 250				
Variable	**Coefficient**	**Std. Error**	**t-Statistic**	**Prob.**
January	10.06521	0.348749	28.86087	0
February	10.05561	0.347507	28.93638	0
March	10.09085	0.344394	29.30033	0
April	10.11935	0.349425	28.96004	0
May	10.225	0.347119	29.45672	0
June	10.23109	0.346896	29.49327	0
July	10.24525	0.348128	29.42953	0
August	10.25894	0.349417	29.36012	0
September	10.22784	0.346684	29.50194	0
October	10.26088	0.346634	29.60148	0
November	10.19701	0.347028	29.38384	0
December	10.12429	0.349255	28.98822	0
Log(C&I Electricity Price)	-0.202295	0.077951	-2.595147	0.0101
Cooling Degree Days	0.000622	0.0000764	8.148743	0
Heating Degree Days	0.000328	0.0000497	6.610873	0
Log(Total Employment/C&I Consumers)	0.530934	0.088259	6.015658	0
2013 Forward	-0.125527	0.023921	-5.247572	0
Weighted Statistics				
Adjusted R-squared: 0.789073				

MCRECC Load Factor Model

Sample: 2007 - 2019
Total Observations: 154

Variable	Coefficient	Std. Error	t-Statistic	Prob.
January	0.63496	0.019625	32.35468	0
February	0.671053	0.019148	35.04466	0
March	0.628937	0.013808	45.54862	0
April Cold Peaking	0.629017	0.011065	56.84797	0
April Hot Peaking	0.748793	0.023472	31.90101	0
May	0.636076	0.026591	23.92087	0
June	0.617738	0.025053	24.65735	0
July	0.618232	0.02604	23.74132	0
August	0.609817	0.026399	23.09969	0
September	0.614158	0.024352	25.22	0
October Cold Peaking	0.65492	0.010088	64.91917	0
October Hot Peaking	0.65788	0.024236	27.14475	0
November	0.643386	0.012405	51.86569	0
December	0.63915	0.016121	39.64587	0
Cooling Degree Days on Peak Day*(AC Saturation)*(1/AC Efficiency)	-0.112885	0.017785	-6.347315	0
Heating Degree Days on Peak Day*Electric Heating Saturation*(1/Heating Efficiency)	-0.097711	0.00623	-15.68304	0
Cooling Degree During Remainder of Month*(AC Saturation)*(1/AC Efficiency)	0.005567	0.000627	8.883967	0
Heating Degree During Remainder of Month*Electric Heating Saturation*(1/Heating Efficiency)	0.004775	0.000341	14.00279	0

Weighted Statistics

Adjusted R-squared: 0.776379

DEMAND-SIDE MANAGEMENT POTENTIAL STUDY

2020

Big Rivers
ELECTRIC CORPORATION

Demand-Side Management Potential Study

Big Rivers Electric Corporation

Henderson, Kentucky

Prepared By:

Clearspring Energy Advisors, LLC
1050 Regent St., Suite L3
Madison, WI 53715
608.442.8668
www.clearspringenergy.com

Presented By:

Joshua P. Hoyt
Principal Consultant

Acknowledgements

Clearspring Energy Advisors, LLC would like to thank the input and assistance from Big Rivers Electric Corporation, including Russ Pogue and Marlene Parsley.

…

Expertise and analysis on this project were provided by Joshua Hoyt (Project Manager), Douglas Carlson (Senior Analyst) and Bryce Frost (Analyst).

Disclaimer

The analysis included in this report incorporates data and estimates from third-party sources and assumptions about future energy use, general costs and conditions that are uncertain. Clearspring Energy Advisors, LLC does not warrant the projections in this report for absolute accuracy. Clearspring holds itself harmless for any actions taken by Big Rivers Electric Corporation or its member-owners in response to the information or recommendations presented herein.

Notice of Confidentiality

Big Rivers Electric Corporation
Demand-Side Management Potential Study

Table of Contents

EXECUTIVE SUMMARY

Big Rivers Electric Corporation
Demand-Side Management Potential Study

Executive Summary

Overview

Big Rivers Electric Corporation (Big Rivers) is a generation and transmission cooperative located in Henderson, Kentucky. Big Rivers provides electric power to three electric distribution cooperatives. As part of its resource planning process and as required by the Kentucky Public Service Commission (KPSC), Big Rivers regularly evaluates its resource options to continue providing high quality service and reliable, least-cost power to its member-owners. Big Rivers engaged Clearspring Energy Advisors, LLC to prepare an economic evaluation of demand-side management potential, including energy efficiency measures and dynamic pricing that would be appropriate for the member-owners of the Big Rivers system. This report, which serves as an input to the Big Rivers Integrated Resource Planning (IRP) process, presents the findings of that study. The overall goals of this study are:

- To use methods that are transparent and consistent with established practice.
- To incorporate Big Rivers data and experience into the process whenever available or relevant.
- To use data and resources that are widely accepted and verified and,
- To provide actionable information that Big Rivers can incorporate into its IRP process.

It is instructive to remember that the analyses presented in this report, and in the many other reports produced just like it, rely on estimates and assumptions. This study deals with complex topics yet many of the specific components of the drivers are unknown. It is therefore required to utilize third-party research, average customer class data and primary research when available to calculate potential outcomes. The expectation of results, therefore, is that they should be reasonable and plausible.

Project Process

A multi-step process was required to develop estimates of energy efficiency potential for the Big Rivers system. This process is informed by Big Rivers' stated objectives:

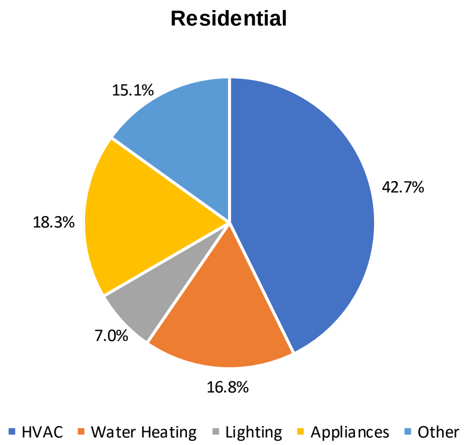
- Develop residential and non-residential segment end-use models of energy use.
- Identify potential demand response / energy efficiency measures.
- Evaluate this measure list with a qualitative screening tool.
- Perform a quantitative economic analysis on the cost-effectiveness of these measures.
- Estimate technical, economic, achievable and program energy efficiency potential.

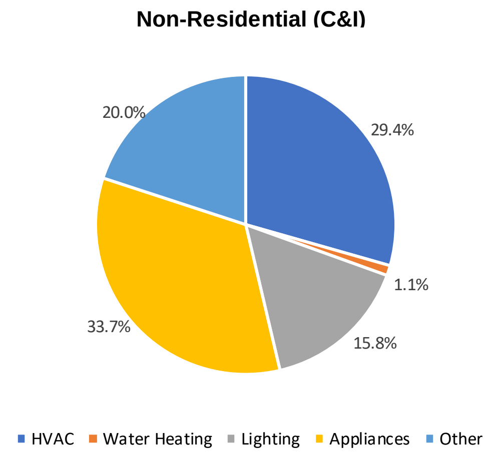
An extensive amount of research was undertaken for this study and a wide variety of data sources were utilized in fulfilling the objectives identified above. These data sources are listed in detail in Section 1.7 of this report.

Baseline End-Use Development

One of the key inputs in determining potential of energy efficiency programs is a reliable baseline to benchmark current energy use by key end-uses. As part of this study, end-use models using both primary and secondary research were developed for the residential and non-residential segments to estimate baseline energy use. The following figures show the percentage of residential and non-residential electricity use by major end-use category for the base year of the study (2020). The methodologies used to estimate the end-use shares are described in more detail in section 2.2.

Figure ES-1
Baseline Electricity End-Uses (%)





Identification of Opportunities

Following the development of the baseline end-use estimates for the residential and non-residential (C&I) segments, a comprehensive list of demand-side measures was developed for evaluation. These were drawn largely from Technical Resource Manuals (TRMs) referenced to calculate specific measure savings. Measure lists were segregated into major customer type (residential and non-residential) and process type (lighting, heating, cooling, appliance, etc.). A total of 196 individual measures were identified with 99 measures identified for the residential segment and 97 for the non-residential segment.

The next step was to evaluate the initial demand-side measure list using a qualitative screening tool designed to eliminate measures that do not fit the criteria. Obvious candidates such as measures relying on natural gas as the primary savings driver were excluded. Multiple questions were developed for each of these categories including technical maturity, utility match, customer acceptance, etc. A total of 133 individual measures were segmented into 60 residential measures and 73 non-residential (C&I).

Demand-Side Savings Potential

A series of economic evaluation tests were used to compare the cumulative financial benefits of implementing a measure against the cumulative costs. Each test categorizes the benefits and costs from the perspective of a key stakeholder being evaluated. When taken together these tests represent a multi-perspective analysis of each measure. The four key perspectives of the evaluation tests below are identified in Section 1.4 of this report.

- Total Resource Cost (TRC)
- Participant Cost (PCT)
- Utility Cost (UCT)
- Rate Impact Measure (RIM)

The economic screening tool utilized for this purpose compares the present value of potential benefits of a measure to the present value of costs, yielding a “benefit-cost ratio.” Benefit-cost ratios greater than one (1.0) indicate that a measure has positive economic potential and, therefore, is worthy of further consideration from a demand-side program perspective. The model assumptions and process are discussed in section 2 of this report.

Four demand-side potential estimates were calculated for this study: technical, economic, achievable and program potential. There are a variety is ways to approach potential calculations and it is important to emphasize that each of these methods are estimates and contain uncertainty. The results are presented in Table ES-1 and ES-2 and are presented in more detail in sections 3 and 4. The results below and the entire study represent Big Rivers’ rural load and excludes direct-serve customers.

Table ES-1
Energy Efficiency Potential (Cumulative Annual) Energy Savings (MWh)

Potential	Residential	Non-Res (C&I)
Technical	290,322	241,646
Economic	217,845	169,463
Achievable	112,308	139,937
Program ($2m)	76,067	122,467
Program ($1m)	39,555	63,683

Table ES-2
Energy Efficiency Potential (Cumulative Annual) Demand Savings (MW)

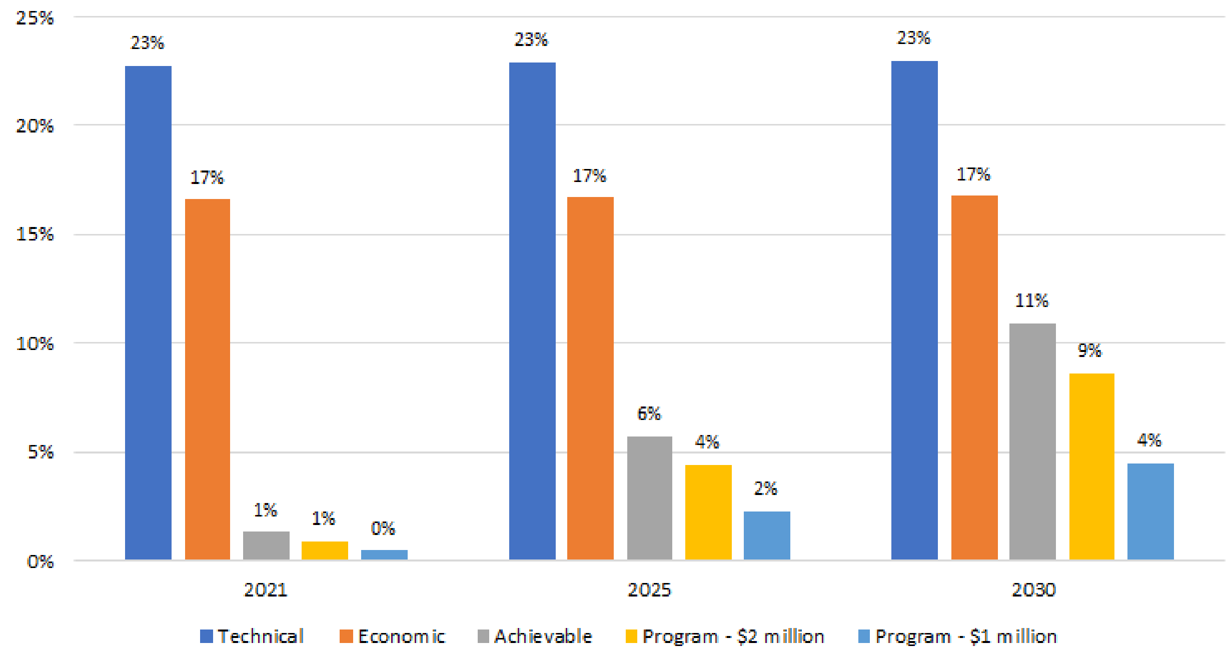
Potential	Residential	Non-Res (C&I)
Technical	81	72
Economic	45	47
Achievable	17	36
Program ($2m)	12	28
Program ($1m)	6	15

As shown in figure ES-2, maximum technical potential represents approximately 23 percent of 2030 retail MWh energy sales for Big Rivers. Economic potential represents 16.7 percent in 2030 while achievable potential is 10.9 percent. These findings are consistent with previous studies which have looked at energy efficiency potential.[1]

Two hypothetical program budget scenarios were also developed as part of this study for the program potential. The $1 million demand-side budget scenario projects energy savings around 4.5 percent over the ten-year study period or roughly 0.5 percent per year with a benefit-cost ratio of 2.7. The $2 million scenario is expected to see 8.6 percent savings by 2030 with a benefit-cost ratio of 2.5. These estimates are consistent with estimates from other utilities as well as with previous filings by Big Rivers.[2]

[1] See “Cracking the TEAPOT…”, ACEEE.
[2] See “Cracking the TEAPOT…”, ACEEE.

Figure ES-2
Energy Efficiency Potential (% Of Retail Energy Sales)



Summary

This demand-side resource potential study covers a range of tasks in estimating the potential energy and demand savings for Big Rivers and its member-owner cooperatives. It establishes baseline energy end-use characteristics for residential and non-residential segments. The study presents a list of potential energy efficiency and demand response measures for evaluation. The cost-effectiveness of these measures is tested. Finally, it presents the estimates of technical, economic, achievable and program energy efficiency potential for Big Rivers. Two program scenarios based on $1 million and $2 million budgets are evaluated as part of the program potential.

There are challenges to the implementation of demand-side programs by Big Rivers. The low energy and capacity cost values in the MISO market make it difficult for many programs to be cost-effective currently. However, energy markets can and do change and as market values rise, so too will cost-effective demand-side opportunities. There are also potential opportunities in segments such as the plug-in electric vehicle market, where potential increases in peak demand can be offset by well-planned time differentiated rates. Other future opportunities may arise as well through new technologies that change the way consumers interact with energy.

In the end, the cost-effective alternatives to generation resources given current and projected installed avoided capacity and energy costs represent a snapshot in time only and are meant to provide guidance to Big Rivers management and staff and member-owner management and staff in their planning process.

SECTION 1

STUDY APPROACH

1.0 Study Approach

1.1 Background

Big Rivers Electric Corporation (Big Rivers) is an electric generation and transmission cooperative located in Henderson, Kentucky which provides electric power to, and is owned by, three-member electric distribution cooperatives. The three distribution cooperatives are Jackson Purchase Energy Corporation, Kenergy Corporation, and Meade County Rural Electric Cooperative Corporation. These three Big Rivers Members serve more than 118,000 residential households, businesses, and farms in western Kentucky. Big Rivers' member-owner service territories are shown in Figure 1.1. As part of its resource planning process, Big Rivers regularly evaluates its resource options to ensure supply of low-cost reliable power to its member-owners.

Figure 1.1
Big Rivers System Service Territory

1.1.1 Clearspring Energy Advisors, LLC

Clearspring Energy was formed in 2004 and has been providing consulting services to utilities, primarily electric cooperatives, for 16 years. Clearspring Energy's staff have worked with over 150 distribution cooperatives, 15 generation and transmission (G&T) cooperatives, investor-owned utilities, and municipalities. During that time, Clearspring Energy's Principals have produced utility-scale energy efficiency studies for eight G&Ts.

Clearspring Energy's staff experience is geographically diverse, including studies in Minnesota, North Dakota, Wisconsin, Iowa, Michigan, Ohio, New Hampshire, Missouri, Indiana, Oklahoma, Illinois, Kansas, Kentucky, Oregon, Pennsylvania, Washington, North Carolina, South Carolina, Texas, and Vermont.

Clearspring Energy's staff includes several members with master's degrees in economics, statistical analysis, and market research. Clearspring Energy's Principals have nearly 100 years of combined experience to draw upon. Clearspring Energy staff have produced numerous reports that have passed regulatory scrutiny at the state, federal and international level. Clearspring Principals have both given and evaluated testimony in those proceedings. The Principals with the most involvement are Joshua Hoyt and Douglas Carlson. Brief biographies of both are presented below.

Joshua Hoyt

Mr. Hoyt is a Principal and co-founder of Clearspring Energy Advisors with 25 years of industry knowledge. He is an experienced economic analyst and manager who has prepared economic studies for over 100 distribution cooperatives, and 10 G&Ts. This includes developing cost-benefit analyses and demand-side program development, as well as measurement and verification tracking of energy efficiency programs. He has also worked as an energy management consultant providing demand and supply side energy solutions for large C&I clients. He holds a master's degree in Economics from Marquette University and has continued his professional development with seminars and university courses on the energy industry, utility deregulation, energy forecasting and survey research.

Douglas Carlson

Mr. Carlson is a Principal and co-founder of Clearspring Energy Advisors. Mr. Carlson has over 25 years of experience in the utility industry with significant work in load forecasting, market research, and demand-side management program evaluation. Mr. Carlson previously served as the Director of DSM Programs for Alliant Energy and was responsible for program development, management, and regulatory approvals. He has also developed and evaluated residential DSM programs for utilities in the Midwest and Northeastern U.S. Mr. Carlson has developed residential end-use models for several cooperative utilities for purposes of load forecasting, load profiling, and DSM program design. Mr. Carlson has a bachelor's degree in Economics, a master's degree in Urban and Regional Planning, and a master's certificate in Energy Analysis and Policy, all from the University of Wisconsin – Madison.

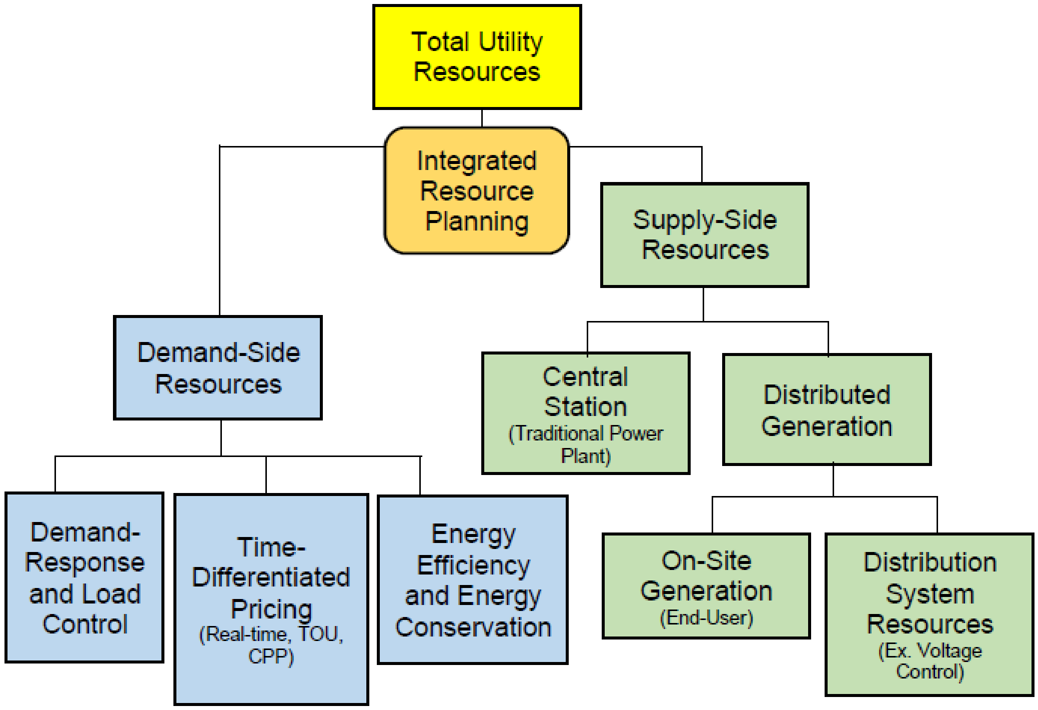
1.2 Study Objectives

The core objective of this study is to identify potential cost-effective demand-side opportunities that can directly and verifiably reduce demand for, and consumption of, electricity. Cost effective demand reduction for electricity may reduce future need for supply-side resources. Traditional generation resources have long planning horizons and capital investment. In contrast, demand-side management options might provide a resource option at lower cost and with more flexibility. Ultimately, the cost of delivering demand-side reductions must compete with other traditional and contemporary resource options to be considered viable. The following process has been outlined by Big Rivers for this project:

- Establish baseline end-use energy characteristics for the residential and non-residential sectors.
- Identify potential demand-side measures including energy efficiency and demand-response categories.
- Evaluate these measures with Clearspring Energy's qualitative screening tool.
- Develop estimates of demand-side measure potential including *technical*, *economic*, *achievable,* and *program*-level potential.
- Perform multi-perspective analyses of the benefits and costs of potential demand-side measures.

The focus of this study is the evaluation of potential demand-side options as part of the overall energy resource planning equation. Figure 1.2 shows resource planning components as part of the integrated resource planning process.

Figure 1.2
Resource Planning Components



The methods and practices in this study use generally accepted approaches and are informed by the previous Demand-Side Management studies. A brief overview of the study approach is presented below with greater detail provided in section 2.0, Foundational Analysis. The analyses presented in this report rely on assumptions about future costs and benefits. This study deals with complex topics and therefore often relies on third-party research, projected customer class data and primary research to calculate potential outcomes. The expectation of the results is that they should be reasonable and plausible.

1.2.1 Baseline End-Use Development

Energy consumption by individual customer classes is a sum of equipment used, energy source, age of equipment and efficiency. End-use models are designed to capture appliance stocks and their corresponding energy and demand usage. Models rely on primary and secondary research to estimate the various portfolio stocks. The model inputs establish a base case appliance stock estimate, benchmarked to the 2020 Electric Load Forecast for use in evaluating the proposed energy efficiency programs.

1.2.2 Identification of Opportunities

One of the first steps in developing energy efficiency potential studies, and potentially programs to deliver savings, is to develop an inclusive set of potential demand-side management measures for residential, commercial, and industrial customers to be evaluated. Numerous studies and tools exist to compile a comprehensive list and the experience of energy agencies and peer utilities and states is important to consider. As discussed in section 2.3.1, Clearspring Energy developed the initial list from recent Technical Resource Manuals (TRMs).

1.2.3 Qualitative Screening Analysis

The initial measure list developed in 1.2.2 was evaluated using a qualitative screening tool to determine which measures should advance to the economic tests in the potential development stage. The qualification screening is a series of questions designed to gauge appropriateness of the measure for inclusion in potential programs. These questions include:

- Is the measure a fit for the utility or its customers?
- Is the measure unproven or too new to be considered?
- Is the technology older and is there a better technology that could replace it?

An example in this study would be the exclusion of energy-efficient natural gas technologies as Big Rivers is solely a provider of electricity.

1.2.4 Demand-Side Savings Potential Analysis

As discussed above in section 1.2, potential demand-side savings represent a resource that could displace traditional generation in the integrated resource plan. There are four potential savings examined in this study including technical, economic, achievable and program potential. The general definition of each is presented in Section 1.5, while the calculation equations are presented in section 2.6.

1.3 Description of Energy Efficiency Measure Types

The measures that make up the comprehensive list that determines the potential estimates can be broadly grouped into two main categories. These categories are hardware and behavioral:

Hardware measures involve the installation of physical equipment either as an upgrade at the time of purchase or as an early retirement or retrofit. The new equipment should use less energy than the baseline equipment it replaces (or would be otherwise purchased) and, if standards apply, be rated as “energy-efficient” by rating agencies (such as ENERGY STAR™) and based on standards set by the Department of Energy (DOE). Examples include purchasing an energy star rated heat pump instead of a standard efficiency model or adding attic insulation to achieve an R-value of 50.

Behavioral measures rely on end-use consumers changing energy consumption patterns in a predictable way. They involve customers making conscious choices that result in lower energy use at a point in time. Examples include setting the temperature of a water heater lower to use less energy for hot water, turning off lights, responding to peak alert notices, and setting back thermostat temperatures. Programmable thermostats with temperature setback capabilities are an example of a hybrid hardware-behavioral measure.

While both types of measures have their place in reducing demand for energy, behavioral measures are often inconsistent due to the factors mentioned above. As such, the focus on hardware-based measures is more reliable to achieving verifiable savings. Behavioral measures can still be a useful tool in energy education programs and on their own when paired with clear incentives and verified reductions.

1.4 Energy Efficiency Evaluation Tests

This study evaluates potential demand-side measures using a series of tests commonly referred to as the “California tests” to determine whether a specific measure deserves to be considered a part of a portfolio of demand-reduction programs.

1.4.1 Evaluation Tests

The evaluation tests performed for this study are economic tests that evaluate cumulative benefits of implementing a measure compared with the cumulative costs of providing it. Each of the tests categorizes these benefits and costs differently based on the perspective of the key stakeholder that is being evaluated. When taken together they represent a multi-perspective analysis of each measure. The four key perspectives of the evaluation tests are[3]:

- Total Resource Cost (TRC)
- Participant Cost (PC)
- Utility Cost (UC)
- Rate Impact Measure (RIM)

Each economic screening tool utilized by Clearspring for this purpose compares the net present value (NPV) of potential benefits of a measure to its costs, yielding a benefit-cost ratio. Benefit-cost ratios greater than one (1.0) indicate that a measure has economic potential and are considered for further demand-side program evaluation. Because the various benefits and costs do not accrue uniformly to stakeholders, a measure may pass the participant economic screening test but may not be cost effective for the utility.

Economic Costs

Costs relevant to economic screening include the incremental cost of the measure, which is the difference between the costs of the energy efficient alternative and its less efficient counterpart, plus net installation, site preparation or disposal costs, if any. For measures that involve the purchase of new appliances or equipment, it is assumed that the decision to replace such appliances or equipment has already been made. In the case of an add-on measure such as home insulation, the incremental cost is simply the installed cost of the measure itself.

Economic Benefits

Economic benefits are defined as real value that is derived from the implementation and operation of the selected measure. The benefits relevant to economic screening include:

- Demand-related avoided costs.
- Energy-related avoided costs.
- Net reductions in operating, maintenance costs or other costs (such as reduced water usage).

Avoided costs of supply are calculated by multiplying a measure's energy savings and demand impacts by the applicable resource cost over its useful life.

Several benefits were not included even though they could potentially have an impact on the benefit-cost analysis. These benefits and the rationale for excluding them are:

- Impact of avoided carbon taxes or surplus credits for cap and trade. The lack of any clearly defined programs makes this problematic.

[3] Understanding Cost-Effectiveness of Energy Efficiency Programs, November 2008

- Environmental external benefits (“externalities”) such as avoiding adverse impacts on human health or the environment are disregarded, because of the complexity and uncertainty of quantifying such benefits.[4]
- Avoided distribution and transmission construction costs. While losses in the distribution and transmission system have been included, benefits in the form of avoided distribution and transmission costs have not been considered primarily due to the fact that Big Rivers’ load is not expected to grow significantly during the study period, putting the value of those benefits (beyond normal system maintenance) in doubt.
- Smaller, less tangible benefits such as decreased water consumption, lower detergent use or other consumer benefits are not explicitly detailed in part due to the difficulty in measurement.

1.4.2 Total Resource Cost Test

Economic potential is based on the financial impact from a Total Resource Cost (TRC) perspective. The test evaluates the benefits and costs from the perspective of all utility customers (participants and non-participants) in the utility service territory. The benefits include avoided capacity and energy costs plus operations and maintenance (O&M) savings and tax credits. Costs include incremental measure costs, program costs and any O&M costs.

1.4.3 Participant Test

The Participant Test focuses on the benefits and costs that accrue to the customer installing the measure. In this case it is the member-owners served by Big Rivers’ three distribution cooperative owners. Benefits include lower electric bills, incentive payments, tax credits (if available), as well as potential O&M savings. The costs include the incremental cost of purchasing and installing the energy efficient technology.

1.4.4 Utility Cost Test

The Utility Cost Test considers measures from the perspective of the utility, government agency, or third party implementing the program and integrates expected program administrative costs, member participation rates, program promotions or incentives as well as measurement and verification costs into the economic screening analysis. Benefits include the avoided energy and demand supply costs.

1.4.5 Rate Impact Measure Test

The Rate Impact Measure or RIM test evaluates the impact on non-participating ratepayers overall. The test evaluates changes in utility revenues and operating costs, comparing savings from avoided energy and capacity costs to costs such as program overhead costs, utility/program administrator incentive and installation costs, and lost revenue due to reduced energy bills.

1.5 Definition of Energy Efficiency Potential

There are four key definitions of potential calculated for this study: technical, economic, achievable and program potential. Each is defined below:

[4] These would be included from the Societal Cost test but not the Total Resource Cost (TRC) perspective used in the economic screening The Societal perspective is not required by the Kentucky PSC and is not included in this analysis.

1.5.1 Technical Potential

Technical potential is the theoretical maximum amount of energy that could be displaced by demand-side measures. It disregards non-engineering constraints such as cost-effectiveness and the willingness of end-users to adopt the efficiency measures. It assumes immediate implementation of all technologically feasible energy saving measures. New customers are assumed to implement efficiency opportunities automatically.

1.5.2 Economic Potential

A subset of technical potential, economic potential excludes measures that have failed the total resource cost test. Both technical and economic potential represent theoretical abstractions of demand-side savings that ignore the “real-world” challenges of implementing such programs. These include utility budgets, administrative capacity, market barriers and customer preferences and behaviors.

1.5.3 Achievable Potential

Achievable potential considers real-world barriers to the end-user when adopting efficiency measures, as well as administration, marketing, and other program costs, plus the challenges most utilities face ramping up programs effectively and efficiently. Measures are considered part of the achievable potential if they pass the Participant Test under aggressive implementation parameters. In this case this involves Big Rivers paying the full incremental cost of the energy efficient measure to the participant in the form of an incentive payment.

1.5.4 Program Potential

Program potential differs from achievable potential in that it focuses on the amount of demand-side savings projected based on a specific program budget and includes administrative cost, promotion, and incentive payments. This study estimates program potential based on two feasible scenarios: $1 million-, and $2 million-dollar total expenditure. The program potential analysis is a general concept and does not represent a proposed program design for Big Rivers or incorporate the member-owner objectives.

1.6 Codes and Standards

This study incorporates the most recent (or important upcoming) federal codes and standards. Various equipment codes and standards are set by the federal government or by consortiums (National Electrical Manufacturers Association) and agencies (ENERGY STAR™). By utilizing the most recent technical resource manuals (TRMs), the analysis of savings is already predisposed to incorporating the newest standards in the modeling process. However, the current and upcoming standards were reviewed to make sure that all standards and codes were up to date in the model development process.

- The 2007 EISA lighting standards effectively transform the lighting market, however there are likely to be opportunities to encourage early retirements, so lighting is not completely removed from consideration.
- Improved water heater standards were utilized which effectively make heat pump water heaters the only efficient option at 55 gallons or above.
- A more detailed list of the key dates of the federal energy standards is presented in Appendix A.

There are numerous factors involved with setting/changing codes and standards including technological, market and political. While it is likely that codes and standards may change over the ten-year window evaluated, it would be speculative to include those in this analysis.

1.7 Data Sources

Information was gathered from a wide variety of sources to develop the initial measure list to be analyzed in the qualitative screening stage. Some of the key data sources utilized include:

Data Sources for Residential End-Use Model

- Big Rivers residential consumer survey (2019).
- Big Rivers electric load forecast (2020).
- Residential Energy Consumption Surveys (RECS), Energy Information Administration (DOE), https://www.eia.gov/consumption/residential/
- Commercial Building Energy Consumption Survey (CBECS), Energy Information Administration (DOE), https://www.eia.gov/consumption/commercial/
- Manufacturing Energy Consumption Survey (MECS), Energy Information Administration (DOE), https://www.eia.gov/consumption/manufacturing/
- County Business Patterns, U.S. Census Bureau. https://www.census.gov/programs-surveys/cbp.html

Data Sources for Energy Efficiency Potential

- "Understanding Cost-Effectiveness of Energy Efficiency Programs: Best Practices, Technical Methods, and Emerging Issues for Policy-Makers," National Action Plan for Energy Efficiency (DOE), November 2008.
- "Cracking the TEAPOT: Technical, Economic, and Achievable Energy Efficiency Potential Studies" https://www.aceee.org/sites/default/files/publications/researchreports/u1407.pdf
- https://www.energy.gov/eere/slsc/energy-efficiency-potential-studies-catalog
- "Guide for Conducting Energy Efficiency Potential Studies," National Action Plan for Energy Efficiency (DOE), November 2007. www.epa.gov/eeactionplan
- https://appliance-standards.org/national

Data Sources for Measure Costs and Savings Estimates

- Missouri Technical Resource Manual (2017)
- Minnesota Technical Resource Manual (2019)
- TVA Technical Resource Manual (2017)
- Michigan Technical Resource Manual (2017)
- Wisconsin Focus on Energy Technical Resource Manual (2019)
- Ohio Technical Resource Manual (2010)
- Massachusetts Technical Resource Manual (2011)
- "Saving Energy Cost-Effectively: A National Review of the Cost of Energy Saved Through Utility Sector Energy Efficiency Programs" ACEEE, 2009.
- DOE - Energy Star Program http://www.energystar.gov/
- American Council for an Energy-Efficient Economy http://www.aceee.org/
- http://energyusecalculator.com/electricity_furnace.htm
- Wisconsin Focus on Energy http://www.focusonenergy.com/
- https://www.kentuckypower.com/save/residential/calculate/

Data Sources (Other)

- Midcontinent Independent System Operator (MISO), https://www.misoenergy.org/
- Big Rivers, hourly load data.
- "The National Potential for Load Flexibility" The Brattle Group, 2019.
- Electric Vehicle Charging Station Pilot Evaluation Report, Xcel Energy
- "An emerging push for time-of-use rates sparks new debates about customer and grid impacts." Utility Dive, 2019.
- "A Survey of Residential Time-Of-Use (TOU) Rates." The Brattle Group, 2019.
- "Guidance for Utilities Commissions on Time of Use Rates: A Shared Perspective from Consumer and Clean Energy Advocates." National Association of Regulatory Utility Commissioners, 2017.
- "International Evidence on Dynamic Pricing." Arcturus, 2013.
- "The Effect of Mandatory Time-of-Use Pricing Reform on Residential Electricity Use." UC Davis and Boston University, 2012.
- "Voluntary Time-of-Use Rates Induced Load Shifting and Peak Load Reduction." Iowa Power, 1993.
- "Symmetric Treatment of Load Generation: A Necessary Condition for Demand Response to Benefit Wholesale Market Efficiency and Manage Intermittency." Stanford University, 2010.

SECTION 2

FOUNDATIONAL ANALYSIS

2.0 Foundational Analysis

2.1 Introduction

The following sections detail the specific process, methodologies and results used in the development of demand-side potential and sample programs for the residential and non-residential segments.

2.2 Baseline End-Use Estimates

Two separate end-use models were developed for this study; residential, and non-residential. Non-residential includes commercial and industrial members served under the rural delivery tariff. End-use models are developed by estimating the portfolio mix and energy use of key appliances for a given class as a baseline to incorporating efficiency changes. These are most often developed for residential applications because of the relative homogeneity of the residential class compared to the commercial and industrial sectors. The importance of the end-use models in this study is that they allow current appliance usage and the relative magnitude of end-use segments to be identified. The results from the residential and non-residential end-use models are presented below along with summary tables.

2.2.1 Residential End-Use Model

The end-use model estimates the number of electrical appliances, average energy use and overall impact on system sales. The residential end-use model was developed using data from Big Rivers' 2019 residential customer survey and appliance energy use information from the Department of Energy's Residential Energy Consumption Survey (RECS).

RECS provides end-use energy estimates by major appliance type. Blended estimates (especially weather-driven ones) such as electric heating, air conditioning and electric water heating were adjusted based on Big Rivers' survey data and modeling from the TRMs using regionally specific heating and cooling data so that the energy use estimates were more aligned with Big Rivers actual experience.

The resulting energy consumption estimates are the product of the number of appliances and the energy use per appliance and are reconciled to the 2020 Big Rivers electric load forecast study using 2020 as a base year and evaluating the measures over the 2021-2030 period.

Residential End-Use Results Summary

The baseline residential end-use shares are presented in Figure 2.1 and Table 2.1 below. They provide the starting point against which to evaluate total potential energy efficiency savings.

Figure 2.1
Residential End-Use %

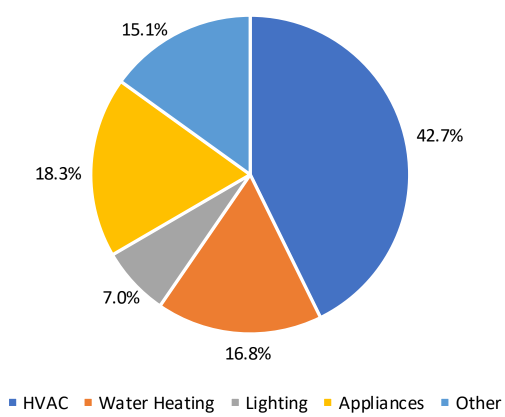


Table 2.1
Residential End-Use %

End-Use	kWh Per Household /1	Big Rivers Survey % /2	Member Count /3	Total Energy (MWh)	Percent of Total %
Space heating	*6,338*	46.7%	47,190	299,089	21.0%
Air handlers (heat)	114	89.8%	90,738	10,344	0.7%
Air conditioning	*2,819*	92.4%	93,369	263,208	18.5%
Air handlers (cool)	136	92.4%	93,369	12,698	0.9%
Ceiling fans	358	90.9%	91,854	32,884	2.3%
Dehumidifiers	768	16.9%	17,077	13,115	0.9%
Water heating	3,476	69.0%	69,724	242,360	17.0%
Clothes washers	73	97.5%	98,523	7,192	0.5%
Clothes dryers	875	92.9%	93,875	82,140	5.8%
Lighting	*1,000*	100.0%	101,049	101,049	7.1%
Refrigerators	579	98.2%	99,230	57,454	4.0%
Second refrig.	487	25.3%	25,565	12,450	0.9%
Separate freezers	513	66.5%	67,198	34,472	2.4%
Cooking	291	72.1%	72,856	21,201	1.5%
Microwaves	110	98.6%	99,634	10,960	0.8%
Dishwashers	116	74.3%	75,079	8,709	0.6%
Most-used TVs	260	93.2%	94,178	24,486	1.7%
Second TVs	141	32.5%	32,841	4,631	0.3%
Pool pumps	1,329	15.3%	15,460	20,547	1.4%
Hot tub pumps	*300*	4.7%	4,749	1,425	0.1%
Hot tub heaters	*1,100*	4.7%	4,749	5,224	0.4%
Other	*1,570*	100.0%	101,049	158,647	11.1%
TOTAL			**101,049**	1,424,287	100.0%

Notes: */1 From EIA, Residential Energy Consumption Survey*
/2 Appliance penetration data from 2019 Big Rivers survey
/3 2020 estimate from 2020 Big Rivers load forecast

2.2.2 Non-Residential End-Use Model

Non-residential customers are comprised of commercial and industrial loads (C&I) excluding accounts under direct serve agreements. Commercial and industrial energy consumption is the product of a variety of end-use applications that vary greatly by industry (and even within specific industry market segments). Big Rivers does not survey commercial and industrial retail members. Clearspring used established third party resources such as the Commercial Building End-Use Survey (CBECS) and Manufacturing End-Use Survey (MECS) published by the Energy

Information Administration, a part of the Department of Energy (DOE) and County Business Patterns (CBP) from the Census Bureau as data resources to develop the non-residential end-use baseline.

The CBECS and MECS surveys are conducted periodically across a nation-wide sample of businesses. Data collected includes building types, building characteristics, energy sources, business segment, major end-use characteristics, and energy efficient technology adoption. The Census CBP is produced annually and includes data on number of establishments and employment size by industry type by county. US Census Bureau's County Business Patterns data was used to develop the number of non-residential members by 2-digit North American Industrial Classification System (NAICS) code industry type in the counties served by Big Rivers' member-owners.

Figure 2.2
Non-Residential Industry %

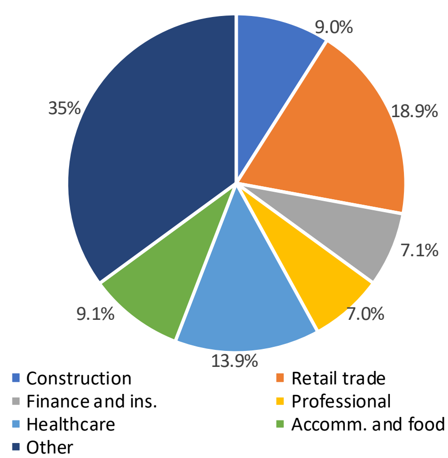


Table 2.2
Non-Residential Breakdown By Industry Type

Code	NAICS Industry	CBP Share %	Retail Accounts
22	Utilities	0.4%	73
23	Construction	9.0%	1,625
31-33	Manufacturing	4.6%	836
42	Wholesale trade	4.6%	826
44-45	Retail trade	18.9%	3,411
48-49	Transp. and warehousing	3.5%	633
51	Information	1.5%	262
52	Finance and insurance	7.1%	1,288
53	Real estate, rental, leasing	3.9%	713
54	Prof./scient./tech. services	7.0%	1,261
56	Admin. and support	4.0%	716
62	Health care and social assist.	13.9%	2,501
72	Accommodation, food services	9.1%	1,639
81	Other services (excl. public admin	12.6%	2,272
	TOTAL	100.0%	**18,422**

Notes: *County Business Patterns, Census.gov*
EIA-DOE, Commercial Building Energy Consumption Survey
EIA-DOE, Manufacturing Energy Consumption Survey
Total represents a weighted average of industry types

Total facility electric energy use was obtained for building/industry types from the Department of Energy (DOE) Commercial Building Energy Consumption Survey (CBECS) and Manufacturing Energy Consumption Survey (MECS). The CBECS survey data is segmented into the following key building types:

- Education
- Food Sales
- Food Service
- Health Care
- Lodging
- Retail
- Office
- Public Assembly / Worship
- Service
- Warehouse
- Other

MECS data is segmented into different categories than the CBECS data. It focuses on process and production energy details as these are of greater weight in the overall manufacturing energy of end-users. The MECS contains the following major end-use categories:

<u>Indirect Process - Boiler</u>
- Conventional Boiler
- CHP or Cogeneration

<u>Direct Process</u>
- Process Heating
- Process Cooling / Refrigeration
- Machine Drive
- Electro-Chemical
- Other Process

<u>Direct Non-Process</u>
- Facility HVAC
- Facility Lighting
- Other Facility Support
- On-Site Transportation
- Conventional Electric Generation
- Other Non-Process

<u>Other</u>
- Other energy

The non-residential end-use model is structured similarly to the residential end-use model described in section 2.2.1 but includes breakouts by business type along with key appliance end-uses (as opposed to specific appliances) and relies on an allocation methodology. These categories include the following end-uses:

- Cooling
- Lighting
- Office Equipment
- Refrigeration
- Ventilation

- Space Heating
- Cooking
- Water Heating
- Other

Construction of the non-residential end-use model required the shares of energy associated with each building industry segment be developed. CBECS and MECS data was matched with the NAICS categories so that electric end-use percentages are available for each industry type. For the manufacturing segment, “Process” end-uses were included in the “Other” category. Weighted averages of end-use percentages were calculated for Big Rivers’ non-residential segment based on the individual industry end-use percentages and the number of establishments by industry type. These percentages were applied to the projected kWh energy use from the 2020 Big Rivers electric load forecast to establish the baseline energy by end-use category.

Non-Residential End-Use Results Summary

A summary of the end-use categories is presented in Figure 2.3 and Table 2.3. The top two electric consumption categories in the non-residential segment are HVAC with 29 percent of total end-use energy and appliances with 34 percent of energy consumption.

Figure 2.3
Non-Residential End-Use %

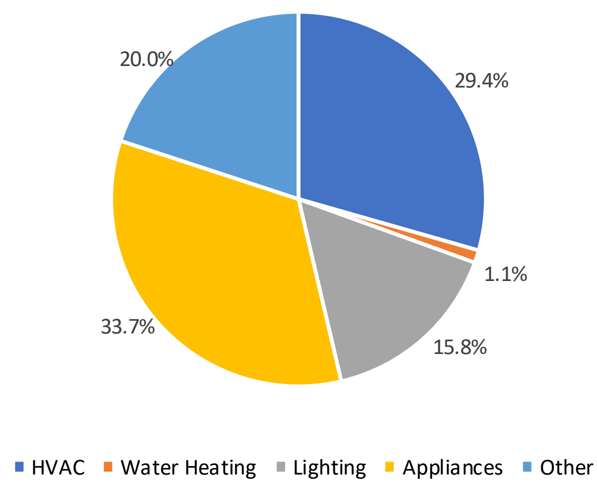


Table 2.3
Non-Residential End-Use Shares

Code	NAICS Industry	Space Heating	Space Cooling	Vent.	Water Heating	Lighting	Cooking	Refrig.	Office Equip.	Comp.	Other	Total
22	Utilities	4%	13%	24%	1%	16%	1%	4%	4%	19%	15%	100%
23	Construction	4%	13%	24%	1%	16%	1%	4%	4%	19%	15%	100%
31-33	Manufacturing	1%	6%	2%	2%	6%	12%	7%	0%	0%	63%	100%
42	Wholesale trade	3%	13%	5%	0%	27%	0%	21%	3%	5%	23%	100%
44-45	Retail trade	2%	8%	10%	2%	15%	5%	43%	2%	2%	10%	100%
48-49	Transp. and warehousing	3%	13%	5%	0%	27%	0%	21%	3%	5%	23%	100%
51	Information	4%	13%	24%	1%	16%	1%	4%	4%	19%	15%	100%
52	Finance and insurance	4%	13%	24%	1%	16%	1%	4%	4%	19%	15%	100%
53	Real estate, rental, leasing	4%	13%	24%	1%	16%	1%	4%	4%	19%	15%	100%
54	Prof./scient./tech. services	4%	13%	24%	1%	16%	1%	4%	4%	19%	15%	100%
56	Admin. and support	4%	13%	24%	1%	16%	1%	4%	4%	19%	15%	100%
62	Health care and social assist.	2%	19%	21%	1%	16%	4%	5%	4%	9%	18%	100%
72	Accommodation, food services	2%	8%	10%	3%	9%	8%	38%	7%	1%	13%	100%
81	Other services (excl. public admin.)	2%	14%	8%	0%	19%	0%	8%	1%	22%	25%	100%
	TOTAL	3%	12%	15%	1%	16%	3%	16%	3%	11%	20%	100%

Notes: *County Business Patterns, Census.gov*
EIA-DOE, Commercial Building Energy Consumption Survey
EIA-DOE, Manufacturing Energy Consumption Survey
Total represents a weighted average of industry types

2.3 Identified Opportunities

Following the development of the end-use models for the residential and non-residential segments, Clearspring researched and created a comprehensive list of demand-side measures for evaluation. This section presents the process.

2.3.1 Energy Efficiency Measure List

Technical Resource Manuals (TRMs) from neighboring states in the region were reviewed for the development of the residential and non-residential measure lists. Section 1.7 presented the list of TRMs used. Greater weight was given to the newer TRMs as it was assumed the most recent measure technology would be found there. The lists of the various TRMs was then consolidated into a master list for the residential and non-residential segments.

The demand-side measure lists were segregated into major customer type (residential and non-residential) as well as process type (lighting, HVAC, water heating, appliance, building envelope, other, etc.). The initial list included nearly 200 measures, although within each category some included multiple iterations.

2.3.2 Final Measure List Results

From the TRM sources mentioned above, a draft list was developed. This list was then provided to Big Rivers for review and comment. A meeting was held to discuss the comments and revisions were then made to arrive at the final measure list for analysis.

A total of 196 individual measures were identified with 99 measures identified for the residential segment and 97 for the non-residential segment. Tables showing the demand-side measures developed for inclusion in the qualitative screening analysis of this study are presented in Appendix A. The following figures show the approximate percentage of each measure by major category for the residential and non-residential segments.

Figure 2.4
Residential Measure End-Use Categories (%)

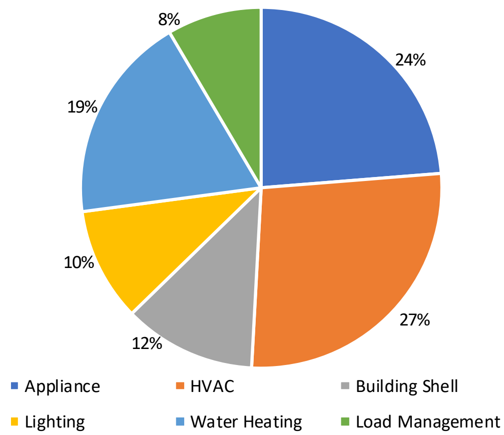
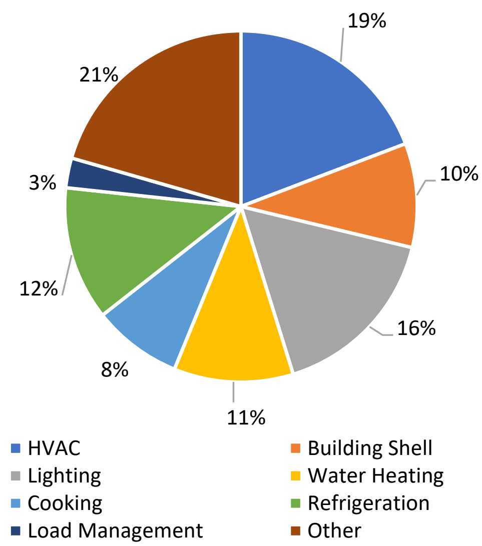


Figure 2.5
Non-Residential Measure End-Use Categories (%)



2.4 Qualitative Screening Process

Clearspring developed a qualitative screening tool to assess the initial measure list. Measures that passed the qualitative screening were then screened for quantitative or economic cost-effectiveness.

2.4.1 Qualitative Screening Model

The qualitative screening tool is derived from a series of questions about the selected measures based on several qualitative characteristics including:

- *Technological maturity*: Is the technology experimental or have its benefits been proven and validated?
- *Market maturity and market transformation*: Is this technology already achieving significant penetration in the market? If so, free riders may be a key concern.
- *Utility match*: Does the proposed measure fit with the characteristics of Big Rivers?

- *Availability of competing measures*: Are there multiple measures that can achieve similar results? Is one measure superior to another?
- *Impact measurement and quantification*: Can the energy and peak demand impacts be quantified, measured, and tracked in a way that confirms a reliable cost-benefit calculation in future assessments?
- *Level of customer acceptance*: Are customers likely to accept the proposed measure and is it easily integrated into their appliance portfolio?

Multiple questions were developed for each of these categories. This had the benefit of allowing some flexibility in screening measures but at the same time made it more difficult to pass measures on the strength of narrow questions. In general, a “No” answer increased the likelihood that a measure would be dropped.

2.4.2 Qualitative Screening Results

The measures identified in the initial measure list were run through the qualitative screening tool in an iterative process. This process is described as follows:

- Clearspring Energy’s team scored the measures in the qualitative screening independently.
- The independent screenings were consolidated into a single draft screening table.
- The draft screening results were provided to Big Rivers for review and comment.

Following that review, a total of 133 individual measures were identified: 60 measures for the residential segment and 73 for the non-residential segment. There are additional sub-categories of these measures that increase the overall number of potential measures to 345. Measures relying on natural gas as the savings driver were excluded. Multi-family residential were included in the totals under the assumption that multi-family units could still take advantage of the programs. The initial qualitative screening results were evaluated by Clearspring Energy and passing measures were moved forward to the economic screening analysis phase. Qualitative screening results can be found in Appendix A.

2.5 Economic Multi-Perspective Model Approach

The 133 measures and sub-measures identified in the qualitative phase were evaluated using the quantitative screening tool in an iterative process.[5] This process is described as follows:

2.5.1 Economic Modeling Process

Economic modeling is a step-by-step approach to calculate the benefit-cost ratio that will be used to evaluate a given measure. The process involves:

- Estimating the monetary value of initial and future costs and benefits of the measure over its useful life.
- Discounting all relevant costs and benefits to their present values using a discount rate.
- Dividing the present value of benefits by the present value of costs to yield the discounted benefit-cost ratio.
- The net present value (NPV) of each measure was calculated to estimate the future savings resulting from measure implementation.

[5] Several measure categories have multiple iterations included in the analysis (such as multiple motor HP sizes).

- Other metrics such the simple payback period, or time required for the return on investment and the cost per kWh of the measure were calculated.

The same process was used for each test in the multi-perspective approach (Total Resource Cost, Participant Cost, Utility Cost, and Rate Impact Measure).

2.5.2 Model Assumptions

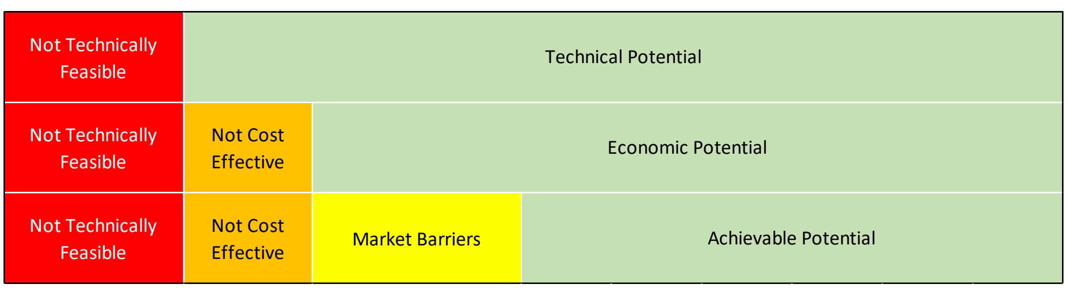
The economic models require a variety of common inputs and assumptions regarding economic conditions. The assumptions included in the analysis are:

- Each measure is assigned a useful life drawn from the technical resource manuals.
- The Big Rivers discount rate is 5.0% and is assumed to remain at that level throughout the study period.
- All incremental O&M costs are assumed to escalate at 2% per year.
- Avoided capacity and energy cost data is based on forward curves developed by ACES Power Marketing for the Midcontinent Independent System Operator (MISO) market.
- Distribution losses of 4.4% and transmission losses of 2.5% were applied to energy and demand as identified in the 2020 Big Rivers load forecast.
- Administration costs of 15% of incentive spending was applied to the overall program cost.[6]

2.6 Demand-Side Potential Approach

As discussed in section 1.5, there are four key definitions of demand-side potential that were calculated for this study. These are technical, economic, achievable and program potential. There are a variety of ways to approach potential calculations and it is as critically important to emphasize that each of these are fundamentally estimates and contain inherent uncertainty.

Figure 2.6
Type of Energy Efficiency Potential



2.6.1 Technical Potential

The overall estimation of technical potential is developed using the following equation:

Residential (MWh) x End-Use Share (%) x Availability Factor (%) x End-Use Savings (%) = End-Use Technical Potential (MWh)

[6] A national study by ACEEE found a range of 8-38% for administrative costs looking across multiple states. See “Saving Energy Cost-Effectively…”, ACEEE, 2009.

The first step in the estimation of technical potential is the assignment of an energy efficiency savings percentage value to each of the end-use categories presented in section 1.5.1. These savings percentages were developed by analyzing the savings calculated for each measure that passed the qualitative screening. Most of the residential measures are based on specific appliances. However, for the heating and cooling categories, equipment savings was combined with building shell savings. The commercial end-use categories are slightly broader, but the same approach was used.

The next step was the development of an availability factor to determine the amount of energy efficiency already achieved for a specific end-use category. To accomplish this for the residential segment, data from the 2019 Big Rivers residential appliance survey was used to determine the percentage of a specific appliance stock that was 5 years old or less.[7] It was assumed that those appliances would already be efficient (or at least unavailable to replace in either case). There were two exceptions to this. If age data was not available, then the average measure life was used assuming an even distribution of age. The other exception was lighting. While new lighting standards are now in effect and it could be argued that the lighting market is transformed, the appliance survey indicated that there were still incandescent and compact-fluorescent lights in homes that could be induced to retrofit. For this reason, a factor of 10 percent was applied to allow for some lighting savings. This same approach was applied to televisions and personal computers.

The final step in the calculation of technical potential was the application of the availability factor and savings percentage to the electric end-use energy percentage developed previously in the baseline end-use model development.

A similar approach was applied to the non-residential segment. CBECS and MECS surveys were reviewed to determine industry-wide energy efficiency adoption. In addition, actual Big Rivers energy efficiency program results from the previous five years were reviewed. In the case where neither of those two approaches were available, then the measure-life retirement assumption referenced in the residential approach was used. Office equipment (largely personal computers and monitors) received the same treatment as residential.

The development of technical potential peak demand savings was calculated by applying the ratio of peak savings to energy savings by measure from the TRMs to the estimated technical potential energy savings. This approach was also used for the economic, achievable and program potential calculations as well.

2.6.2 Economic Potential

Economic potential, as described in section 1.5.2, differs from technical potential only in that it removes those measures that fail the Total Resource Cost (TRC) cost test described earlier. To accomplish this, the technical potential savings that was calculated previously was multiplied by a TRC factor developed for each end-use category. In summary, the economic potential equation is defined as:

End-Use Technical Potential (MWh) x TRC Factor (%) = End-Use Economic Potential (MWh)

[7] Big Rivers historic DSM program results over the past five years were reviewed to make sure they did not reveal a greater share of adoption than the 5-year assumption would.

The TRC factor for each end-use was based on an analysis of the sub-measures in each category that failed or passed. In most cases, the TRC factor was binary (a 1 or 0) and when in the absence of a clear reason otherwise was set to 1 (100%). There were several adjustments to this approach, however.

For the residential segment, the HVAC TRC factor was reduced by the market shares of geothermal and mini-split heat pumps as they failed the TRC test. Central air conditioners also failed and represent roughly 50 percent of the cooling market, so that TRC factor was similarly reduced. The lighting TRC was factor was set at 50 percent, again based on the concept that there is perhaps some retrofit savings that could be justified despite the assumption of a transformed lighting market.

Non-residential segment HVAC and water heating end-uses were largely left intact from the technical potential. Cooking was reduced to 14 percent as many of the cooking measures failed the TRC test. Office equipment was set to zero as most of the office equipment represent computers and monitors which were deemed to be a transformed market. Roughly half of the lighting measures passed the TRC, as did 80 percent of refrigeration. The Other category (which includes the process uses from manufacturing) was set at 88 percent as most of those measures passed the TRC test.

2.6.3 Achievable Potential

As described in section 1.5.3, achievable potential represents the amount of energy efficiency that could be realized under aggressive promotion, including the utility paying up to 100 percent of the incremental cost of a measure. The overall achievable potential equation is presented below:

End-Use Economic Potential (MWh) x Program Factor (%) x Adoption Factor (%) x Measure-Life Factor (%) = End-Use Achievable Potential (MWh)

The first step is the development of a program factor. Like the TRC factor described in economic potential, it represents a percentage of measure savings that passes the participant test in the multi-perspective models after an assumption of Big Rivers paying 100 percent of the incremental cost. The only adjustment to the residential segment was to de-rate high investment cost equipment (HVAC and water heating) by the Big Rivers area poverty rate of 16% to represent a market barrier. For the non-residential segment, HVAC, refrigeration and other were reduced by the percentage of measures that failed the participant test at the 100 percent of incremental cost incentive.

Next, an adoption factor was applied as a barrier based on the idea that it is unreasonable to think that 100 percent of a measure would be replaced. This considers that there are technical or other constraints that could inhibit adoption. In the absence of specific data, a standard 0.95 factor was applied to de-rate achievable potential. It is highly likely that this factor should be lower, reflecting actual higher technical and market barriers. This represents a conservative estimate that was deemed reasonable and plausible.

Finally, a measure-life factor was applied to each end-use based on the measure life assuming a regular replacement rate of equipment (rather than the full immediate adoption assumption in the technical and economic potential estimates).

2.6.4 Program Potential

How much demand-side savings could realistically be achieved under a set of programs with a defined hypothetical spending budget defines program potential, as discussed in section 1.5.4. The program potential equation is then:

End-Use Achievable Potential (MWh) x Replacement Rate x Budget Factor = End-Use Program Potential (MWh)

For the purposes of this study, two budget scenarios were developed. Scenario 1 assumes a budget of $2 million while scenario 2 is based on a budget of $1 million. It is important to note that the budget assumptions and the savings estimates for the program potential savings are hypothetical scenarios only. Rather than selecting a specific set of programs for this analysis, it was assumed that all of the measures from the achievable potential would be available.

The cumulative achievable savings for the existing and new member end-users was developed using an age-replacement method. Savings were assumed to accrue based on a replacement rate as appliances and equipment wear out and are replaced by new, efficient equipment. This was calculated on an end-use basis by assuming a regular replacement based on the end-use measure life taken from the multi-perspective measure models and applying that over the ten-year study window.

The budget cost of acquiring the end-use program savings was developed by multiplying the program MWh by the $/MWh measure cost derived from the multi-perspective evaluation models. A budget factor was then used to scale the total cost up or down to match with the program-level budget assumed in each scenario.

SECTION 3

RESIDENTIAL ENERGY EFFICIENCY POTENTIAL

3.0 Residential Energy Efficiency Potential

3.1 Introduction

This section presents the results from the various potential estimates for the residential segment. The four potential definitions presented are technical, economic, achievable and program. The process and assumptions have been described previously in sections 1 and 2.

3.2 Technical Potential

Technical potential represents an estimate of maximum energy efficiency potential. A total of the 60 residential measures passed the qualitative screening test and were modeled. The results were used to estimate overall technical potential. The following tables present the results of the technical potential analysis for the residential energy efficiency measures:

Table 3.1
Residential Technical Potential By Major End-Use Category

	Category	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Energy (MWh)	HVAC	153,755	154,936	155,528	155,958	156,262	156,466	156,599	156,653	156,611	156,481
	Water Heating	88,145	88,816	89,152	89,397	89,569	89,686	89,761	89,791	89,768	89,694
	Appliance	30,883	31,186	31,338	31,448	31,526	31,579	31,613	31,627	31,616	31,583
	Lighting	3,062	3,222	3,302	3,361	3,402	3,429	3,447	3,455	3,449	3,431
	Other	8,667	8,720	8,746	8,765	8,779	8,788	8,794	8,796	8,794	8,789
	Total	284,513	286,881	288,066	288,929	289,538	289,948	290,214	290,322	290,239	289,978
	Category	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Demand (MW)	HVAC	63.5	64.0	64.3	64.5	64.6	64.7	64.7	64.8	64.7	64.7
	Water Heating	8.8	8.9	8.9	8.9	9.0	9.0	9.0	9.0	9.0	9.0
	Appliance	4.9	5.0	5.0	5.0	5.0	5.1	5.1	5.1	5.1	5.1
	Lighting	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Other	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4
	Total	79.7	80.3	80.6	80.9	81.0	81.1	81.2	81.2	81.2	81.2

Note: MISO Summer Peak
Note: Cumulative Annual Impact

Table 3.2
Residential Technical Potential By End-Use (MWh)

End-Use	Category	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Space heating	HVAC	70,368	70,909	71,180	71,377	71,516	71,610	71,671	71,695	71,676	71,617
Air handlers (heat	HVAC	1,445	1,456	1,462	1,466	1,469	1,471	1,472	1,472	1,472	1,471
Air conditioning	HVAC	60,213	60,704	60,950	61,129	61,255	61,340	61,395	61,418	61,400	61,346
Air handlers (cool	HVAC	1,673	1,686	1,693	1,698	1,701	1,704	1,705	1,706	1,706	1,704
Ceiling fans	HVAC	17,024	17,130	17,183	17,221	17,248	17,267	17,279	17,283	17,280	17,268
Dehumidifiers	HVAC	3,033	3,051	3,060	3,067	3,072	3,075	3,077	3,078	3,077	3,075
Water heating	Water Heating	88,145	88,816	89,152	89,397	89,569	89,686	89,761	89,791	89,768	89,694
Clothes washers	Appliance	2,065	2,085	2,095	2,103	2,108	2,112	2,114	2,115	2,114	2,112
Clothes dryers	Appliance	12,264	12,384	12,445	12,489	12,520	12,541	12,554	12,560	12,555	12,542
Lighting	Lighting	3,062	3,222	3,302	3,361	3,402	3,429	3,447	3,455	3,449	3,431
Refrigerators	Appliance	3,713	3,745	3,762	3,773	3,782	3,787	3,791	3,793	3,791	3,788
Second refrig.	Appliance	8,046	8,116	8,151	8,177	8,195	8,207	8,215	8,218	8,216	8,208
Separate freezers	Appliance	2,228	2,247	2,257	2,264	2,269	2,272	2,275	2,276	2,275	2,273
Cooking	Appliance	936	942	945	947	949	950	951	951	951	950
Microwaves	Appliance	484	487	489	490	491	491	491	492	491	491
Dishwashers	Appliance	675	681	684	686	688	689	690	690	690	689
Most-used TVs	Appliance	398	418	429	436	442	445	448	448	448	445
Second TVs	Appliance	75	79	81	82	84	84	85	85	85	84
Pool pumps	Other	967	973	976	978	980	981	981	982	981	981
Hot tub pumps	Other	67	67	68	68	68	68	68	68	68	68
Hot tub heaters	Other	246	247	248	249	249	249	250	250	250	249
Other	Other	7,387	7,432	7,454	7,471	7,482	7,490	7,495	7,497	7,495	7,490
	Total	284,513	286,881	288,066	288,929	289,538	289,948	290,214	290,322	290,239	289,978

Note: Cumulative Annual Impact

Table 3.3
Residential Technical Potential By End-Use (MW - Summer)

End-Use	Category	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Space heating	HVAC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Air handlers (heat	HVAC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Air conditioning	HVAC	60.2	60.7	60.9	61.1	61.3	61.3	61.4	61.4	61.4	61.3
Air handlers (cool	HVAC	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Ceiling fans	HVAC	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Dehumidifiers	HVAC	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9
Water heating	Water Heating	8.8	8.9	8.9	8.9	9.0	9.0	9.0	9.0	9.0	9.0
Clothes washers	Appliance	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Clothes dryers	Appliance	2.1	2.1	2.1	2.1	2.2	2.2	2.2	2.2	2.2	2.2
Lighting	Lighting	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Refrigerators	Appliance	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Second refrig.	Appliance	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
Separate freezers	Appliance	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Cooking	Appliance	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Microwaves	Appliance	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Dishwashers	Appliance	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Most-used TVs	Appliance	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Second TVs	Appliance	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pool pumps	Other	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Hot tub pumps	Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hot tub heaters	Other	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Other	Other	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1
	Total	79.7	80.3	80.6	80.9	81.0	81.1	81.2	81.2	81.2	81.2

Note: Cumulative Annual Impact

3.3 Economic Potential

A subset of technical potential, the economic potential represents those measures that pass the total resource cost test (TRC). Of the 60 measures presented in the technical potential analysis, 18 measures yielded a benefit-cost greater that one and, therefore, passed the economic screening test. As described previously, these results were then used to estimate economic potential for the residential segment. The following tables present the results of the economic potential estimates.

Table 3.4
Residential Economic Potential By Major End-Use Category

	Category	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Energy (MWh)	HVAC	104,373	105,185	105,592	105,888	106,097	106,238	106,329	106,366	106,338	106,248
	Water Heating	88,145	88,816	89,152	89,397	89,569	89,686	89,761	89,791	89,768	89,694
	Appliance	16,051	16,194	16,265	16,317	16,354	16,379	16,395	16,401	16,396	16,381
	Lighting	1,531	1,611	1,651	1,680	1,701	1,715	1,724	1,727	1,725	1,716
	Other	3,506	3,528	3,538	3,546	3,552	3,555	3,558	3,559	3,558	3,555
	Total	213,607	215,334	216,199	216,828	217,273	217,573	217,766	217,845	217,784	217,594
	Category	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Demand (MW)	HVAC	32.9	33.2	33.3	33.4	33.5	33.5	33.6	33.6	33.6	33.5
	Water Heating	8.8	8.9	8.9	8.9	9.0	9.0	9.0	9.0	9.0	9.0
	Appliance	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9
	Lighting	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Other	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
	Total	44.6	45.0	45.2	45.3	45.4	45.4	45.5	45.5	45.5	45.4

Note: MISO Summer Peak

Note: Cumulative Annual Impact

Table 3.5
Residential Economic Potential By End-Use (MWh)

End-Use	Category	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Space heating	HVAC	68,116	68,640	68,902	69,093	69,228	69,318	69,377	69,401	69,383	69,325
Air handlers (heat)	HVAC	1,445	1,456	1,462	1,466	1,469	1,471	1,472	1,472	1,472	1,471
Air conditioning	HVAC	30,107	30,352	30,475	30,564	30,628	30,670	30,698	30,709	30,700	30,673
Air handlers (cool)	HVAC	1,673	1,686	1,693	1,698	1,701	1,704	1,705	1,706	1,706	1,704
Ceiling fans	HVAC	0	0	0	0	0	0	0	0	0	0
Dehumidifiers	HVAC	3,033	3,051	3,060	3,067	3,072	3,075	3,077	3,078	3,077	3,075
Water heating	Water Heating	88,145	88,816	89,152	89,397	89,569	89,686	89,761	89,791	89,768	89,694
Clothes washers	Appliance	2,065	2,085	2,095	2,103	2,108	2,112	2,114	2,115	2,114	2,112
Clothes dryers	Appliance	0	0	0	0	0	0	0	0	0	0
Lighting	Lighting	1,531	1,611	1,651	1,680	1,701	1,715	1,724	1,727	1,725	1,716
Refrigerators	Appliance	3,713	3,745	3,762	3,773	3,782	3,787	3,791	3,793	3,791	3,788
Second refrig.	Appliance	8,046	8,116	8,151	8,177	8,195	8,207	8,215	8,218	8,216	8,208
Separate freezers	Appliance	2,228	2,247	2,257	2,264	2,269	2,272	2,275	2,276	2,275	2,273
Cooking	Appliance	0	0	0	0	0	0	0	0	0	0
Microwaves	Appliance	0	0	0	0	0	0	0	0	0	0
Dishwashers	Appliance	0	0	0	0	0	0	0	0	0	0
Most-used TVs	Appliance	0	0	0	0	0	0	0	0	0	0
Second TVs	Appliance	0	0	0	0	0	0	0	0	0	0
Pool pumps	Other	0	0	0	0	0	0	0	0	0	0
Hot tub pumps	Other	0	0	0	0	0	0	0	0	0	0
Hot tub heaters	Other	0	0	0	0	0	0	0	0	0	0
Other	Other	3,506	3,528	3,538	3,546	3,552	3,555	3,558	3,559	3,558	3,555
	Total	213,607	215,334	216,199	216,828	217,273	217,573	217,766	217,845	217,784	217,594

Note: Cumulative Annual Impact

Table 3.6
Residential Economic Potential By End-Use (MW - Summer)

End-Use	Category	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Space heating	HVAC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Air handlers (heat)	HVAC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Air conditioning	HVAC	30.1	30.4	30.5	30.6	30.6	30.7	30.7	30.7	30.7	30.7
Air handlers (cool)	HVAC	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Ceiling fans	HVAC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Dehumidifiers	HVAC	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9
Water heating	Water Heating	8.8	8.9	8.9	8.9	9.0	9.0	9.0	9.0	9.0	9.0
Clothes washers	Appliance	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Clothes dryers	Appliance	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Lighting	Lighting	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Refrigerators	Appliance	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Second refrig.	Appliance	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
Separate freezers	Appliance	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Cooking	Appliance	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Microwaves	Appliance	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Dishwashers	Appliance	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Most-used TVs	Appliance	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Second TVs	Appliance	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pool pumps	Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hot tub pumps	Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hot tub heaters	Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other	Other	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
	Total	44.6	45.0	45.2	45.3	45.4	45.4	45.5	45.5	45.5	45.4

Note: Cumulative Annual Impact

3.4 Achievable Potential

As discussed in section 1.5, achievable potential removes the unrealistic “immediate adoption” constraint of the technical and economic potential calculations and instead imagines the natural adoption of energy efficiency measures under an aggressive incentive of 100 percent of incremental measure cost. Of the 18 measures that passed the TRC screening test, all measures yielded a benefit-cost greater than one from the participant screening test and, therefore, would be considered for achievable energy efficiency potential. The following tables present the results of the economic screening for the residential achievable potential.

Table 3.7
Residential Achievable Potential By Major End-Use Category

	Category	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Energy (MWh)	HVAC	4,616	8,932	12,922	16,822	20,652	24,428	28,163	31,855	35,493	39,083
	Water Heating	6,131	12,017	17,636	23,182	28,671	34,114	39,525	44,900	50,232	55,524
	Appliance	1,717	3,373	4,961	6,530	8,085	9,629	11,164	12,690	13,262	13,824
	Lighting	208	381	517	642	759	869	975	1,076	1,171	1,260
	Other	284	558	822	1,084	1,343	1,601	1,857	2,112	2,366	2,618
	Total	12,956	25,262	36,858	48,260	59,510	70,641	81,684	92,633	102,524	112,308
	Category	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Demand (MW)	HVAC	1.5	2.9	4.2	5.5	6.7	8.0	9.2	10.4	11.6	12.8
	Water Heating	0.6	1.2	1.8	2.3	2.9	3.4	4.0	4.5	5.0	5.6
	Appliance	0.2	0.4	0.6	0.8	1.0	1.1	1.3	1.5	1.6	1.6
	Lighting	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Other	0.1	0.2	0.2	0.3	0.4	0.4	0.5	0.6	0.7	0.7
	Total	2.4	4.7	6.8	8.9	10.9	13.0	15.0	17.0	18.8	20.7

Note: MISO Summer Peak
Note: Cumulative Annual Impact

Table 3.8
Residential Achievable Potential By End-Use (MWh)

End-Use	Category	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Space heating	HVAC	2,848	5,506	7,954	10,346	12,693	15,005	17,291	19,550	21,775	23,968
Air handlers (heat)	HVAC	106	207	303	397	490	583	674	765	855	945
Air conditioning	HVAC	1,275	2,459	3,547	4,607	5,647	6,670	7,681	8,679	9,661	10,629
Air handlers (cool)	HVAC	124	241	352	462	570	677	783	888	992	1,095
Ceiling fans	HVAC	0	0	0	0	0	0	0	0	0	0
Dehumidifiers	HVAC	264	519	766	1,010	1,253	1,494	1,734	1,972	2,210	2,446
Water heating	Water Heating	6,131	12,017	17,636	23,182	28,671	34,114	39,525	44,900	50,232	55,524
Clothes washers	Appliance	166	324	471	617	760	901	1,041	1,180	1,318	1,454
Clothes dryers	Appliance	0	0	0	0	0	0	0	0	0	0
Lighting	Lighting	208	381	517	642	759	869	975	1,076	1,171	1,260
Refrigerators	Appliance	294	573	837	1,097	1,354	1,608	1,860	2,111	2,358	2,603
Second refrig.	Appliance	1,041	2,051	3,028	3,995	4,956	5,910	6,861	7,808	7,805	7,798
Separate freezers	Appliance	217	425	625	821	1,016	1,209	1,401	1,592	1,781	1,969
Cooking	Appliance	0	0	0	0	0	0	0	0	0	0
Microwaves	Appliance	0	0	0	0	0	0	0	0	0	0
Dishwashers	Appliance	0	0	0	0	0	0	0	0	0	0
Most-used TVs	Appliance	0	0	0	0	0	0	0	0	0	0
Second TVs	Appliance	0	0	0	0	0	0	0	0	0	0
Pool pumps	Other	0	0	0	0	0	0	0	0	0	0
Hot tub pumps	Other	0	0	0	0	0	0	0	0	0	0
Hot tub heaters	Other	0	0	0	0	0	0	0	0	0	0
Other	Other	284	558	822	1,084	1,343	1,601	1,857	2,112	2,366	2,618
	Total	12,956	25,262	36,858	48,260	59,510	70,641	81,684	92,633	102,524	112,308

Note: Cumulative Annual Impact

Table 3.9
Residential Achievable Potential By End-Use (MW - Summer)

End-Use	Category	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Space heating	HVAC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Air handlers (heat)	HVAC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Air conditioning	HVAC	1.3	2.5	3.5	4.6	5.6	6.7	7.7	8.7	9.7	10.6
Air handlers (cool)	HVAC	0.1	0.1	0.2	0.3	0.3	0.4	0.5	0.5	0.6	0.6
Ceiling fans	HVAC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Dehumidifiers	HVAC	0.2	0.3	0.5	0.6	0.8	0.9	1.1	1.2	1.4	1.5
Water heating	Water Heating	0.6	1.2	1.8	2.3	2.9	3.4	4.0	4.5	5.0	5.6
Clothes washers	Appliance	0.0	0.0	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2
Clothes dryers	Appliance	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Lighting	Lighting	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Refrigerators	Appliance	0.0	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.3	0.3
Second refrig.	Appliance	0.1	0.2	0.3	0.5	0.6	0.7	0.8	0.9	0.9	0.9
Separate freezers	Appliance	0.0	0.0	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2
Cooking	Appliance	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Microwaves	Appliance	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Dishwashers	Appliance	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Most-used TVs	Appliance	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Second TVs	Appliance	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pool pumps	Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hot tub pumps	Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hot tub heaters	Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other	Other	0.1	0.2	0.2	0.3	0.4	0.4	0.5	0.6	0.7	0.7
	Total	2.4	4.7	6.8	8.9	10.9	13.0	15.0	17.0	18.8	20.7

Note: Cumulative Annual Impact

3.5 Program Potential

Program potential, the most realistic of the various potential estimates, is based on specific assumptions of differing energy efficiency budget scenarios. Two scenarios were developed based on total energy efficiency budgets of $1 million and $2 million, respectively. The incentive levels for each of the measures was 35 percent of incremental cost to be consistent with the previous filing. Of the measures that passed the TRC economic screening test, 18 measures yielded a benefit-cost greater than one from the program perspective. The following tables present the results of the economic screening for residential program portion of the total potential under the $1 million budget scenario. Figure 3.1 compares graphically the benefit-cost ratios greater than 1.0 of the top measures. Lighting, insulation, and water heat-related measures dominate the field.

Figure 3.1
Residential Top (>1.0) Measures By Benefit-Cost Ratio (TRC)

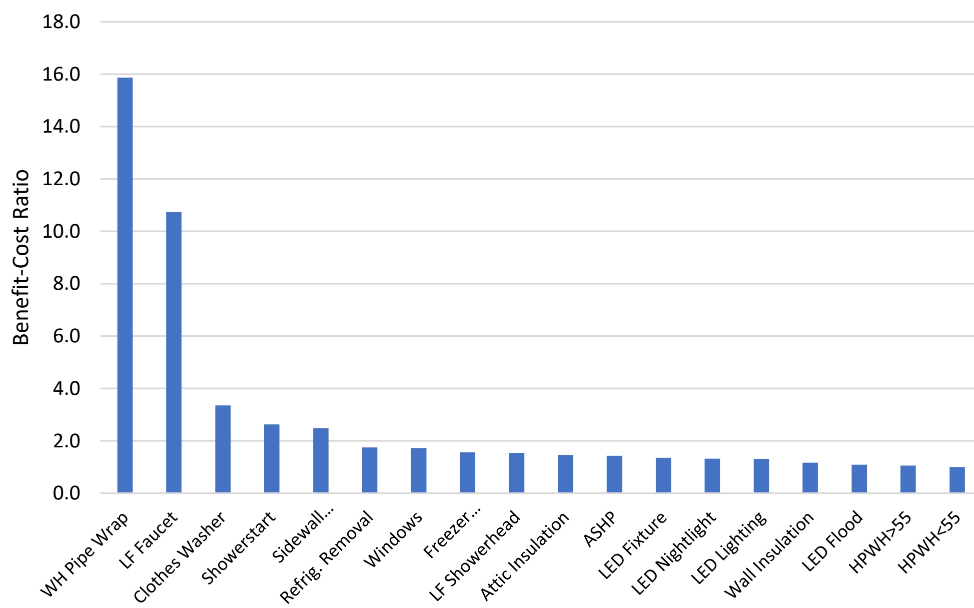


Table 3.10
Residential Program Potential By Major End-Use Category ($1 Million Scenario)

	Category	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Energy (MWh)	HVAC	928	1,857	2,785	3,714	4,642	5,571	6,499	7,428	8,356	9,285
	Water Heating	2,224	4,448	6,672	8,896	11,120	13,344	15,568	17,792	20,017	22,241
	Appliance	752	1,503	2,255	3,007	3,758	4,510	5,262	6,013	6,258	6,502
	Lighting	48	96	144	192	239	287	335	383	431	479
	Other	105	210	315	420	525	629	734	839	944	1,049
	Total	4,057	8,114	12,171	16,228	20,285	24,342	28,399	32,456	36,005	39,555
	Category	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Demand (MW)	HVAC	0.3	0.6	1.0	1.3	1.6	1.9	2.2	2.5	2.9	3.2
	Water Heating	0.2	0.4	0.7	0.9	1.1	1.3	1.6	1.8	2.0	2.2
	Appliance	0.1	0.2	0.3	0.4	0.4	0.5	0.6	0.7	0.7	0.8
	Lighting	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Other	0.0	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.3	0.3
	Total	0.7	1.3	2.0	2.6	3.3	3.9	4.6	5.3	5.9	6.5

Note: MISO Summer Peak
Note: Cumulative Annual Impact

Table 3.11
Residential Program Potential By End-Use (MWh) ($1 Million Scenario)

End-Use	Category	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Space heating	HVAC	521	1,041	1,562	2,082	2,603	3,124	3,644	4,165	4,686	5,206
Air handlers (heat)	HVAC	33	66	98	131	164	197	230	262	295	328
Air conditioning	HVAC	231	462	693	924	1,155	1,385	1,616	1,847	2,078	2,309
Air handlers (cool)	HVAC	38	76	114	152	190	228	266	304	342	380
Ceiling fans	HVAC	0	0	0	0	0	0	0	0	0	0
Dehumidifiers	HVAC	106	212	318	424	530	637	743	849	955	1,061
Water heating	Water Hea	2,224	4,448	6,672	8,896	11,120	13,344	15,568	17,792	20,017	22,241
Clothes washers	Appliance	54	108	162	216	271	325	379	433	487	541
Clothes dryers	Appliance	0	0	0	0	0	0	0	0	0	0
Lighting	Lighting	48	96	144	192	239	287	335	383	431	479
Refrigerators	Appliance	97	194	291	387	484	581	678	775	872	969
Second refrig.	Appliance	507	1,015	1,522	2,030	2,537	3,045	3,552	4,060	4,060	4,060
Separate freezers	Appliance	93	186	280	373	466	559	652	746	839	932
Cooking	Appliance	0	0	0	0	0	0	0	0	0	0
Microwaves	Appliance	0	0	0	0	0	0	0	0	0	0
Dishwashers	Appliance	0	0	0	0	0	0	0	0	0	0
Most-used TVs	Appliance	0	0	0	0	0	0	0	0	0	0
Second TVs	Appliance	0	0	0	0	0	0	0	0	0	0
Pool pumps	Other	0	0	0	0	0	0	0	0	0	0
Hot tub pumps	Other	0	0	0	0	0	0	0	0	0	0
Hot tub heaters	Other	0	0	0	0	0	0	0	0	0	0
Other	Other	105	210	315	420	525	629	734	839	944	1,049
	Total	4,057	8,114	12,171	16,228	20,285	24,342	28,399	32,456	36,005	39,555

Note: Cumulative Annual Impact

Table 3.12
Residential Program Potential By End-Use (MW - Summer) ($1 Million Scenario)

End-Use	Category	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Space heating	HVAC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Air handlers (heat)	HVAC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Air conditioning	HVAC	0.2	0.5	0.7	0.9	1.2	1.4	1.6	1.8	2.1	2.3
Air handlers (cool)	HVAC	0.0	0.0	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2
Ceiling fans	HVAC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Dehumidifiers	HVAC	0.1	0.1	0.2	0.3	0.3	0.4	0.5	0.5	0.6	0.7
Water heating	Water Hea	0.2	0.4	0.7	0.9	1.1	1.3	1.6	1.8	2.0	2.2
Clothes washers	Appliance	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1
Clothes dryers	Appliance	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Lighting	Lighting	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Refrigerators	Appliance	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1
Second refrig.	Appliance	0.1	0.1	0.2	0.2	0.3	0.3	0.4	0.5	0.5	0.5
Separate freezers	Appliance	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1
Cooking	Appliance	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Microwaves	Appliance	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Dishwashers	Appliance	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Most-used TVs	Appliance	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Second TVs	Appliance	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pool pumps	Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hot tub pumps	Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hot tub heaters	Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other	Other	0.0	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.3	0.3
	Total	0.7	1.3	2.0	2.6	3.3	3.9	4.6	5.3	5.9	6.5

Note: Cumulative Annual Impact

Table 3.13
Residential Program Potential By Major End-Use Category ($2 Million Scenario)

	Category	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Energy (MWh)	HVAC	1,786	3,571	5,357	7,142	8,928	10,713	12,499	14,284	16,070	17,855
	Water Heating	4,277	8,554	12,831	17,108	21,385	25,662	29,939	34,216	38,493	42,770
	Appliance	1,446	2,891	4,337	5,782	7,228	8,673	10,119	11,564	12,034	12,503
	Lighting	92	184	276	368	460	553	645	737	829	921
	Other	202	403	605	807	1,009	1,210	1,412	1,614	1,816	2,017
	Total	7,802	15,604	23,406	31,208	39,010	46,811	54,613	62,415	69,241	76,067

	Category	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Demand (MW)	HVAC	0.6	1.2	1.8	2.4	3.1	3.7	4.3	4.9	5.5	6.1
	Water Heating	0.4	0.9	1.3	1.7	2.1	2.6	3.0	3.4	3.8	4.3
	Appliance	0.2	0.3	0.5	0.7	0.8	1.0	1.2	1.4	1.4	1.5
	Lighting	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Other	0.1	0.1	0.2	0.2	0.3	0.3	0.4	0.4	0.5	0.6
	Total	1.3	2.5	3.8	5.1	6.3	7.6	8.8	10.1	11.3	12.4

Note: MISO Summer Peak

Note: Cumulative Annual Impact

SECTION 4

NON-RESIDENTIAL ENERGY EFFICIENCY POTENTIAL

4.0 Non-Residential Energy Efficiency Potential

4.1 Introduction

Section 4 presents the results from the various potential estimates for the non-residential segment. The four potential categories presented are technical, economic, achievable and program. Non-residential is assumed to consist of the commercial and industrial retail segments and excludes accounts under direct serve agreements. The process and assumptions have been described previously in sections 1 and 2.

4.2 Technical Potential

Technical potential represents an estimate of maximum energy efficiency potential. A total of the 73 non-residential measures passed the qualitative screening test and were modeled. The following tables present the results of the technical potential analysis for the non-residential energy efficiency measures.

Table 4.1
Non-Residential Technical Potential By Major End-Use Category

	Category	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Energy (MWh)	HVAC	52,445	52,167	52,661	53,089	53,543	53,999	54,232	54,671	55,108	55,482
	Water Heating	4,011	3,991	4,026	4,056	4,088	4,120	4,137	4,167	4,198	4,224
	Lighting	58,293	58,003	58,516	58,962	59,433	59,907	60,149	60,606	61,060	61,449
	Appliance	89,846	89,333	90,243	91,032	91,868	92,708	93,137	93,947	94,750	95,441
	Other	23,775	23,658	23,866	24,045	24,236	24,427	24,525	24,710	24,893	25,050
	Total	228,371	227,153	229,312	231,185	233,168	235,161	236,179	238,101	240,008	241,646
	Category	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Demand (MW)	HVAC	38.6	38.4	38.7	39.0	39.4	39.7	39.9	40.2	40.5	40.8
	Water Heating	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
	Lighting	6.7	6.6	6.7	6.7	6.8	6.8	6.9	6.9	7.0	7.0
	Appliance	12.3	12.2	12.4	12.6	12.8	13.0	13.1	13.3	13.5	13.7
	Other	9.1	9.1	9.2	9.2	9.3	9.4	9.4	9.5	9.6	9.6
	Total	67.0	66.6	67.4	68.0	68.7	69.3	69.7	70.3	71.0	71.5

Note: MISO Summer Peak
Note: Cumulative Annual Impact

Table 4.2
Non-Residential Technical Potential By End-Use (MWh)

End-Use	Category	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Space Heating	HVAC	5,636	5,606	5,659	5,705	5,754	5,803	5,828	5,875	5,922	5,962
Space Cooling	HVAC	27,387	27,241	27,499	27,723	27,960	28,198	28,319	28,549	28,777	28,972
Ventilation	HVAC	19,423	19,320	19,503	19,662	19,830	19,998	20,085	20,247	20,409	20,548
Water Heating	Water Heatin	4,011	3,991	4,026	4,056	4,088	4,120	4,137	4,167	4,198	4,224
Lighting	Lighting	58,293	58,003	58,516	58,962	59,433	59,907	60,149	60,606	61,060	61,449
Cooking	Appliance	3,679	3,661	3,693	3,720	3,749	3,778	3,793	3,821	3,849	3,873
Refrigeration	Appliance	84,052	83,634	84,374	85,017	85,696	86,380	86,729	87,388	88,041	88,603
Office Equipment	Appliance	2,116	2,038	2,176	2,296	2,423	2,550	2,615	2,738	2,860	2,965
Other (incl. Process	Other	23,775	23,658	23,866	24,045	24,236	24,427	24,525	24,710	24,893	25,050
	Total	228,371	227,153	229,312	231,185	233,168	235,161	236,179	238,101	240,008	241,646

Note: Cumulative Annual Impact

Table 4.3
Non-Residential Technical Potential By End-Use (MW - Summer)

End-Use	Category	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Space Heating	HVAC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Space Cooling	HVAC	27.4	27.2	27.5	27.7	28.0	28.2	28.3	28.5	28.8	29.0
Ventilation	HVAC	11.2	11.1	11.2	11.3	11.4	11.5	11.6	11.6	11.7	11.8
Water Heating	Water Heating	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Lighting	Lighting	6.7	6.6	6.7	6.7	6.8	6.8	6.9	6.9	7.0	7.0
Cooking	Appliance	0.6	0.6	0.6	0.6	0.6	0.6	0.7	0.7	0.7	0.7
Refrigeration	Appliance	9.5	9.5	9.6	9.6	9.7	9.8	9.8	9.9	10.0	10.0
Office Equipment	Appliance	2.1	2.0	2.2	2.3	2.4	2.6	2.6	2.7	2.9	3.0
Other (incl. Process	Other	9.1	9.1	9.2	9.2	9.3	9.4	9.4	9.5	9.6	9.6
	Total	67.0	66.6	67.4	68.0	68.7	69.3	69.7	70.3	71.0	71.5

Note: Cumulative Annual Impact

4.3 Economic Potential

A subset of technical potential, the economic potential represents those measures that pass the Total Resource Cost test (TRC). Of the 73 non-residential measures that presented in the technical potential screening, 45 measures yielded a benefit-cost greater than one, passing the economic screening test and were used to estimate economic potential. The following tables present the results of the economic potential estimates for the non-residential segment.

Table 4.4
Non-Residential Economic Potential By Major End-Use Category

	Category	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Energy (MWh)	HVAC	35,934	35,743	36,082	36,375	36,686	36,999	37,158	37,459	37,758	38,015
	Water Heating	3,971	3,952	3,986	4,016	4,047	4,079	4,095	4,126	4,156	4,182
	Lighting	32,061	31,902	32,184	32,429	32,688	32,949	33,082	33,333	33,583	33,797
	Appliance	67,756	67,420	68,016	68,534	69,082	69,633	69,914	70,445	70,972	71,425
	Other	20,922	20,819	21,002	21,160	21,328	21,496	21,582	21,744	21,906	22,044
	Total	160,645	159,836	161,270	162,514	163,831	165,155	165,831	167,108	168,375	169,463

	Category	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Demand (MW)	HVAC	24.9	24.7	25.0	25.2	25.4	25.6	25.7	25.9	26.1	26.3
	Water Heating	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
	Lighting	3.7	3.6	3.7	3.7	3.7	3.8	3.8	3.8	3.8	3.9
	Appliance	7.7	7.7	7.7	7.8	7.9	7.9	8.0	8.0	8.1	8.1
	Other	8.0	8.0	8.1	8.1	8.2	8.3	8.3	8.4	8.4	8.5
	Total	44.7	44.4	44.9	45.2	45.6	46.0	46.2	46.5	46.9	47.2

Note: MISO Summer Peak

Note: Cumulative Annual Impact

Table 4.5
Non-Residential Economic Potential By End-Use (MWh)

End-Use	Category	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Space Heating	HVAC	2,818	2,803	2,829	2,852	2,877	2,901	2,914	2,937	2,961	2,981
Space Cooling	HVAC	13,693	13,621	13,749	13,861	13,980	14,099	14,160	14,274	14,388	14,486
Ventilation	HVAC	19,423	19,320	19,503	19,662	19,830	19,998	20,085	20,247	20,409	20,548
Water Heating	Water Heating	3,971	3,952	3,986	4,016	4,047	4,079	4,095	4,126	4,156	4,182
Lighting	Lighting	32,061	31,902	32,184	32,429	32,688	32,949	33,082	33,333	33,583	33,797
Cooking	Appliance	515	513	517	521	525	529	531	535	539	542
Refrigeration	Appliance	67,241	66,907	67,499	68,013	68,557	69,104	69,383	69,910	70,433	70,882
Office Equipment	Appliance	0	0	0	0	0	0	0	0	0	0
Other (incl. Process)	Other	20,922	20,819	21,002	21,160	21,328	21,496	21,582	21,744	21,906	22,044
	Total	160,645	159,836	161,270	162,514	163,831	165,155	165,831	167,108	168,375	169,463

Note: Cumulative Annual Impact

Table 4.6
Non-Residential Economic Potential By End-Use (MW - Summer)

End-Use	Category	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Space Heating	HVAC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Space Cooling	HVAC	13.7	13.6	13.7	13.9	14.0	14.1	14.2	14.3	14.4	14.5
Ventilation	HVAC	11.2	11.1	11.2	11.3	11.4	11.5	11.6	11.6	11.7	11.8
Water Heating	Water Heating	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Lighting	Lighting	3.7	3.6	3.7	3.7	3.7	3.8	3.8	3.8	3.8	3.9
Cooking	Appliance	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Refrigeration	Appliance	7.6	7.6	7.7	7.7	7.8	7.8	7.9	7.9	8.0	8.0
Office Equipment	Appliance	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other (incl. Process)	Other	8.0	8.0	8.1	8.1	8.2	8.3	8.3	8.4	8.4	8.5
	Total	44.7	44.4	44.9	45.2	45.6	46.0	46.2	46.5	46.9	47.2

Note: Cumulative Annual Impact

4.4 Achievable Potential

Of the 45 measures that passed the TRC screening test, all measures yielded a benefit-cost greater than one from the participant perspective under the aggressive incremental cost assumption. The following tables present the results of the economic screening for the non-residential achievable potential.

Table 4.7
Non-Residential Achievable Potential By Major End-Use Category

	Category	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Energy (MWh)	HVAC	3,193	5,222	7,754	10,243	12,749	15,256	17,617	20,114	22,608	25,063
	Water Heating	406	693	1,032	1,366	1,703	2,039	2,360	2,695	3,030	3,361
	Lighting	3,032	5,092	7,572	10,017	12,475	14,934	17,272	19,723	22,172	24,587
	Appliance	7,985	13,918	20,737	27,482	34,255	41,031	47,550	54,308	61,061	67,743
	Other	2,289	3,950	5,882	7,791	9,709	11,627	13,468	15,381	17,293	19,183
	Total	16,904	28,875	42,976	56,898	70,889	84,887	98,268	112,221	126,164	139,937

	Category	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Demand (MW)	HVAC	2.2	3.6	5.4	7.1	8.8	10.6	12.2	13.9	15.6	17.3
	Water Heating	0.0	0.1	0.1	0.1	0.2	0.2	0.2	0.3	0.3	0.3
	Lighting	0.3	0.6	0.9	1.1	1.4	1.7	2.0	2.3	2.5	2.8
	Appliance	0.9	1.6	2.4	3.1	3.9	4.7	5.4	6.2	6.9	7.7
	Other	0.9	1.5	2.3	3.0	3.7	4.5	5.2	5.9	6.6	7.4
	Total	4.4	7.4	11.0	14.5	18.0	21.6	25.0	28.5	32.1	35.6

Note: MISO Summer Peak
Note: Cumulative Annual Impact

Table 4.8
Non-Residential Achievable Potential By End-Use (MWh)

End-Use	Category	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Space Heating	HVAC	250	409	608	803	1,000	1,196	1,382	1,577	1,773	1,965
Space Cooling	HVAC	1,217	1,990	2,955	3,903	4,858	5,813	6,713	7,665	8,615	9,550
Ventilation	HVAC	1,726	2,823	4,191	5,536	6,891	8,246	9,523	10,872	12,220	13,547
Water Heating	Water Heating	406	693	1,032	1,366	1,703	2,039	2,360	2,695	3,030	3,361
Lighting	Lighting	3,032	5,092	7,572	10,017	12,475	14,934	17,272	19,723	22,172	24,587
Cooking	Appliance	49	84	125	165	205	246	285	325	365	405
Refrigeration	Appliance	7,935	13,834	20,612	27,317	34,049	40,785	47,266	53,983	60,695	67,338
Office Equipment	Appliance	0	0	0	0	0	0	0	0	0	0
Other (incl. Process)	Other	2,289	3,950	5,882	7,791	9,709	11,627	13,468	15,381	17,293	19,183
	Total	16,904	28,875	42,976	56,898	70,889	84,887	98,268	112,221	126,164	139,937

Note: Cumulative Annual Impact

Table 4.9
Non-Residential Achievable Potential By End-Use (MW - Summer)

End-Use	Category	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Space Heating	HVAC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Space Cooling	HVAC	1.2	2.0	3.0	3.9	4.9	5.8	6.7	7.7	8.6	9.6
Ventilation	HVAC	1.0	1.6	2.4	3.2	4.0	4.7	5.5	6.3	7.0	7.8
Water Heating	Water Heating	0.0	0.1	0.1	0.1	0.2	0.2	0.2	0.3	0.3	0.3
Lighting	Lighting	0.3	0.6	0.9	1.1	1.4	1.7	2.0	2.3	2.5	2.8
Cooking	Appliance	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1
Refrigeration	Appliance	0.9	1.6	2.3	3.1	3.9	4.6	5.4	6.1	6.9	7.6
Office Equipment	Appliance	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other (incl. Process)	Other	0.9	1.5	2.3	3.0	3.7	4.5	5.2	5.9	6.6	7.4
	Total	4.4	7.4	11.0	14.5	18.0	21.6	25.0	28.5	32.1	35.6

Note: Cumulative Annual Impact

4.5 Program Potential

As mentioned in section 3.5, two program scenarios were developed based on $1 million and $2 million total budgets (residential and non-residential combined). The selected incentive level for each of the measures was 35 percent of incremental cost. Of the measures that passed the TRC screening test, 45 measures yielded a benefit-cost greater than one under the program analysis. The following tables present the results of the economic screening for the non-residential program portion of potential under the $1 million budget scenario. The following chart compares graphically the non-residential benefit-cost ratios greater than 1.0 of the top-20 measures. A broad mix of measure-types make up the list.

Figure 4.1
Non-Residential Top 20 Measures By Benefit-Cost Ratio (TRC)

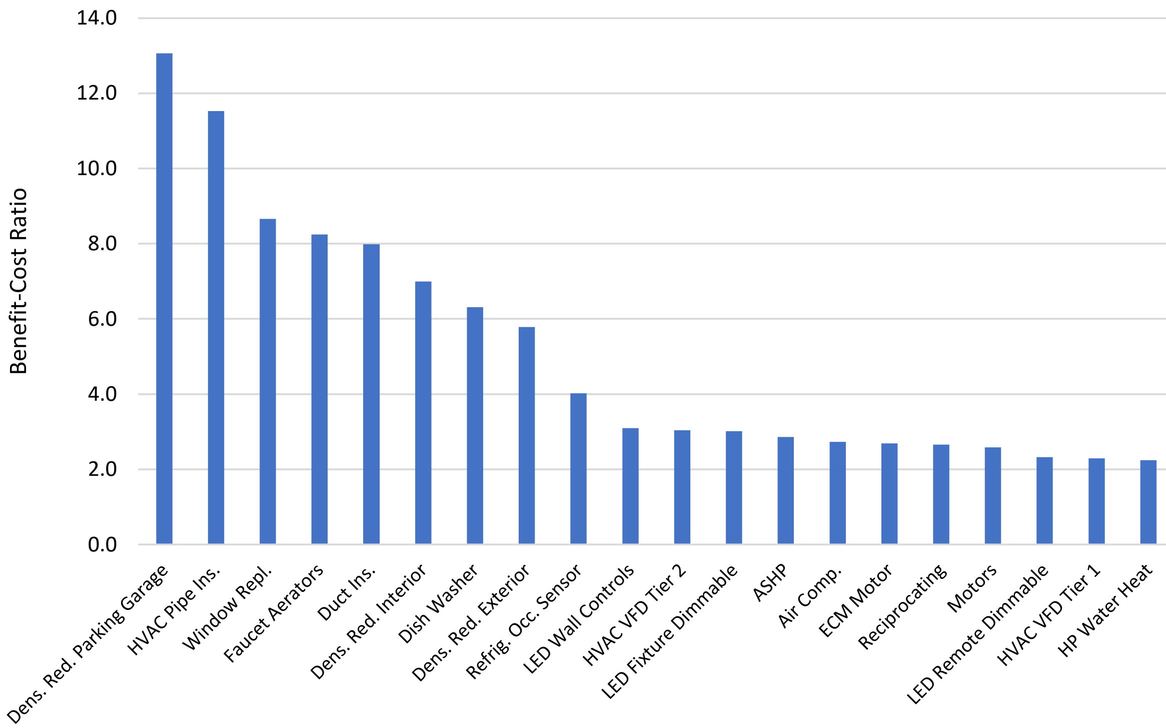


Table 4.10
Non-Residential Program Potential By Major End-Use Category ($1 Million Scenario)

	Category	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Energy (MWh)	HVAC	844	1,688	2,532	3,376	4,219	5,063	5,907	6,751	7,595	8,439
	Water Heating	146	291	437	583	728	874	1,019	1,165	1,311	1,456
	Lighting	954	1,908	2,862	3,816	4,771	5,725	6,679	7,633	8,587	9,541
	Appliance	3,518	7,036	10,553	14,071	17,589	21,107	24,625	28,142	31,660	35,178
	Other	907	1,814	2,721	3,627	4,534	5,441	6,348	7,255	8,162	9,068
	Total	6,368	12,737	19,105	25,473	31,841	38,210	44,578	50,946	57,315	63,683
	Category	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Demand (MW)	HVAC	0.6	1.2	1.7	2.3	2.9	3.5	4.1	4.6	5.2	5.8
	Water Heating	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1
	Lighting	0.1	0.2	0.3	0.4	0.5	0.7	0.8	0.9	1.0	1.1
	Appliance	0.4	0.8	1.2	1.6	2.0	2.4	2.8	3.2	3.6	4.0
	Other	0.3	0.7	1.0	1.4	1.7	2.1	2.4	2.8	3.1	3.5
	Total	1.5	2.9	4.4	5.8	7.3	8.7	10.2	11.6	13.1	14.5

Note: MISO Summer Peak
Note: Cumulative Annual Impact

Table 4.11
Non-Residential Program Potential By End-Use (MWh) ($1 Million Scenario)

End-Use	Category	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Space Heating	HVAC	64	128	192	255	319	383	447	511	575	639
Space Cooling	HVAC	310	621	931	1,242	1,552	1,862	2,173	2,483	2,794	3,104
Ventilation	HVAC	470	939	1,409	1,878	2,348	2,818	3,287	3,757	4,227	4,696
Water Heating	Water Hea	146	291	437	583	728	874	1,019	1,165	1,311	1,456
Lighting	Lighting	954	1,908	2,862	3,816	4,771	5,725	6,679	7,633	8,587	9,541
Cooking	Appliance	16	32	49	65	81	97	113	130	146	162
Refrigeration	Appliance	3,502	7,003	10,505	14,006	17,508	21,010	24,511	28,013	31,514	35,016
Office Equipment	Appliance	0	0	0	0	0	0	0	0	0	0
Other (incl. Process	Other	907	1,814	2,721	3,627	4,534	5,441	6,348	7,255	8,162	9,068
	Total	6,368	12,737	19,105	25,473	31,841	38,210	44,578	50,946	57,315	63,683

Note: Cumulative Annual Impact

Table 4.12
Non-Residential Program Potential By End-Use (MW - Summer) ($1 Million Scenario)

End-Use	Category	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Space Heating	HVAC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Space Cooling	HVAC	0.3	0.6	0.9	1.2	1.6	1.9	2.2	2.5	2.8	3.1
Ventilation	HVAC	0.3	0.5	0.8	1.1	1.4	1.6	1.9	2.2	2.4	2.7
Water Heating	Water Hea	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Lighting	Lighting	0.1	0.2	0.3	0.4	0.5	0.7	0.8	0.9	1.0	1.1
Cooking	Appliance	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Refrigeration	Appliance	0.4	0.8	1.2	1.6	2.0	2.4	2.8	3.2	3.6	4.0
Office Equipment	Appliance	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other (incl. Process	Other	0.3	0.7	1.0	1.4	1.7	2.1	2.4	2.8	3.1	3.5
	Total	1.5	2.9	4.4	5.8	7.3	8.7	10.2	11.6	13.1	14.5

Note: Cumulative Annual Impact

Table 4.13
Non-Residential Program Potential By Major End-Use Category ($2 Million Scenario)

	Category	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Energy (MWh)	HVAC	1,623	3,246	4,869	6,491	8,114	9,737	11,360	12,983	14,606	16,229
	Water Heating	280	560	840	1,120	1,400	1,680	1,961	2,241	2,521	2,801
	Lighting	1,835	3,670	5,505	7,339	9,174	11,009	12,844	14,679	16,514	18,349
	Appliance	6,765	13,530	20,295	27,060	33,825	40,590	47,355	54,120	60,885	67,650
	Other	1,744	3,488	5,232	6,976	8,720	10,463	12,207	13,951	15,695	17,439
	Total	12,247	24,493	36,740	48,987	61,233	73,480	85,727	97,974	110,220	122,467
	Category	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Demand (MW)	HVAC	1.1	2.2	3.3	4.5	5.6	6.7	7.8	8.9	10.0	11.2
	Water Heating	0.0	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.3	0.3
	Lighting	0.2	0.4	0.6	0.8	1.0	1.3	1.5	1.7	1.9	2.1
	Appliance	0.8	1.5	2.3	3.1	3.8	4.6	5.4	6.2	6.9	7.7
	Other	0.7	1.3	2.0	2.7	3.4	4.0	4.7	5.4	6.0	6.7
	Total	2.8	5.6	8.4	11.2	14.0	16.8	19.6	22.3	25.1	27.9

Note: MISO Summer Peak

Note: Cumulative Annual Impact

SECTION 5

DEMAND RESPONSE ANALYSIS

5.0 Demand Response Analysis

5.1 Introduction

In recent years, more electric utilities around the country have implemented both load control programs and innovative pricing techniques to achieve reductions in peak demand for power. Currently about 50% of investor-owned utilities nationwide offer optional time-differentiated rates for residential customers.[8] At present, less than 2% residential customers have elected to use them, but this is changing rapidly. Following several large-scale pilots, California is in the process of implementing default TOU rates for all regulated electric utilities that will apply to more than 20 million customers.

A recent report by the Brattle Group reviewed existing demand response (DR) in the U.S. It showed existing peak capacity could be reduced by 6.7 percent of current load under existing structures and systems. The report also highlighted that traditional DR deployment has largely stagnated and that new, more flexible and complex systems would be needed to expand the penetration of DR.

The benefits of load management and more accurate and transparent wholesale price signals can result in resource cost reductions by forestalling generation, transmission, and distribution investment. This section describes a number of these measures and presents multi-perspective model results for consideration.

5.2 Demand Response Considerations

There are several factors to consider in the evaluation of load control and time-differentiated pricing. This section discusses some of these factors.

5.2.1 Demand Response Benefits and Costs

When properly designed and implemented, time-differentiated power pricing and load control can provide certain benefits, including:

- Reductions in customers' bills by shifting usage to lower cost periods or avoidance of high cost periods.
- Reductions in power consumption during high-cost periods that may serve to avoid future capital investment and operating costs required to meet peak demand.
- Closer alignment with actual cost causation principles by having retail electric rates reflective of marginal generation costs (better price signals).

There are also potential costs and barriers associated with time-differentiated pricing and load control. These can include:

- Metering Infrastructure:
    - Advanced metering infrastructure (AMI), which allows for measurement and data collection of high frequency time stamped energy use, is not required for time-of-use (TOU) rates because the period and pricing are fixed up-front. Meters would, however, need to be set up and programmed for TOU metering.
    - AMI interval metering is required for load management, real-time pricing, critical peak pricing, and peak-time rebate programs.

[8] Brattle Group, 2019

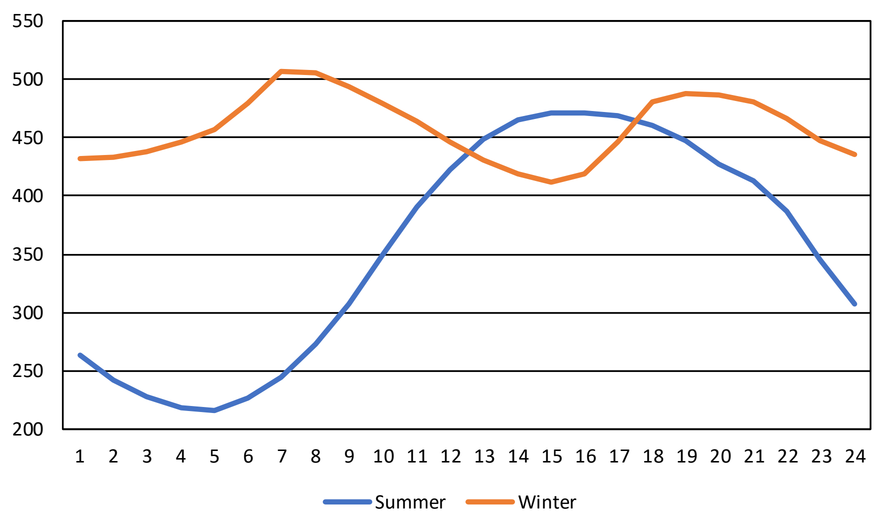
- The cost of devices that enable greater savings and usage control under the program. For example, some utilities provide free smart thermostats to customers that enroll in TOU programs to enable load shifting and increase program benefits.
- Inconvenience, loss of comfort, or even health and safety issues for consumers when reducing air-conditioning or space heating usage on, respectively, very hot or cold days, or shifting power consuming activities to inconvenient times of day.
- Increased customer exposure to volatile wholesale power prices.
- Higher bills for those customers with higher on-peak consumption that is difficult or impossible to avoid.
- Administrative burdens associated with rate studies (to design the rates), load management, metering, billing, and back office functions.

5.2.2 Demand Response Structural Considerations

Designing successful demand response programs involves substantial up-front analysis of key system data. A review of Big Rivers' system load shape during seasonal peak days over the past five years reveals several insights into Big Rivers' load profile and the implications for load management:

- The summer afternoon/evening load shape is very flat from 2:00pm to 8:00pm. Any shifting of load to off-peak periods would need a load control strategy lasting many hours and could prove to be extremely difficult due to member acceptance and comfort issues.
- Big Rivers' winter peak demand generally occurs during the morning hours, however the difference between morning and evening peaks is so close that any load control would likely need to cover both periods, making it difficult to find adequate time to shift load.

Figure 5.1
Big Rivers Average Peak Day Load Shape 2015-2019 (MW)



There is one very important caveat to the discussion of load management as it pertains to demand response. All the analysis and modeling is backward looking with perfect knowledge of the daily load shape and makes the assumption that Big Rivers would be able to hit the peak hours 100 percent of the time. In actual practice, predicting any day's hourly loads is far more difficult to achieve and would likely require longer periods of control that still would have an error rate attached that would make actual experience less accurate. This can have impacts on customer acceptance and comfort.

5.2.3 Dynamic Market Pricing Structural Considerations

To provide appropriate price signals to member utilities, and subsequently to end-users through retail rate design, wholesale power rates should follow generation and transmission cost drivers. For example, if the generating utility's demand-related costs are driven by the necessity of meeting system coincident peak demand, its demand charges should be based on some measure of the member's contribution to the system coincident peak. Since energy-related costs vary with the time-of-day during which energy is consumed, wholesale energy rates should be time-differentiated. TOU pilot programs around the U.S. and elsewhere can provide some lessons:

- Participants respond to on-peak/off-peak price differentials by reducing on-peak power usage. The ratio of the on-peak price to the off-peak prices creates the incentive for load reductions during on-peak periods and, not surprisingly, is the primary driver of customer response to TOU rates. The bigger the on-peak to off-peak price ratio, the bigger the response. A review of recent economic studies of various TOU programs around the country indicates that customer response is minimal with on-peak to off-peak price ratios of less than 2/1, resulting in on-peak usage reductions of only 1% to 8%. Ratios of between 5/1 and 10/1 can produce load shifts of between 10% to 25%. The highest response to TOU rate is found among customers with larger homes, higher household income and retirees.[9]
- Higher response rates depend on the availability of enabling technologies. Enabling technologies include programmable thermostats, advanced thermostats, timer controls on water heaters, "4-hour delay" buttons already on most dishwashers, washing machines and dryers manufactured since 1995, and the "smart" appliances that are currently beginning to appear on the market.
- Customer education is critical to TOU program success, ranging from providing information on when peak, off-peak and super peak periods are in effect, advising customers on ways to reduce usage during on-peak periods, providing reminders seasonally or otherwise and, especially, making enabling technologies available through participation in the program. Customers tend to participate in voluntary TOU rate programs if they think they will save money.
- Rate design is critically important. If the TOU rate is designed properly, an average residential customer who does not change their behavior should be revenue neutral (i.e. they should pay the same). However, no individual within a customer class is "average", so to a limited extent there will be winners and losers among consumers that do not change their previous usage patterns in response to time-differentiated price signals. Those with high on-peak demands and little flexibility will likely pay higher rates under a TOU structure.
- Underestimating the cost and effort associated with billing, customer information system modifications, customer service representative training and other operational efforts necessary to implement time-differentiated rates can affect success of these programs.

The results presented below are generalized to gauge the relative effectiveness of these two options. Before any program could be implemented, significant additional downstream analysis would be required. This includes detailed load research studies to determine if implementation would be successful.

[9] Utility Dive 2019, Iowa Power Study 1993, Brattle Group 2019

5.3 Load Management and Control

This section presents the options for load management that were evaluated as part of this study.

5.3.1 Background

Load management includes the interruption of select appliances or portions of load, either for brief or extended periods. While large commercial and industrial (C&I) end-users have the largest curtailable loads and often provide the majority of peak load reduction potential (especially in more urban areas), some utilities aggregate small but equally valuable loads in the residential sector such as air conditioning and electric water heating for load management purposes. These programs can be voluntary (if appropriately metered) or automatic and can rely on aggregate power savings or utilize advanced metering and meter-reading devices. The following load control measures were evaluated in the economic screening:

- Cycling of central air conditioning (25%)
- Cycling of central air conditioning (50%)
- Cycling of electric water heating (25%)
- Cycling of electric water heating (50%)
- Peak-Time Rebate (Residential)
- Direct Load Control (Non-Residential)

5.3.2 Central-Air Conditioner Cycling

Cycling of central air-conditioners attempts to “flatten” the peak, shifting load to hours outside the peak window. Care needs to be exercised so that a secondary bounce-back peak does not occur. For the purposes of this study, two options were evaluated. The first looked at four cycling groups such that only 25 percent of air conditioners were controlled at any moment during the peak period while the second evaluated two control groups (50% control). The control window was assumed to an afternoon summer peak window of six hours. Table 5.1 presents the results. Neither option passed the three perspectives shown below (Total Resource Cost, Utility and Participant).

Table 5.1
Central Air Conditioner Cycling Program Benefit-Cost Ratios

Program	TRC	Utility	Participant
Air Conditioner Cycling (25%)	0.5	0.2	2.2
Air Conditioner Cycling (50%)	1.0	0.5	2.2

5.3.3 Electric Storage Water Heater Cycling

Like air-conditioners, a cycling program was developed for water heating assuming the same set of criteria. Table 5.2 presents the results of the water heater cycling options modeled. Neither option passed all three perspective analyses in the table below.

Table 5.2
Electric Storage Water Heater Cycling Program Benefit-Cost Ratios

Program	TRC	Utility	Participant
Water Heater Cycling (25%)	0.1	0.0	2.2
Water Heater Cycling (50%)	0.2	0.1	2.2

5.3.4 Peak-Time Rebate (Residential)

Peak-time rebates (PTR) are an interesting option for load control in that they rely on voluntary choice by members to control energy use in exchange for a direct bill credit. As such, they do not require expensive equipment to implement. The assumptions for the PTR program modeled include 10 control events per year including approximately 20 hours of event control and an incentive of $1 per kWh reduced. Rebates are calculated using statistical modeling to determine the amount of energy saved during peak periods. Table 5.3 presents the results and shows that this type of program could result in cost-effective reductions.

Table 5.3
Peak-Time Rebate (PTR) Program Benefit-Cost Ratios

Program	TRC	Utility	Participant
Residential PTR	8.1	1.0	5.8

5.3.5 Direct Load Control (Non-Residential)

Direct load control of non-residential facilities (in part or whole) is most often paired with backup generation equipment to avoid loss of production for the commercial and industrial entities. The assumptions utilized here include 350 kW of control over the 100 hours each year with the highest MISO market price. Two separate options were evaluated. One where the ownership of the backup equipment rests with the end-user and the other where Big Rivers would own the equipment.[10] The differential between the market price and system average market rate was split between the end-user and Big Rivers as an incentive.

Table 5.4
Direct Load Control (DLC) Program Benefit-Cost Ratios

Program	TRC	Utility	Participant
DLC (Customer Ownership)	0.8	18.7	0.3
DLC (Utility Ownership)	0.8	0.7	1.3

5.4 Dynamic Pricing and Rate Options

Time-differentiated rates have been increasingly proposed and implemented in recent years. Time-differentiated rates allow utilities to charge customers not only based on how much energy they consume, but when they consume it, and are therefore more closely related to cost incurrence than flat rates.

5.4.1 Background

Time-differentiated rate structures include time-of-use (TOU), critical peak pricing (CPP), and real-time pricing (RTP). The most common form of time-differentiated electric rates in practice is TOU rates which divide electric usage into two or three blocks according to the time of day in which it is consumed, applying higher rates to historically high cost times. Time-differentiated periods can include on-peak, super peak, shoulder and off-peak, with defined durations and seasonality. Most systems peak on hot summer days, but some systems peak during the winter heating season.

[10] DLC without backup generation was not modeled due to the inherent issues with interrupting economic production in non-residential commercial customers.

CPP rates are designed to shave system peaks during periods when wholesale power prices are very high, typically due to extreme outdoor temperature. RTP rates pass through actual hourly wholesale prices allowing consumers to respond according to their preferences, usually with a look-back period or true-up mechanism.

TOU rates are static but typically subject to periodic power cost adjustment mechanisms. RTP, and CPP rates are dynamic because they reflect actual market power prices and involve notification protocols which alert customers to high cost periods to which they may respond by reducing demand. TOU rates can be implemented using meters with at least as many registers as there are pricing periods. Dynamic pricing, where retail prices vary with real-time system conditions, requires interval meters to implement and communication systems for end-users to monitor prices.

For the purposes of this study, two different time-of-use style rates were evaluated: a time of use rate reflective of Big Rivers' wholesale market (MISO) and a time-of-use rate designed to deter plug-in electric vehicle use during peak periods. A third option looking specifically at plug-in electric vehicles was also evaluated.

- Market-Based Time-of-Use (TOU)
- Market-Based Critical Peak (CPP)
- Plug-In Electric Vehicle TOU

5.4.2 Market-Based TOU

As discussed in section 5.2.3, the differential between on-peak and off-peak price is a critical component to achieving the desired effects of pushing energy use out of the peak window. One of the biggest detriments to implementing this for Big Rivers is the fact that MISO market prices (specifically Zone 6) are very low and the differential between the two periods is small (approximately 1.1 cents per kWh). Despite that fact, two programs were modeled. The first is a standard static TOU rate based on the market price differential between on and off-peak periods. The second was a CPP super-peak based on the highest priced 100 hours where the peak period is approximately six times higher.

The results for both programs show that these programs pass the economic tests despite the lower differentials. This is because all three Big Rivers cooperatives have already implemented AMI-AMR infrastructure, removing a key up-front cost from the analysis. The bigger question, especially for the TOU option is whether the low-price differential would achieve the results assumed here. Research suggests that greater peak to non-peak price ratios are required for meaningful peak kW reduction.[11] Table 5.5 presents the results of the time-of-use pricing program options.

Table 5.5
Time-of-Use Program Benefit-Cost Ratios

Program	TRC	Utility	Participant
Residential TOU	2.9	4.8	4.0
Residential CPP	7.3	12.2	13.3
Non-Residential TOU	3.4	20.5	17.6
Non-Residential CPP	1.3	6.8	6.5

[11] "An Emerging Push…", Utility Dive, 2019.

5.4.3 Plug-In Electric Vehicle TOU

Plug-in electric vehicles (EVs) represent an interesting challenge to utilities. As the vehicle market changes and more plug-in electric vehicles are purchased, the potential capacity and energy impact on utilities could be dramatic once a critical threshold is reached. Current market penetration is low, but sales continue to grow as a percentage of vehicle purchases. A typical level 2 charger can average 4-12 kW in demand (sometimes more). While there is some data to support a diversified kW estimate, the reality of how vehicles will be re-charged in rural areas is still very much unknown and will be based on driving patterns, commute times and battery range.

A review of EV programs around the country shows that there is split between the "punitive" pricing TOU and simply using 5:1 ratio TOUs that apply to all customers.[12] The analysis in Table 5.6 presents the results based on a $0.50 per kWh peak price to incentivize end-users to charge outside of the peak window.

Table 5.6
Electric Vehicle Time-of-Use Program Benefit-Cost Ratios

Program	TRC	Utility	Participant
Plug-In EV TOU	0.6	1.2	5.9

5.5 Summary

While both load control and time-differentiated pricing are worthwhile objectives, they require additional studies and extensive analysis beyond the scope of this study before implementation could occur. Based on the results presented here, we recommend further evaluation with movement in the direction of wholesale pricing based on cost causation to support cost-effective load management incentives.

With the possible exception of the PTR program, based on the information about Big Rivers' peak day load shapes and results obtained from the TRC tests, it is not recommended that Big Rivers pursue an integrated load management program at this time. Big Rivers may wish to re-evaluate load management in the future as its load shape and avoided costs change.

[12] It is assumed the same 5:1 TOU ratio of pricing netting a 10% reduction would apply. Further analysis would be needed to determine if this would be enough to avoid the impending peak increases under a full market transformation scenario.

APPENDIX A

APPLIANCE STANDARDS CHANGE LIST

Product Covered	Initial Legislation	Last Standard Published	Compliance Date	Issued By	Proposed Standards Due	New Final Standard Due	Potential Compliance Date	States With Standard
Residential								
Battery Chargers	EPACT 2005	2016	2018	DOE	2022	2024	2026	CA, OR
Boilers	NAECA 1987	2016	2021	DOE	2022	2024	2029	
Ceiling Fans	EPACT 2005	2017	2020	DOE	2023	2025	2028	
Central Air Conditioners and Heat Pumps	NAECA 1987	2017	2023	DOE	2023	2025	2030	
Clothes Dryers	NAECA 1987	2011	2015	DOE	2017	2019	2022	
Clothes Washers	NAECA 1987	2012	2018	DOE	2018	2020	2024	
Compact Audio Equipment								CA, CT, OR
Computers and Computer Systems				N/A				CA, CO, HI, VT, WA
Cooking Products	NAECA 1987	2009	2012	DOE		2017	2020	
Dehumidifiers	EPACT 2005	2016	2019	DOE	2022	2024	2027	
Direct Heating Equipment *	NAECA 1987	2010	2013	DOE	2019	2021	2024	
Dishwashers *	NAECA 1987	2012	2013	DOE	2019	2021	2024	
DVD Players and Recorders								CA, CT, OR
Electric Vehicle Supply Equipment								
External Power Supplies	EPACT 2005	2014	2016	DOE		2021		CA
Faucets	EPACT 1992	1992	1994	Congress				CA, CO, HI, NY, VT, WA
Furnace Fans	EPACT 2005	2014	2019	DOE	2020	2022	2025	
Furnaces	NAECA 1987	2007	2015	DOE		2016		
Game Consoles				N/A				
Hearth Products				N/A				
Lawn Spray Sprinklers								CA,CO,HI,VT,WA
Microwave Ovens	NAECA 1987	2013	2016	DOE	2019	2021	2024	
Miscellaneous Refrigeration Products		2016	2019	DOE	2022	2024	2027	
Pool Heaters	NAECA 1987	2010	2013	DOE	2016	2018	2021	
Pool Pumps		2017	2021	DOE	2023	2025	2028	
Portable Air Conditioners	NAECA 1987	2020	2025	DOE	2026	2028	2031	CA, CO, VT, WA
Portable Electric Spas								AZ, CA, CO, CT, OR, VT, WA
Refrigerators and Freezers	NAECA 1987	2011	2014	DOE	2017	2019	2022	
Residential Ventilating Fans								CO, VT, WA
Room Air Conditioners	NAECA 1987	2011	2014	DOE	2017	2019	2022	
Set-top Boxes				N/A				
Showerheads	EPACT 1992	19920	1994	Congress				CA, CO, HI, NY, VT, WA
Televisions	NAECA 1987			N/A				CA, CT, OR
Water Heaters	NAECA 1987	2010	2015	DOE	2016	2018	2023	
Commercial/Industrial								
Automatic Commercial Ice Makers	EPACT 2005	2015	2018	DOE	2021	2023	2026	
Commercial Boilers	EPACT 1992	2020	2023	DOE	2026	2028	2031	
Commercial CAC and HP (65,000 Btu/hr to 760,000 Btu/hr)	EPACT 1992	2016	2018	DOE	2022	2024	2029	
Commercial CAC and HP (<65,000 Btu/hr)	EPACT 1992	2015	2017	DOE	2021	2023	2026	
Commercial CAC and HP (Water- and Evaporatively-Cooled)	EPACT 1992	2012	2013	DOE	2018	2020	2023	
Commercial Clothes Washers	EPACT 2005	2014	2018	DOE	2020	2022	2025	
Commercial Dishwashers								CO, VT, WA
Commercial Fryers								CO, VT, WA
Commercial Ovens								
Commercial Refrigeration Equipment	EPACT 2005	2014	2017	DOE		2020	2023	
Commercial Steam Cookers								CO, VT, WA
Commercial Warm Air Furnaces	EPACT 1992	2016	2023	DOE	2022	2024	2029	
Commercial Water Heaters	EPACT 1992	2001	2003	DOE		2018	2021	
Compressors		2020	2025	DOE	2026	2028	2031	CA, CO, VT, WA
Computer Room Air Conditioners	EPACT 1992	2012	2013	DOE		2018	2021	
Distribution Transformers: Liquid-Immersed	EPACT 1992	2013	2016	DOE	2019	2021	2024	
Distribution Transformers: Low-Voltage Dry-Type	EPACT 2005	2013	2016	DOE	2019	2021	2024	
Distribution Transformers: Medium-Voltage Dry-Type	EPACT 1992	2013	2016	DOE	2019	2021	2024	
Electric Motors	EPACT 1992	2014	2016	DOE	2020	2022	2025	
Fans and Blowers	EPACT 1992			N/A				
Hot Food Holding Cabinets								CA, CO, CT, DC, MD, NH, OR, RI, VT, WA
Packaged Terminal AC and HP	EPACT 1992	2015	2017	DOE	2021	2023	2026	

Product Covered	Initial Legislation	Last Standard Published	Compliance Date	Issued By	Proposed Standards Due	New Final Standard Due	Potential Compliance Date	States With Standard
Pre-Rinse Spray Valves	EPACT 2005	2016	2019	DOE	2022	2024	2027	
Pumps, Commercial and Industrial	EPACT 1992	2016	2020	DOE	2022	2024	2027	
Single Package Vertical Air Conditioners and Heat Pumps	EPACT 1992	2015	2019	DOE	2021	2023	2026	
Small Electric Motors	EPACT 1992	2010	2015	DOE	2016	2018	2021	
Uninterruptible Power Supplies	EPACT 2005	2020	2020	DOE	2026	2028	2030	CO, VT, WA
Unit Heaters	EPACT 2005	2005	2008	Congress				
Vending Machines	EPACT 2005	2016	2019	DOE	2022	2024	2027	
Walk-In Coolers and Freezers	EISA 2007	2014	2017	DOE		2020	2023	
Water-Source Heat Pumps	EPACT 1992	2015	2015	DOE	2021	2023	2026	
Lighting								
Candelabra & Intermediate Base Incandescent Lamps		2007	2012	Congress				
Ceiling Fan Light Kits	EPACT 2005	2016	2019	DOE	2022	2024	2027	
Compact Fluorescent Lamps	EPACT 2005	2005	2006	Congress				
Deep-Dimming Fluorescent Ballasts								CA
Fluorescent Lamp Ballasts	NAECA 1988 1988	2011	2014	DOE	2017	2019	2022	
General Service Fluorescent Lamps	EPACT 1992	2015	2018	DOE	2021	2023	2026	
General Service Lamps	EISA 2007	2007	2012	Congress		2022	2025	CA, CO, NV, VT, WA
HID Lamps	EPACT 1992	2015		DOE	2018	2020	2023	
High Light Output Double-Ended Quartz Halogen Lamps								OR
High-CRI Linear Fluorescent Lamps								CO, HI, VT, WA
Illuminated Exit Signs	EPACT 2005	2005	2006	Congress				
Incandescent Reflector Lamps	EPACT 1992	2009	2012	DOE		2014	2017	
Luminaires	EPACT 1992			N/A				
Mercury Vapor Lamp Ballasts	EPACT 2005	2005	2008	Congress				
Metal Halide Lamp Fixtures	EISA 2007	2014	2017	DOE		2019	2022	CA
Small-Diameter Directional Lamps								CA
Torchiere Lighting Fixtures	EPACT 2005	2005	2006	Congress				
Traffic Signals	EPACT 2005	2005	2006	Congress				

APPENDIX B

DEMAND-SIDE MEASURE LIST

Qualitative Screening Results - Residential

Big Rivers Electric Cooperative

	Class	Category	Measure	Qualitative	Notes
1	Residential	Appliance	Clothes Dryer – Electric - Energy Star	Pass	
2	Residential	Appliance	Clothes Dryer – gas - Energy Star	Fail	Utility match
3	Residential	Appliance	Clothes Washer ENERGY STAR, Electric Water heater, Electric Dryer	Pass	
4	Residential	Appliance	Clothes Washer ENERGY STAR, Electric Water heater, Gas Dryer	Pass	
5	Residential	Appliance	Clothes Washer ENERGY STAR, Gas water heater, Electric dryer	Fail	Utility match
6	Residential	Appliance	Clothes Washer ENERGY STAR, Gas water heater, Gas dryer	Fail	Utility match
7	Residential	Appliance	ENERGY STAR Personal Computer	Fail	Market transformation
8	Residential	Appliance	ENERGY STAR Computer Monitor	Fail	Market transformation
9	Residential	Appliance	ENERGY STAR Computer Printer/copier	Fail	Market transformation
10	Residential	Appliance	ENERGY STAR Dishwasher - elec water heater	Pass	
11	Residential	Appliance	ENERGY STAR Dishwasher - gas water heater	Fail	Utility match
12	Residential	Appliance	Energy Star Televisions	Fail	Market transformation
13	Residential	Appliance	ENERGY STAR TV + 20% (<30")	Fail	Market transformation
14	Residential	Appliance	ENERGY STAR TV + 20% (31-50")	Fail	Market transformation
15	Residential	Appliance	ENERGY STAR TV + 20% (over 50")	Fail	Market transformation
16	Residential	Appliance	Freezer Coil Cleaning	Pass	
17	Residential	Appliance	Freezer Recycling	Pass	
18	Residential	Appliance	Freezers ENERGY STAR - Chest Freezer	Pass	
19	Residential	Appliance	Freezers ENERGY STAR - Upright Freezer	Pass	
20	Residential	Appliance	Pool heaters - electric	Fail	BREC low saturation %
21	Residential	Appliance	Pool pumps - ENERGY STAR	Fail	BREC low saturation %
22	Residential	Appliance	Refrigerator Coil Cleaning	Pass	
23	Residential	Appliance	Refrigerator Recycling	Pass	
24	Residential	Appliance	Refrigerators Freezers ENERGY STAR - Bottom Freezer	Pass	
25	Residential	Appliance	Refrigerators Freezers ENERGY STAR - Side by Side	Pass	
26	Residential	Appliance	Refrigerators Freezers ENERGY STAR - Top Freezer	Pass	
27	Residential	Appliance	Smart Power Strip	Pass	
28	Residential	Building Shell	Air Sealing	Pass	
29	Residential	Building Shell	Cool roof	Pass	
30	Residential	Building Shell	Door	Fail	Unlikely to pass economic test
31	Residential	Building Shell	Insulation - Attic/Ceiling	Pass	
32	Residential	Building Shell	Insulation - Basement rim joist	Pass	
33	Residential	Building Shell	Insulation - Wall	Pass	
34	Residential	Building Shell	Storm Windows	Fail	Unlikely to pass economic test
35	Residential	Building Shell	Window Film	Pass	
36	Residential	Building Shell	Windows - ENERGY STAR	Pass	
37	Residential	HVAC	Air Source Heat Pump	Pass	
38	Residential	HVAC	Boiler	Fail	Utility match
39	Residential	HVAC	Central Air Conditioning - New - ENERGY STAR	Pass	
40	Residential	HVAC	Dehumidifier - ENERGY STAR	Pass	
41	Residential	HVAC	Dehumidifier Recycling	Pass	
42	Residential	HVAC	Duct Sealing	Pass	
43	Residential	HVAC	ECM Furnace Fan	Pass	
44	Residential	HVAC	Ground Source Heat Pumps	Pass	
45	Residential	HVAC	Programmable Thermostats	Pass	
46	Residential	HVAC	Residential Central AC Maintenance/Tune Up	Pass	
47	Residential	HVAC	Residential Heating System Tune Up - Electric heat	Pass	
48	Residential	HVAC	Residential Heating System Tune Up - Gas heat	Fail	Utility match
49	Residential	HVAC	Room A/C recycling	Pass	
50	Residential	HVAC	Room Air Conditioning - Energy Star <8,000 BTU/Hr	Pass	
51	Residential	HVAC	Room Air Conditioning - Energy Star >=8,000 BTU/Hr	Pass	
52	Residential	HVAC	Single-Package and Split System Unitary Air Conditioner	Pass	
53	Residential	HVAC	Smart Thermostats	Pass	
54	Residential	HVAC	Ventilation air/heat ERV high-efficiency	Pass	

Qualitative Screening Results - Residential

Big Rivers Electric Cooperative

	Class	Category	Measure	Qualitative	Notes
55	Residential	Lighting	ENERGY STAR Ceiling Fan	Pass	
56	Residential	Lighting	LED Flood PAR (use average values)	Pass	
57	Residential	Lighting	LED Night Light	Pass	
58	Residential	Lighting	LED Task Light	Fail	Low market potential
59	Residential	Lighting	Replace CFL with LED - socket bulbs (use average values)	Pass	
60	Residential	Lighting	Replace fluorescent fixtures w/LED (use average values)	Pass	
61	Residential	Lighting	Replace specialty lighting w/ LED (candlabra, etc.)	Fail	Low market potential
62	Residential	Lighting	Security lighting - LED retrofit	Pass	
63	Residential	Miscellaneous	Air Purifier/Cleaner	Pass	
64	Residential	Miscellaneous	Water Cooler	Fail	Low market potential
65	Residential	Multi-Family	Multi-Family Air Sealing	Fail	BREC 94% ownership rate
66	Residential	Multi-Family	Multi-Family Showerheads and Aerators	Fail	BREC 94% ownership rate
67	Residential	Multi-Family	Multi-Family Tank and Pipe Wrap	Fail	BREC 94% ownership rate
68	Residential	Multi-Family	Multi-Family Efficient Lighting	Fail	BREC 94% ownership rate
69	Residential	Multi-Family	Multi-Family HVAC Tune Up	Fail	BREC 94% ownership rate
70	Residential	Multi-Family	Multi-Family Insulation Upgrades	Fail	BREC 94% ownership rate
71	Residential	Multi-Family	Multi-Family Refrigerators and Freezers	Fail	BREC 94% ownership rate
72	Residential	Multi-Family	Multi-Family Thermostats	Fail	BREC 94% ownership rate
73	Residential	Water Heating	Domestic Hot Water Pipe Insulation (Retrofit) w/electric WH	Pass	
74	Residential	Water Heating	Domestic Hot Water Pipe Insulation (Retrofit) w/gas WH	Fail	Utility match
75	Residential	Water Heating	Gravity Film Heat Exchanger GFX electric water heater	Pass	
76	Residential	Water Heating	Gravity Film Heat Exchanger GFX gas water heater	Fail	Utility match
77	Residential	Water Heating	Heat Pump Water Heaters (Time of Sale) - <55 gal.	Pass	
78	Residential	Water Heating	Heat Pump Water Heaters (Time of Sale) - >55 gal.	Pass	
79	Residential	Water Heating	Waterbed Mattress Replacement	Fail	Low market potential
80	Residential	Water Heating	Low Flow Bathroom Faucet Aerator (Retrofit) w/electric WH	Pass	
81	Residential	Water Heating	Low Flow Bathroom Faucet Aerator (Retrofit) w/gas WH	Fail	Utility match
82	Residential	Water Heating	Low Flow Kitchen Faucet Aerator (Retrofit) w/electric WH	Pass	
83	Residential	Water Heating	Low Flow Kitchen Faucet Aerator (Retrofit) w/gas WH	Fail	Utility match
84	Residential	Water Heating	Low Flow Showerhead (Retrofit) w/electric WH	Pass	
85	Residential	Water Heating	Low Flow Showerhead (Retrofit) w/gas WH	Fail	Utility match
86	Residential	Water Heating	Shower Start with Shower Head 1.75 gpm electric water heater	Pass	
87	Residential	Water Heating	Shower Start with Shower Head 1.75 gpm gas water heater	Fail	Utility match
88	Residential	Water Heating	Solar Water Heater with Electric Backup (Retrofit)	Fail	Utility match
89	Residential	Water Heating	Solar Water Heater with gas Backup (Retrofit)	Fail	Utility match
90	Residential	Water Heating	Thermostatic Restrictor Shower Valve	Pass	
91	Residential	Water Heating	Water Heater - High Efficiency ELECTRIC	Pass	
92	Residential	Water Heating	Water Heater - High Efficiency GAS	Fail	Utility match
93	Residential	Water Heating	Water Heater Wrap (Direct Install) w/electric WH	Pass	
94	Residential	Water Heating	Water Heater Wrap (Direct Install) w/gas WH	Fail	Utility match
95	Residential	Load Management	Water Heater Cycling - 25%	Pass	
96	Residential	Load Management	Water Heater Cycling - 50%	Pass	
97	Residential	Load Management	Air Conditioner Cycling - 25%	Pass	
98	Residential	Load Management	Air Conditioner Cycling - 50%	Pass	
99	Residential	Load Management	Peak Time Rebate Program	Pass	

Qualitative Screening Results - Commercial

Big Rivers Electric Cooperative

	Class	Category	Measure	Qualitative	Notes
1	Commercial	Building Shell	Commercial Air Filtration	Pass	
2	Commercial	Building Shell	Commercial Window Film	Pass	
3	Commercial	Building Shell	Cool Roof	Pass	
4	Commercial	Building Shell	High Performance Glazing	Pass	
5	Commercial	Building Shell	Roof Insulation	Pass	
6	Commercial	Building Shell	Window glazing/sealing	Pass	
7	Commercial	Building Shell	Window replacement	Pass	
8	Commercial	Cooking	Combination Oven	Pass	
9	Commercial	Cooking	Convection Oven	Pass	
10	Commercial	Cooking	ENERGY STAR Fryers	Pass	
11	Commercial	Cooking	ENERGY STAR Griddle	Pass	
12	Commercial	Cooking	Infrared Charbroiler	Fail	Utility match
13	Commercial	Cooking	Infrared Rotisserie Oven	Fail	Utility match
14	Commercial	Cooking	Infrared Salamander Broiler	Fail	Utility match
15	Commercial	Cooking	Kitchen Demand Ventilation Controls	Pass	
16	Commercial	Cooking	Rack Oven	Fail	Utility match
17	Commercial	Cooking	Steam Cookers	Pass	
18	Commercial	HVAC	Advanced RTU Controls	Pass	
19	Commercial	HVAC	Boiler	Fail	Utility match
20	Commercial	HVAC	Chilled Water Reset Controls	Pass	
21	Commercial	HVAC	Commercial HVAC Maintenance/Tune Up - Electric heat	Pass	
22	Commercial	HVAC	Commercial HVAC Maintenance/Tune Up - Gas heat	Fail	Utility match
23	Commercial	HVAC	ECM motors on furnaces	Pass	
24	Commercial	HVAC	Electric Chiller	Pass	
25	Commercial	HVAC	ENERGY STAR Room Air Conditioner for Commercial Use	Pass	
26	Commercial	HVAC	Heat Pump Systems	Pass	
27	Commercial	HVAC	High Speed Fans	Pass	
28	Commercial	HVAC	High Volume Low Speed Fans	Pass	
29	Commercial	HVAC	Insulating HVAC Supply Ductwork in Unconditioned Space	Pass	
30	Commercial	HVAC	Outside Air Economizer with Dual-Enthalpy Sensors	Pass	
31	Commercial	HVAC	Refrigeration Suction and Liquid Pipe Insulation - HVAC	Pass	
32	Commercial	HVAC	Single-Package and Split System Unitary Air Conditioners	Pass	
33	Commercial	HVAC	Variable Frequency Drives for HVAC Applications	Pass	
34	Commercial	Lighting	Ballast replace magnetic w/electric	Pass	
35	Commercial	Lighting	C&I Lighting Controls (daylighting & Occ. Sensors)	Pass	
36	Commercial	Lighting	C&I Lighting Occupancy Sensors	Pass	
37	Commercial	Lighting	Interior Highbay LED Fixtures	Pass	
38	Commercial	Lighting	Interior Lowbay LED Fixtures	Pass	
39	Commercial	Lighting	LED Case Lighting with/without Motion Sensors	Pass	
40	Commercial	Lighting	LED Exit Signs	Pass	
41	Commercial	Lighting	LED Grow Light	Fail	Small market potential
42	Commercial	Lighting	LED replace fluorescent tubes	Pass	
43	Commercial	Lighting	Light Tube Commercial Skylight	Pass	
44	Commercial	Lighting	Lighting Power Density Reduction (and de-lamping)	Pass	
45	Commercial	Lighting	Lighting Systems (Non-Controls)	Pass	
46	Commercial	Lighting	Security lights - LED retrofit	Pass	
47	Commercial	Lighting	Traffic Signals	Fail	Utility match
48	Commercial	Other	Clothes Washer ENERGY STAR, Electric Water heater, Electric Dryer	Pass	
49	Commercial	Other	Clothes Washer ENERGY STAR, Electric Water heater, Gas Dryer	Pass	
50	Commercial	Other	Clothes Washer ENERGY STAR, Gas water heater, Electric dryer	Fail	Utility match
51	Commercial	Other	Clothes Washer ENERGY STAR, Gas water heater, Gas dryer	Fail	Utility match

Qualitative Screening Results - Commercial

Big Rivers Electric Cooperative

	Class	Category	Measure	Qualitative	Notes
52	Commercial	Other	Commercial Plug Load – Smart Strip Plug Outlets	Pass	
53	Commercial	Other	Efficient New (VSD) Air Compressors	Pass	
54	Commercial	Other	Air Compressors - Tune up	Pass	
55	Commercial	Other	ENERGY STAR Ice Machine	Pass	
56	Commercial	Other	ES Restaurant Dishwasher, High Temp - Electric water heat	Pass	
57	Commercial	Other	ES Restaurant Dishwasher, High Temp - Gas water heat	Fail	Utility match
58	Commercial	Other	High Efficiency Hand Dryer	Pass	
59	Commercial	Other	High Efficiency Pumps and Pumping Efficiency Improvements	Pass	
60	Commercial	Other	High Efficiency Commercial Clothes Washer	Pass	
61	Commercial	Other	High Efficiency Motors	Pass	
62	Commercial	Other	Plug Load Occupancy Sensor	Pass	
63	Commercial	Other	Spray Nozzles for Food Service - Electric water heat	Pass	
64	Commercial	Other	Spray Nozzles for Food Service - Gas water heat	Fail	Utility match
65	Commercial	Other	Variable Frequency Drives (VFDs)	Pass	
66	Commercial	Other	Vending Machine Occupancy Sensors	Pass	
67	Commercial	Refrigeration	Automatic Door Closers for Refrigerated Walk-in Coolers/Freezers	Pass	
68	Commercial	Refrigeration	Commercial fridge/freezers occupancy sensors	Pass	
69	Commercial	Refrigeration	Door Gaskets - Cooler and Freezer	Pass	
70	Commercial	Refrigeration	Door Heater Controls for Cooler or Freezer	Pass	
71	Commercial	Refrigeration	Refrigerated Case Covers	Pass	
72	Commercial	Refrigeration	Refrigeration tune up	Pass	
73	Commercial	Refrigeration	Solid Door Refrigerators & Freezers	Pass	
74	Commercial	Refrigeration	Strip Curtain for Walk-in Coolers and Freezers	Pass	
75	Commercial	Refrigeration	Walk-in Cooler Evaporator Motor Reduction	Pass	
76	Commercial	Water Heating	Bathroom faucet aerators - Electric water heat	Pass	
77	Commercial	Water Heating	Bathroom faucet aerators - Gas water heat	Fail	Utility match
78	Commercial	Water Heating	Condensing Water Heater (Gas)	Fail	Utility match
79	Commercial	Water Heating	Heat Pump Water Heaters	Pass	
80	Commercial	Water Heating	High Efficiency Indirect Water Heater (Gas)	Fail	Utility match
81	Commercial	Water Heating	High Efficiency Storage Tank Water Heater - Electric	Pass	
82	Commercial	Water Heating	High Efficiency Storage Tank Water Heater - Gas	Fail	Utility match
83	Commercial	Water Heating	High Efficiency Tankless Water Heater (Gas)	Fail	Utility match
84	Commercial	Water Heating	High Efficiency Water Heater - Electric	Pass	
85	Commercial	Water Heating	High Efficiency Water Heater - Gas	Fail	Utility match
86	Commercial	Water Heating	Hot water heater tank wrap - Electric water heat	Pass	
87	Commercial	Water Heating	Hot water pipe wrap - Electric water heat	Pass	
88	Commercial	Water Heating	Hot water pipe wrap - Gas water heat	Fail	Utility match
89	Commercial	Water Heating	Low Flow Showerhead	Pass	
90	Commercial	Water Heating	Low Flow Showerhead (Gas)	Fail	Utility match
91	Commercial	Water Heating	Ozone Laundry	Pass	
92	Commercial	Water Heating	Pool Heater	Fail	Small market potential
93	Commercial	Water Heating	Pool/Spa Cover	Fail	Small market potential
94	Commercial	Water Heating	Pre-Rinse Spray Valve (Gas)	Fail	Utility match
95	Commercial	Water Heating	Steam Trap (Repair/Replace) (Gas)	Fail	Utility match
96	Commercial	Load Management	Facility Load Control	Pass	
97	Commercial	Load Management	Peak Time Rebate Program	Pass	

APPENDIX C

MULTI-PERSPECTIVE MODEL RESULTS

Big Rivers Electric Corporation

Energy Efficiency Program Evaluation Summary - Residential

April 2020

Class	Measure	Measure Code	Annual kWh	Summer Peak kW	Winter Peak kW	Participant	Program	Total Resource Cost	RIM	Lifetime $/kWh	Simple Payback (yrs)
Water Heat	Hot Water Pipe Wrap	WH Pipe Wrap	242	0.03	0.03	47.7	39.4	15.9	0.3	$0.008	1.9
Water Heat	Low Flow Faucet Aerator Replacement	LF Faucet	77	0.01	0.01	32.8	26.7	10.7	0.3	$0.010	2.2
Appliance	Clothes Washer	Clothes Washer	279	0.04	0.04	10.7	2.9	3.4	0.4	$0.038	0.0
Water Heat	Shower Start Showerhead	Showerstart	394	0.02	0.02	8.4	6.5	2.6	0.3	$0.008	0.6
Shell	Sidewall Insulation Retrofit	Sidewall Insulation	1297	0.16	0.30	6.9	6.2	2.5	0.4	$0.004	1.8
Appliance	Refrigerator Removal and Recycling	Refrig. Removal	1027	0.13	0.13	6.1	1.5	1.8	0.3	$0.002	0.0
Shell	Exterior Windows Upgrade	Windows	363	0.06	0.12	4.7	4.3	1.7	0.4	$0.007	2.6
Appliance	Freezer Removal and Recycling	Freezer Removal	894	0.15	0.15	5.4	1.4	1.6	0.4	$0.057	0.0
Water Heat	Low Flow Showerhead Replacement	LF Showerhead	186	0.01	0.01	5.0	3.8	1.5	0.3	$0.001	0.2
Shell	Attic Insulation Retrofit	Attic Insulation	5187	0.32	1.28	4.4	3.6	1.5	0.4	$0.007	2.9
HVAC	High Efficiency Air Source Heat Pump	ASHP	1554	0.30	0.55	4.2	3.5	1.4	0.4	$0.008	2.2
Lighting	LED Lighting Fixture Replacement	LED Fixture	44	0.01	0.00	4.3	3.4	1.4	0.3	$0.007	1.8
Lighting	LED Night Light	LED Nightlight	22	0.00	0.00	4.7	3.3	1.3	0.3	$0.009	2.1
Lighting	LED Lighting Retrofit	LED Lighting	5	0.00	0.01	4.6	3.3	1.3	0.3	$0.008	1.4
Shell	Wall Insulation Retrofit	Wall Insulation	2596	0.04	0.67	3.7	2.9	1.2	0.4	$0.009	3.5
Lighting	LED Flood	LED Flood	54	0.00	0.01	3.9	2.7	1.1	0.3	$0.026	4.0
Water Heat	Heat Pump Water Heater	HPWH>55	3366	0.34	0.87	3.5	2.8	1.1	0.3	$0.009	2.1
Water Heat	Heat Pump Water Heater	HPWH<55	2732	0.27	0.71	3.4	2.8	1.0	0.3	$0.010	2.2
HVAC	Room AC Recycling	Room AC Recyc.	113	0.11	0.00	2.0	2.1	0.8	0.4	$0.022	0.7
Appliance	Smart Strip	Smart Strip	59	0.01	0.01	3.5	0.7	0.8	0.3	$0.000	0.0
Appliance	Clothes Dryer	Clothes Dryer	160	0.03	0.03	3.4	0.7	0.8	0.4	$0.025	3.9
Water Heat	Water Heater Wrap	WH Tank Wrap	99	0.01	0.01	2.6	1.9	0.8	0.3	$0.015	2.4
Water Heat	Thermostatic Restriction Valve	Therm. Restr.	78	0.01	0.01	2.5	1.8	0.7	0.3	$0.004	0.7
HVAC	Dehumidifier Recycling	Dehumid. Recyc.	139	0.04	0.00	2.3	1.8	0.7	0.5	$0.001	0.2
Appliance	Dishwasher	Dishwasher	84	0.03	0.03	2.6	0.6	0.7	0.3	$0.009	0.0
HVAC	Air Conditioner / Heat Pump Tune Up	HVAC Tune Up	1637	0.28	0.44	2.1	1.6	0.7	0.3	$0.035	5.4
HVAC	Advanced Programmable Thermostat	Adv. Thermostat	286	0.15	0.15	1.7	1.5	0.6	0.3	$0.054	15.4
HVAC	Central Air Conditioning System	Central AC	171	0.15	0.00	1.3	1.3	0.5	0.5	$0.031	8.8
Shell	Air Sealing Retrofit	Air Sealing	577	0.09	0.46	1.6	1.1	0.5	0.3	$0.024	5.8
Lighting	Ceiling Fan	Ceiling Fan	135	0.00	0.00	1.7	1.0	0.4	0.3	$0.039	0.0
HVAC	Duct Sealing Retrofit	Duct Sealing	1107	0.07	0.50	1.5	0.9	0.4	0.4	$0.018	2.2
HVAC	Ground Source Heat Pump	GSHP	5125	0.32	1.35	1.4	0.9	0.4	0.5	$0.086	12.1
HVAC	Standard Programmable Thermostat	Prog. Thermostat	70	0.00	0.00	1.3	0.8	0.3	0.3	$0.029	8.1
HVAC	ECM Furnace Fan	ECM Fan	248	0.20	0.20	0.8	0.5	0.2	0.3	$0.027	8.6
HVAC	Mini-Split System AC	Mini-Split AC	1853	0.06	0.39	0.9	0.5	0.2	0.5	$0.022	2.7
Water Heat	Gravity Film Heat Exchanger (GFX)	GFX	208	0.02	0.02	0.8	0.4	0.1	0.3	$0.001	0.1

Big Rivers Electric Corporation

Energy Efficiency Program Evaluation Summary - C&I

April 2020

Class	Measure	Measure Code	Annual kWh	Summer Peak kW	Winter Peak kW	Participant	Program	Total Resource Cost	RIM	Lifetime $/kWh	Simple Payback (yrs)
Lighting	Lighting Power Density Reduction	Dens. Red. Parking Garage	8,760	1.00	1.00	28.0	32.5	13.1	0.5	$0.001	0.2
HVAC	Insulate HVAC Pipes (boiler/AC)	HVAC Pipe Ins.	113	0.04	0.04	20.6	28.6	11.5	0.6	$0.001	0.5
Shell	Window Replacement Upgrade	Window Repl.	363	0.06	0.00	16.3	21.5	8.7	0.5	$0.001	0.7
Water Heat	Faucet Aerators	Faucet Aerators	279	0.03	0.03	17.7	20.5	8.2	0.5	$0.001	0.3
HVAC	Insulate Ductwork	Duct Ins.	32	0.01	0.01	13.8	19.8	8.0	0.6	$0.002	0.9
Lighting	Lighting Power Density Reduction	Dens. Red. Interior	4,319	1.00	1.00	14.0	17.4	7.0	0.5	$0.002	0.4
Appliance	Commercial Dishwashers	Dish Washer	11,863	1.81	1.81	13.2	15.7	6.3	0.5	$0.002	0.6
Lighting	Lighting Power Density Reduction	Dens. Red. Exterior	2669	1.00	1.00	10.5	14.4	5.8	0.5	$0.002	0.7
Refrigeratior	Occupancy Sensors in Commercial Refrig	Refrig. Occ. Sensor	195	0.02	0.02	9.0	10.0	4.0	0.4	$0.003	0.9
Lighting	LED Lighting Controls	LED Wall Controls	575	0.03	0.05	7.1	7.7	3.1	0.4	$0.004	0.6
HVAC	VFDs for HVAC Applications	HVAC VFD Tier 2	1490	0.22	0.22	6.6	7.5	3.0	0.5	$0.004	1.2
Lighting	LED Lighting Controls	LED Fixture Dimmable	575	0.16	0.16	6.1	7.5	3.0	0.5	$0.004	0.8
HVAC	Hi-Eff Air Source Heat Pump	ASHP	7143	3.57	3.57	5.0	3.9	2.9	0.5	$0.009	1.6
Appliance	Air Compressor Efficiency	Air Comp.	624	0.09	0.09	5.8	6.8	2.7	0.5	$0.005	0.1
HVAC	Commercial ECM Blower Motors for HVAC	ECM Motor	240	0.22	0.22	4.0	6.7	2.7	0.7	$0.007	1.5
HVAC	High Efficiency Water-Cooled Chillers - HVAC	Reciprocating	12789	6.44	0.00	4.5	6.6	2.7	0.6	$0.005	2.3
Appliance	High Efficiency Motors	Motors	7,387	0.41	0.41	6.0	6.4	2.6	0.4	$0.004	1.3
Lighting	LED Lighting Controls	LED Remote Dimmable	575	0.16	0.16	4.7	5.8	2.3	0.5	$0.006	1.0
HVAC	VFDs for HVAC Applications	HVAC VFD Tier 1	1,122	0.16	0.16	5.0	5.7	2.3	0.4	$0.005	1.6
Water Heat	Heat Pump Water Heaters	HP Water Heat	21,156	4.20	4.20	4.8	5.6	2.2	0.5	$0.005	1.7
Refrigeratior	Refrigerator Low-Heat and No-Heat Doors	Low-Heat Doors	6,719	0.69	0.69	5.0	5.4	2.2	0.4	$0.005	1.3
Lighting	LED Exit Sign Retrofit	LED Exit	83	0.10	0.10	2.8	5.3	2.1	0.8	$0.009	3.2
Water Heat	Low-Flow Showerheads	LF Shower	250	0.02	0.02	4.7	5.0	2.0	0.4	$0.006	1.2
HVAC	HVAC Split and Unitary Systems	HVAC SplitSys	2,967	1.48	1.48	3.5	2.4	2.0	0.5	$0.014	3.0
Lighting	LED Lighting Controls	LED Ceiling Controls	575	0.03	0.05	4.7	4.9	2.0	0.4	$0.006	1.0
Lighting	High Bay HID Retrofit	8T8 - 1000W HID	2005	0.46	0.46	3.9	4.5	1.8	0.5	$0.007	1.7
Lighting	High Bay HID Retrofit	8T8 - 1000W HID	2,005	0.46	0.46	3.9	4.5	1.8	0.5	$0.007	1.7
Water Heat	Hot Water Pipe Wrap	WH Pipe Wrap	14	0.01	0.01	2.9	4.4	1.8	0.6	$0.009	3.8
Refrigeratior	Refrigerator Automatic Door Closers	Refrig. Closers	1,625	0.22	0.22	3.9	4.3	1.7	0.4	$0.007	1.2
HVAC	Window Air Conditioning for C&I	Window AC	52	0.06	0.00	2.2	4.2	1.7	0.7	$0.011	5.0
Lighting	High Bay HID Retrofit	4T5-250W HID	882	0.20	0.20	3.5	4.1	1.6	0.5	$0.007	1.9
Lighting	High Bay HID Retrofit	6T8 - 400W HID	961	0.22	0.22	3.3	3.7	1.5	0.5	$0.008	2.1
Cooking	Commercial Ovens & Fryers	Ovens	1879	0.43	0.43	3.1	3.5	1.4	0.4	$0.008	2.2
Appliance	Commercial Advanced Power Strips	Adv. Power Strip	354	0.04	0.04	3.1	3.3	1.3	0.4	$0.009	1.7
Appliance	High Efficiency Pumps	Hi-E Pumps >=5hp	201	0.05	0.05	2.8	3.3	1.3	0.5	$0.009	3.0
Cooking	Steam Cookers	6-pan	15170	3.46	3.46	2.9	3.2	1.3	0.4	$0.009	2.4
Cooking	Steam Cookers	5-pan	13139	3.16	3.16	2.6	2.8	1.1	0.4	$0.011	2.8
Lighting	High Bay HID Retrofit	4T8 - 250W HID	616	0.14	0.14	2.6	2.8	1.1	0.4	$0.011	2.8
Appliance	Variable Frequency Drives	VFD >=5hp	1,082	0.23	0.23	2.5	2.8	1.1	0.4	$0.010	3.4
Cooking	Steam Cookers	4-pan	12159	2.85	2.85	2.4	2.6	1.0	0.4	$0.011	3.0
Lighting	LED Lighting Controls	LED Fixture Controls	575	0.03	0.05	2.6	2.6	1.0	0.4	$0.011	1.9
HVAC	Guest Room Energy Management	HVAC Sensors	1,114	0.00	0.00	2.6	2.6	1.0	0.4	$0.011	2.0
Appliance	Commercial Vending Machine Controls	Vending Controls	800	0.04	0.04	2.6	2.5	1.0	0.4	$0.011	2.4
HVAC	Rooftop Unit Controls	RTU Control	1,275	0.92	0.92	1.8	2.4	1.0	0.5	$0.017	3.7
Cooking	Steam Cookers	3-pan	11188	2.55	2.55	2.2	2.4	1.0	0.4	$0.012	3.3
Lighting	LEDs Replace Fluorescent Tubes	Grow Light	4	0.00	0.00	2.2	2.3	0.9	0.4	$0.013	3.1
Lighting	High Bay HID Retrofit	3T5-250W HID	449	0.10	0.10	2.1	2.2	0.9	0.4	$0.013	3.5

Lighting	High Bay HID Retrofit	8T8 - 400W HID	649	0.15	0.15	2.1	2.2	0.9	0.4	$0.013	3.5
HVAC	High Efficiency Water-Cooled Chillers - HVAC	Chiller-Water	19184	9.66	0.00	1.7	2.1	0.8	0.5	$0.017	7.2
HVAC	High-Efficiency Fans (High and Low Speed)	Fans	10018	0.00	0.00	1.7	1.9	0.8	0.4	$0.017	3.8
Appliance	High Efficiency Pumps	Hi-E Pumps <=5hp	201	0.05	0.05	1.8	1.9	0.8	0.4	$0.016	5.1
Appliance	Variable Frequency Drives	VFD <=5hp	1,082	0.23	0.23	1.8	1.9	0.8	0.4	$0.015	5.0
Lighting	High Bay HID Retrofit	6T5-1000W HID	1,456	0.33	0.33	1.8	1.8	0.7	0.4	$0.016	4.2
Refrigeratior	Evaporator Fan Motor Efficiency, Walk-In Coc	Evap. Fan Motor	1,462	0.15	0.15	1.9	1.8	0.7	0.4	$0.015	4.8
Appliance	Commercial High-Efficiency Clothes Washers	Clothes Washer	884	0.02	0.02	1.9	1.7	0.7	0.4	$0.016	2.5
HVAC	High Efficiency Air-Cooled Chillers - HVAC	Chiller-Air	10743	0.00	0.00	1.3	1.7	0.7	0.5	$0.024	10.4
HVAC	Commercial Air Conditioner Tune-Up	AC Tune-Up	521	0.31	0.00	1.3	1.5	0.6	0.4	$0.027	3.0
Appliance	High Efficiency Hand Dryer	Hand Dryer	965	0.11	0.11	1.6	1.5	0.6	0.4	$0.019	4.1
Lighting	LED Lighting Controls	LED Switch Controls	575	0.14	0.14	1.4	1.3	0.5	0.4	$0.024	4.2
Lighting	Low Bay HID Retrofit	HID LB Retrofit	2,669	1.00	1.00	1.3	1.3	0.5	0.4	$0.024	9.6
Refrigeratior	Energy Star Refrigerator Solid Doors	Refrig. Solid Door	1486	0.17	0.17	1.4	1.2	0.5	0.3	$0.023	6.1
Refrigeratior	Energy Star Refrigerator Glass Doors	Refrig. Glass Door	1,486	0.17	0.17	1.4	1.2	0.5	0.3	$0.023	6.1
Lighting	C&I Lighting Occupance Sensors	LED Wall Sensors	288	0.01	0.01	1.4	1.1	0.5	0.3	$0.023	5.1
Refrigeratior	Refrigerator Replace Old Gaskets	Refrig. Gasket	98	0.01	0.01	1.3	1.1	0.4	0.3	$0.030	2.6
Lighting	LED Case Lighting - with Motion Sensors	LED Case Lights	951	0.10	0.10	1.2	1.1	0.4	0.3	$0.028	4.9
Lighting	LED Lighting Controls	LED Central Controls	192	0.00	0.00	1.3	1.0	0.4	0.3	$0.027	4.7
Cooking	Commercial Ovens & Fryers	Comb. Oven	18,432	4.20	4.20	1.1	1.0	0.4	0.3	$0.031	8.1
Lighting	High Bay HID Retrofit	6T5-400W HID	374	0.09	0.09	1.1	0.9	0.4	0.3	$0.031	8.2
Refrigeratior	Cooler Night Curtains, Open Coolers	Night Curtains	903	0.00	0.00	1.2	0.9	0.4	0.3	$0.031	3.4
Refrigeratior	Strip Curtains for Walk-In Freezers and Cooler	Strip Curtains	315	0.04	0.04	1.0	0.8	0.3	0.3	$0.040	3.5
HVAC	Economizer	Economizer	1,073	0.25	0.25	0.9	0.8	0.3	0.3	$0.037	12.3
HVAC	High Efficiency Water-Cooled Chillers - HVAC	Centrifugal	17861	8.99	0.00	0.8	0.8	0.3	0.3	$0.045	19.6
HVAC	High-Efficiency Chiller for AC	AC Chiller	1913	0.00	0.00	1.0	0.8	0.3	0.3	$0.032	14.0
Lighting	C&I Lighting Occupance Sensors	LED Ceiling Sensors	288	0.01	0.01	1.0	0.7	0.3	0.3	$0.037	8.2
Lighting	C&I Lighting Occupance Sensors	LED Fixture Sensors	288	0.01	0.01	1.0	0.7	0.3	0.3	$0.037	8.2
Cooking	Commercial Ovens & Fryers	Griddle	2,594	0.59	0.59	0.9	0.6	0.3	0.3	$0.047	12.2
Shell	Commercial Window Film	Window Film	645	0.43	0.00	0.7	0.6	0.3	0.3	$0.062	13.7
Cooking	Commercial Ovens & Fryers	Fryers	1,166	0.20	0.20	0.8	0.6	0.2	0.3	$0.049	12.9
Lighting	LEDs Replace Fluorescent Tubes	LED Gen. Interior	70	0.01	0.01	0.8	0.6	0.2	0.3	$0.048	18.9
Lighting	LEDs Replace Fluorescent Tubes	2x4LED - T5	70	0.01	0.01	0.8	0.6	0.2	0.3	$0.048	18.9
Water Heat	Water Heater Tank Wrap	WH Tank Wrap	79	0.01	0.01	0.8	0.5	0.2	0.3	$0.059	6.5
Lighting	LEDs Replace Fluorescent Tubes	2x4LED - T8	54	0.01	0.01	0.7	0.5	0.2	0.2	$0.058	22.9
Lighting	Light Tube	Daylight Tube	344	0.06	0.06	0.7	0.4	0.2	0.2	$0.067	20.5
Lighting	Replace T12 Lights & Magnetic Ballast	Ballast Retrofit	54	0.01	0.01	0.6	0.3	0.1	0.2	$0.088	29.0
Shell	Cool Roof	Cool Roof	222	0.15	0.00	0.5	0.3	0.1	0.2	$0.121	39.7
HVAC	Ground Source Heat Pump	GSHP	21,736	0.00	0.00	0.6	0.3	0.1	0.2	$0.077	34.4
Refrigeratior	Energy Star Ice Machine	Ice Machine	501	0.05	0.05	0.6	0.3	0.1	0.2	$0.093	17.2
Lighting	LEDs Replace Fluorescent Tubes	4LED - T5	26	0.00	0.00	0.6	0.3	0.1	0.2	$0.096	37.8
Lighting	LEDs Replace Fluorescent Tubes	4LED - T8	19	0.00	0.00	0.5	0.2	0.1	0.2	$0.118	46.4
Shell	Roof Insulation	Roof Insulation	36	0.24	0.00	0.4	0.2	0.1	0.2	$0.760	332.7
Lighting	LEDs Replace Fluorescent Tubes	2LED - T8	16	0.00	0.00	0.5	0.2	0.1	0.1	$0.169	66.5
Commercial	Chilled Water Reset Controls	Chilled Water Reset	130	0.00	0.00	0.5	0.1	0.0	0.1	$0.221	44.9
HVAC	Chilled Water Reset Controls	Rotary Screw	130	0.00	0.00	0.5	0.1	0.0	0.1	$0.211	46.1
Commercial	LEDs Replace Fluorescent Tubes	2LED - T5	10	0.00	0.00	0.3	0.2	0.0	0.1	$0.165	146.7
Lighting	LEDs Replace Fluorescent Tubes	2LED - T5	10	0.00	0.00	0.4	0.1	0.0	0.1	$0.300	118.0
Commercial	Window Glazing	Window Glazing	260	0.07	0.00	0.5	0.1	0.0	0.0	$0.553	155.4
Shell	Window Glazing	Window Glazing	260	0.07	0.00	0.4	0.1	0.0	0.1	$0.424	185.7

Appendix C
Cross-Reference to Staff's 2017 IRP Recommendations

Section / Number	Staff Recommendations Recommendation	2020 IRP Reference
Load Forecasting Recommendation 1	Continue to explore ways to enhance residential and small C&I load forecasts and provide discussions of any refinements to forecasting methodology.	IRP - Section 3.7; Appendix A - Section 7.5
Load Forecasting Recommendation 2	Continue to provide comparisons of actual to forecasted results for the residential and small C&I classes along with discussions of reasons for any differences between forecasted and actual results.	IRP - Sections 3.3.1, 3.3.2; Appendix A - Sections 2.1.1, 2.2.1, 8
Load Forecasting Recommendation 3	Continue to provide comparisons between actual and forecasted summer and winter peak demands using a variety of normalization periods. Provide a discussion of the reasons for any significant differences between actual and forecasted peak demands.	IRP - Sections 3.4, 3.6; Appendix A - Sections 6, 8
Load Forecasting Recommendation 4	Continue to explore new markets, including economic development efforts within its service territory, to replace the loss of smelter loads and provide a discussion of BREC's efforts and how its efforts are reflected in the load forecast.	IRP - Section 2.7, 3.3.8; Appendix A - Sections 2.7; 3.2, 3.3
Demand-Side Management and Energy Efficiency Recommendation 1	Continue to work with Member Systems and community action agencies to look for ways to enhance the low-income weatherization program.	IRP - Section 2.10
Demand-Side Management and Energy Efficiency Recommendation 2	Continue to monitor new technologies and best practices that may lower BREC's DSM program costs and or enhance program benefits. Provide updates on consideration of existing and potential DSM programs in BREC's service territory.	IRP - Section 4.9; Appendix B
Supply-Side Resource Assessment Recommendation 1	BREC's next IRP should continue to include scenarios where one or more existing coal-fired units are retired, converted to use alternate fuels, or sold.	IRP - Section 1.22, Chapters 5, 8

Appendix C
Cross-Reference to Staff's 2017 IRP Recommendations

Section / Number	Staff Recommendations Recommendation	2020 IRP Reference
Renewable Generation and Distributed Generation Recommendation 1	Consideration of renewable generation to meet its customers' goals in its modeling and provide a discussion of its assessment of renewable power in its next IRP, especially when considering the future impact of GHG/carbon regulation and related costs per ton of CO_2	IRP - Chapters 5, 8
Renewable Generation and Distributed Generation Recommendation 2	A discussion of its consideration of and costs associated with distributed generation in its next IRP.	IRP - Section 5.5
Renewable Generation and Distributed Generation Recommendation 3	Information from its member-owner cooperatives on their customers' net metering statistics and activities in its next IRP.	IRP - Section 5.5.1
Renewable Generation and Distributed Generation Recommendation 4	Current and accurate cost assumptions in its modeling for renewable resources.	IRP - Chapter 8 (Table 8.4)
Generation Efficiency Recommendation 1	Specific generation efficiency improvements and activities undertaken.	IRP - Sections 5.1, 5.2
Generation Efficiency Recommendation 2	Endeavors to increase generation and transmission efficiency should include the impact of the efforts instituted to comply with environmental regulations.	IRP - Sections 5.5, 6.1, 6.3
Compliance Planning Recommendation 1	Compliance actions relating to current and pending environmental regulations.	IRP - Section 5.6.1, 5.6.2, 5.6.3, 5.6.5
Compliance Planning Recommendation 2	Address more fully the Sierra Club's comments regarding the Coleman Station and Reid Unit 1 regarding the cost assumptions and the SWEA's comments regarding renewables in the modeling for supply-side resources.	IRP - Sections 1.2.2, 2.9, 5.6

Appendix C
Cross-Reference to 807 KAR 5:058

Citation	Intergrated Resource Plan Regulation Regulation	2020 IRP Reference (*Where Applicable*)
807 KAR 5:058 § 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 § 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 § 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	Big Rivers has elected to follow the electronic filing procedures, and will electronically file the IRP with the Commission. One hardcopy of the IRP will be provided to the Commission once the current state of emergency is lifted pursuant to the Commission's Orders in Case No. 2020-00085
807 KAR 5:058 § 2(1)(a)	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
807 KAR 5:058 § 2(1)(b)	The schedule shall provide at such time as all electric utilities have filed integrated resource plans, the sequence shall repeat.	Noted
807 KAR 5:058 § 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.	IRP - Section 2.10

Appendix C
Cross-Reference to 807 KAR 5:058

Citation	Intergrated Resource Plan Regulation Regulation	2020 IRP Reference (*Where Applicable*)
807 KAR 5:058 § 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
807 KAR 5:058 § 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.	Big Rivers will provide notice as required
807 KAR 5:058 § 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 § 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 § 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.	*See* Appendix C Cross-Reference Listing
807 KAR 5:058 § 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.	IRP Section 1.1

Appendix C
Cross-Reference to 807 KAR 5:058

Citation	Intergrated Resource Plan Regulation Regulation	2020 IRP Reference (*Where Applicable*)
807 KAR 5:058 § 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	IRP Chapter 1
807 KAR 5:058 § 5(2)	Description of models, methods, data, and key assumptions used to develop the results contained in the plan	IRP Chapters 3, 4, 8; Appendix A - Load Forecast Study; Appendix F - Techncial Appendix; Appendix G - Model Output
807 KAR 5:058 § 5(3)	Summary of forecasts of energy and peak demand, and key economic and demographic assumptions or projections underlying these forecasts	IRP Chapter 3; Appendix A - Load Forecast Study
807 KAR 5:058 § 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	IRP Sections 6.3 8.2, 8.3, Chapter 9
807 KAR 5:058 § 5(5)	Steps to be taken during the next three (3) years to implement the plan	IRP Chapter 9
807 KAR 5:058 § 5(6)	Discussion of key issues or uncertainties that could affect successful implementation of the plan.	IRP Sections 8.2, 8.3, Chapter 9
807 KAR 5:058 § 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.	IRP Chapter 2
807 KAR 5:058 § 7(1)	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:	IRP Chapter 3; Appendix A
807 KAR 5:058 § 7(1)(a)	(a) Residential heating;	n/a

Appendix C
Cross-Reference to 807 KAR 5:058

Citation	Intergrated Resource Plan Regulation Regulation	2020 IRP Reference (*Where Applicable*)
807 KAR 5:058 § 7(1)(b)	(b) Residential non-heating;	n/a
807 KAR 5:058 § 7(1)(c)	(c) Total residential (total of paragraphs (a) and (b) of this subsection);	IRP Section 3.3.1; Appendix A - Load Forecast Study Section 2.1, Chapter 8
807 KAR 5:058 § 7(1)(d)	(d) Commercial;	IRP Section 3.3.2, 3.3.3; Appendix A - Load Forecast Study Section 2.2, Chapter 8
807 KAR 5:058 § 7(1)(e)	(e) Industrial;	IRP Section 3.3.2, 3.3.3, 3.3.4; Appendix A - Load Forecast Study Section 2.2, Chapter 8
807 KAR 5:058 § 7(1)(f)	(f) Sales for resale;	IRP Section 3.3.8; Appendix A - Load Forecast Study Section 2.7, 3.2
807 KAR 5:058 § 7(1)(g)	(g) Utility use and other.	IRP Sections 3.3.5, 3.3.6, 3.3.7; Appendix A - Load Forecast Study Chapter 2
807 KAR 5:058 § 7(1)	The utility shall also provide data at any greater level of disaggregation available.	Appendix A - Load Forecast Study Chapter 2
807 KAR 5:058 § 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:	IRP Chapter 3; Appendix A - Load Forecast Study Chapters 2 and 3
807 KAR 5:058 § 7(2)(a)	Average annual number of customers by class as defined in subsection (1) of this section;	IRP Chapter 3; Appendix A - Load Forecast Study Chapter 2

Appendix C
Cross-Reference to 807 KAR 5:058

Citation	Intergrated Resource Plan Regulation Regulation	2020 IRP Reference (*Where Applicable*)
807 KAR 5:058 § 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	IRP Chapter 3; Appendix A - Load Forecast Study Chapters 6 and 8
807 KAR 5:058 § 7(2)(c)	Recorded and weather-normalized coincident peak demand in summer and winter for the system	IRP Section 1.2.6, Chapter 3; Appendix A - Load Forecast Study Chapter 6
807 KAR 5:058 § 7(2)(d)	Total energy sales and coincident peak demand to retail and wholesale customers for which the utility has firm, contractual commitments	IRP Sections 3.1, 3.3; Appendix A - Load Forecst Study Chapters 2, 3
807 KAR 5:058 § 7(2)(e)	Total energy sales and coincident peak demand to retail and wholesale customers for which service is provided under an interruptible or curtail-able contract or tariff or under some other nonfirm basis	IRP Sections 3.3.9, 4.6
807 KAR 5:058 § 7(2)(f)	Annual energy losses for the system	IRP Chapter 3 Section 3.1, 3.2; Appendix A - Load Forecast Study
807 KAR 5:058 § 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	IRP Section 2.9, 4.6, Appendix B - DSM Potential Study
807 KAR 5:058 § 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.	IRP Chapter 3

Appendix C
Cross-Reference to 807 KAR 5:058

Citation	Intergrated Resource Plan Regulation Regulation	2020 IRP Reference (*Where Applicable*)
807 KAR 5:058 § 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.	IRP Chapter 3; Appendix A - Load Forecast Study
807 KAR 5:058 § 7(4)(a)	Annual energy sales and generation for the system and sales disaggregated by class as defined in subsection (1) of this section	IRP Chapter 3; Appendix A - Load Forecast Study
807 KAR 5:058 § 7(4)(b)	Summer and winter coincident peak demand for the system	IRP Section 3.3.2; Appendix A - Load Forecast Study Section 3.1
807 KAR 5:058 § 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	Appendix A - Load Forecst Study Chapter 9
807 KAR 5:058 § 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	IRP Section 3.5; Appendix A - Load Forecast Study Chapter 4
807 KAR 5:058 § 7(4)(e)	Any other data or exhibits which illustrate projected changes in load or load characteristics	IRP Chapter 3; Appendix A - Load Forecast Study
807 KAR 5:058 § 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

Appendix C
Cross-Reference to 807 KAR 5:058

Citation	Intergrated Resource Plan Regulation Regulation	2020 IRP Reference (*Where Applicable*)
807 KAR 5:058 § 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
807 KAR 5:058 § 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 § 7(7)(a)	The plan shall include a complete description and discussion of all data sets used in producing the forecasts	IRP Section 3.7; Appendix A - Load Forecst Study Chapter 7
807 KAR 5:058 § 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	IRP Section 3.7; Appendix A - Load Forecast Study Chapter 7
807 KAR 5:058 § 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)	IRP Chapter 3; Appendix A - Load Forecast Study
807 KAR 5:058 § 7(7)(d)	The plan shall include a complete description and discussion of the utility's treatment and assessment of load forecast uncertainty	IRP Section 3.6; Appendix A - Load Forecast Study Chapters 5, 8
807 KAR 5:058 § 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;	Appendix A - Load Forecast Study Chapter 7
	2. Changes in population and economic conditions in the utility's service territory and general region;	Appendix A - Load Forecast Study Chapter 7
	3. Development and potential market penetration of new appliances, equipment, and technologies that use electricity or competing fuels; and	Appendix A - Load Forecast Study Chapter 7; Appendix B - DSM Potential Stidy

Appendix C
Cross-Reference to 807 KAR 5:058

Citation	Intergrated Resource Plan Regulation Regulation	2020 IRP Reference (*Where Applicable*)
	4. Continuation of existing company and government sponsored conservation and load management or other demand-side programs	IRP Section 4.9
807 KAR 5:058 § 7(7)(f)	Research and development efforts underway or planned to improve per-formance, efficiency, or capabilities of the utility's load forecasting methods	IRP Section 3.8
807 KAR 5:058 § 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. Technical discussions, descriptions, and supporting documentation shall be contained in a technical appendix	IRP Section 3.8; Appendix B - DSM Potential Study
807 KAR 5:058 § 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.	IRP Chapters 8 and 9
807 KAR 5:058 § 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	IRP Chapter 8 - Table 8.1, Sections 6.1, 6.3
807 KAR 5:058 § 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	IRP Section 4.9, Chapter 8, Appendix B

Appendix C
Cross-Reference to 807 KAR 5:058

Citation	Intergrated Resource Plan Regulation Regulation	2020 IRP Reference (*Where Applicable*)
807 KAR 5:058 § 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	IRP Sections 8.1, 8.2, Chapter 9
807 KAR 5:058 § 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	IRP Chapters 5, 8, 9
807 KAR 5:058 § 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 § 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	IRP Section 1.2.5, 6.2; Appendix E - Transmission System Map

Appendix C
Cross-Reference to 807 KAR 5:058

Citation	Intergrated Resource Plan Regulation Regulation	2020 IRP Reference (*Where Applicable*)
807 KAR 5:058 § 8(3)(b)	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: 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; 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.	 IRP Sections 1.2.4, 5.2 IRP Sections 1.2.4, 5.2 IRP Sections 1.2.4, 5.2 IRP Sections 1.2.4, 5.2 IRP Sections 1.2.4, 5.2 IRP Section 5.2 , 8.2 IRP Section 5.2, 8.2 IRP Section 8.2.2 IRP Sections 1.2.4, 5.2 IRP Sections 1.2.4, 5.2 IRP Sections 1.2.4, 5.3 IRP Sections 1.2.4, 5.4 IRP Chapter 8 - Tables 8.9, 8.10, 8.11
807 KAR 5:058 § 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.	IRP Chapters 8, 9

Appendix C
Cross-Reference to 807 KAR 5:058

Citation	Intergrated Resource Plan Regulation Regulation	2020 IRP Reference (*Where Applicable*)
807 KAR 5:058 § 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.	IRP Chapters 8, 9
807 KAR 5:058 § 8(3)(e)	For each existing and new conservation and load management or other demand-side programs included in the plan: 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.	Appendix B - DSM Potential Study

Appendix C
Cross-Reference to 807 KAR 5:058

Citation	Intergrated Resource Plan Regulation Regulation	2020 IRP Reference (*Where Applicable*)
807 KAR 5:058 § 8(4)(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.	IRP Chapter 8 - Table 8.11
807 KAR 5:058 § 8(4)(b)	On planned annual generation: 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 demandside programs;	IRP Chpater 8 - Tables 8.9, 8.10, and 8.11

Appendix C
Cross-Reference to 807 KAR 5:058

Citation	Intergrated Resource Plan Regulation Regulation	2020 IRP Reference (*Where Applicable*)
807 KAR 5:058 § 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.	IRP Chapter 8, Table 8.11
807 KAR 5:058 § 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;	IRP Chapters 8 and 9
807 KAR 5:058 § 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	IRP Chapters 8 and 9
807 KAR 5:058 § 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	IRP Chapters 8 and 9
807 KAR 5:058 § 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	IRP Sections 7.6, 8.2

Appendix C
Cross-Reference to 807 KAR 5:058

Citation	Intergrated Resource Plan Regulation Regulation	2020 IRP Reference (*Where Applicable*)
807 KAR 5:058 § 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	IRP Section 3.8
807 KAR 5:058 § 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	IRP Section 5.6.1, 5.6.2 Table 5.6.1
807 KAR 5:058 § 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	IRP Chapters 8, 9; Appendix G - Technical Appendix
807 KAR 5:058 § 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	IRP Chapter 8, Table 8.9
807 KAR 5:058 § 9(2)	The integrated resource plan shall, at a minimum, include and discuss the following financial information: Discount rate used in present value calculations	IRP Chapter 8
807 KAR 5:058 § 9(3)	The integrated resource plan shall, at a minimum, include and discuss the following financial information: Nominal and real revenue requirements by year	IRP Chapter 8, Table 8.9
807 KAR 5:058 § 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	IRP Chapter 8, Table 8.15

Appendix C
Cross-Reference to 807 KAR 5:058

Citation	Intergrated Resource Plan Regulation Regulation	2020 IRP Reference (*Where Applicable*)
807 KAR 5:058 §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	Big Rivers will publish notice as required
807 KAR 5:058 § 11(1)	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 § 11(2)	The commission may convene conferences to discuss the filed plan and all other matters relative to review of the plan.	Noted
807 KAR 5:058 § 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 § 11(4)	A utility shall respond to the staff's comments and recommendations in its next integrated resource plan filing	Noted

Appendix D
Big Rivers' Responses to Staff's Recommendations on Big Rivers 2017 IRP

Staff Recommendations Section / Number	Recommendation	2020 IRP Reference	Big Rivers' Response
Load Forecasting Recommendation 1	Continue to explore ways to enhance residential and small C&I load forecasts and provide discussions of any refinements to forecasting methodology.	IRP - Section 3.7; Appendix A - Section 7.5	Big Rivers contracted with Clearspring Energy Advisors for the 2020 Long Term Load Forecast, as compared to recent forecasts prepared by GDS Associates, Inc. Clearspring's method used some different approaches from GDS, as highlighted in Section 7.5 of Appendix A, including a 15 year weather normal for the base case load forecasts compared to GDS' 20 year weather normal.
Load Forecasting Recommendation 2	Continue to provide comparisons of actual to forecasted results for the residential and small C&I classes along with discussions of reasons for any differences between forecasted and actual results.	IRP - Sections 3.3.1, 3.3.2; Appendix A - Sections 2.1.1, 2.2.1, 8	Appendix A Load Forecast Report Chapter 8 Tracking Analysis highlights Comparisons to the 2017 Forecasts by Class, as well as comparison of previous forecasts to actual loads.
Load Forecasting Recommendation 3	Continue to provide comparisons between actual and forecasted summer and winter peak demands using a variety of normalization periods. Provide a discussion of the reasons for any significant differences between actual and forecasted peak demands.	IRP - Sections 3.4, 3.6; Appendix A - Sections 6, 8	IRP Section 3.4 includes a table comparing historical actual and weather-normalized Winter/Summer demand and energy. Section 3.6 discusses various normalization periods.

Appendix D
Big Rivers' Responses to Staff's Recommendations on Big Rivers 2017 IRP

Staff Recommendations Section / Number	Recommendation	2020 IRP Reference	Big Rivers' Response
Load Forecasting Recommendation 4	Continue to explore new markets, including economic development efforts within its service territory, to replace the loss of smelter loads and provide a discussion of BREC's efforts and how its efforts are reflected in the load forecast.	IRP - Section 2.7, 3.3.8; Appendix A - Sections 2.7; 3.2, 3.3	IRP Section 2.7 discusses short and intermediate-term sales, and participating with local partners in economic development efforts. This has so far resulted in significant member load growth with the addition of a Direct Serve consumer as discussed in Sections 3.2 and 3.3.4. Section 3.3.8 discusses Non-Member Sales achieved.
Demand-Side Management and Energy Efficiency Recommendation 1	Continue to work with Member Systems and community action agencies to look for ways to enhance the low-income weatherization program.	IRP - Section 2.9	In Case No. 2019-00193 Big Rivers filed to implement DSM-14 Low-Income Weatherization Support program, which has been approved as a pilot and was launched in early 2020. As of filing this IRP, the COVID outbreak has disrupted work on the program.
Demand-Side Management and Energy Efficiency Recommendation 2	Continue to monitor new technologies and best practices that may lower BREC's DSM program costs and or enhance program benefits. Provide updates on consideration of existing and potential DSM programs in BREC's service territory.	IRP - Section 4.9; Appendix B	IRP Section 4.9 outlines the conclusions of the 2020 DSM Potential Study, including that Big Rivers will continue to monitor the cost-effectiveness of DR, work with Member-Owners to evaluate EE in both residential and non-residential sectors, maintain education for Member-Owners staff, as well as monitor opportunities for new technologies and demand response.
Supply-Side Resource Assessment Recommendation 1	BREC's next IRP should continue to include scenarios where one or more existing coal-fired units are retired, converted to use alternate fuels, or sold.	IRP - Section 1.22, Chapters 5, 8	IRP Section 1.2.2 and Chapter 2 discuss retirement of Coleman and Reid 1 and three solar power purchase agreements totaling 260 MW. Chapter 8 discusses the treatment of Existing and New or Potential Big Rivers Assets included in this IRP analysis

Appendix D
Big Rivers' Responses to Staff's Recommendations on Big Rivers 2017 IRP

Staff Recommendations Section / Number	Recommendation	2020 IRP Reference	Big Rivers' Response
Renewable Generation and Distributed Generation Recommendation 1	Consideration of renewable generation to meet its customers' goals in its modeling and provide a discussion of its assessment of renewable power in its next IRP, especially when considering the future impact of GHG/carbon regulation and related costs per ton of CO_2	IRP - Chapters 5, 8	Sections 5.6 and 5.7 discuss Big Rivers' Environmental Compliance Plans. Chapter 8 discusses the treatment of Existing and New or Potential Big Rivers Assets included in this IRP analysis, including the proposed 260 MW solar PPAs.
Renewable Generation and Distributed Generation Recommendation 2	A discussion of its consideration of and costs associated with distributed generation in its next IRP.	IRP - Section 5.5	Section 5.5 says the Big Rivers works with MISO on generation interconnections, including proposed projects on the sub-transmission system. MISO transmission planning allows distributed generation as alternatives to planned transmission projects. And, Big Rivers works with direct-serve consumers who wish to build generation for co-generation purposes.
Renewable Generation and Distributed Generation Recommendation 3	Information from its member-owner cooperatives on their customers' net metering statistics and activities in its next IRP.	IRP - Section 5.5.1	Net-metered distributed generation installations among retail members of the Member-Owners has risen to more than 2.5 MW since 2016.
Renewable Generation and Distributed Generation Recommendation 4	Current and accurate cost assumptions in its modeling for renewable resources.	IRP - Chapter 8 (Table 8.4)	Solar resources were included at current PPA prices.

Appendix D
Big Rivers' Responses to Staff's Recommendations on Big Rivers 2017 IRP

Staff Recommendations: Section / Number	Staff Recommendations: Recommendation	2020 IRP Reference	Big Rivers' Response
Generation Efficiency Recommendation 1	Specific generation efficiency improvements and activities undertaken.	IRP - Sections 5.1, 5.2	As wholesale power market prices have dropped over the past few years, Big Rivers has been able to significantly lower the historical minimum generation limits on its generators in order to minimize losses in the MISO power market during off-peak hours, thereby keeping the units running and available for the peak hours in the market. For the Big Rivers base load units, the heat rate has improved 137 BTU/kWh or 1.2% in the 11-year period from 2009 to 2019. Investments in high performance human machine interfaces, operations training simulators, reducing controllable losses, maintenance, instrument tuning, and coal pulverizer tuning, all help keep Big Rivers units operating efficiently.
Generation Efficiency Recommendation 2	Endeavors to increase generation and transmission efficiency should include the impact of the efforts instituted to comply with environmental regulations.	IRP - Sections 5.5, 6.1, 6.3	As a member of MISO , Big Rivers participates in coordinated short-and long-term planning, that supports development of infrastructure sufficiently robust to meet local and regional standards. Big Rivers has analyzed all relevant environmental compliance provisions and outlined plans to achieve compliance, and will comply with MISO coordinated planning process.
Compliance Planning Recommendation 1	Compliance actions relating to current and pending environmental regulations.	IRP - Section 5.6.1, 5.6.2, 5.6.3, 5.6.5	Big Rivers has closely analyzed all relevant environmental compliance provisions and has outlined plans to achieve compliance within the time allowed by the regulations.

Appendix D
Big Rivers' Responses to Staff's Recommendations on Big Rivers 2017 IRP

Staff Recommendations: Section / Number	Staff Recommendations: Recommendation	2020 IRP Reference	Big Rivers' Response
Compliance Planning Recommendation 2	Address more fully the Sierra Club's comments regarding the Coleman Station and Reid Unit 1 regarding the cost assumptions and the SWEA's comments regarding renewables in the modeling for supply-side resources.	IRP - Sections 1.2.2, 2.9, 5.6	Coleman Station and Reid 1 retiring in 2020, renewables including hydropower and solar included in this analysis.

Big Rivers
ELECTRIC CORPORATION

Your Touchstone Energy® Cooperative

In the Matter of:

ELECTRONIC	)	**Case No.**
2020 INTEGRATED RESOUCE PLAN	)	**2020-00299**
OF BIG RIVERS ELECTRIC CORPORATION	)	

CONFIDENTIAL

Appendix E
Big Rivers Transmission System Map
FILED: September 21, 2020

INFORMATION SUBMITTED WITH
MOTION FOR CONFIDENTIAL TREATMENT

In the Matter of:

ELECTRONIC 2020 INTEGRATED RESOUCE PLAN OF BIG RIVERS ELECTRIC CORPORATION	)))	Case No. 2020-00299

CONFIDENTIAL

Appendix F
ACES Forward price Curve Methodology
FILED: September 21, 2020

INFORMATION SUBMITTED WITH
MOTION FOR CONFIDENTIAL TREATMENT

Big Rivers
ELECTRIC CORPORATION

Your Touchstone Energy® Cooperative

In the Matter of:

ELECTRONIC	)	**Case No.**
2020 INTEGRATED RESOUCE PLAN	)	**2020-00299**
OF BIG RIVERS ELECTRIC CORPORATION	)	

CONFIDENTIAL

Appendix F
JD Energy Long-term Coal and Petcoke Price Forecast: 2019-2050
FILED: September 21, 2020

INFORMATION SUBMITTED WITH
MOTION FOR CONFIDENTIAL TREATMENT

In the Matter of:

ELECTRONIC 2020 INTEGRATED RESOUCE PLAN OF BIG RIVERS ELECTRIC CORPORATION	)))	Case No. 2020-00299

CONFIDENTIAL

Appendix E
J D. Energy Coal Forecast Tables
FILED: September 21, 2020

INFORMATION SUBMITTED WITH
MOTION FOR CONFIDENTIAL TREATMENT

EIA Capital Cost Estimates

U.S. Energy Information Administration (EIA) Cost and Performance Characteristics of New Generating Technologies
Annual Energy Outlook 2020 (February 2020)

Plant Type		Plant Characteristics		Plant Costs (2019$)					
		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	Ratio	$/kW	$/kW	$/kW-yr	$/MWh
Coal	Ultra Supercritical Coal with 30% CCS	650	9,751	$ 4,558	1.01	$ 35	**$ 4,593**	**$ 54.30**	**$ 7.08**
	Ultra Supercritical Coal with 90% CCS	650	12,507	$ 5,876	1.01	$ 63	**$ 5,939**	**$ 59.54**	**$ 10.98**
Natural Gas/Oil	Combined Cycle - single shaft	418	6,431	$ 1,084	0.99	$ (8)	**$ 1,076**	**$ 14.10**	**$ 2.55**
	Combined Cycle - multi shaft	1,083	6,370	$ 958	0.99	$ (7)	**$ 951**	**$ 12.20**	**$ 1.87**
	Combined Cycle - 90% CCS	377	7,124	$ 2,481	1.00	$ (4)	**$ 2,477**	**$ 27.60**	**$ 5.84**
	Combustion Turbine - aeroderivative	105	9,124	$ 1,175	0.99	$ (7)	**$ 1,168**	**$ 16.30**	**$ 4.70**
	Combustion Turbine - industrial frame	237	9,905	$ 713	0.99	$ (4)	**$ 709**	**$ 7.00**	**$ 4.50**
	Reciprocating Internal Combustion Engine	21	8,295	$ 1,810	1.01	$ 13	**$ 1,823**	**$ 35.16**	**$ 5.69**
Uranium	Advanced Nuclear	2,156	10,608	$ 6,041	1.03	$ 204	**$ 6,245**	**$ 121.64**	**$ 2.37**
	Small Modular Reactor	600	10,046	$ 6,191	1.01	$ 85	**$ 6,276**	**$ 95.00**	**$ 3.00**
Biomass	Biomass	50	13,300	$ 4,097	1.00	$ (2)	**$ 4,095**	**$ 125.72**	**$ 4.83**
Wind	Onshore Wind - Great Plains	200	N/A	$ 1,265	1.01	$ 19	**$ 1,284**	**$ 26.34**	**$ -**
Solar	Solar Thermal	115	N/A	$ 7,221	1.04	$ 256	**$ 7,477**	**$ 85.40**	**$ -**
	Solar - Photovoltaic - Tracking	150	N/A	$ 1,313	0.99	$ (8)	**$ 1,305**	**$ 15.25**	**$ -**
	Solar - Photovoltaic - Tracking + Battery Storage	150	N/A	$ 1,755	1.00	$ 5	**$ 1,760**	**$ 31.27**	**$ -**
Storage	Battery Storage (50 MW/100 MWh)	50	N/A	$ 845	1.02	$ 17	**$ 862**	**$ 12.90**	
	Battery Storage (50 MW/200 MWh)	50	N/A	$ 1,389	1.02	$ 28	**$ 1,417**	**$ 24.80**	

EIA Capital Cost Estimates

U.S. Energy Information Administration (EIA) Cost and Performance Characteristics of New Generating Technologies
Annual Energy Outlook 2019 (January 2019)

Plant Type		Plant Characteristics		Plant Costs (2018$)					
		Capacity	Heat Rate	Overnight Capital Cost - Base Project	Location Variation (SRCE)	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 with 30% CCS	650	9,750	$ 5,169	-9%	$ (445)	**$ 4,724**	**$ 72.12**	**$ 7.31**
	Ultra Supercritical Coal with 90% CCS	650	11,650	$ 5,716	-9%	$ (492)	**$ 5,224**	**$ 83.75**	**$ 9.89**
Natural Gas/Oil	Combined Cycle (CC)	702	6,600	$ 999	-8%	$ (83)	**$ 916**	**$ 11.33**	**$ 3.61**
	Advanced Combined Cycle (ACC)	1,100	6,300	$ 794	-3%	$ (20)	**$ 774**	**$ 10.30**	**$ 2.06**
	Advanced Combined Cycle (ACC) with CCS	340	7,525	$ 2,205	-7%	$ (160)	**$ 2,045**	**$ 34.43**	**$ 7.34**
	Combustion Turbine (CT)	100	9,840	$ 1,126	-4%	$ (50)	**$ 1,076**	**$ 18.03**	**$ 3.61**
	Advanced Combustion Turbine	237	9,800	$ 691	-3%	$ (22)	**$ 669**	**$ 7.01**	**$ 11.02**
	Reciprocating Internal Combustion Engine	85	8,500	$ 1,371	-8%	$ (116)	**$ 1,255**	**$ 7.11**	**$ 6.03**
Uranium	Advanced Nuclear (AN)	2,234	10,461	$ 6,034	-3%	$ (199)	**$ 5,835**	**$ 103.31**	**$ 2.37**
Biomass	Biomass (BBFB)	50	13,500	$ 3,900	-7%	$ (258)	**$ 3,642**	**$ 114.39**	**$ 5.70**
Wind	Onshore Wind (WN)	100		$ 1,624	39%	$ 632	**$ 2,256**	**$ 48.42**	**$ -**
Solar	Solar Thermal	100		$ 4,291		N/A	**N/A**	**$ 72.84**	**$ -**
	Solar - Photovoltaic - Tracking (PV)	150		$ 1,969	-29%	$ (577)	**$ 1,392**	**$ 22.46**	**$ -**
	Solar - Photovoltaic - Tracking	150		$ 1,783	-27%	$ (478)	**$ 1,305**	**$ 22.46**	**$ -**
Storage	Battery Storage (BES)	30		$ 1,950	-2%	$ (30)	**$ 1,920**	**$ 36.32**	**$ 7.26**

Energy Information Administration
Capital Cost Estimates

2016 EIA Capital Cost Estimates

U.S. Energy Information Administration (EIA) Capital Cost Estimates
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 Combustion 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**

2024 -2043 ST Plan Portfolio Results - Base Case						
Generation Portfolio	**Cost to Serve Load $M**		**Average Energy Position**	**Average Reserve Capacity Margin**		**Comment**
	NPV, 2024$	**Ranking**	**MWh**	**MW**	**%**	
Status Quo (Wilson, RCT, SEPA, Green)	[redacted]	7	887,309	243.1	29.4%	No Solar Added
+ Solar	[redacted]	6	1,450,055	427.4	51.8%	Current Position
+ Solar, Green Idled	[redacted]	5	(500,458)	(11.8)	-1.4%	Proposed Option
+ Solar, Green and Reid CT Idled, + 150 MW NGCC Sebree	[redacted]	4	606,067	72.2	8.7%	Proposed Option
+ Solar, Green Idled and Exit SEPA, + 260 MW NGCC Sebree	[redacted]	3	1,180,621	57.2	6.9%	Proposed Option
+ Solar, Green and Reid CT idled, Exit SEPA, + 330 NGCC Sebree	[redacted]	2	1,687,738	65.2	7.9%	Proposed Option
+ Solar, Green Idled, + 90 MW NGCC Sebree	[redacted]	**1**	**173,877**	**73.7**	**8.9%**	**Least cost (Base case)**

Big Rivers' Member Load		
Year	Energy, MWh	NCP, MW
2024	4,409,889	815
2025	4,415,339	817
2026	4,425,681	819
2027	4,427,519	819
2028	4,436,200	820
2029	4,439,269	821
2030	4,443,020	822
2031	4,448,003	823
2032	4,462,278	825
2033	4,462,294	826
2034	4,466,493	827
2035	4,470,695	828
2036	4,477,410	829
2037	4,479,154	830
2038	4,482,805	831
2039	4,482,692	832
2040	4,486,504	833
2041	4,482,635	834
2042	4,483,054	835
2043	4,482,822	836

Short Term Plan
Load Exhibit Summary
Production Cost Model

Solar Profile and Cost				
Year	Generation MWh	NCF, %	Cost $M	Cost $/MWh
2024	591,843	25.9%	[redacted]	
2025	587,693	25.8%		
2026	584,724	25.7%		
2027	581,756	25.5%		
2028	579,946	25.4%		
2029	575,820	25.3%		
2030	572,852	25.2%		
2031	569,884	25.0%		
2032	568,050	24.9%		
2033	563,947	24.8%		
2034	560,979	24.6%		
2035	558,011	24.5%		
2036	556,154	24.4%		
2037	552,075	24.2%		
2038	549,107	24.1%		
2039	546,139	24.0%		
2040	544,257	23.8%		
2041	540,202	23.7%		
2042	537,234	23.6%		
2043	534,266	23.5%		

Short Term Plan
Solar Profile and Cost Exhibit
Production Cost Model

Native Load	2024	2025	2026	2027	2028	2029	2030
Energy, MWh	4,409,889	4,415,339	4,425,681	4,427,519	4,436,200	4,439,269	4,443,020
Energy Cost, $M	[redacted]						
Peak Load NCP - MW	815.0	817.0	819.0	819.0	820.0	821.0	822.0
Capacity Requirement (MISO PRMR), MW	880.9	883.8	886.0	886.0	887.1	888.2	889.2
Capacity Cost, $M	[redacted]						
Total Cost, $M	[redacted]						
Total Cost, $/MWh	[redacted]						
Total Cost, $/MW-Day Capacity	[redacted]						

Native Load Cost Summary	Total Load Cost, $M			Average Load Cost, $M/Yr			Load
	2024-2033	2034-2043	2024-2043	2024-2033	2034-2043	2024-2043	2024-2033
Load Cost	[redacted]						

Generation, MWh Generation Portfolio	2024	2025	2026	2027	2028	2029	2030
Status Quo (Wilson, RCT, SEPA, Green)	4,582,934	4,698,784	3,981,576	4,513,075	3,946,400	3,976,869	3,891,843
+ Solar	5,174,777	5,286,476	4,566,301	5,094,831	4,526,347	4,552,689	4,464,695
+ Solar, Green Idled	3,909,273	4,128,242	3,558,355	4,102,130	3,811,073	3,957,013	3,742,559
+ Solar, Green and Reid CT idled, Exit SEPA, + 330 NGCC Sebree	6,254,152	6,473,598	5,931,481	6,522,126	6,140,140	6,251,123	6,100,941
+ Solar, Green Idled, + 90 MW NGCC Sebree	4,627,774	4,848,782	4,286,545	4,844,810	4,527,473	4,662,904	4,465,500
+ Solar, Green and Reid CT Idled, + 150 MW NGCC Sebree	5,084,150	5,299,518	4,742,101	5,303,766	4,974,340	5,106,341	4,922,060
+ Solar, Green Idled and Exit SEPA, + 260 MW NGCC Sebree	5,717,943	5,942,802	5,395,015	5,980,650	5,613,673	5,729,254	5,564,055

Energy Position, MWh Generation Portfolio	2024	2025	2026	2027	2028	2029	2030
Status Quo (Wilson, RCT, SEPA, Green)	173,045	283,445	(444,105)	85,556	(489,800)	(462,400)	(551,177)
+ Solar	764,888	871,137	140,620	667,312	90,147	113,420	21,675
+ Solar, Green Idled	(500,616)	(287,097)	(867,326)	(325,389)	(625,127)	(482,256)	(700,461)
+ Solar, Green and Reid CT idled, Exit SEPA, + 330 NGCC Sebree	1,844,263	2,058,259	1,505,800	2,094,607	1,703,940	1,811,854	1,657,921
+ Solar, Green Idled, + 90 MW NGCC Sebree	217,885	433,443	(139,136)	417,291	91,273	223,635	22,480
+ Solar, Green and Reid CT Idled, + 150 MW NGCC Sebree	674,261	884,179	316,420	876,247	538,140	667,072	479,040
+ Solar, Green Idled and Exit SEPA, + 260 MW NGCC Sebree	1,308,054	1,527,463	969,334	1,553,131	1,177,473	1,289,985	1,121,035

Short Term Plan
Cost to Serve Load
Production Cost Model

Native Load	2031	2032	2033	2034	2035	2036	2037
Energy, MWh	4,448,003	4,462,278	4,462,294	4,466,493	4,470,695	4,477,410	4,479,154
Energy Cost, $M	[redacted]						
Peak Load NCP - MW	823.0	825.0	826.0	827.0	828.0	829.0	830.0
Capacity Requirement (MISO PRMR), MW	890.3	892.5	893.6	894.6	895.7	896.8	897.9
Capacity Cost, $M	[redacted]						
Total Cost, $M							
Total Cost, $/MWh							
Total Cost, $/MW-Day Capacity							

Native Load Cost Summary	Cost, NPV 2024$, $M		Load Cost , Avg. NPV 2024$, $M/Yr		
	2034-2043	2024-2043	2024-2033	2034-2043	2024-2043
Load Cost	[redacted]				

Generation, MWh Generation Portfolio	2031	2032	2033	2034	2035	2036	2037
Status Quo (Wilson, RCT, SEPA, Green)	4,348,347	3,808,380	4,841,662	4,538,109	5,362,566	5,658,842	6,327,462
+ Solar	4,918,231	4,376,430	5,405,610	5,099,088	5,920,577	6,214,995	6,879,537
+ Solar, Green Idled	4,099,774	3,743,713	4,125,158	3,618,842	4,025,238	3,968,970	4,154,284
+ Solar, Green and Reid CT idled, Exit SEPA, + 330 NGCC Sebree	6,397,543	5,995,684	6,437,573	5,833,180	6,247,332	6,249,181	6,317,429
+ Solar, Green Idled, + 90 MW NGCC Sebree	4,805,610	4,434,878	4,834,636	4,300,506	4,708,469	4,667,245	4,819,836
+ Solar, Green and Reid CT Idled, + 150 MW NGCC Sebree	5,252,872	4,880,354	5,285,616	4,736,850	5,147,870	5,119,632	5,253,324
+ Solar, Green Idled and Exit SEPA, + 260 MW NGCC Sebree	5,871,854	5,473,412	5,907,762	5,321,095	5,732,017	5,719,209	5,809,990

Energy Position, MWh Generation Portfolio	2031	2032	2033	2034	2035	2036	2037
Status Quo (Wilson, RCT, SEPA, Green)	(99,656)	(653,898)	379,368	71,616	891,871	1,181,432	1,848,308
+ Solar	470,228	(85,848)	943,316	632,595	1,449,882	1,737,585	2,400,383
+ Solar, Green Idled	(348,229)	(718,565)	(337,136)	(847,651)	(445,457)	(508,440)	(324,870)
+ Solar, Green and Reid CT idled, Exit SEPA, + 330 NGCC Sebree	1,949,540	1,533,406	1,975,279	1,366,687	1,776,637	1,771,771	1,838,275
+ Solar, Green Idled, + 90 MW NGCC Sebree	357,607	(27,400)	372,342	(165,987)	237,774	189,835	340,682
+ Solar, Green and Reid CT Idled, + 150 MW NGCC Sebree	804,869	418,076	823,322	270,357	677,175	642,222	774,170
+ Solar, Green Idled and Exit SEPA, + 260 MW NGCC Sebree	1,423,851	1,011,134	1,445,468	854,602	1,261,322	1,241,799	1,330,836

Short Term Plan
Cost to Serve Load
Production Cost Model

Native Load	2038	2039	2040	2041	2042	2043
Energy, MWh	4,482,805	4,482,692	4,486,504	4,482,635	4,483,054	4,482,822
Energy Cost, $M	[redacted]					
Peak Load NCP - MW	831.0	832.0	833.0	834.0	835.0	836.0
Capacity Requirement (MISO PRMR), MW	899.0	900.1	901.2	902.3	903.4	904.5
Capacity Cost, $M	[redacted]					
Total Cost, $M						
Total Cost, $/MWh						
Total Cost, $/MW-Day Capacity						

Native Load Cost Summary
Load Cost

Generation, MWh						
Generation Portfolio	2038	2039	2040	2041	2042	2043
Status Quo (Wilson, RCT, SEPA, Green)	6,711,663	7,009,214	7,079,914	7,279,108	6,864,325	7,488,854
+ Solar	7,260,769	7,555,353	7,624,171	7,819,310	7,401,559	8,023,120
+ Solar, Green Idled	4,066,064	4,148,089	3,996,444	4,093,884	3,670,922	4,234,572
+ Solar, Green and Reid CT idled, Exit SEPA, + 330 NGCC Sebree	6,210,431	6,218,205	6,065,547	5,979,238	5,447,757	5,845,850
+ Solar, Green Idled, + 90 MW NGCC Sebree	4,725,771	4,787,390	4,634,677	4,681,920	4,229,237	4,747,339
+ Solar, Green and Reid CT Idled, + 150 MW NGCC Sebree	5,158,019	5,206,603	5,056,080	5,070,167	4,598,127	5,087,317
+ Solar, Green Idled and Exit SEPA, + 260 MW NGCC Sebree	5,704,882	5,727,958	5,573,229	5,525,654	5,016,832	5,448,898

Energy Position, MWh							
Generation Portfolio	2038	2039	2040	2041	2042	2043	Average
Status Quo (Wilson, RCT, SEPA, Green)	2,228,858	2,526,522	2,593,410	2,796,473	2,381,271	3,006,032	887,309
+ Solar	2,777,964	3,072,661	3,137,667	3,336,675	2,918,505	3,540,298	1,450,055
+ Solar, Green Idled	(416,741)	(334,603)	(490,060)	(388,751)	(812,132)	(248,250)	(500,458)
+ Solar, Green and Reid CT idled, Exit SEPA, + 330 NGCC Sebree	1,727,626	1,735,513	1,579,043	1,496,603	964,703	1,363,028	1,687,738
+ Solar, Green Idled, + 90 MW NGCC Sebree	242,966	304,698	148,173	199,285	(253,817)	264,517	173,877
+ Solar, Green and Reid CT Idled, + 150 MW NGCC Sebree	675,214	723,911	569,576	587,532	115,073	604,495	606,067
+ Solar, Green Idled and Exit SEPA, + 260 MW NGCC Sebree	1,222,077	1,245,266	1,086,725	1,043,019	533,778	966,076	1,180,621

Short Term Plan
Cost to Serve Load
Production Cost Model

Firm Capacity, MW							
Generation Portfolio	2024	2025	2026	2027	2028	2029	2030
Status Quo (Wilson, RCT, SEPA, Green)	1,069	1,069	1,069	1,069	1,069	1,069	1,069
+ Solar	1,266	1,265	1,263	1,262	1,261	1,259	1,258
+ Solar, Green Idled	827	825	824	823	821	820	819
+ Solar, Green and Reid CT idled, Exit SEPA, + 330 NGCC Sebree	904	902	901	900	898	897	896
+ Solar, Green Idled, + 90 MW NGCC Sebree	912	911	910	908	907	906	904
+ Solar, Green and Reid CT Idled, + 150 MW NGCC Sebree	911	909	908	907	905	904	903
+ Solar, Green Idled and Exit SEPA, + 260 MW NGCC Sebree	896	894	893	892	890	889	888

Reserve Capacity Position, MW							
Generation Portfolio	2024	2025	2026	2027	2028	2029	2030
Status Quo (Wilson, RCT, SEPA, Green)	254	252	250	250	249	248	247
+ Solar	451	448	444	443	441	438	436
+ Solar, Green Idled	12	8	5	4	1	(1)	(3)
+ Solar, Green and Reid CT idled, Exit SEPA, + 330 NGCC Sebree	89	85	82	81	78	76	74
+ Solar, Green Idled, + 90 MW NGCC Sebree	97	94	91	89	87	85	82
+ Solar, Green and Reid CT Idled, + 150 MW NGCC Sebree	96	92	89	88	85	83	81
+ Solar, Green Idled and Exit SEPA, + 260 MW NGCC Sebree	81	77	74	73	70	68	66

Reserve Capacity Margin, %							
Generation Portfolio	2024	2025	2026	2027	2028	2029	2030
Status Quo (Wilson, RCT, SEPA, Green)	31.2%	30.9%	30.5%	30.5%	30.4%	30.2%	30.1%
+ Solar	55.3%	54.8%	54.2%	54.1%	53.7%	53.4%	53.0%
+ Solar, Green Idled	1.4%	1.0%	0.6%	0.5%	0.2%	-0.1%	-0.4%
+ Solar, Green and Reid CT idled, Exit SEPA, + 330 NGCC Sebree	10.9%	10.4%	10.0%	9.9%	9.6%	9.3%	9.0%
+ Solar, Green Idled, + 90 MW NGCC Sebree	11.9%	11.5%	11.1%	10.9%	10.6%	10.3%	10.0%
+ Solar, Green and Reid CT Idled, + 150 MW NGCC Sebree	11.7%	11.3%	10.9%	10.7%	10.4%	10.1%	9.8%
+ Solar, Green Idled and Exit SEPA, + 260 MW NGCC Sebree	9.9%	9.5%	9.0%	8.9%	8.6%	8.3%	8.0%

Short Term Plan
Cost to Serve Load
Production Cost Model

Firm Capacity, MW							
Generation Portfolio	2031	2032	2033	2034	2035	2036	2037
Status Quo (Wilson, RCT, SEPA, Green)	1,069	1,069	1,069	1,069	1,069	1,069	1,069
+ Solar	1,257	1,255	1,254	1,253	1,252	1,250	1,249
+ Solar, Green Idled	818	816	815	814	812	811	810
+ Solar, Green and Reid CT idled, Exit SEPA, + 330 NGCC Sebree	895	893	892	891	889	888	887
+ Solar, Green Idled, + 90 MW NGCC Sebree	903	902	900	899	898	897	895
+ Solar, Green and Reid CT Idled, + 150 MW NGCC Sebree	902	900	899	898	896	895	894
+ Solar, Green Idled and Exit SEPA, + 260 MW NGCC Sebree	887	885	884	883	881	880	879

Reserve Capacity Position, MW							
Generation Portfolio	2031	2032	2033	2034	2035	2036	2037
Status Quo (Wilson, RCT, SEPA, Green)	246	244	243	242	241	240	239
+ Solar	434	430	428	426	424	421	419
+ Solar, Green Idled	(5)	(9)	(11)	(13)	(16)	(18)	(20)
+ Solar, Green and Reid CT idled, Exit SEPA, + 330 NGCC Sebree	72	68	66	64	61	59	57
+ Solar, Green Idled, + 90 MW NGCC Sebree	80	77	74	72	70	68	65
+ Solar, Green and Reid CT Idled, + 150 MW NGCC Sebree	79	75	73	71	68	66	64
+ Solar, Green Idled and Exit SEPA, + 260 MW NGCC Sebree	64	60	58	56	53	51	49

Reserve Capacity Margin, %							
Generation Portfolio	2031	2032	2033	2034	2035	2036	2037
Status Quo (Wilson, RCT, SEPA, Green)	29.9%	29.6%	29.4%	29.3%	29.1%	29.0%	28.8%
+ Solar	52.7%	52.2%	51.8%	51.5%	51.2%	50.8%	50.5%
+ Solar, Green Idled	-0.7%	-1.1%	-1.3%	-1.6%	-1.9%	-2.2%	-2.4%
+ Solar, Green and Reid CT idled, Exit SEPA, + 330 NGCC Sebree	8.7%	8.3%	8.0%	7.7%	7.4%	7.1%	6.8%
+ Solar, Green Idled, + 90 MW NGCC Sebree	9.7%	9.3%	9.0%	8.7%	8.4%	8.1%	7.9%
+ Solar, Green and Reid CT Idled, + 150 MW NGCC Sebree	9.5%	9.1%	8.8%	8.5%	8.3%	8.0%	7.7%
+ Solar, Green Idled and Exit SEPA, + 260 MW NGCC Sebree	7.7%	7.3%	7.0%	6.7%	6.4%	6.2%	5.9%

Short Term Plan
Cost to Serve Load
Production Cost Model

Firm Capacity, MW						
Generation Portfolio	2038	2039	2040	2041	2042	2043
Status Quo (Wilson, RCT, SEPA, Green)	1,069	1,069	1,069	1,069	1,069	1,069
+ Solar	1,248	1,246	1,245	1,244	1,242	1,241
+ Solar, Green Idled	808	807	806	805	803	802
+ Solar, Green and Reid CT idled, Exit SEPA, + 330 NGCC Sebree	885	884	883	882	880	879
+ Solar, Green Idled, + 90 MW NGCC Sebree	894	893	891	890	889	887
+ Solar, Green and Reid CT Idled, + 150 MW NGCC Sebree	892	891	890	889	887	886
+ Solar, Green Idled and Exit SEPA, + 260 MW NGCC Sebree	877	876	875	874	872	871

Reserve Capacity Position, MW							
Generation Portfolio	2038	2039	2040	2041	2042	2043	Average
Status Quo (Wilson, RCT, SEPA, Green)	238	237	236	235	234	233	243
+ Solar	417	414	412	410	407	405	427
+ Solar, Green Idled	(23)	(25)	(27)	(29)	(32)	(34)	(12)
+ Solar, Green and Reid CT idled, Exit SEPA, + 330 NGCC Sebree	54	52	50	48	45	43	65
+ Solar, Green Idled, + 90 MW NGCC Sebree	63	61	58	56	54	51	74
+ Solar, Green and Reid CT Idled, + 150 MW NGCC Sebree	61	59	57	55	52	50	72
+ Solar, Green Idled and Exit SEPA, + 260 MW NGCC Sebree	46	44	42	40	37	35	57

Reserve Capacity Margin, %							
Generation Portfolio	2038	2039	2040	2041	2042	2043	Average
Status Quo (Wilson, RCT, SEPA, Green)	28.7%	28.5%	28.4%	28.2%	28.0%	27.9%	29.4%
+ Solar	50.1%	49.8%	49.5%	49.1%	48.8%	48.5%	51.8%
+ Solar, Green Idled	-2.7%	-3.0%	-3.3%	-3.5%	-3.8%	-4.1%	-1.4%
+ Solar, Green and Reid CT idled, Exit SEPA, + 330 NGCC Sebree	6.5%	6.3%	6.0%	5.7%	5.4%	5.1%	7.9%
+ Solar, Green Idled, + 90 MW NGCC Sebree	7.6%	7.3%	7.0%	6.7%	6.4%	6.1%	8.9%
+ Solar, Green and Reid CT Idled, + 150 MW NGCC Sebree	7.4%	7.1%	6.8%	6.5%	6.3%	6.0%	8.7%
+ Solar, Green Idled and Exit SEPA, + 260 MW NGCC Sebree	5.6%	5.3%	5.0%	4.7%	4.5%	4.2%	6.9%

Short Term Plan
Cost to Serve Load
Production Cost Model

Net Cost (Revenue), $M							
Generation Portfolio	2024	2025	2026	2027	2028	2029	2030
Status Quo (Wilson, RCT, SEPA, Green)	[redacted]						
+ Solar	[redacted]						
+ Solar, Green Idled	[redacted]						
+ Solar, Green and Reid CT idled, Exit SEPA, + 330 NGCC Sebree	[redacted]						
+ Solar, Green Idled, + 90 MW NGCC Sebree	[redacted]						
+ Solar, Green and Reid CT Idled, + 150 MW NGCC Sebree	[redacted]						
+ Solar, Green Idled and Exit SEPA, + 260 MW NGCC Sebree	[redacted]						

Cost to Serve Load, $M							
Generation Portfolio	2024	2025	2026	2027	2028	2029	2030
Status Quo (Wilson, RCT, SEPA, Green)	[redacted]						
+ Solar	[redacted]						
+ Solar, Green Idled	[redacted]						
+ Solar, Green and Reid CT idled, Exit SEPA, + 330 NGCC Sebree	[redacted]						
+ Solar, Green Idled, + 90 MW NGCC Sebree	[redacted]						
+ Solar, Green and Reid CT Idled, + 150 MW NGCC Sebree	[redacted]						
+ Solar, Green Idled and Exit SEPA, + 260 MW NGCC Sebree	[redacted]						

Cost to Serve Load	Total Cost to Serve Load, $M			Average Cost to Serve Load, $M/Yr			Cost to Se
Generation Portfolio	2024-2033	2034-2043	2024-2043	2024-2033	2034-2043	2024-2043	2024-2033
Status Quo (Wilson, RCT, SEPA, Green)	[redacted]						
+ Solar	[redacted]						
+ Solar, Green Idled	[redacted]						
+ Solar, Green and Reid CT idled, Exit SEPA, + 330 NGCC Sebree	[redacted]						
+ Solar, Green Idled, + 90 MW NGCC Sebree	[redacted]						
+ Solar, Green and Reid CT Idled, + 150 MW NGCC Sebree	[redacted]						
+ Solar, Green Idled and Exit SEPA, + 260 MW NGCC Sebree	[redacted]						

Short Term Plan
Cost to Serve Load
Production Cost Model

Net Cost (Revenue), $M							
Generation Portfolio	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**
Status Quo (Wilson, RCT, SEPA, Green)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
+ Solar	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
+ Solar, Green Idled	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
+ Solar, Green and Reid CT idled, Exit SEPA, + 330 NGCC Sebree	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
+ Solar, Green Idled, + 90 MW NGCC Sebree	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
+ Solar, Green and Reid CT Idled, + 150 MW NGCC Sebree	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
+ Solar, Green Idled and Exit SEPA, + 260 MW NGCC Sebree	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Cost to Serve Load, $M							
Generation Portfolio	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**
Status Quo (Wilson, RCT, SEPA, Green)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
+ Solar	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
+ Solar, Green Idled	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
+ Solar, Green and Reid CT idled, Exit SEPA, + 330 NGCC Sebree	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
+ Solar, Green Idled, + 90 MW NGCC Sebree	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
+ Solar, Green and Reid CT Idled, + 150 MW NGCC Sebree	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
+ Solar, Green Idled and Exit SEPA, + 260 MW NGCC Sebree	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Cost to Serve Load	rve Load, NPV 2024$, $M		Cost to Serve Load, Avg. NPV 2024$, $M/Yr		
Generation Portfolio	**2034-2043**	**2024-2043**	**2024-2033**	**2034-2043**	**2024-2043**
Status Quo (Wilson, RCT, SEPA, Green)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
+ Solar	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
+ Solar, Green Idled	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
+ Solar, Green and Reid CT idled, Exit SEPA, + 330 NGCC Sebree	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
+ Solar, Green Idled, + 90 MW NGCC Sebree	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
+ Solar, Green and Reid CT Idled, + 150 MW NGCC Sebree	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
+ Solar, Green Idled and Exit SEPA, + 260 MW NGCC Sebree	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Short Term Plan
Cost to Serve Load
Production Cost Model

Net Cost (Revenue), $M						
Generation Portfolio	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**
Status Quo (Wilson, RCT, SEPA, Green)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
+ Solar	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
+ Solar, Green Idled	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
+ Solar, Green and Reid CT idled, Exit SEPA, + 330 NGCC Sebree	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
+ Solar, Green Idled, + 90 MW NGCC Sebree	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
+ Solar, Green and Reid CT Idled, + 150 MW NGCC Sebree	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
+ Solar, Green Idled and Exit SEPA, + 260 MW NGCC Sebree	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Cost to Serve Load, $M						
Generation Portfolio	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**
Status Quo (Wilson, RCT, SEPA, Green)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
+ Solar	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
+ Solar, Green Idled	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
+ Solar, Green and Reid CT idled, Exit SEPA, + 330 NGCC Sebree	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
+ Solar, Green Idled, + 90 MW NGCC Sebree	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
+ Solar, Green and Reid CT Idled, + 150 MW NGCC Sebree	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
+ Solar, Green Idled and Exit SEPA, + 260 MW NGCC Sebree	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Cost to Serve Load
Generation Portfolio
Status Quo (Wilson, RCT, SEPA, Green)
+ Solar
+ Solar, Green Idled
+ Solar, Green and Reid CT idled, Exit SEPA, + 330 NGCC Sebree
+ Solar, Green Idled, + 90 MW NGCC Sebree
+ Solar, Green and Reid CT Idled, + 150 MW NGCC Sebree
+ Solar, Green Idled and Exit SEPA, + 260 MW NGCC Sebree

Short Term Plan
Cost to Serve Load
Production Cost Model

2024 - 2043 Unit/Station Summary Base						
	Wilson	**Green - Coal**	**Green NG (Firm)**	**Green NG (No Firm)**	**SEPA**	**Reid CT**
Generation, Avg Annual MWh	3,110,617	1,950,513	992,239	229,848	267,000	17,367
Capacity Factor, %	86%	49%	27%	6%	17%	3%
Firm Capacity, MW	393.5	439.2	400.6	400.6	178.0	58.5
Total Generation Variable Cost, $/MWh - Nominal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Gross Margin, $M - Nominal/Yr	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Gross Margin, $M - NPV 2024$ Avg./Yr	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Fixed and Capital Cost, $M - Nominal/Yr.	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Fixed and Capital Cost, $M - NPV 2024$ Avg./Yr.	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capacity Revenue, $M - Nominal/Yr.	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capacity Revenue, $M - NPV 2024$ Avg./Yr.	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Net Fixed and Capital Cost less Capacity Revenue, $M - Nominal/Yr.	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Net Fixed and Capital Cost less Capacity Revenue, $M - NPV 2024$ Avg./Yr.	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Cost (Revenue), $M - Nominal/Yr	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Cost (Revenue), $M - NPV 2024$ Avg./Yr	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Cost (Revenue), $/MWh - Nominal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Cost (Revenue), $/MWh - NPV 2024$	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Cost (Revenue), $/kW-Year - Nominal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Cost (Revenue), $/kW-Year - NPV 2024$	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

2024 - 2043 Unit/Station Summary Base					
	Solar	NGCC	NGCC	NGCC	NGCC
Generation, Avg Annual MWh	562,747	674,335	1,123,892	1,948,079	2,472,562
Capacity Factor, %	25%	86%	86%	86%	86%
Firm Capacity, MW	184.3	85.5	142.5	247.0	`
Total Generation Variable Cost, $/MWh - Nominal	[redacted]				
Gross Margin, $M - Nominal/Yr	[redacted]				
Gross Margin, $M - NPV 2024$ Avg./Yr	[redacted]				
Total Fixed and Capital Cost, $M - Nominal/Yr.	[redacted]				
Total Fixed and Capital Cost, $M - NPV 2024$ Avg./Yr.	[redacted]				
Capacity Revenue, $M - Nominal/Yr.	[redacted]				
Capacity Revenue, $M - NPV 2024$ Avg./Yr.	[redacted]				
Net Fixed and Capital Cost less Capacity Revenue, $M - Nominal/Yr.	[redacted]				
Net Fixed and Capital Cost less Capacity Revenue, $M - NPV 2024$ Avg./Yr.	[redacted]				
Cost (Revenue), $M - Nominal/Yr	[redacted]				
Cost (Revenue), $M - NPV 2024$ Avg./Yr	[redacted]				
Cost (Revenue), $/MWh - Nominal	[redacted]				
Cost (Revenue), $/MWh - NPV 2024$	[redacted]				
Cost (Revenue), $/kW-Year - Nominal	[redacted]				
Cost (Revenue), $/kW-Year - NPV 2024$	[redacted]				

Base Case

Base Case Annual Inflation Rate

	Production Cost (Annual inflation)	2024	2025	2026	2027	2028	2029	2030
Production Cost (Nominal)	Total Production Cost, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Production Cost, cents/kWh	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Fixed O&M Cost (Incl. New Capital), $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Fixed O&M Cost, (Incl. New Capital) $/kW-yr	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Variable Cost, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Variable Cost, cents/kWh	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Production Cost -(2024$)		**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Production Cost (Real)	Total Production Cost, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Production Cost, cents/kWh	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Fixed O&M Cost (Incl. New Capital), $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Fixed O&M Cost, (Incl. New Capital) $/kW-yr	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Variable Cost, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Variable Cost, cents/kWh	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Market Revenue		**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Nominal	MISO Pool (Energy) Revenue, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	REC Revenue, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	MISO Capacity Revenue, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total MISO Revenue, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Real 2024$	MISO Pool (Energy) Revenue, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	REC Revenue, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	MISO Capacity Revenue, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total MISO Revenue, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Short Term Plan
Base Case Cost
Production Cost Model

Base Case

Base Case Annual Inflation Rate

	Production Cost (Annual inflation)	2031	2032	2033	2034	2035	2036	2037
Production Cost (Nominal)	Total Production Cost, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Production Cost, cents/kWh	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Fixed O&M Cost (Incl. New Capital), $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Fixed O&M Cost, (Incl. New Capital) $/kW-yr	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Variable Cost, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Variable Cost, cents/kWh	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Production Cost -(2024$)		**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**
Production Cost (Real)	Total Production Cost, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Production Cost, cents/kWh	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Fixed O&M Cost (Incl. New Capital), $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Fixed O&M Cost, (Incl. New Capital) $/kW-yr	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Variable Cost, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Variable Cost, cents/kWh	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Market Revenue		**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**
Nominal	MISO Pool (Energy) Revenue, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	REC Revenue, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	MISO Capacity Revenue, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total MISO Revenue, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Real 2024$	MISO Pool (Energy) Revenue, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	REC Revenue, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	MISO Capacity Revenue, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total MISO Revenue, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Base Case

Base Case Annual Inflation Rate

	Production Cost (Annual inflation)	2038	2039	2040	2041	2042	2043
Production Cost (Nominal)	Total Production Cost, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Production Cost, cents/kWh	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Fixed O&M Cost (Incl. New Capital), $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Fixed O&M Cost, (Incl. New Capital) $/kW-yr	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Variable Cost, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Variable Cost, cents/kWh	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Production Cost -(2024$)		2038	2039	2040	2041	2042	2043
Production Cost (Real)	Total Production Cost, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Production Cost, cents/kWh	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Fixed O&M Cost (Incl. New Capital), $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Fixed O&M Cost, (Incl. New Capital) $/kW-yr	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Variable Cost, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Variable Cost, cents/kWh	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Market Revenue		2038	2039	2040	2041	2042	2043
Nominal	MISO Pool (Energy) Revenue, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	REC Revenue, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	MISO Capacity Revenue, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total MISO Revenue, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Real 2024$	MISO Pool (Energy) Revenue, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	REC Revenue, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	MISO Capacity Revenue, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total MISO Revenue, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Short Term Plan
Base Case Cost
Production Cost Model

Base Case

Base Case Annual Inflation Rate

Operating Performance -KPIs		2024	2025	2026	2027	2028	2029	2030
KPIs	Net Capacity (Summer), MW	1,005	1,004	1,002	1,001	1,000	999	997
	Net Capacity (Winter), MW	1,005	1,004	1,002	1,001	1,000	999	997
	Net Generation, GWh	4,628	4,849	4,287	4,845	4,527	4,663	4,465
	Cost to Serve Load (Annual inflation)	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Nominal	Cost to Serve Load, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Cost to Serve Load, cents/KWh	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Real 2024$	Cost to Serve Load, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Cost to Serve Load, cents/KWh	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Nominal	Load Market Cost, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Generation Market Revenue, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Net Market, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Real 2024$	Load Market Cost, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Generation Market Revenue, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Net Market, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Load, GWh	4,410	4,415	4,426	4,428	4,436	4,439	4,443

Short Term Plan
Base Case Cost
Production Cost Model

Base Case

[redacted]	Base Case Annual Inflation Rate

Operating Performance -KPIs		2031	2032	2033	2034	2035	2036	2037
KPIs	Net Capacity (Summer), MW	996	995	993	992	991	989	988
	Net Capacity (Winter), MW	996	995	993	992	991	989	988
	Net Generation, GWh	4,806	4,435	4,835	4,301	4,708	4,667	4,820
[redacted]	Cost to Serve Load (Annual inflation)	2031	2032	2033	2034	2035	2036	2037
Nominal	Cost to Serve Load, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Cost to Serve Load, cents/KWh	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Real 2024$	Cost to Serve Load, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Cost to Serve Load, cents/KWh	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Nominal	Load Market Cost, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Generation Market Revenue, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Net Market, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Real 2024$	Load Market Cost, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Generation Market Revenue, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Net Market, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Load, GWh	4,448	4,462	4,462	4,466	4,471	4,477	4,479

Short Term Plan
Base Case Cost
Production Cost Model

Base Case

[redacted]	Base Case Annual Inflation Rate

Operating Performance -KPIs		2038	2039	2040	2041	2042	2043
KPIs	Net Capacity (Summer), MW	987	986	984	983	982	980
	Net Capacity (Winter), MW	987	986	984	983	982	980
	Net Generation, GWh	4,726	4,787	4,635	4,682	4,229	4,747
[redacted]	Cost to Serve Load (Annual inflation)	2038	2039	2040	2041	2042	2043
Nominal	Cost to Serve Load, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Cost to Serve Load, cents/KWh	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Real 2024$	Cost to Serve Load, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Cost to Serve Load, cents/KWh	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Nominal	Load Market Cost, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Generation Market Revenue, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Net Market, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Real 2024$	Load Market Cost, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Generation Market Revenue, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Net Market, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Load, GWh	4,483	4,483	4,487	4,483	4,483	4,483

Base Case

[redacted]	Base Case Annual Inflation Rate

Wilson - Coal

		2024	2025	2026	2027	2028	2029	2030
[redacted]	**Production Cost (Annual inflation)**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Production Cost (Nominal)	Total Production Cost, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Production Cost, cents/kWh	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Fixed O&M Cost (Incl. New Capital), $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Fixed O&M Cost, (Incl. New Capital) $/kW-yr	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Variable Cost, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Variable Cost, cents/kWh	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Production Cost -(2024$)		**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
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 (Incl. New Capital), $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Fixed O&M Cost, (Incl. New Capital) $/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]
Market Revenue		**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Nominal	MISO Pool (Energy) Revenue, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	MISO Capacity Revenue, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total MISO Revenue, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Real 2024$	MISO Pool (Energy) Revenue, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	MISO Capacity Revenue, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total MISO Revenue, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Operating Performance -KPIs		**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
KPIs	Net Capacity (Summer), MW	412	412	412	412	412	412	412
	Net Capacity (Winter), MW	412	412	412	412	412	412	412
	Net Generation, GWh	3,028	3,244	2,677	3,217	2,933	3,087	2,877

Short Term Plan
Base Case Cost
Production Cost Model

Base Case

[redacted] **Base Case Annual Inflation Rate**

Wilson - Coal

[redacted]	Production Cost (Annual inflation)	2031	2032	2033	2034	2035	2036	2037
Production Cost (Nominal)	Total Production Cost, $M	[redacted]						
	Total Production Cost, cents/kWh	[redacted]						
	Total Fixed O&M Cost (Incl. New Capital), $M	[redacted]						
	Total Fixed O&M Cost, (Incl. New Capital) $/kW-yr	[redacted]						
	Total Variable Cost, $M	[redacted]						
	Total Variable Cost, cents/kWh	[redacted]						
Production Cost -(2024$)		**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**
Production Cost (Real)	Total Production Cost, $000	[redacted]						
	Total Production Cost, cents/kWh	[redacted]						
	Total Fixed O&M Cost (Incl. New Capital), $M	[redacted]						
	Total Fixed O&M Cost, (Incl. New Capital) $/kW-yr	[redacted]						
	Total Variable Cost, $000	[redacted]						
	Total Variable Cost, cents/kWh	[redacted]						
Market Revenue		**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**
Nominal	MISO Pool (Energy) Revenue, $M	[redacted]						
	MISO Capacity Revenue, $M	[redacted]						
	Total MISO Revenue, $M	[redacted]						
Real 2024$	MISO Pool (Energy) Revenue, $M	[redacted]						
	MISO Capacity Revenue, $M	[redacted]						
	Total MISO Revenue, $M	[redacted]						
Operating Performance -KPIs		**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**
KPIs	Net Capacity (Summer), MW	412	412	412	412	412	412	412
	Net Capacity (Winter), MW	412	412	412	412	412	412	412
	Net Generation, GWh	3,240	2,893	3,272	2,773	3,184	3,133	3,325

Short Term Plan
Base Case Cost
Production Cost Model

Base Case

[redacted]	Base Case Annual Inflation Rate

Wilson - Coal							
[redacted]	**Production Cost (Annual inflation)**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**
Production Cost (Nominal)	Total Production Cost, $M	[redacted]					
	Total Production Cost, cents/kWh						
	Total Fixed O&M Cost (Incl. New Capital), $M						
	Total Fixed O&M Cost, (Incl. New Capital) $/kW-yr						
	Total Variable Cost, $M						
	Total Variable Cost, cents/kWh						
	Production Cost -(2024$)	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**
Production Cost (Real)	Total Production Cost, $000	[redacted]					
	Total Production Cost, cents/kWh						
	Total Fixed O&M Cost (Incl. New Capital), $M						
	Total Fixed O&M Cost, (Incl. New Capital) $/kW-yr						
	Total Variable Cost, $000						
	Total Variable Cost, cents/kWh						
	Market Revenue	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**
Nominal	MISO Pool (Energy) Revenue, $M	[redacted]					
	MISO Capacity Revenue, $M						
	Total MISO Revenue, $M						
Real 2024$	MISO Pool (Energy) Revenue, $M						
	MISO Capacity Revenue, $M						
	Total MISO Revenue, $M						
	Operating Performance -KPIs	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**
KPIs	Net Capacity (Summer), MW	412	412	412	412	412	412
	Net Capacity (Winter), MW	412	412	412	412	412	412
	Net Generation, GWh	3,242	3,328	3,181	3,283	2,863	3,431

Short Term Plan
Base Case Cost
Production Cost Model

Base Case

	Base Case Annual Inflation Rate

Reid CT - Natural Gas								
	Production Cost (Annual inflation)	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Production Cost (Nominal)	Total Production Cost, $M	[redacted]						
	Total Production Cost, cents/kWh	[redacted]						
	Total Fixed O&M Cost (Incl. New Capital), $M	[redacted]						
	Total Fixed O&M Cost, (Incl. New Capital) $/kW-yr	[redacted]						
	Total Variable Cost, $M	[redacted]						
	Total Variable Cost, cents/kWh	[redacted]						
Production Cost -(2024$)		**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Production Cost (Real)	Total Production Cost, $000	[redacted]						
	Total Production Cost, cents/kWh	[redacted]						
	Total Fixed O&M Cost (Incl. New Capital), $M	[redacted]						
	Total Fixed O&M Cost, (Incl. New Capital) $/kW-yr	[redacted]						
	Total Variable Cost, $000	[redacted]						
	Total Variable Cost, cents/kWh	[redacted]						
Market Revenue		**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Nominal	MISO Pool (Energy) Revenue, $M	[redacted]						
	MISO Capacity Revenue, $M	[redacted]						
	Total MISO Revenue, $M	[redacted]						
Real 2024$	MISO Pool (Energy) Revenue, $M	[redacted]						
	MISO Capacity Revenue, $M	[redacted]						
	Total MISO Revenue, $M	[redacted]						
Operating Performance -KPIs		**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
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	23	30	30	36	31	27	25

Short Term Plan
Base Case Cost
Production Cost Model

Base Case

[redacted]	Base Case Annual Inflation Rate

Reid CT - Natural Gas								
[redacted]	**Production Cost (Annual inflation)**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**
Production Cost (Nominal)	Total Production Cost, $M	[redacted]						
	Total Production Cost, cents/kWh							
	Total Fixed O&M Cost (Incl. New Capital), $M							
	Total Fixed O&M Cost, (Incl. New Capital) $/kW-yr							
	Total Variable Cost, $M							
	Total Variable Cost, cents/kWh							
Production Cost -(2024$)		**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**
Production Cost (Real)	Total Production Cost, $000	[redacted]						
	Total Production Cost, cents/kWh							
	Total Fixed O&M Cost (Incl. New Capital), $M							
	Total Fixed O&M Cost, (Incl. New Capital) $/kW-yr							
	Total Variable Cost, $000							
	Total Variable Cost, cents/kWh							
Market Revenue		**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**
Nominal	MISO Pool (Energy) Revenue, $M	[redacted]						
	MISO Capacity Revenue, $M							
	Total MISO Revenue, $M							
Real 2024$	MISO Pool (Energy) Revenue, $M							
	MISO Capacity Revenue, $M							
	Total MISO Revenue, $M							
Operating Performance -KPIs		**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**
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	23	15	22	18	16	13	10

Short Term Plan
Base Case Cost
Production Cost Model

Base Case

[redacted]	Base Case Annual Inflation Rate

Reid CT - Natural Gas

[redacted]	**Production Cost (Annual inflation)**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**
Production Cost (Nominal)	Total Production Cost, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Production Cost, cents/kWh	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Fixed O&M Cost (Incl. New Capital), $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Fixed O&M Cost, (Incl. New Capital) $/kW-yr	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Variable Cost, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Variable Cost, cents/kWh	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Production Cost -(2024$)		**2038**	**2039**	**2040**	**2041**	**2042**	**2043**
Production Cost (Real)	Total Production Cost, $000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Production Cost, cents/kWh	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Fixed O&M Cost (Incl. New Capital), $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Fixed O&M Cost, (Incl. New Capital) $/kW-yr	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Variable Cost, $000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Variable Cost, cents/kWh	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Market Revenue		**2038**	**2039**	**2040**	**2041**	**2042**	**2043**
Nominal	MISO Pool (Energy) Revenue, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	MISO Capacity Revenue, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total MISO Revenue, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Real 2024$	MISO Pool (Energy) Revenue, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	MISO Capacity Revenue, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total MISO Revenue, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Operating Performance -KPIs		**2038**	**2039**	**2040**	**2041**	**2042**	**2043**
KPIs	Net Capacity (Summer), MW	65	65	65	65	65	65
	Net Capacity (Winter), MW	65	65	65	65	65	65
	Net Generation, GWh	8	7	4	4	3	2

Base Case

Base Case Annual Inflation Rate

NGCC Sebree - Natural Gas

	Production Cost (Annual inflation)	2024	2025	2026	2027	2028	2029	2030
Production Cost (Nominal)	Total Production Cost, $M	[redacted]						
	Total Production Cost, cents/kWh							
	Total Fixed O&M Cost (Incl. New Capital), $M							
	Total Fixed O&M Cost, (Incl. New Capital) $/kW-yr							
	Total Variable Cost, $M							
	Total Variable Cost, cents/kWh							
	Production Cost -(2024$)	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Production Cost (Real)	Total Production Cost, $000	[redacted]						
	Total Production Cost, cents/kWh							
	Total Fixed O&M Cost (Incl. New Capital), $M							
	Total Fixed O&M Cost, (Incl. New Capital) $/kW-yr							
	Total Variable Cost, $000							
	Total Variable Cost, cents/kWh							
	Market Revenue	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Nominal	MISO Pool (Energy) Revenue, $M	[redacted]						
	MISO Capacity Revenue, $M							
	Total MISO Revenue, $M							
Real 2024$	MISO Pool (Energy) Revenue, $M							
	MISO Capacity Revenue, $M							
	Total MISO Revenue, $M							
	Operating Performance -KPIs	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
KPIs	Net Capacity (Summer), MW	90	90	90	90	90	90	90
	Net Capacity (Winter), MW	90	90	90	90	90	90	90
	Net Generation, GWh	719	721	728	743	716	706	723

Short Term Plan
Base Case Cost
Production Cost Model

Base Case

[redacted]	Base Case Annual Inflation Rate

NGCC Sebree - Natural Gas

[redacted]	Production Cost (Annual inflation)	2031	2032	2033	2034	2035	2036	2037
Production Cost (Nominal)	Total Production Cost, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Production Cost, cents/kWh	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Fixed O&M Cost (Incl. New Capital), $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Fixed O&M Cost, (Incl. New Capital) $/kW-yr	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Variable Cost, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Variable Cost, cents/kWh	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Production Cost -(2024$)		2031	2032	2033	2034	2035	2036	2037
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 (Incl. New Capital), $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Fixed O&M Cost, (Incl. New Capital) $/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]
Market Revenue		2031	2032	2033	2034	2035	2036	2037
Nominal	MISO Pool (Energy) Revenue, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	MISO Capacity Revenue, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total MISO Revenue, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Real 2024$	MISO Pool (Energy) Revenue, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	MISO Capacity Revenue, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total MISO Revenue, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Operating Performance -KPIs		2031	2032	2033	2034	2035	2036	2037
KPIs	Net Capacity (Summer), MW	90	90	90	90	90	90	90
	Net Capacity (Winter), MW	90	90	90	90	90	90	90
	Net Generation, GWh	706	691	709	682	683	698	666

Base Case

[redacted]	Base Case Annual Inflation Rate

NGCC Sebree - Natural Gas

[redacted]	Production Cost (Annual inflation)	2038	2039	2040	2041	2042	2043
Production Cost (Nominal)	Total Production Cost, $M	[redacted]					
	Total Production Cost, cents/kWh						
	Total Fixed O&M Cost (Incl. New Capital), $M						
	Total Fixed O&M Cost, (Incl. New Capital) $/kW-yr						
	Total Variable Cost, $M						
	Total Variable Cost, cents/kWh						
Production Cost -(2024$)		2038	2039	2040	2041	2042	2043
Production Cost (Real)	Total Production Cost, $000	[redacted]					
	Total Production Cost, cents/kWh						
	Total Fixed O&M Cost (Incl. New Capital), $M						
	Total Fixed O&M Cost, (Incl. New Capital) $/kW-yr						
	Total Variable Cost, $000						
	Total Variable Cost, cents/kWh						
Market Revenue		2038	2039	2040	2041	2042	2043
Nominal	MISO Pool (Energy) Revenue, $M	[redacted]					
	MISO Capacity Revenue, $M						
	Total MISO Revenue, $M						
Real 2024$	MISO Pool (Energy) Revenue, $M						
	MISO Capacity Revenue, $M						
	Total MISO Revenue, $M						
Operating Performance -KPIs		2038	2039	2040	2041	2042	2043
KPIs	Net Capacity (Summer), MW	90	90	90	90	90	90
	Net Capacity (Winter), MW	90	90	90	90	90	90
	Net Generation, GWh	660	639	638	588	558	513

Short Term Plan
Base Case Cost
Production Cost Model

Base Case

[redacted]	Base Case Annual Inflation Rate

SEPA - Hydro								
[redacted]	**Production Cost (Annual inflation)**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Production Cost (Nominal)	Total Production Cost, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Production Cost, cents/kWh	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Fixed O&M Cost (Incl. New Capital), $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Fixed O&M Cost, (Incl. New Capital) $/kW-yr	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Variable Cost, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Production Cost -(2024$)		**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
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 (Incl. New Capital), $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Fixed O&M Cost, (Incl. New Capital) $/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]
Market Revenue		**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Nominal	MISO Pool (Energy) Revenue, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	MISO Capacity Revenue, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total MISO Revenue, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Real 2024$	MISO Pool (Energy) Revenue, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	MISO Capacity Revenue, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total MISO Revenue, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Operating Performance -KPIs		**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
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

Base Case

	Base Case Annual Inflation Rate

SEPA - Hydro

	Production Cost (Annual inflation)	2031	2032	2033	2034	2035	2036	2037
Production Cost (Nominal)	Total Production Cost, $M	[redacted]						
	Total Production Cost, cents/kWh							
	Total Fixed O&M Cost (Incl. New Capital), $M							
	Total Fixed O&M Cost, (Incl. New Capital) $/kW-yr							
	Total Variable Cost, $M							
	Total Variable Cost, cents/kWh							
	Production Cost -(2024$)	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**
Production Cost (Real)	Total Production Cost, $000	[redacted]						
	Total Production Cost, cents/kWh							
	Total Fixed O&M Cost (Incl. New Capital), $M							
	Total Fixed O&M Cost, (Incl. New Capital) $/kW-yr							
	Total Variable Cost, $000							
	Total Variable Cost, cents/kWh							
	Market Revenue	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**
Nominal	MISO Pool (Energy) Revenue, $M	[redacted]						
	MISO Capacity Revenue, $M							
	Total MISO Revenue, $M							
Real 2024$	MISO Pool (Energy) Revenue, $M							
	MISO Capacity Revenue, $M							
	Total MISO Revenue, $M							
	Operating Performance -KPIs	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**
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

Short Term Plan
Base Case Cost
Production Cost Model

Base Case

[redacted]	Base Case Annual Inflation Rate

SEPA - Hydro

	Production Cost (Annual inflation)	2038	2039	2040	2041	2042	2043
Production Cost (Nominal)	Total Production Cost, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Production Cost, cents/kWh	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Fixed O&M Cost (Incl. New Capital), $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Fixed O&M Cost, (Incl. New Capital) $/kW-yr	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Variable Cost, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Variable Cost, cents/kWh	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Production Cost -(2024$)	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**
Production Cost (Real)	Total Production Cost, $000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Production Cost, cents/kWh	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Fixed O&M Cost (Incl. New Capital), $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Fixed O&M Cost, (Incl. New Capital) $/kW-yr	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Variable Cost, $000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Variable Cost, cents/kWh	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Market Revenue	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**
Nominal	MISO Pool (Energy) Revenue, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	MISO Capacity Revenue, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total MISO Revenue, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Real 2024$	MISO Pool (Energy) Revenue, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	MISO Capacity Revenue, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total MISO Revenue, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Operating Performance -KPIs	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**
KPIs	Net Capacity (Summer), MW	178	178	178	178	178	178
	Net Capacity (Winter), MW	178	178	178	178	178	178
	Net Generation, GWh	267	267	267	267	267	267

Short Term Plan
Base Case Cost
Production Cost Model

Base Case

Base Case Annual Inflation Rate

Solar - Renewable

	Production Cost (Annual inflation)	2024	2025	2026	2027	2028	2029	2030
Production Cost (Nominal)	Total Production Cost, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Production Cost, cents/kWh	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Fixed O&M Cost (Incl. New Capital), $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Fixed O&M Cost, (Incl. New Capital) $/kW-yr	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Variable Cost, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Variable Cost, cents/kWh	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Production Cost -(2024$)	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
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 (Incl. New Capital), $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Fixed O&M Cost, (Incl. New Capital) $/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]
	Market Revenue	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Nominal	MISO Pool (Energy) Revenue, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	REC Revenue, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	MISO Capacity Revenue, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total MISO Revenue, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Real 2024$	MISO Pool (Energy) Revenue, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	REC Revenue, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	MISO Capacity Revenue, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total MISO Revenue, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Operating Performance -KPIs	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
KPIs	Net Capacity (Summer), MW	260	259	257	256	255	254	252
	Net Capacity (Winter), MW	260	259	257	256	255	254	252
	Net Generation, GWh	592	588	585	582	580	576	573

Base Case

[redacted]	Base Case Annual Inflation Rate

Solar - Renewable

	Production Cost (Annual inflation)	2031	2032	2033	2034	2035	2036	2037
Production Cost (Nominal)	Total Production Cost, $M	[redacted]						
	Total Production Cost, cents/kWh							
	Total Fixed O&M Cost (Incl. New Capital), $M							
	Total Fixed O&M Cost, (Incl. New Capital) $/kW-yr							
	Total Variable Cost, $M							
	Total Variable Cost, cents/kWh							
	Production Cost -(2024$)	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**
Production Cost (Real)	Total Production Cost, $000	[redacted]						
	Total Production Cost, cents/kWh							
	Total Fixed O&M Cost (Incl. New Capital), $M							
	Total Fixed O&M Cost, (Incl. New Capital) $/kW-yr							
	Total Variable Cost, $000							
	Total Variable Cost, cents/kWh							
	Market Revenue	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**
Nominal	MISO Pool (Energy) Revenue, $M	[redacted]						
	REC Revenue, $M							
	MISO Capacity Revenue, $M							
	Total MISO Revenue, $M							
Real 2024$	MISO Pool (Energy) Revenue, $M							
	REC Revenue, $M							
	MISO Capacity Revenue, $M							
	Total MISO Revenue, $M							
	Operating Performance -KPIs	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**
KPIs	Net Capacity (Summer), MW	251	250	248	247	246	244	243
	Net Capacity (Winter), MW	251	250	248	247	246	244	243
	Net Generation, GWh	570	568	564	561	558	556	552

Base Case

[redacted]	Base Case Annual Inflation Rate

Solar - Renewable

[redacted]	Production Cost (Annual inflation)	2038	2039	2040	2041	2042	2043
Production Cost (Nominal)	Total Production Cost, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Production Cost, cents/kWh	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Fixed O&M Cost (Incl. New Capital), $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Fixed O&M Cost, (Incl. New Capital) $/kW-yr	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Variable Cost, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Variable Cost, cents/kWh	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Production Cost -(2024$)		2038	2039	2040	2041	2042	2043
Production Cost (Real)	Total Production Cost, $000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Production Cost, cents/kWh	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Fixed O&M Cost (Incl. New Capital), $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Fixed O&M Cost, (Incl. New Capital) $/kW-yr	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Variable Cost, $000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total Variable Cost, cents/kWh	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Market Revenue		2038	2039	2040	2041	2042	2043
Nominal	MISO Pool (Energy) Revenue, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	REC Revenue, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	MISO Capacity Revenue, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total MISO Revenue, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Real 2024$	MISO Pool (Energy) Revenue, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	REC Revenue, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	MISO Capacity Revenue, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total MISO Revenue, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Operating Performance -KPIs		2038	2039	2040	2041	2042	2043
KPIs	Net Capacity (Summer), MW	242	241	239	238	237	235
	Net Capacity (Winter), MW	242	241	239	238	237	235
	Net Generation, GWh	549	546	544	540	537	534

System - Base Case

Performance	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Generation - GWh	**4,628**	**4,849**	**4,287**	**4,845**	**4,527**	**4,663**	**4,465**	**4,806**	**4,435**	**4,835**
- Coal	3,028	3,244	2,677	3,217	2,933	3,087	2,877	3,240	2,893	3,272
- Hydro	267	267	267	267	267	267	267	267	267	267
- Natural Gas	741	750	758	779	747	733	748	729	706	731
- Solar	592	588	585	582	580	576	573	570	568	564
Winter Capacity, MW	**1,005**	**1,004**	**1,002**	**1,001**	**1,000**	**999**	**997**	**996**	**995**	**993**
- Coal	412	412	412	412	412	412	412	412	412	412
- Hydro	178	178	178	178	178	178	178	178	178	178
- Natural Gas	155	155	155	155	155	155	155	155	155	155
- Solar	260	259	257	256	255	254	252	251	250	248
Summer Capacity, MW	**1,005**	**1,004**	**1,002**	**1,001**	**1,000**	**999**	**997**	**996**	**995**	**993**
- Coal	412	412	412	412	412	412	412	412	412	412
- Hydro	178	178	178	178	178	178	178	178	178	178
- Natural Gas	155	155	155	155	155	155	155	155	155	155
- Solar	260	259	257	256	255	254	252	251	250	248
Firm Capacity, MW	**912**	**911**	**910**	**908**	**907**	**906**	**904**	**903**	**902**	**900**
- Coal	393	393	393	393	393	393	393	393	393	393
- Hydro	178	178	178	178	178	178	178	178	178	178
- Natural Gas	144	144	144	144	144	144	144	144	144	144
- Solar	197	195	194	193	191	190	189	188	186	185
Net Capacity Factor, %	**52.4%**	**55.0%**	**48.7%**	**55.1%**	**51.6%**	**53.2%**	**51.0%**	**54.9%**	**50.8%**	**55.4%**
Fuel Usage (Thermal Units), GBtu	[redacted]									
- Coal										
- Natural Gas										
Heat Rate (Thermal Units), BTU/kWh										
- Coal										
- Natural Gas										

Short Term Plan
Base Case Performance
Production Cost Model

System - Base Case

Performance	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Generation - GWh	**4,301**	**4,708**	**4,667**	**4,820**	**4,726**	**4,787**	**4,635**	**4,682**	**4,229**	**4,747**
- Coal	2,773	3,184	3,133	3,325	3,242	3,328	3,181	3,283	2,863	3,431
- Hydro	267	267	267	267	267	267	267	267	267	267
- Natural Gas	700	699	711	676	667	646	642	592	562	515
- Solar	561	558	556	552	549	546	544	540	537	534
Winter Capacity, MW	**992**	**991**	**989**	**988**	**987**	**986**	**984**	**983**	**982**	**980**
- Coal	412	412	412	412	412	412	412	412	412	412
- Hydro	178	178	178	178	178	178	178	178	178	178
- Natural Gas	155	155	155	155	155	155	155	155	155	155
- Solar	247	246	244	243	242	241	239	238	237	235
Summer Capacity, MW	**992**	**991**	**989**	**988**	**987**	**986**	**984**	**983**	**982**	**980**
- Coal	412	412	412	412	412	412	412	412	412	412
- Hydro	178	178	178	178	178	178	178	178	178	178
- Natural Gas	155	155	155	155	155	155	155	155	155	155
- Solar	247	246	244	243	242	241	239	238	237	235
Firm Capacity, MW	**899**	**898**	**897**	**895**	**894**	**893**	**891**	**890**	**889**	**887**
- Coal	393	393	393	393	393	393	393	393	393	393
- Hydro	178	178	178	178	178	178	178	178	178	178
- Natural Gas	144	144	144	144	144	144	144	144	144	144
- Solar	184	182	181	180	178	177	176	175	173	172
Net Capacity Factor, %	**49.4%**	**54.1%**	**53.7%**	**55.5%**	**54.5%**	**55.3%**	**53.6%**	**54.2%**	**49.0%**	**55.1%**
Fuel Usage (Thermal Units), GBtu	[redacted]									
- Coal	[redacted]									
- Natural Gas	[redacted]									
Heat Rate (Thermal Units), BTU/kWh	[redacted]									
- Coal	[redacted]									
- Natural Gas	[redacted]									

Short Term Plan
Base Case Performance
Production Cost Model

System - Base Case

Wilson - Coal

Performance	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Generation - GWh	3,028	3,244	2,677	3,217	2,933	3,087	2,877	3,240	2,893	3,272
Winter Capacity, MW	412	412	412	412	412	412	412	412	412	412
Summer Capacity, MW	412	412	412	412	412	412	412	412	412	412
Firm Capacity, MW	393	393	393	393	393	393	393	393	393	393
Net Capacity Factor, %	83.7%	89.9%	74.2%	89.1%	81.1%	85.5%	79.7%	89.8%	79.9%	90.7%
Fuel Usage (Thermal Units), GBtu	[redacted]									
Heat Rate (Thermal Units), BTU/kWh	[redacted]									

Reid CT - NG

Performance	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Generation - GWh	23	30	30	36	31	27	25	23	15	22
Winter Capacity, MW	65	65	65	65	65	65	65	65	65	65
Summer Capacity, MW	65	65	65	65	65	65	65	65	65	65
Firm Capacity, MW	59	59	59	59	59	59	59	59	59	59
Net Capacity Factor, %	4.0%	5.2%	5.3%	6.4%	5.4%	4.8%	4.5%	4.1%	2.7%	3.9%
Fuel Usage (Thermal Units), GBtu	[redacted]									
Heat Rate (Thermal Units), BTU/kWh	[redacted]									

NGCC Sebree - NG

Performance	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Generation - GWh	719	721	728	743	716	706	723	706	691	709
Winter Capacity, MW	90	90	90	90	90	90	90	90	90	90
Summer Capacity, MW	90	90	90	90	90	90	90	90	90	90
Firm Capacity, MW	86	86	86	86	86	86	86	86	86	86
Net Capacity Factor, %	90.9%	91.4%	92.4%	94.2%	90.6%	89.5%	91.7%	89.5%	87.4%	90.0%
Fuel Usage (Thermal Units), GBtu	[redacted]									
Heat Rate (Thermal Units), BTU/kWh	[redacted]									

Short Term Plan
Base Case Performance
Production Cost Model

System - Base Case

Wilson - Coal

Performance	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Generation - GWh	2,773	3,184	3,133	3,325	3,242	3,328	3,181	3,283	2,863	3,431
Winter Capacity, MW	412	412	412	412	412	412	412	412	412	412
Summer Capacity, MW	412	412	412	412	412	412	412	412	412	412
Firm Capacity, MW	393	393	393	393	393	393	393	393	393	393
Net Capacity Factor, %	76.8%	88.2%	86.6%	92.1%	89.8%	92.2%	87.9%	91.0%	79.3%	95.1%
Fuel Usage (Thermal Units), GBtu	[redacted]									
Heat Rate (Thermal Units), BTU/kWh	[redacted]									

Reid CT - NG

Performance	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Generation - GWh	18	16	13	10	8	7	4	4	3	2
Winter Capacity, MW	65	65	65	65	65	65	65	65	65	65
Summer Capacity, MW	65	65	65	65	65	65	65	65	65	65
Firm Capacity, MW	59	59	59	59	59	59	59	59	59	59
Net Capacity Factor, %	3.2%	2.8%	2.3%	1.8%	1.3%	1.2%	0.7%	0.7%	0.6%	0.3%
Fuel Usage (Thermal Units), GBtu	[redacted]									
Heat Rate (Thermal Units), BTU/kWh	[redacted]									

NGCC Sebree - NG

Performance	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Generation - GWh	682	683	698	666	660	639	638	588	558	513
Winter Capacity, MW	90	90	90	90	90	90	90	90	90	90
Summer Capacity, MW	90	90	90	90	90	90	90	90	90	90
Firm Capacity, MW	86	86	86	86	86	86	86	86	86	86
Net Capacity Factor, %	86.5%	86.7%	88.3%	84.4%	83.7%	81.1%	80.7%	74.6%	70.8%	65.0%
Fuel Usage (Thermal Units), GBtu	[redacted]									
Heat Rate (Thermal Units), BTU/kWh	[redacted]									

Short Term Plan
Base Case Performance
Production Cost Model

System - Base Case

SEPA - Hydro

Performance	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Generation - GWh	267	267	267	267	267	267	267	267	267	267
Winter Capacity, MW	178	178	178	178	178	178	178	178	178	178
Summer Capacity, MW	178	178	178	178	178	178	178	178	178	178
Firm Capacity, MW	178	178	178	178	178	178	178	178	178	178
Net Capacity Factor, %	17.1%	17.1%	17.1%	17.1%	17.1%	17.1%	17.1%	17.1%	17.1%	17.1%

Solar PPA Henderson

Performance	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Generation - GWh	361	358	356	355	353	351	349	347	346	344
Winter Capacity, MW	160	159	158	158	157	156	155	154	154	153
Summer Capacity, MW	160	159	158	158	157	156	155	154	154	153
Firm Capacity, MW	116	115	115	114	113	112	111	111	110	109
Net Capacity Factor, %	25.7%	25.6%	25.4%	25.3%	25.1%	25.0%	24.9%	24.8%	24.6%	24.5%

Solar PPA McCracken

Performance	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Generation - GWh	140	139	138	138	137	136	135	135	134	133
Winter Capacity, MW	60	60	59	59	59	59	58	58	58	57
Summer Capacity, MW	60	60	59	59	59	59	58	58	58	57
Firm Capacity, MW	49	49	49	49	48	48	48	47	47	47
Net Capacity Factor, %	26.6%	26.4%	26.3%	26.2%	26.0%	25.9%	25.8%	25.6%	25.5%	25.4%

Solar PPA Meade

Performance	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Generation - GWh	91	91	90	90	89	89	88	88	88	87
Winter Capacity, MW	40	40	40	39	39	39	39	39	38	38
Summer Capacity, MW	40	40	40	39	39	39	39	39	38	38
Firm Capacity, MW	31	31	31	31	30	30	30	30	30	29
Net Capacity Factor, %	26.0%	25.8%	25.7%	25.6%	25.4%	25.3%	25.2%	25.1%	24.9%	24.8%

System - Base Case

SEPA - Hydro

Performance	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Generation - GWh	267	267	267	267	267	267	267	267	267	267
Winter Capacity, MW	178	178	178	178	178	178	178	178	178	178
Summer Capacity, MW	178	178	178	178	178	178	178	178	178	178
Firm Capacity, MW	178	178	178	178	178	178	178	178	178	178
Net Capacity Factor, %	17.1%	17.1%	17.1%	17.1%	17.1%	17.1%	17.1%	17.1%	17.1%	17.1%

Solar PPA Henderson

Performance	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Generation - GWh	342	340	339	336	335	333	332	329	327	326
Winter Capacity, MW	152	151	150	150	149	148	147	146	146	145
Summer Capacity, MW	152	151	150	150	149	148	147	146	146	145
Firm Capacity, MW	108	107	107	106	105	104	103	103	102	101
Net Capacity Factor, %	24.4%	24.3%	24.1%	24.0%	23.9%	23.7%	23.6%	23.5%	23.4%	23.2%

Solar PPA McCracken

Performance	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Generation - GWh	133	132	132	131	130	129	129	128	127	126
Winter Capacity, MW	57	57	56	56	56	56	55	55	55	54
Summer Capacity, MW	57	57	56	56	56	56	55	55	55	54
Firm Capacity, MW	46	46	46	46	45	45	45	44	44	44
Net Capacity Factor, %	25.2%	25.1%	25.0%	24.8%	24.7%	24.6%	24.4%	24.3%	24.2%	24.0%

Solar PPA Meade

Performance	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Generation - GWh	86	86	86	85	85	84	84	83	83	82
Winter Capacity, MW	38	38	38	37	37	37	37	37	36	36
Summer Capacity, MW	38	38	38	37	37	37	37	37	36	36
Firm Capacity, MW	29	29	29	29	28	28	28	28	28	27
Net Capacity Factor, %	24.7%	24.5%	24.4%	24.3%	24.2%	24.0%	23.9%	23.8%	23.6%	23.5%

Big Rivers Native Load Cost, MISO									
Year	Energy MISO Cost			Capacity MISO Cost			Total MISO Cost		
	MWh	$M	$/MWh	PRMR	$M	$/MW-Day	MWh	$M	$/MWh
2021	3,330,269	[redacted]	[redacted]	666.7	[redacted]	[redacted]	3,330,269	[redacted]	[redacted]
2022	4,384,110	[redacted]	[redacted]	882.6	[redacted]	[redacted]	4,384,110	[redacted]	[redacted]
2023	4,395,839	[redacted]	[redacted]	879.8	[redacted]	[redacted]	4,395,839	[redacted]	[redacted]
2024	4,409,889	[redacted]	[redacted]	880.9	[redacted]	[redacted]	4,409,889	[redacted]	[redacted]
2025	4,415,339	[redacted]	[redacted]	883.8	[redacted]	[redacted]	4,415,339	[redacted]	[redacted]
2026	4,425,681	[redacted]	[redacted]	886.0	[redacted]	[redacted]	4,425,681	[redacted]	[redacted]
2027	4,427,519	[redacted]	[redacted]	886.0	[redacted]	[redacted]	4,427,519	[redacted]	[redacted]
2028	4,436,200	[redacted]	[redacted]	887.1	[redacted]	[redacted]	4,436,200	[redacted]	[redacted]
2029	4,439,269	[redacted]	[redacted]	888.2	[redacted]	[redacted]	4,439,269	[redacted]	[redacted]
2030	4,443,020	[redacted]	[redacted]	889.2	[redacted]	[redacted]	4,443,020	[redacted]	[redacted]
2031	4,448,003	[redacted]	[redacted]	890.3	[redacted]	[redacted]	4,448,003	[redacted]	[redacted]
2032	4,462,278	[redacted]	[redacted]	892.5	[redacted]	[redacted]	4,462,278	[redacted]	[redacted]
2033	4,462,294	[redacted]	[redacted]	893.6	[redacted]	[redacted]	4,462,294	[redacted]	[redacted]
2034	4,466,493	[redacted]	[redacted]	894.6	[redacted]	[redacted]	4,466,493	[redacted]	[redacted]
2035	4,470,695	[redacted]	[redacted]	895.7	[redacted]	[redacted]	4,470,695	[redacted]	[redacted]
2036	4,477,410	[redacted]	[redacted]	896.8	[redacted]	[redacted]	4,477,410	[redacted]	[redacted]
2037	4,479,154	[redacted]	[redacted]	897.9	[redacted]	[redacted]	4,479,154	[redacted]	[redacted]
2038	4,482,805	[redacted]	[redacted]	899.0	[redacted]	[redacted]	4,482,805	[redacted]	[redacted]
2039	4,482,692	[redacted]	[redacted]	900.1	[redacted]	[redacted]	4,482,692	[redacted]	[redacted]
2040	4,486,504	[redacted]	[redacted]	901.2	[redacted]	[redacted]	4,486,504	[redacted]	[redacted]
2041	4,482,635	[redacted]	[redacted]	902.3	[redacted]	[redacted]	4,482,635	[redacted]	[redacted]
2042	4,483,054	[redacted]	[redacted]	903.4	[redacted]	[redacted]	4,483,054	[redacted]	[redacted]
2043	4,482,822	[redacted]	[redacted]	904.5	[redacted]	[redacted]	4,482,822	[redacted]	[redacted]

Short Term Plan
Load Cost
Production Cost Model

	Wilson Fixed O&M Costs - Coal-Fired, Coleman Scrubber moved Spring 2022 ($M)							
	2021	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
Non-Labor Routine	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Non-Labor Outage	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Labor Plant Staff	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Labor Support Staff	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Non-Labor (Landfill Dredging and other costs not incl. in Non-Fuel VOM dispatch)					[redacted]	[redacted]	[redacted]	[redacted]
Plant Capital Costs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
ECP Capital Costs (2020 projected spend $4.15M)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
ECP Capital Costs (Total Spend in 2022$)		[redacted]						
Annualized to 2043		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Fixed O&M Cost (Incl. Plant Capital and ECP Capital Annualized)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

	Wilson Fixed O&M Costs - Coal-Fired, Coleman Scrubber moved Spring 2022 ($M)							
	2029	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
Non-Labor Routine	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Non-Labor Outage	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Labor Plant Staff	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Labor Support Staff	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Non-Labor (Landfill Dredging and other costs not incl. in Non-Fuel VOM dispatch)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Plant Capital Costs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
ECP Capital Costs (2020 projected spend $4.15M)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
ECP Capital Costs (Total Spend in 2022$)								
Annualized to 2043	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Fixed O&M Cost (Incl. Plant Capital and ECP Capital Annualized)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Short Term Plan
Fixed and Cap Cost
Production Cost Model

	Wilson Fixed O&M Costs - Coal-Fired, Coleman Scrubber moved Spring 2022 ($M)						
	2037	2038	2039	2040	2041	2042	2043
Non-Labor Routine	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Non-Labor Outage	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Labor Plant Staff	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Labor Support Staff	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Non-Labor (Landfill Dredging and other costs not incl. in Non-Fuel VOM dispatch)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Plant Capital Costs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
ECP Capital Costs (2020 projected spend $4.15M)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
ECP Capital Costs (Total Spend in 2022$)							
Annualized to 2043	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Fixed O&M Cost (Incl. Plant Capital and ECP Capital Annualized)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

	Green Fixed O&M Costs (Reduced Capactiy Factor, Econ Commit) - Coal-Fired ($M)							
	2021	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
Non-Labor Routine	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
G1 Non-Labor Outage	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
G2 Non-Labor Outage	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Labor Plant Staff	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Labor Support Staff	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Non-Labor (Landfill Dredging and other costs not incl. in Non-Fuel VOM for dispatch)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Plant Capital Costs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
G1 Outage Capital Costs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
G2 Outage Capital Costs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
ECP Capital Costs (No Pond Closure) - G1 (Green Total in 2024$ /2)				[redacted]				
ECP Capital Costs (No Pond Closure) - G2 (Green Total in 2024$/2)				[redacted]				
Annualized to 2043				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Fixed O&M Cost (Incl. Plant Capital - ECP Capital Annualized)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Difference for High Capacity Factor	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Generation MWh adder		2,585,076	65.0%					
Green Fixed Cost Adder Check (Green Generation X Adder)				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Green Capacity Factor				31.7%	29.1%	25.3%	25.0%	17.9%

	Green Fixed O&M Costs (Reduced Capactiy Factor, Econ Commit) - Coal-Fired ($M)							
	2029	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
Non-Labor Routine	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
G1 Non-Labor Outage	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
G2 Non-Labor Outage	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Labor Plant Staff	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Labor Support Staff	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Non-Labor (Landfill Dredging and other costs not incl. in Non-Fuel VOM for dispatch)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Plant Capital Costs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
G1 Outage Capital Costs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
G2 Outage Capital Costs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
ECP Capital Costs (No Pond Closure) - G1 (Green Total in 2024$ /2)								
ECP Capital Costs (No Pond Closure) - G2 (Green Total in 2024$/2)								
Annualized to 2043	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Fixed O&M Cost (Incl. Plant Capital - ECP Capital Annualized)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Difference for High Capacity Factor	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Generation MWh adder		[redacted]						
Green Fixed Cost Adder Check (Green Generation X Adder)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Green Capacity Factor	15.0%	18.2%	20.6%	15.9%	32.2%	37.2%	47.7%	56.3%

	Green Fixed O&M Costs (Reduced Capactiy Factor, Econ Commit) - Coal-Fired ($M)						
	2037	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**
Non-Labor Routine	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
G1 Non-Labor Outage	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
G2 Non-Labor Outage	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Labor Plant Staff	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Labor Support Staff	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Non-Labor (Landfill Dredging and other costs not incl. in Non-Fuel VOM for dispatch)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Plant Capital Costs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
G1 Outage Capital Costs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
G2 Outage Capital Costs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
ECP Capital Costs (No Pond Closure) - G1 (Green Total in 2024$ /2)							
ECP Capital Costs (No Pond Closure) - G2 (Green Total in 2024$/2)							
Annualized to 2043	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Fixed O&M Cost (Incl. Plant Capital - ECP Capital Annualized)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Difference for High Capacity Factor	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Generation MWh adder				[redacted]			[redacted]
Green Fixed Cost Adder Check (Green Generation X Adder)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Green Capacity Factor	68.5%	80.3%	85.7%	91.0%	93.7%	93.8%	95.3%

Short Term Plan
Fixed and Cap Cost
Production Cost Model

	Green Fixed O&M Costs (Reduced Capacity Factor) - Gas-Fired ($M)							
	2021	2022	2023	2024	2025	2026	2027	2028
Non-Labor Routine	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
G1 Non-Labor Outage	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
G2 Non-Labor Outage	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Labor Plant Staff	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Labor Support Staff	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Plant Capital Costs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
G1 Outage Capital Costs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
G2 Outage Capital Costs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Gas Line (2019 Eco-Energy)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
G1 Firm Gas ($0.1688/MMBtu)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
G2 Firm Gas ($0.1688/MMBtu)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
ECP Capital Costs (No Pond Closure) - G1 (Green Total in 2024$ /2)				[redacted]				
ECP Capital Costs (No Pond Closure) - G2 (Green Total in 2024$/2)				[redacted]				
Annualized to 2043				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Fixed O&M Cost (Incl. Plant Capital - ECP Capital Annualized)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

	Reid CT Fixed O&M Costs ($M)							
	2021	2022	2023	2024	2025	2026	2027	2028
Non-Labor Routine	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Non-Labor Outage	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Labor Plant Staff (not included in Sebree)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Labor Support Staff	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Plant Capital Costs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
No Firm Gas ($0.1688/MMBtu)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
ECP Capital Costs (No Pond Closure)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Fixed O&M Cost (Incl. Plant Capital and ECP Capital)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Short Term Plan
Fixed and Cap Cost
Production Cost Model

	Green Fixed O&M Costs (Reduced Capacity Factor) - Gas-Fired ($M)							
	2029	2030	2031	2032	2033	2034	2035	2036
Non-Labor Routine	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
G1 Non-Labor Outage	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
G2 Non-Labor Outage	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Labor Plant Staff	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Labor Support Staff	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Plant Capital Costs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
G1 Outage Capital Costs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
G2 Outage Capital Costs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Gas Line (2019 Eco-Energy)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
G1 Firm Gas ($0.1688/MMBtu)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
G2 Firm Gas ($0.1688/MMBtu)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
ECP Capital Costs (No Pond Closure) - G1 (Green Total in 2024$ /2)								
ECP Capital Costs (No Pond Closure) - G2 (Green Total in 2024$/2)								
Annualized to 2043	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Fixed O&M Cost (Incl. Plant Capital - ECP Capital Annualized)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

	Reid CT Fixed O&M Costs ($M)							
	2029	2030	2031	2032	2033	2034	2035	2036
Non-Labor Routine	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Non-Labor Outage	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Labor Plant Staff (not included in Sebree)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Labor Support Staff	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Plant Capital Costs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
No Firm Gas ($0.1688/MMBtu)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
ECP Capital Costs (No Pond Closure)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Fixed O&M Cost (Incl. Plant Capital and ECP Capital)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Short Term Plan
Fixed and Cap Cost
Production Cost Model

	Green Fixed O&M Costs (Reduced Capacity Factor) - Gas-Fired ($M)						
	2037	2038	2039	2040	2041	2042	2043
Non-Labor Routine	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
G1 Non-Labor Outage	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
G2 Non-Labor Outage	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Labor Plant Staff	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Labor Support Staff	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Plant Capital Costs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
G1 Outage Capital Costs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
G2 Outage Capital Costs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Gas Line (2019 Eco-Energy)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
G1 Firm Gas ($0.1688/MMBtu)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
G2 Firm Gas ($0.1688/MMBtu)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
ECP Capital Costs (No Pond Closure) - G1 (Green Total in 2024$ /2)							
ECP Capital Costs (No Pond Closure) - G2 (Green Total in 2024$/2)							
Annualized to 2043	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Fixed O&M Cost (Incl. Plant Capital - ECP Capital Annualized)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

	Reid CT Fixed O&M Costs ($M)						
	2037	2038	2039	2040	2041	2042	2043
Non-Labor Routine	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Non-Labor Outage	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Labor Plant Staff (not included in Sebree)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Labor Support Staff	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Plant Capital Costs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
No Firm Gas ($0.1688/MMBtu)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
ECP Capital Costs (No Pond Closure)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Fixed O&M Cost (Incl. Plant Capital and ECP Capital)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

	NGCC - Coleman							
	2021	2022	2023	2024	2025	2026	2027	2028
Fixed O&M Cost ($M) (592 MW Capacity) (Outage Maint in VOM)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Firm Gas Cost ($M) (592 MW Capacity)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Gas Service Cost ($M) (592 MW Capacity)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Build Cost, $M (592 Net MW Capacity)	[redacted]	[redacted]	[redacted]	[redacted]				
Annualized to 2043	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Fixed O&M Cost ($M) (592 MW Capacity	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

	NGCC - Sebree							
	2021	2022	2023	2024	2025	2026	2027	2028
Fixed O&M Cost ($M) (592 MW Capacity) (Outage Maint in VOM)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Firm Gas Cost ($M) (592 MW Capacity)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Gas Service Cost ($M) (592 MW Capacity)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Build Cost, $M (592 Net MW Capacity)	[redacted]	[redacted]	[redacted]	[redacted]				
Annualized to 2043	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Fixed O&M Cost ($M) (592 MW Capacity	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

	NGCT - Industrial Frame							
	2021	2022	2023	2024	2025	2026	2027	2028
Fixed O&M Cost ($M) (237 MW Capacity) (Outage Maint in VOM)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Firm Gas Cost ($M) (237 MW Capacity)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Gas Service Cost ($M) (237 MW Capacity)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Build Cost, $M (237 Net MW Capacity)	[redacted]	[redacted]	[redacted]	[redacted]				
Annualized to 2043	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Fixed O&M Cost ($M) (592 MW Capacity	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Short Term Plan
Fixed and Cap Cost
Production Cost Model

	NGCC - Coleman							
	2029	2030	2031	2032	2033	2034	2035	2036
Fixed O&M Cost ($M) (592 MW Capacity) (Outage Maint in VOM)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Firm Gas Cost ($M) (592 MW Capacity)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Gas Service Cost ($M) (592 MW Capacity)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Build Cost, $M (592 Net MW Capacity)								
Annualized to 2043	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Fixed O&M Cost ($M) (592 MW Capacity	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

	NGCC - Sebree							
	2029	2030	2031	2032	2033	2034	2035	2036
Fixed O&M Cost ($M) (592 MW Capacity) (Outage Maint in VOM)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Firm Gas Cost ($M) (592 MW Capacity)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Gas Service Cost ($M) (592 MW Capacity)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Build Cost, $M (592 Net MW Capacity)								
Annualized to 2043	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Fixed O&M Cost ($M) (592 MW Capacity	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

	NGCT - Industrial Frame							
	2029	2030	2031	2032	2033	2034	2035	2036
Fixed O&M Cost ($M) (237 MW Capacity) (Outage Maint in VOM)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Firm Gas Cost ($M) (237 MW Capacity)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Gas Service Cost ($M) (237 MW Capacity)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Build Cost, $M (237 Net MW Capacity)								
Annualized to 2043	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Fixed O&M Cost ($M) (592 MW Capacity	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Short Term Plan
Fixed and Cap Cost
Production Cost Model

	NGCC - Coleman						
	2037	2038	2039	2040	2041	2042	2043
Fixed O&M Cost ($M) (592 MW Capacity) (Outage Maint in VOM)	[redacted]						
Firm Gas Cost ($M) (592 MW Capacity)							
Gas Service Cost ($M) (592 MW Capacity)							
Build Cost, $M (592 Net MW Capacity)							
Annualized to 2043	[redacted]						
Total Fixed O&M Cost ($M) (592 MW Capacity							

	NGCC - Sebree						
	2037	2038	2039	2040	2041	2042	2043
Fixed O&M Cost ($M) (592 MW Capacity) (Outage Maint in VOM)	[redacted]						
Firm Gas Cost ($M) (592 MW Capacity)							
Gas Service Cost ($M) (592 MW Capacity)							
Build Cost, $M (592 Net MW Capacity)							
Annualized to 2043	[redacted]						
Total Fixed O&M Cost ($M) (592 MW Capacity							

	NGCT - Industrial Frame						
	2037	2038	2039	2040	2041	2042	2043
Fixed O&M Cost ($M) (237 MW Capacity) (Outage Maint in VOM)	[redacted]						
Firm Gas Cost ($M) (237 MW Capacity)							
Gas Service Cost ($M) (237 MW Capacity)							
Build Cost, $M (237 Net MW Capacity)							
Annualized to 2043	[redacted]						
Total Fixed O&M Cost ($M) (592 MW Capacity							

Fuel Oil Start Fuel	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Delivered Price, $/MMBtu	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Wilson Usage, MMBtu	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Wilson Cost, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Green 1 Usage, MMBtu	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Green 1 Cost, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Green 2 Usage, MMBtu	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Green 2 Cost, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

NG Price, $/MMBtu	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Green NG Usage, MMBtu	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Green NG Cost, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Short Term Plan
Start Fuel Oil
Production Cost Model

Fuel Oil Start Fuel	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Delivered Price, $/MMBtu	[redacted]										
Wilson Usage, MMBtu											
Wilson Cost, $M											
Green 1 Usage, MMBtu											
Green 1 Cost, $M											
Green 2 Usage, MMBtu											
Green 2 Cost, $M											

NG Price, $/MMBtu	[redacted]
Green NG Usage, MMBtu	
Green NG Cost, $M	

Short Term Plan
Start Fuel Oil
Production Cost Model

2024 -2043 LT Plan Portfolio Results - Other Scenarios

Scenario	Generation Portfolio (Max Capacity) for Least Cost Plan							Average Energy Position	Average Reserve Capacity Margin	
	Wilson	Solar	Reid CT	SEPA	NGCC	PPA - Block	NPV, 2024$	MWh	MW	%
Big Rivers Base Case (ST Plan)	**412**	**260**	**65**	**178**	**90**	**-**	[redacted]	**173,877**	**73.7**	**8.9%**
Preliminary LT Plan	412	260	65	-	250 - 290	-	[redacted]	1,158,103	74.8	9.1%
LT Plan - Carbon ACES	412	260	-	-	320 - 360	-	[redacted]	1,397,356	76.0	9.2%
LT Plan - Carbon IHS	412	260	65	178	70	0 - 30	[redacted]	(2,138,244)	71.5	8.7%
LT Plan - No Capacity Price	412	260	-	-	-	290 - 330	[redacted]	(1,027,079)	67.9	8.2%
LT Plan - REC None	412	260	65	-	250 - 290	-	[redacted]	1,158,103	74.8	9.1%
LT Plan - REC Ohio Solar	412	260	65	-	250 - 290	-	[redacted]	1,158,103	74.8	9.1%
LT Plan - Solar Capacity ELCC	412	260	65	-	380 - 420	-	[redacted]	2,167,400	75.3	9.1%
LT Plan - No NGCC Option	412	260	65	178	-	60 - 100	[redacted]	(723,091)	68.7	8.3%

2024 -2043 LT Plan Portfolio Results - Multi-Variable Price Scenarios

Scenario	Generation Portfolio (Max Capacity) for Least Cost Plan						Cost to Serve Load $M	Average Energy Position	Average Reserve Capacity Margin	
	Wilson	Solar	Reid CT	SEPA	NGCC	PPA - Block	NPV, 2024$	MWh	MW	%
Big Rivers Base Case (ST Plan)	**412**	**260**	**65**	**178**	**90**	**-**	[redacted]	**173,877**	**73.7**	**8.9%**
Preliminary LT Plan	412	260	65	-	250 - 290	-	[redacted]	1,158,103	74.8	9.1%
LT Plan - 40% Higher All	412	260	-	-	320 - 360	-	[redacted]	1,722,754	76.0	9.2%
LT Plan - 40% Higher LMP - Coal&NG 30% Higher	412	260	-	-	320 - 360	-	[redacted]	1,900,586	76.0	9.2%
LT Plan - 40% Higher LMP - Coal&NG 50% Higher	412	260	-	178	130 - 170	-	[redacted]	168,534	76.1	9.2%
LT Plan - 20% Higher All	412	260	-	-	320 - 360	-	[redacted]	1,685,165	76.0	9.2%
LT Plan - 20% Higher LMP - Coal&NG 10% Higher	412	260	-	-	320 - 360	-	[redacted]	1,906,117	76.0	9.2%
LT Plan - 20% Higher LMP - Coal&NG 30% Higher	412	260	-	178	130 - 170	-	[redacted]	60,458	74.5	9.0%
LT Plan - 20% Lower All	412	260	65	178	70 - 90	0 - 10	[redacted]	(133,646)	72.4	8.8%
LT Plan - 20% Lower LMP - Coal&NG 10% Lower	412	260	65	178	60	0 - 40	[redacted]	(937,142)	69.2	8.4%
LT Plan - 20% Lower LMP - Coal&NG 30% Lower	412	260	65	-	260 - 300	-	[redacted]	1,449,759	75.4	9.1%
LT Plan - 40% Lower All	412	260	65	178	-	60 - 100	[redacted]	(845,039)	68.9	8.3%
LT Plan - 40% Lower LMP - Coal&NG 30% Lower	412	260	65	178	-	60 - 100	[redacted]	(1,625,698)	68.9	8.3%
LT Plan - 40% Lower LMP - Coal&NG 50% Lower	412	260	65	-	250 - 290	-	[redacted]	1,473,128	74.8	9.1%

2024 -2043 LT Plan Portfolio Results - Single Variable Price Scenarios

Scenario	Generation Portfolio (Max Capacity) for Least Cost Plan						Cost to Serve Load $M	Average Energy Position	Average Capacity Reserve Margin	
	Wilson	Solar	Reid CT	SEPA	NGCC	PPA - Block	NPV, 2024$	MWh	MW	%
Big Rivers Base Case (ST Plan)	**412**	**260**	**65**	**178**	**90**	**-**	[redacted]	**173,877**	**73.7**	**8.9%**
Preliminary LT Plan	412	260	65	-	250 - 290	-	[redacted]	1,158,103	74.8	9.1%
Base 50% Higher LMP	412	260	-	-	320 - 360	-	[redacted]	2,168,192	76.0	9.2%
Base 40% Higher LMP	412	260	-	-	320 - 360	-	[redacted]	2,151,463	76.0	9.2%
Base 30% Higher LMP	412	260	-	-	320 - 360	-	[redacted]	2,107,767	76.0	9.2%
Base 20% Higher LMP	412	260	-	-	320 - 360	-	[redacted]	2,016,990	76.0	9.2%
Base 10% Higher LMP	412	260	-	-	320 - 360	-	[redacted]	1,909,052	76.0	9.2%
Base 10% Lower LMP	412	260	65	178	70 - 80	0 - 20	[redacted]	(701,848)	71.1	8.6%
Base 20% Lower LMP	412	260	65	178	-	60 - 100	[redacted]	(1,948,726)	68.9	8.3%
Base 30% Lower LMP	412	260	65	178	-	60 - 100	[redacted]	(2,725,702)	68.9	8.3%
Base 40% Lower LMP	412	260	65	178	-	60 - 100	[redacted]	(3,296,519)	68.9	8.3%
Base 50% Lower LMP	412	260	65	178	-	60 - 100	[redacted]	(3,551,426)	68.9	8.3%
Base 50% Higher Coal	412	260	65	-	250 - 290	-	[redacted]	(979,590)	74.8	9.1%
Base 40% Higher Coal	412	260	65	-	250 - 290	-	[redacted]	(633,256)	74.8	9.1%
Base 30% Higher Coal	412	260	65	-	250 - 290	-	[redacted]	(215,249)	74.8	9.1%
Base 20% Higher Coal	412	260	65	-	250 - 290	-	[redacted]	270,320	74.8	9.1%
Base 10% Higher Coal	412	260	65	-	250 - 290	-	[redacted]	736,351	74.8	9.1%
Base 10% Lower Coal	412	260	65	-	250 - 290	-	[redacted]	1,322,442	74.8	9.1%
Base 20% Lower Coal	412	260	65	-	250 - 290	-	[redacted]	1,429,019	74.8	9.1%
Base 30% Lower Coal	412	260	65	-	250 - 290	-	[redacted]	1,515,801	74.8	9.1%
Base 40% Lower Coal	412	260	65	-	250 - 290	-	[redacted]	1,540,455	74.8	9.1%
Base 50% Lower Coal	412	260	65	-	250 - 290	-	[redacted]	1,544,179	74.8	9.1%

Long Term Plan (Yearly Sensitivities)
Single Variable Exhibit
Production Cost Model

2024 -2043 LT Plan Portfolio Results - Single Variable Price Scenarios										
Scenario	Generation Portfolio (Max Capacity) for Least Cost Plan						Cost to Serve Load $M	Average Energy Position	Average Capacity Reserve Margin	
	Wilson	Solar	Reid CT	SEPA	NGCC	PPA - Block	NPV, 2024$	MWh	MW	%
Base 50% Higher NG	412	260	65	178	-	60 - 100	[redacted]	(759,982)	68.9	8.3%
Base 40% Higher NG	412	260	65	178	-	60 - 100	[redacted]	(759,951)	68.9	8.3%
Base 30% Higher NG	412	260	65	178	-	60 - 100	[redacted]	(759,559)	68.9	8.3%
Base 20% Higher NG	412	260	65	178	70	0 - 30	[redacted]	(307,139)	69.8	8.5%
Base 10% Higher NG	412	260	65	178	70 - 90	0 - 10	[redacted]	(147,464)	72.4	8.8%
Base 10% Lower NG	412	260	-	-	320 - 360	-	[redacted]	1,747,807	76.0	9.2%
Base 20% Lower NG	412	260	-	-	320 - 360	-	[redacted]	1,781,692	76.0	9.2%
Base 30% Lower NG	412	260	-	-	320 - 360	-	[redacted]	1,793,578	76.0	9.2%
Base 40% Lower NG	412	260	-	-	320 - 360	-	[redacted]	1,795,308	76.0	9.2%
Base 50% Lower NG	412	260	-	-	320 - 360	-	[redacted]	1,795,308	76.0	9.2%

Long Term Plan (Yearly Sensitivities)
Single Variable Exhibit
Production Cost Model

	Nominal, $M		NPV 2024$, $M					
	Total	Avg/Yr.	Total	Avg/Yr.	2024	2025	2026	2027
Load Cost 50% Higher LMP	[redacted]							
Load Cost 40% Higher LMP	[redacted]							
Load Cost 30% Higher LMP	[redacted]							
Load Cost 20% Higher LMP	[redacted]							
Load Cost 10% Higher LMP	[redacted]							
Load MISO Cost, $M	[redacted]							
Load Cost 10% Lower LMP	[redacted]							
Load Cost 20% Lower LMP	[redacted]							
Load Cost 30% Lower LMP	[redacted]							
Load Cost 40% Lower LMP	[redacted]							
Load Cost 50% Lower LMP	[redacted]							
Cost to Serve Load (Load Cost - System Net Profit)								
LT Plan - Base	[redacted]							
Base 50% Higher LMP	[redacted]							
Base 40% Higher LMP	[redacted]							
Base 30% Higher LMP	[redacted]							
Base 20% Higher LMP	[redacted]							
Base 10% Higher LMP	[redacted]							
Base 10% Lower LMP	[redacted]							
Base 20% Lower LMP	[redacted]							
Base 30% Lower LMP	[redacted]							
Base 40% Lower LMP	[redacted]							
Base 50% Lower LMP	[redacted]							

Long Term Plan (Yearly Sensitivities)
Cost to Serve Load
Production Cost Model

	2028	2029	2030	2031	2032	2033	2034	2035
Load Cost 50% Higher LMP	[redacted]							
Load Cost 40% Higher LMP	[redacted]							
Load Cost 30% Higher LMP	[redacted]							
Load Cost 20% Higher LMP	[redacted]							
Load Cost 10% Higher LMP	[redacted]							
Load MISO Cost, $M	[redacted]							
Load Cost 10% Lower LMP	[redacted]							
Load Cost 20% Lower LMP	[redacted]							
Load Cost 30% Lower LMP	[redacted]							
Load Cost 40% Lower LMP	[redacted]							
Load Cost 50% Lower LMP	[redacted]							
Cost to Serve Load (Load Cost - System Net Profit)								
LT Plan - Base	[redacted]							
Base 50% Higher LMP	[redacted]							
Base 40% Higher LMP	[redacted]							
Base 30% Higher LMP	[redacted]							
Base 20% Higher LMP	[redacted]							
Base 10% Higher LMP	[redacted]							
Base 10% Lower LMP	[redacted]							
Base 20% Lower LMP	[redacted]							
Base 30% Lower LMP	[redacted]							
Base 40% Lower LMP	[redacted]							
Base 50% Lower LMP	[redacted]							

Long Term Plan (Yearly Sensitivities)
Cost to Serve Load
Production Cost Model

	2036	2037	2038	2039	2040	2041	2042	2043
Load Cost 50% Higher LMP	[redacted]							
Load Cost 40% Higher LMP								
Load Cost 30% Higher LMP								
Load Cost 20% Higher LMP								
Load Cost 10% Higher LMP								
Load MISO Cost, $M								
Load Cost 10% Lower LMP								
Load Cost 20% Lower LMP								
Load Cost 30% Lower LMP								
Load Cost 40% Lower LMP								
Load Cost 50% Lower LMP								
Cost to Serve Load (Load Cost - System Net Profit)								
LT Plan - Base	[redacted]							
Base 50% Higher LMP								
Base 40% Higher LMP								
Base 30% Higher LMP								
Base 20% Higher LMP								
Base 10% Higher LMP								
Base 10% Lower LMP								
Base 20% Lower LMP								
Base 30% Lower LMP								
Base 40% Lower LMP								
Base 50% Lower LMP								

Case No. 2020-00299
Big Rivers 2020 IRP
G-7

Long Term Plan (Yearly Sensitivities)
Cost to Serve Load
Production Cost Model

	Nominal, $M		NPV 2024$, $M					
	Total	Avg/Yr.	Total	Avg/Yr.	2024	2025	2026	2027
Base 50% Higher Coal	[redacted]							
Base 40% Higher Coal	[redacted]							
Base 30% Higher Coal	[redacted]							
Base 20% Higher Coal	[redacted]							
Base 10% Higher Coal	[redacted]							
Base 10% Lower Coal	[redacted]							
Base 20% Lower Coal	[redacted]							
Base 30% Lower Coal	[redacted]							
Base 40% Lower Coal	[redacted]							
Base 50% Lower Coal	[redacted]							
Base 50% Higher NG	[redacted]							
Base 40% Higher NG	[redacted]							
Base 30% Higher NG	[redacted]							
Base 20% Higher NG	[redacted]							
Base 10% Higher NG	[redacted]							
Base 10% Lower NG	[redacted]							
Base 20% Lower NG	[redacted]							
Base 30% Lower NG	[redacted]							
Base 40% Lower NG	[redacted]							
Base 50% Lower NG	[redacted]							

Long Term Plan (Yearly Sensitivities)
Cost to Serve Load
Production Cost Model

	2028	2029	2030	2031	2032	2033	2034	2035
Base 50% Higher Coal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Base 40% Higher Coal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Base 30% Higher Coal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Base 20% Higher Coal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Base 10% Higher Coal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Base 10% Lower Coal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Base 20% Lower Coal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Base 30% Lower Coal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Base 40% Lower Coal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Base 50% Lower Coal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Base 50% Higher NG	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Base 40% Higher NG	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Base 30% Higher NG	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Base 20% Higher NG	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Base 10% Higher NG	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Base 10% Lower NG	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Base 20% Lower NG	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Base 30% Lower NG	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Base 40% Lower NG	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Base 50% Lower NG	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Long Term Plan (Yearly Sensitivities)
Cost to Serve Load
Production Cost Model

	2036	2037	2038	2039	2040	2041	2042	2043
Base 50% Higher Coal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Base 40% Higher Coal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Base 30% Higher Coal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Base 20% Higher Coal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Base 10% Higher Coal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Base 10% Lower Coal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Base 20% Lower Coal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Base 30% Lower Coal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Base 40% Lower Coal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Base 50% Lower Coal	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Base 50% Higher NG	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Base 40% Higher NG	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Base 30% Higher NG	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Base 20% Higher NG	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Base 10% Higher NG	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Base 10% Lower NG	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Base 20% Lower NG	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Base 30% Lower NG	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Base 40% Lower NG	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Base 50% Lower NG	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Long Term Plan (Yearly Sensitivities)
Cost to Serve Load
Production Cost Model

	Nominal, $M		NPV 2024$, $M					
	Total	Avg/Yr.	Total	Avg/Yr.	2024	2025	2026	2027
LT Plan - 40% Higher All	[redacted]							
LT Plan - 40% Higher LMP - Coal&NG 30% Higher	[redacted]							
LT Plan - 40% Higher LMP - Coal&NG 50% Higher	[redacted]							
LT Plan - 20% Higher All	[redacted]							
LT Plan - 20% Higher LMP - Coal&NG 10% Higher	[redacted]							
LT Plan - 20% Higher LMP - Coal&NG 30% Higher	[redacted]							
LT Plan - 20% Lower All	[redacted]							
LT Plan - 20% Lower LMP - Coal&NG 10% Lower	[redacted]							
LT Plan - 20% Lower LMP - Coal&NG 30% Lower	[redacted]							
LT Plan - 40% Lower All	[redacted]							
LT Plan - 40% Lower LMP - Coal&NG 30% Lower	[redacted]							
LT Plan - 40% Lower LMP - Coal&NG 50% Lower	[redacted]							
LT Plan - Carbon ACES	[redacted]							
LT Plan - Carbon IHS	[redacted]							
LT Plan - No Capacity Price	[redacted]							
LT Plan - REC None	[redacted]							
LT Plan - REC Ohio Solar	[redacted]							
LT Plan - Solar Capacity IHS	[redacted]							

Long Term Plan (Yearly Sensitivities)
Cost to Serve Load
Production Cost Model

	2028	2029	2030	2031	2032	2033	2034	2035
LT Plan - 40% Higher All	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
LT Plan - 40% Higher LMP - Coal&NG 30% Higher	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
LT Plan - 40% Higher LMP - Coal&NG 50% Higher	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
LT Plan - 20% Higher All	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
LT Plan - 20% Higher LMP - Coal&NG 10% Higher	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
LT Plan - 20% Higher LMP - Coal&NG 30% Higher	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
LT Plan - 20% Lower All	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
LT Plan - 20% Lower LMP - Coal&NG 10% Lower	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
LT Plan - 20% Lower LMP - Coal&NG 30% Lower	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
LT Plan - 40% Lower All	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
LT Plan - 40% Lower LMP - Coal&NG 30% Lower	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
LT Plan - 40% Lower LMP - Coal&NG 50% Lower	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
LT Plan - Carbon ACES	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
LT Plan - Carbon IHS	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
LT Plan - No Capacity Price	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
LT Plan - REC None	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
LT Plan - REC Ohio Solar	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
LT Plan - Solar Capacity IHS	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Long Term Plan (Yearly Sensitivities)
Cost to Serve Load
Production Cost Model

	2036	2037	2038	2039	2040	2041	2042	2043
LT Plan - 40% Higher All	[redacted]							
LT Plan - 40% Higher LMP - Coal&NG 30% Higher								
LT Plan - 40% Higher LMP - Coal&NG 50% Higher								
LT Plan - 20% Higher All								
LT Plan - 20% Higher LMP - Coal&NG 10% Higher								
LT Plan - 20% Higher LMP - Coal&NG 30% Higher								
LT Plan - 20% Lower All								
LT Plan - 20% Lower LMP - Coal&NG 10% Lower								
LT Plan - 20% Lower LMP - Coal&NG 30% Lower								
LT Plan - 40% Lower All								
LT Plan - 40% Lower LMP - Coal&NG 30% Lower								
LT Plan - 40% Lower LMP - Coal&NG 50% Lower								
LT Plan - Carbon ACES								
LT Plan - Carbon IHS								
LT Plan - No Capacity Price								
LT Plan - REC None								
LT Plan - REC Ohio Solar								
LT Plan - Solar Capacity IHS								

Long Term Plan (Yearly Sensitivities)
Cost to Serve Load
Production Cost Model

	Average	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Load Energy, GWh	**4,455**	**4,410**	**4,415**	**4,426**	**4,428**	**4,436**	**4,439**	**4,443**	**4,448**	**4,462**	**4,462**
Energy Position (System Generation - Load)											
LT Plan - Base	**1,158**	976	1,192	776	1,143	935	853	808	1,095	920	1,305
Base 50% Higher LMP	**2,168**	2,027	2,188	1,724	2,167	2,062	2,219	1,983	2,302	2,108	2,293
Base 40% Higher LMP	**2,151**	2,003	2,173	1,699	2,149	2,031	2,168	1,943	2,287	2,088	2,281
Base 30% Higher LMP	**2,108**	1,955	2,120	1,649	2,077	1,952	2,063	1,873	2,218	2,008	2,233
Base 20% Higher LMP	**2,017**	1,847	1,992	1,514	1,921	1,827	1,915	1,716	2,059	1,836	2,132
Base 10% Higher LMP	**1,909**	1,703	1,851	1,397	1,831	1,734	1,828	1,612	1,943	1,737	1,946
Base 10% Lower LMP	**(702)**	(960)	(911)	(1,249)	(1,060)	(1,140)	(1,297)	(1,241)	(1,015)	(1,240)	(751)
Base 20% Lower LMP	**(1,949)**	(2,430)	(2,348)	(2,509)	(2,462)	(2,593)	(2,678)	(2,600)	(2,484)	(2,646)	(2,279)
Base 30% Lower LMP	**(2,726)**	(3,134)	(3,106)	(3,134)	(3,133)	(3,178)	(3,250)	(3,184)	(3,166)	(3,247)	(3,093)
Base 40% Lower LMP	**(3,297)**	(3,405)	(3,401)	(3,435)	(3,439)	(3,476)	(3,478)	(3,460)	(3,459)	(3,498)	(3,463)
Base 50% Lower LMP	**(3,551)**	(3,535)	(3,545)	(3,562)	(3,568)	(3,581)	(3,588)	(3,591)	(3,597)	(3,621)	(3,609)
Base 50% Higher Coal	**(980)**	(1,437)	(1,343)	(1,387)	(1,362)	(1,324)	(1,419)	(1,374)	(1,385)	(1,402)	(1,209)
Base 40% Higher Coal	**(633)**	(1,191)	(1,089)	(1,150)	(1,138)	(1,130)	(1,225)	(1,158)	(1,146)	(1,178)	(945)
Base 30% Higher Coal	**(215)**	(871)	(702)	(816)	(755)	(811)	(940)	(849)	(788)	(880)	(468)
Base 20% Higher Coal	**270**	(254)	(132)	(339)	(204)	(298)	(409)	(376)	(212)	(373)	72
Base 10% Higher Coal	**736**	370	543	186	411	286	113	183	389	186	762
Base 10% Lower Coal	**1,322**	1,116	1,364	901	1,354	1,250	1,305	1,098	1,335	1,173	1,414
Base 20% Lower Coal	**1,429**	1,290	1,538	1,069	1,489	1,358	1,409	1,233	1,497	1,307	1,609
Base 30% Lower Coal	**1,516**	1,393	1,662	1,188	1,648	1,517	1,614	1,391	1,646	1,472	1,706
Base 40% Lower Coal	**1,540**	1,433	1,697	1,225	1,683	1,559	1,684	1,450	1,677	1,507	1,731
Base 50% Lower Coal	**1,544**	1,433	1,697	1,231	1,691	1,572	1,700	1,458	1,685	1,517	1,731
Base 50% Higher NG	**(760)**	(818)	(690)	(1,107)	(752)	(1,036)	(1,069)	(1,119)	(826)	(1,035)	(684)
Base 40% Higher NG	**(760)**	(818)	(690)	(1,106)	(751)	(1,036)	(1,069)	(1,119)	(826)	(1,035)	(684)
Base 30% Higher NG	**(760)**	(817)	(690)	(1,106)	(751)	(1,035)	(1,068)	(1,118)	(826)	(1,035)	(683)
Base 20% Higher NG	**(307)**	(285)	(157)	(571)	(212)	(503)	(552)	(600)	(313)	(534)	(175)
Base 10% Higher NG	**(147)**	(254)	(127)	(540)	(180)	(389)	(450)	(495)	(133)	(354)	2
Base 10% Lower NG	**1,748**	1,566	1,686	1,274	1,629	1,432	1,375	1,331	1,703	1,482	1,842
Base 20% Lower NG	**1,782**	1,585	1,705	1,289	1,643	1,450	1,398	1,350	1,721	1,519	1,862
Base 30% Lower NG	**1,794**	1,585	1,705	1,289	1,644	1,450	1,410	1,360	1,736	1,534	1,879
Base 40% Lower NG	**1,795**	1,585	1,705	1,289	1,644	1,450	1,410	1,360	1,736	1,535	1,879
Base 50% Lower NG	**1,795**	1,585	1,705	1,289	1,644	1,450	1,410	1,360	1,736	1,535	1,879

Long Term Plan (Yearly Sensitivities)
Energy Summary
Production Cost Model

	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Load Energy, GWh	**4,466**	**4,471**	**4,477**	**4,479**	**4,483**	**4,483**	**4,487**	**4,483**	**4,483**	**4,483**
Energy Position (System Generation - Load)										
LT Plan - Base	890	1,316	1,281	1,531	1,379	1,579	1,376	1,491	855	1,106
Base 50% Higher LMP	1,844	2,375	2,189	2,360	2,159	2,351	2,252	2,426	1,970	2,418
Base 40% Higher LMP	1,825	2,362	2,185	2,355	2,155	2,349	2,248	2,425	1,968	2,414
Base 30% Higher LMP	1,805	2,337	2,169	2,345	2,145	2,339	2,238	2,412	1,959	2,403
Base 20% Higher LMP	1,724	2,284	2,140	2,324	2,125	2,320	2,226	2,405	1,938	2,364
Base 10% Higher LMP	1,530	2,138	2,050	2,248	2,057	2,265	2,169	2,323	1,815	2,184
Base 10% Lower LMP	(848)	(325)	(315)	(105)	(211)	63	(93)	65	(463)	(48)
Base 20% Lower LMP	(2,271)	(1,891)	(1,683)	(1,270)	(1,117)	(753)	(654)	(410)	(783)	(323)
Base 30% Lower LMP	(3,053)	(2,916)	(2,822)	(2,433)	(2,187)	(1,750)	(1,315)	(962)	(1,069)	(461)
Base 40% Lower LMP	(3,457)	(3,400)	(3,378)	(3,327)	(3,240)	(3,030)	(2,749)	(2,241)	(2,065)	(1,470)
Base 50% Lower LMP	(3,611)	(3,601)	(3,586)	(3,533)	(3,517)	(3,481)	(3,436)	(3,363)	(3,236)	(2,969)
Base 50% Higher Coal	(1,212)	(1,136)	(994)	(794)	(581)	(169)	305	590	366	828
Base 40% Higher Coal	(929)	(763)	(529)	(176)	54	451	790	1,053	664	1,019
Base 30% Higher Coal	(479)	(187)	90	466	659	1,002	1,117	1,336	800	1,082
Base 20% Higher Coal	32	450	715	1,096	1,029	1,328	1,300	1,441	842	1,095
Base 10% Higher Coal	613	1,108	1,147	1,338	1,266	1,523	1,355	1,477	849	1,100
Base 10% Lower Coal	986	1,493	1,454	1,650	1,423	1,604	1,390	1,495	857	1,106
Base 20% Lower Coal	1,178	1,619	1,516	1,674	1,437	1,612	1,392	1,495	857	1,106
Base 30% Lower Coal	1,228	1,655	1,535	1,684	1,446	1,612	1,392	1,495	857	1,106
Base 40% Lower Coal	1,248	1,667	1,539	1,684	1,446	1,612	1,392	1,495	857	1,106
Base 50% Lower Coal	1,248	1,667	1,539	1,684	1,446	1,612	1,392	1,495	857	1,106
Base 50% Higher NG	(1,074)	(622)	(722)	(439)	(553)	(328)	(501)	(304)	(759)	(307)
Base 40% Higher NG	(1,074)	(622)	(722)	(439)	(553)	(328)	(501)	(304)	(759)	(307)
Base 30% Higher NG	(1,074)	(622)	(722)	(439)	(553)	(328)	(501)	(304)	(759)	(307)
Base 20% Higher NG	(580)	(142)	(267)	(31)	(216)	(38)	(247)	(105)	(597)	(178)
Base 10% Higher NG	(394)	48	(65)	202	49	243	26	159	(378)	25
Base 10% Lower NG	1,440	1,965	1,880	2,128	2,011	2,243	2,156	2,319	1,815	2,186
Base 20% Lower NG	1,469	2,004	1,912	2,185	2,067	2,292	2,214	2,405	1,947	2,392
Base 30% Lower NG	1,488	2,023	1,928	2,202	2,086	2,313	2,230	2,421	1,964	2,414
Base 40% Lower NG	1,488	2,023	1,931	2,207	2,093	2,318	2,236	2,424	1,970	2,422
Base 50% Lower NG	1,488	2,023	1,931	2,207	2,093	2,318	2,236	2,424	1,970	2,422

Long Term Plan (Yearly Sensitivities)
Energy Summary
Production Cost Model

	Average	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
LT Plan - 40% Higher All	**1,723**	1,580	1,720	1,313	1,679	1,483	1,394	1,371	1,743	1,513	1,819
LT Plan - 40% Higher LMP - Coal&NG 30% Higher	**1,901**	1,689	1,838	1,388	1,820	1,720	1,800	1,599	1,934	1,728	1,939
LT Plan - 40% Higher LMP - Coal&NG 50% Higher	**169**	(80)	0	(292)	7	(282)	(420)	(312)	(29)	(261)	232
LT Plan - 20% Higher All	**1,685**	1,562	1,706	1,279	1,639	1,441	1,346	1,325	1,703	1,444	1,804
LT Plan - 20% Higher LMP - Coal&NG 10% Higher	**1,906**	1,697	1,852	1,393	1,826	1,724	1,822	1,605	1,943	1,737	1,947
LT Plan - 20% Higher LMP - Coal&NG 30% Higher	**60**	(214)	(129)	(407)	(111)	(406)	(557)	(421)	(187)	(401)	116
LT Plan - 20% Lower All	**(134)**	(279)	(132)	(553)	(184)	(439)	(502)	(534)	(168)	(390)	27
LT Plan - 20% Lower LMP - Coal&NG 10% Lower	**(937)**	(1,170)	(1,147)	(1,445)	(1,243)	(1,426)	(1,549)	(1,514)	(1,330)	(1,501)	(1,059)
LT Plan - 20% Lower LMP - Coal&NG 30% Lower	**1,450**	1,187	1,424	981	1,403	1,317	1,388	1,178	1,423	1,275	1,508
LT Plan - 40% Lower All	**(845)**	(923)	(820)	(1,234)	(874)	(1,195)	(1,258)	(1,273)	(987)	(1,220)	(755)
LT Plan - 40% Lower LMP - Coal&NG 30% Lower	**(1,626)**	(2,009)	(1,975)	(2,193)	(2,059)	(2,232)	(2,295)	(2,289)	(2,118)	(2,311)	(1,897)
LT Plan - 40% Lower LMP - Coal&NG 50% Lower	**1,473**	1,230	1,476	1,016	1,442	1,354	1,422	1,208	1,446	1,289	1,556
LT Plan - Carbon ACES	**1,397**	1,528	1,660	1,241	1,605	1,399	1,314	1,270	1,638	1,379	1,765
LT Plan - Carbon IHS	**(2,138)**	(227)	(95)	(509)	(147)	(436)	(486)	(2,862)	(2,922)	(3,046)	(3,044)
LT Plan - No Capacity Price	**(1,027)**	(1,085)	(958)	(1,374)	(1,019)	(1,303)	(1,336)	(1,386)	(1,093)	(1,302)	(951)
LT Plan - REC None	**1,158**	976	1,192	776	1,143	935	853	808	1,095	920	1,305
LT Plan - REC Ohio Solar	**1,158**	976	1,192	776	1,143	935	853	808	1,095	920	1,305
LT Plan - Solar Capacity IHS	**2,167**	2,038	2,174	1,757	2,209	1,917	1,896	1,854	2,140	1,945	2,343

Long Term Plan (Yearly Sensitivities)
Energy Summary
Production Cost Model

	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
LT Plan - 40% Higher All	1,408	1,933	1,848	2,059	1,919	2,128	1,994	2,106	1,482	1,684
LT Plan - 40% Higher LMP - Coal&NG 30% Higher	1,527	2,135	2,040	2,245	2,057	2,265	2,167	2,319	1,812	2,168
LT Plan - 40% Higher LMP - Coal&NG 50% Higher	62	522	419	645	558	841	655	767	160	486
LT Plan - 20% Higher All	1,388	1,897	1,794	2,020	1,869	2,098	1,974	2,044	1,410	1,608
LT Plan - 20% Higher LMP - Coal&NG 10% Higher	1,529	2,137	2,043	2,241	2,057	2,265	2,169	2,323	1,815	2,176
LT Plan - 20% Higher LMP - Coal&NG 30% Higher	(17)	472	377	585	501	721	541	625	26	384
LT Plan - 20% Lower All	(371)	66	(41)	220	106	326	140	301	(219)	179
LT Plan - 20% Lower LMP - Coal&NG 10% Lower	(1,169)	(609)	(558)	(303)	(404)	(117)	(243)	(82)	(568)	(140)
LT Plan - 20% Lower LMP - Coal&NG 30% Lower	1,126	1,626	1,608	1,790	1,593	1,799	1,616	1,854	1,364	1,757
LT Plan - 40% Lower All	(1,086)	(643)	(746)	(486)	(571)	(328)	(501)	(310)	(760)	(306)
LT Plan - 40% Lower LMP - Coal&NG 30% Lower	(1,894)	(1,464)	(1,269)	(866)	(891)	(571)	(575)	(353)	(772)	(316)
LT Plan - 40% Lower LMP - Coal&NG 50% Lower	1,179	1,663	1,620	1,799	1,601	1,806	1,627	1,781	1,308	1,722
LT Plan - Carbon ACES	1,332	1,777	1,577	1,685	1,356	1,198	1,011	418	(151)	(697)
LT Plan - Carbon IHS	(3,073)	(3,071)	(3,091)	(3,088)	(3,123)	(3,128)	(3,084)	(3,057)	(3,009)	(2,917)
LT Plan - No Capacity Price	(1,341)	(889)	(990)	(706)	(820)	(595)	(768)	(572)	(1,026)	(574)
LT Plan - REC None	890	1,316	1,281	1,531	1,379	1,579	1,376	1,491	855	1,106
LT Plan - REC Ohio Solar	890	1,316	1,281	1,531	1,379	1,579	1,376	1,491	855	1,106
LT Plan - Solar Capacity IHS	1,919	2,334	2,294	2,530	2,362	2,551	2,336	2,415	1,698	1,858

Long Term Plan (Yearly Sensitivities)
Energy Summary
Production Cost Model

	Average	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Load Peak, MW	**825**	**815**	**817**	**819**	**819**	**820**	**821**	**822**	**823**	**825**	**826**
Reserve Capacity (System Firm Capacity - Load Peak)											
LT Plan - Base	**75**	**71**	**77**	**74**	**73**	**80**	**78**	**75**	**73**	**79**	**77**
Base 50% Higher LMP	**76**	79	76	73	71	78	76	74	81	78	75
Base 40% Higher LMP	**76**	79	76	73	71	78	76	74	81	78	75
Base 30% Higher LMP	**76**	79	76	73	71	78	76	74	81	78	75
Base 20% Higher LMP	**76**	79	76	73	71	78	76	74	81	78	75
Base 10% Higher LMP	**76**	79	76	73	71	78	76	74	81	78	75
Base 10% Lower LMP	**71**	78	75	72	70	77	75	73	71	67	75
Base 20% Lower LMP	**69**	72	68	65	64	71	69	67	75	71	69
Base 30% Lower LMP	**69**	72	68	65	64	71	69	67	75	71	69
Base 40% Lower LMP	**69**	72	68	65	64	71	69	67	75	71	69
Base 50% Lower LMP	**69**	72	68	65	64	71	69	67	75	71	69
Base 50% Higher Coal	**75**	71	77	74	73	80	78	75	73	79	77
Base 40% Higher Coal	**75**	71	77	74	73	80	78	75	73	79	77
Base 30% Higher Coal	**75**	71	77	74	73	80	78	75	73	79	77
Base 20% Higher Coal	**75**	71	77	74	73	80	78	75	73	79	77
Base 10% Higher Coal	**75**	71	77	74	73	80	78	75	73	79	77
Base 10% Lower Coal	**75**	71	77	74	73	80	78	75	73	79	77
Base 20% Lower Coal	**75**	71	77	74	73	80	78	75	73	79	77
Base 30% Lower Coal	**75**	71	77	74	73	80	78	75	73	79	77
Base 40% Lower Coal	**75**	71	77	74	73	80	78	75	73	79	77
Base 50% Lower Coal	**75**	71	77	74	73	80	78	75	73	79	77

Long Term Plan (Yearly Sensitivities)
Reserve Capacity - MW
Production Cost Model

	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Load Peak, MW	**827**	**828**	**829**	**830**	**831**	**832**	**833**	**834**	**835**	**836**
Reserve Capacity (System Firm Capacity - Load Peak)										
LT Plan - Base	**75**	**72**	**80**	**77**	**75**	**73**	**70**	**68**	**66**	**63**
Base 50% Higher LMP	73	80	78	76	73	71	78	76	74	71
Base 40% Higher LMP	73	80	78	76	73	71	78	76	74	71
Base 30% Higher LMP	73	80	78	76	73	71	78	76	74	71
Base 20% Higher LMP	73	80	78	76	73	71	78	76	74	71
Base 10% Higher LMP	73	80	78	76	73	71	78	76	74	71
Base 10% Lower LMP	73	70	68	66	63	71	69	67	64	62
Base 20% Lower LMP	67	74	72	70	67	65	63	71	68	66
Base 30% Lower LMP	67	74	72	70	67	65	63	71	68	66
Base 40% Lower LMP	67	74	72	70	67	65	63	71	68	66
Base 50% Lower LMP	67	74	72	70	67	65	63	71	68	66
Base 50% Higher Coal	75	72	80	77	75	73	70	68	66	63
Base 40% Higher Coal	75	72	80	77	75	73	70	68	66	63
Base 30% Higher Coal	75	72	80	77	75	73	70	68	66	63
Base 20% Higher Coal	75	72	80	77	75	73	70	68	66	63
Base 10% Higher Coal	75	72	80	77	75	73	70	68	66	63
Base 10% Lower Coal	75	72	80	77	75	73	70	68	66	63
Base 20% Lower Coal	75	72	80	77	75	73	70	68	66	63
Base 30% Lower Coal	75	72	80	77	75	73	70	68	66	63
Base 40% Lower Coal	75	72	80	77	75	73	70	68	66	63
Base 50% Lower Coal	75	72	80	77	75	73	70	68	66	63

Long Term Plan (Yearly Sensitivities)
Reserve Capacity - MW
Production Cost Model

	Average	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Base 50% Higher NG	**69**	72	68	65	64	71	69	67	75	71	69
Base 40% Higher NG	**69**	72	68	65	64	71	69	67	75	71	69
Base 30% Higher NG	**69**	72	68	65	64	71	69	67	75	71	69
Base 20% Higher NG	**70**	78	75	72	70	68	66	73	71	68	65
Base 10% Higher NG	**72**	78	75	72	70	77	75	73	80	77	74
Base 10% Lower NG	**76**	79	76	73	71	78	76	74	81	78	75
Base 20% Lower NG	**76**	79	76	73	71	78	76	74	81	78	75
Base 30% Lower NG	**76**	79	76	73	71	78	76	74	81	78	75
Base 40% Lower NG	**76**	79	76	73	71	78	76	74	81	78	75
Base 50% Lower NG	**76**	79	76	73	71	78	76	74	81	78	75
LT Plan - 40% Higher All	**76**	79	76	73	71	78	76	74	81	78	75
LT Plan - 40% Higher LMP - Coal&NG 30% Higher	**76**	79	76	73	71	78	76	74	81	78	75
LT Plan - 40% Higher LMP - Coal&NG 50% Higher	**76**	77	73	80	78	76	74	81	79	75	73
LT Plan - 20% Higher All	**76**	79	76	73	71	78	76	74	81	78	75
LT Plan - 20% Higher LMP - Coal&NG 10% Higher	**76**	79	76	73	71	78	76	74	81	78	75
LT Plan - 20% Higher LMP - Coal&NG 30% Higher	**75**	77	73	80	78	76	74	81	79	75	73
LT Plan - 20% Lower All	**72**	78	75	72	70	77	75	73	80	77	74
LT Plan - 20% Lower LMP - Coal&NG 10% Lower	**69**	69	65	72	71	68	66	74	72	68	66
LT Plan - 20% Lower LMP - Coal&NG 30% Lower	**75**	71	77	74	73	80	78	75	73	79	77
LT Plan - 40% Lower All	**69**	72	68	65	64	71	69	67	75	71	69
LT Plan - 40% Lower LMP - Coal&NG 30% Lower	**69**	72	68	65	64	71	69	67	75	71	69
LT Plan - 40% Lower LMP - Coal&NG 50% Lower	**75**	71	77	74	73	80	78	75	73	79	77
LT Plan - Carbon ACES	**76**	79	76	73	71	78	76	74	81	78	75
LT Plan - Carbon IHS	**71**	78	75	72	70	78	76	73	71	68	65
LT Plan - No Capacity Price	**68**	65	72	69	67	65	73	70	68	65	72
LT Plan - REC None	**75**	71	77	74	73	80	78	75	73	79	77
LT Plan - REC Ohio Solar	**75**	71	77	74	73	80	78	75	73	79	77
LT Plan - Solar Capacity IHS	**75**	80	75	71	78	74	81	77	74	80	77

Long Term Plan (Yearly Sensitivities)
Reserve Capacity - MW
Production Cost Model

	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Base 50% Higher NG	67	74	72	70	67	65	63	71	68	66
Base 40% Higher NG	67	74	72	70	67	65	63	71	68	66
Base 30% Higher NG	67	74	72	70	67	65	63	71	68	66
Base 20% Higher NG	73	71	69	66	64	72	69	67	65	62
Base 10% Higher NG	72	70	68	65	73	71	68	66	64	61
Base 10% Lower NG	73	80	78	76	73	71	78	76	74	71
Base 20% Lower NG	73	80	78	76	73	71	78	76	74	71
Base 30% Lower NG	73	80	78	76	73	71	78	76	74	71
Base 40% Lower NG	73	80	78	76	73	71	78	76	74	71
Base 50% Lower NG	73	80	78	76	73	71	78	76	74	71
LT Plan - 40% Higher All	73	80	78	76	73	71	78	76	74	71
LT Plan - 40% Higher LMP - Coal&NG 30% Higher	73	80	78	76	73	71	78	76	74	71
LT Plan - 40% Higher LMP - Coal&NG 50% Higher	80	78	76	73	71	78	76	74	71	69
LT Plan - 20% Higher All	73	80	78	76	73	71	78	76	74	71
LT Plan - 20% Higher LMP - Coal&NG 10% Higher	73	80	78	76	73	71	78	76	74	71
LT Plan - 20% Higher LMP - Coal&NG 30% Higher	80	78	76	73	71	69	66	64	62	59
LT Plan - 20% Lower All	72	70	68	65	73	71	68	66	64	61
LT Plan - 20% Lower LMP - Coal&NG 10% Lower	74	71	69	67	64	72	70	68	65	63
LT Plan - 20% Lower LMP - Coal&NG 30% Lower	75	72	80	77	75	73	70	78	75	73
LT Plan - 40% Lower All	67	74	72	70	67	65	63	71	68	66
LT Plan - 40% Lower LMP - Coal&NG 30% Lower	67	74	72	70	67	65	63	71	68	66
LT Plan - 40% Lower LMP - Coal&NG 50% Lower	75	72	80	77	75	73	70	68	66	63
LT Plan - Carbon ACES	73	80	78	76	73	71	78	76	74	71
LT Plan - Carbon IHS	73	81	69	66	64	72	69	67	65	62
LT Plan - No Capacity Price	70	68	66	63	71	69	66	64	62	59
LT Plan - REC None	75	72	80	77	75	73	70	68	66	63
LT Plan - REC Ohio Solar	75	72	80	77	75	73	70	68	66	63
LT Plan - Solar Capacity IHS	75	72	79	77	75	72	70	68	65	63

Long Term Plan (Yearly Sensitivities)
Reserve Capacity - MW
Production Cost Model

	Average	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Load Peak, MW	**825**	**815**	**817**	**819**	**819**	**820**	**821**	**822**	**823**	**825**	**826**
Reserve Capacity (% Load Peakk)											
LT Plan - Base	**9.1%**	**8.7%**	**9.5%**	**9.0%**	**8.9%**	**9.7%**	**9.5%**	**9.2%**	**8.9%**	**9.6%**	**9.3%**
Base 50% Higher LMP	**9.2%**	9.7%	9.3%	8.9%	8.7%	9.6%	9.3%	9.0%	9.8%	9.4%	9.1%
Base 40% Higher LMP	**9.2%**	9.7%	9.3%	8.9%	8.7%	9.6%	9.3%	9.0%	9.8%	9.4%	9.1%
Base 30% Higher LMP	**9.2%**	9.7%	9.3%	8.9%	8.7%	9.6%	9.3%	9.0%	9.8%	9.4%	9.1%
Base 20% Higher LMP	**9.2%**	9.7%	9.3%	8.9%	8.7%	9.6%	9.3%	9.0%	9.8%	9.4%	9.1%
Base 10% Higher LMP	**9.2%**	9.7%	9.3%	8.9%	8.7%	9.6%	9.3%	9.0%	9.8%	9.4%	9.1%
Base 10% Lower LMP	**8.6%**	9.6%	9.2%	8.7%	8.6%	9.4%	9.2%	8.9%	8.6%	8.1%	9.1%
Base 20% Lower LMP	**8.3%**	8.8%	8.4%	7.9%	7.8%	8.7%	8.4%	8.1%	9.1%	8.6%	8.3%
Base 30% Lower LMP	**8.3%**	8.8%	8.4%	7.9%	7.8%	8.7%	8.4%	8.1%	9.1%	8.6%	8.3%
Base 40% Lower LMP	**8.3%**	8.8%	8.4%	7.9%	7.8%	8.7%	8.4%	8.1%	9.1%	8.6%	8.3%
Base 50% Lower LMP	**8.3%**	8.8%	8.4%	7.9%	7.8%	8.7%	8.4%	8.1%	9.1%	8.6%	8.3%
Base 50% Higher Coal	**9.1%**	8.7%	9.5%	9.0%	8.9%	9.7%	9.5%	9.2%	8.9%	9.6%	9.3%
Base 40% Higher Coal	**9.1%**	8.7%	9.5%	9.0%	8.9%	9.7%	9.5%	9.2%	8.9%	9.6%	9.3%
Base 30% Higher Coal	**9.1%**	8.7%	9.5%	9.0%	8.9%	9.7%	9.5%	9.2%	8.9%	9.6%	9.3%
Base 20% Higher Coal	**9.1%**	8.7%	9.5%	9.0%	8.9%	9.7%	9.5%	9.2%	8.9%	9.6%	9.3%
Base 10% Higher Coal	**9.1%**	8.7%	9.5%	9.0%	8.9%	9.7%	9.5%	9.2%	8.9%	9.6%	9.3%
Base 10% Lower Coal	**9.1%**	8.7%	9.5%	9.0%	8.9%	9.7%	9.5%	9.2%	8.9%	9.6%	9.3%
Base 20% Lower Coal	**9.1%**	8.7%	9.5%	9.0%	8.9%	9.7%	9.5%	9.2%	8.9%	9.6%	9.3%
Base 30% Lower Coal	**9.1%**	8.7%	9.5%	9.0%	8.9%	9.7%	9.5%	9.2%	8.9%	9.6%	9.3%
Base 40% Lower Coal	**9.1%**	8.7%	9.5%	9.0%	8.9%	9.7%	9.5%	9.2%	8.9%	9.6%	9.3%
Base 50% Lower Coal	**9.1%**	8.7%	9.5%	9.0%	8.9%	9.7%	9.5%	9.2%	8.9%	9.6%	9.3%

Long Term Plan (Yearly Sensitivities)
Reserve Capacity - %
Production Cost Model

	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Load Peak, MW	**827**	**828**	**829**	**830**	**831**	**832**	**833**	**834**	**835**	**836**
Reserve Capacity (% Load Peakk)										
LT Plan - Base	**9.0%**	**8.7%**	**9.6%**	**9.3%**	**9.0%**	**8.7%**	**8.4%**	**8.2%**	**7.9%**	**7.6%**
Base 50% Higher LMP	8.8%	9.7%	9.4%	9.1%	8.8%	8.5%	9.4%	9.1%	8.8%	8.5%
Base 40% Higher LMP	8.8%	9.7%	9.4%	9.1%	8.8%	8.5%	9.4%	9.1%	8.8%	8.5%
Base 30% Higher LMP	8.8%	9.7%	9.4%	9.1%	8.8%	8.5%	9.4%	9.1%	8.8%	8.5%
Base 20% Higher LMP	8.8%	9.7%	9.4%	9.1%	8.8%	8.5%	9.4%	9.1%	8.8%	8.5%
Base 10% Higher LMP	8.8%	9.7%	9.4%	9.1%	8.8%	8.5%	9.4%	9.1%	8.8%	8.5%
Base 10% Lower LMP	8.8%	8.5%	8.2%	7.9%	7.6%	8.5%	8.3%	8.0%	7.7%	7.4%
Base 20% Lower LMP	8.1%	9.0%	8.7%	8.4%	8.1%	7.8%	7.5%	8.5%	8.2%	7.9%
Base 30% Lower LMP	8.1%	9.0%	8.7%	8.4%	8.1%	7.8%	7.5%	8.5%	8.2%	7.9%
Base 40% Lower LMP	8.1%	9.0%	8.7%	8.4%	8.1%	7.8%	7.5%	8.5%	8.2%	7.9%
Base 50% Lower LMP	8.1%	9.0%	8.7%	8.4%	8.1%	7.8%	7.5%	8.5%	8.2%	7.9%
Base 50% Higher Coal	9.0%	8.7%	9.6%	9.3%	9.0%	8.7%	8.4%	8.2%	7.9%	7.6%
Base 40% Higher Coal	9.0%	8.7%	9.6%	9.3%	9.0%	8.7%	8.4%	8.2%	7.9%	7.6%
Base 30% Higher Coal	9.0%	8.7%	9.6%	9.3%	9.0%	8.7%	8.4%	8.2%	7.9%	7.6%
Base 20% Higher Coal	9.0%	8.7%	9.6%	9.3%	9.0%	8.7%	8.4%	8.2%	7.9%	7.6%
Base 10% Higher Coal	9.0%	8.7%	9.6%	9.3%	9.0%	8.7%	8.4%	8.2%	7.9%	7.6%
Base 10% Lower Coal	9.0%	8.7%	9.6%	9.3%	9.0%	8.7%	8.4%	8.2%	7.9%	7.6%
Base 20% Lower Coal	9.0%	8.7%	9.6%	9.3%	9.0%	8.7%	8.4%	8.2%	7.9%	7.6%
Base 30% Lower Coal	9.0%	8.7%	9.6%	9.3%	9.0%	8.7%	8.4%	8.2%	7.9%	7.6%
Base 40% Lower Coal	9.0%	8.7%	9.6%	9.3%	9.0%	8.7%	8.4%	8.2%	7.9%	7.6%
Base 50% Lower Coal	9.0%	8.7%	9.6%	9.3%	9.0%	8.7%	8.4%	8.2%	7.9%	7.6%

Long Term Plan (Yearly Sensitivities)
Reserve Capacity - %
Production Cost Model

	Average	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Base 50% Higher NG	**8.3%**	8.8%	8.4%	7.9%	7.8%	8.7%	8.4%	8.1%	9.1%	8.6%	8.3%
Base 40% Higher NG	**8.3%**	8.8%	8.4%	7.9%	7.8%	8.7%	8.4%	8.1%	9.1%	8.6%	8.3%
Base 30% Higher NG	**8.3%**	8.8%	8.4%	7.9%	7.8%	8.7%	8.4%	8.1%	9.1%	8.6%	8.3%
Base 20% Higher NG	**8.5%**	9.6%	9.2%	8.7%	8.6%	8.3%	8.0%	8.9%	8.6%	8.2%	7.9%
Base 10% Higher NG	**8.8%**	9.6%	9.2%	8.7%	8.6%	9.4%	9.2%	8.9%	9.7%	9.3%	9.0%
Base 10% Lower NG	**9.2%**	9.7%	9.3%	8.9%	8.7%	9.6%	9.3%	9.0%	9.8%	9.4%	9.1%
Base 20% Lower NG	**9.2%**	9.7%	9.3%	8.9%	8.7%	9.6%	9.3%	9.0%	9.8%	9.4%	9.1%
Base 30% Lower NG	**9.2%**	9.7%	9.3%	8.9%	8.7%	9.6%	9.3%	9.0%	9.8%	9.4%	9.1%
Base 40% Lower NG	**9.2%**	9.7%	9.3%	8.9%	8.7%	9.6%	9.3%	9.0%	9.8%	9.4%	9.1%
Base 50% Lower NG	**9.2%**	9.7%	9.3%	8.9%	8.7%	9.6%	9.3%	9.0%	9.8%	9.4%	9.1%
LT Plan - 40% Higher All	**9.2%**	9.7%	9.3%	8.9%	8.7%	9.6%	9.3%	9.0%	9.8%	9.4%	9.1%
LT Plan - 40% Higher LMP - Coal&NG 30% Higher	**9.2%**	9.7%	9.3%	8.9%	8.7%	9.6%	9.3%	9.0%	9.8%	9.4%	9.1%
LT Plan - 40% Higher LMP - Coal&NG 50% Higher	**9.2%**	9.4%	9.0%	9.7%	9.6%	9.3%	9.0%	9.8%	9.5%	9.1%	8.8%
LT Plan - 20% Higher All	**9.2%**	9.7%	9.3%	8.9%	8.7%	9.6%	9.3%	9.0%	9.8%	9.4%	9.1%
LT Plan - 20% Higher LMP - Coal&NG 10% Higher	**9.2%**	9.7%	9.3%	8.9%	8.7%	9.6%	9.3%	9.0%	9.8%	9.4%	9.1%
LT Plan - 20% Higher LMP - Coal&NG 30% Higher	**9.0%**	9.4%	9.0%	9.7%	9.6%	9.3%	9.0%	9.8%	9.5%	9.1%	8.8%
LT Plan - 20% Lower All	**8.8%**	9.6%	9.2%	8.7%	8.6%	9.4%	9.2%	8.9%	9.7%	9.3%	9.0%
LT Plan - 20% Lower LMP - Coal&NG 10% Lower	**8.4%**	8.4%	8.0%	8.8%	8.6%	8.3%	8.1%	9.0%	8.7%	8.3%	8.0%
LT Plan - 20% Lower LMP - Coal&NG 30% Lower	**9.1%**	8.7%	9.5%	9.0%	8.9%	9.7%	9.5%	9.2%	8.9%	9.6%	9.3%
LT Plan - 40% Lower All	**8.3%**	8.8%	8.4%	7.9%	7.8%	8.7%	8.4%	8.1%	9.1%	8.6%	8.3%
LT Plan - 40% Lower LMP - Coal&NG 30% Lower	**8.3%**	8.8%	8.4%	7.9%	7.8%	8.7%	8.4%	8.1%	9.1%	8.6%	8.3%
LT Plan - 40% Lower LMP - Coal&NG 50% Lower	**9.1%**	8.7%	9.5%	9.0%	8.9%	9.7%	9.5%	9.2%	8.9%	9.6%	9.3%
LT Plan - Carbon ACES	**9.2%**	9.7%	9.3%	8.9%	8.7%	9.6%	9.3%	9.0%	9.8%	9.4%	9.1%
LT Plan - Carbon IHS	**8.7%**	9.6%	9.2%	8.7%	8.6%	9.5%	9.2%	8.9%	8.6%	8.2%	7.9%
LT Plan - No Capacity Price	**8.2%**	8.0%	8.8%	8.4%	8.2%	7.9%	8.8%	8.6%	8.3%	7.8%	8.8%
LT Plan - REC None	**9.1%**	8.7%	9.5%	9.0%	8.9%	9.7%	9.5%	9.2%	8.9%	9.6%	9.3%
LT Plan - REC Ohio Solar	**9.1%**	8.7%	9.5%	9.0%	8.9%	9.7%	9.5%	9.2%	8.9%	9.6%	9.3%
LT Plan - Solar Capacity IHS	**9.1%**	9.8%	9.2%	8.6%	9.5%	9.1%	9.8%	9.4%	9.0%	9.7%	9.4%

Long Term Plan (Yearly Sensitivities)
Reserve Capacity - %
Production Cost Model

	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Base 50% Higher NG	8.1%	9.0%	8.7%	8.4%	8.1%	7.8%	7.5%	8.5%	8.2%	7.9%
Base 40% Higher NG	8.1%	9.0%	8.7%	8.4%	8.1%	7.8%	7.5%	8.5%	8.2%	7.9%
Base 30% Higher NG	8.1%	9.0%	8.7%	8.4%	8.1%	7.8%	7.5%	8.5%	8.2%	7.9%
Base 20% Higher NG	8.8%	8.6%	8.3%	8.0%	7.7%	8.6%	8.3%	8.0%	7.7%	7.5%
Base 10% Higher NG	8.7%	8.4%	8.1%	7.9%	8.8%	8.5%	8.2%	7.9%	7.6%	7.3%
Base 10% Lower NG	8.8%	9.7%	9.4%	9.1%	8.8%	8.5%	9.4%	9.1%	8.8%	8.5%
Base 20% Lower NG	8.8%	9.7%	9.4%	9.1%	8.8%	8.5%	9.4%	9.1%	8.8%	8.5%
Base 30% Lower NG	8.8%	9.7%	9.4%	9.1%	8.8%	8.5%	9.4%	9.1%	8.8%	8.5%
Base 40% Lower NG	8.8%	9.7%	9.4%	9.1%	8.8%	8.5%	9.4%	9.1%	8.8%	8.5%
Base 50% Lower NG	8.8%	9.7%	9.4%	9.1%	8.8%	8.5%	9.4%	9.1%	8.8%	8.5%
LT Plan - 40% Higher All	8.8%	9.7%	9.4%	9.1%	8.8%	8.5%	9.4%	9.1%	8.8%	8.5%
LT Plan - 40% Higher LMP - Coal&NG 30% Higher	8.8%	9.7%	9.4%	9.1%	8.8%	8.5%	9.4%	9.1%	8.8%	8.5%
LT Plan - 40% Higher LMP - Coal&NG 50% Higher	9.7%	9.4%	9.1%	8.8%	8.5%	9.4%	9.1%	8.8%	8.5%	8.2%
LT Plan - 20% Higher All	8.8%	9.7%	9.4%	9.1%	8.8%	8.5%	9.4%	9.1%	8.8%	8.5%
LT Plan - 20% Higher LMP - Coal&NG 10% Higher	8.8%	9.7%	9.4%	9.1%	8.8%	8.5%	9.4%	9.1%	8.8%	8.5%
LT Plan - 20% Higher LMP - Coal&NG 30% Higher	9.7%	9.4%	9.1%	8.8%	8.5%	8.2%	8.0%	7.7%	7.4%	7.1%
LT Plan - 20% Lower All	8.7%	8.4%	8.1%	7.9%	8.8%	8.5%	8.2%	7.9%	7.6%	7.3%
LT Plan - 20% Lower LMP - Coal&NG 10% Lower	8.9%	8.6%	8.3%	8.0%	7.8%	8.7%	8.4%	8.1%	7.8%	7.5%
LT Plan - 20% Lower LMP - Coal&NG 30% Lower	9.0%	8.7%	9.6%	9.3%	9.0%	8.7%	8.4%	9.3%	9.0%	8.7%
LT Plan - 40% Lower All	8.1%	9.0%	8.7%	8.4%	8.1%	7.8%	7.5%	8.5%	8.2%	7.9%
LT Plan - 40% Lower LMP - Coal&NG 30% Lower	8.1%	9.0%	8.7%	8.4%	8.1%	7.8%	7.5%	8.5%	8.2%	7.9%
LT Plan - 40% Lower LMP - Coal&NG 50% Lower	9.0%	8.7%	9.6%	9.3%	9.0%	8.7%	8.4%	8.2%	7.9%	7.6%
LT Plan - Carbon ACES	8.8%	9.7%	9.4%	9.1%	8.8%	8.5%	9.4%	9.1%	8.8%	8.5%
LT Plan - Carbon IHS	8.8%	9.8%	8.3%	8.0%	7.7%	8.6%	8.3%	8.0%	7.7%	7.5%
LT Plan - No Capacity Price	8.5%	8.2%	7.9%	7.6%	8.5%	8.2%	8.0%	7.7%	7.4%	7.1%
LT Plan - REC None	9.0%	8.7%	9.6%	9.3%	9.0%	8.7%	8.4%	8.2%	7.9%	7.6%
LT Plan - REC Ohio Solar	9.0%	8.7%	9.6%	9.3%	9.0%	8.7%	8.4%	8.2%	7.9%	7.6%
LT Plan - Solar Capacity IHS	9.0%	8.7%	9.6%	9.3%	9.0%	8.7%	8.4%	8.1%	7.8%	7.6%

Long Term Plan (Yearly Sensitivities)
Reserve Capacity - %
Production Cost Model

Sensitivity	Capacity Additions							
	NGCC - Sebree		PPA - Block		Solar - PPA (260 MW)		Total	
	2024	2043	2024	2043	2024	2043	2024	2043
Base Case Portfolio	**90**	**90**	**-**	**-**	**197**	**172**	**287**	**262**
LT Plan - Base	250	290	-	-	197	172	447	462
Base 50% Higher LMP	320	360	-	-	197	172	517	532
Base 40% Higher LMP	320	360	-	-	197	172	517	532
Base 30% Higher LMP	320	360	-	-	197	172	517	532
Base 20% Higher LMP	320	360	-	-	197	172	517	532
Base 10% Higher LMP	320	360	-	-	197	172	517	532
Base 10% Lower LMP	70	80	-	20	197	172	267	272
Base 20% Lower LMP	-	-	60	100	197	172	257	272
Base 30% Lower LMP	-	-	60	100	197	172	257	272
Base 40% Lower LMP	-	-	60	100	197	172	257	272
Base 50% Lower LMP	-	-	60	100	197	172	257	272
Base 50% Higher Coal	250	290	-	-	197	172	447	462
Base 40% Higher Coal	250	290	-	-	197	172	447	462
Base 30% Higher Coal	250	290	-	-	197	172	447	462
Base 20% Higher Coal	250	290	-	-	197	172	447	462
Base 10% Higher Coal	250	290	-	-	197	172	447	462
Base 10% Lower Coal	250	290	-	-	197	172	447	462
Base 20% Lower Coal	250	290	-	-	197	172	447	462
Base 30% Lower Coal	250	290	-	-	197	172	447	462
Base 40% Lower Coal	250	290	-	-	197	172	447	462
Base 50% Lower Coal	250	290	-	-	197	172	447	462

Long Term Plan (Yearly Sensitivities)
Capacity Changes from Base
Production Cost Model

Sensitivity	Capacity Subtractions					Net Capacity Changes	
	Green 1	Green 2	Reid CT	SEPA	Total	2024	2043
Base Case Portfolio	**231**	**223**	**-**	**-**	**454**	**(167)**	**(192)**
LT Plan - Base	231	223	-	178	632	(185)	(170)
Base 50% Higher LMP	231	223	65	178	697	(180)	(165)
Base 40% Higher LMP	231	223	65	178	697	(180)	(165)
Base 30% Higher LMP	231	223	65	178	697	(180)	(165)
Base 20% Higher LMP	231	223	65	178	697	(180)	(165)
Base 10% Higher LMP	231	223	65	178	697	(180)	(165)
Base 10% Lower LMP	231	223	-		454	(187)	(182)
Base 20% Lower LMP	231	223	-		454	(197)	(182)
Base 30% Lower LMP	231	223	-		454	(197)	(182)
Base 40% Lower LMP	231	223	-		454	(197)	(182)
Base 50% Lower LMP	231	223	-		454	(197)	(182)
Base 50% Higher Coal	231	223	-	178	632	(185)	(170)
Base 40% Higher Coal	231	223	-	178	632	(185)	(170)
Base 30% Higher Coal	231	223	-	178	632	(185)	(170)
Base 20% Higher Coal	231	223	-	178	632	(185)	(170)
Base 10% Higher Coal	231	223	-	178	632	(185)	(170)
Base 10% Lower Coal	231	223	-	178	632	(185)	(170)
Base 20% Lower Coal	231	223	-	178	632	(185)	(170)
Base 30% Lower Coal	231	223	-	178	632	(185)	(170)
Base 40% Lower Coal	231	223	-	178	632	(185)	(170)
Base 50% Lower Coal	231	223	-	178	632	(185)	(170)

Long Term Plan (Yearly Sensitivities)
Capacity Changes from Base
Production Cost Model

Sensitivity	Capacity Additions							
	NGCC - Sebree		PPA - Block		Solar - PPA (260 MW)		Total	
	2024	2043	2024	2043	2024	2043	2024	2043
Base 50% Higher NG	-	-	60	100	197	172	257	272
Base 40% Higher NG	-	-	60	100	197	172	257	272
Base 30% Higher NG	-	-	60	100	197	172	257	272
Base 20% Higher NG	70	70	-	30	197	172	267	272
Base 10% Higher NG	70	90	-	10	197	172	267	272
Base 10% Lower NG	320	360	-	-	197	172	517	532
Base 20% Lower NG	320	360	-	-	197	172	517	532
Base 30% Lower NG	320	360	-	-	197	172	517	532
Base 40% Lower NG	320	360	-	-	197	172	517	532
Base 50% Lower NG	320	360	-	-	197	172	517	532
LT Plan - 40% Higher All	320	360	-	-	197	172	517	532
LT Plan - 40% Higher LMP - Coal&NG 30% Higher	320	360	-	-	197	172	517	532
LT Plan - 40% Higher LMP - Coal&NG 50% Higher	130	170	-	-	197	172	327	342
LT Plan - 20% Higher All	320	360	-	-	197	172	517	532
LT Plan - 20% Higher LMP - Coal&NG 10% Higher	320	360	-	-	197	172	517	532
LT Plan - 20% Higher LMP - Coal&NG 30% Higher	130	160	-	-	197	172	327	332
LT Plan - 20% Lower All	70	90	-	10	197	172	267	272
LT Plan - 20% Lower LMP - Coal&NG 10% Lower	60	60	-	40	197	172	257	272
LT Plan - 20% Lower LMP - Coal&NG 30% Lower	250	300	-	-	197	172	447	472
LT Plan - 40% Lower All	-	-	60	100	197	172	257	272
LT Plan - 40% Lower LMP - Coal&NG 30% Lower	-	-	60	100	197	172	257	272
LT Plan - 40% Lower LMP - Coal&NG 50% Lower	250	290	-	-	197	172	447	462
LT Plan - Carbon ACES	320	360	-	-	197	172	517	532
LT Plan - Carbon IHS	70	70	-	30	197	172	267	272
LT Plan - No Capacity Price	-	-	290	330	197	172	487	502
LT Plan - REC None	250	290	-	-	197	172	447	462
LT Plan - REC Ohio Solar	250	290	-	-	197	172	447	462
LT Plan - Solar Capacity IHS	380	420	-	-	82	48	462	468

Long Term Plan (Yearly Sensitivities)
Capacity Changes from Base
Production Cost Model

Sensitivity	Capacity Subtractions					Net Capacity Changes	
	Green 1	Green 2	Reid CT	SEPA	Total	2024	2043
Base 50% Higher NG	231	223	-		454	(197)	(182)
Base 40% Higher NG	231	223	-		454	(197)	(182)
Base 30% Higher NG	231	223	-		454	(197)	(182)
Base 20% Higher NG	231	223	-		454	(187)	(182)
Base 10% Higher NG	231	223	-		454	(187)	(182)
Base 10% Lower NG	231	223	65	178	697	(180)	(165)
Base 20% Lower NG	231	223	65	178	697	(180)	(165)
Base 30% Lower NG	231	223	65	178	697	(180)	(165)
Base 40% Lower NG	231	223	65	178	697	(180)	(165)
Base 50% Lower NG	231	223	65	178	697	(180)	(165)
LT Plan - 40% Higher All	231	223	65	178	697	(180)	(165)
LT Plan - 40% Higher LMP - Coal&NG 30% Higher	231	223	65	178	697	(180)	(165)
LT Plan - 40% Higher LMP - Coal&NG 50% Higher	231	223	65		519	(192)	(177)
LT Plan - 20% Higher All	231	223	65	178	697	(180)	(165)
LT Plan - 20% Higher LMP - Coal&NG 10% Higher	231	223	65	178	697	(180)	(165)
LT Plan - 20% Higher LMP - Coal&NG 30% Higher	231	223	65		519	(192)	(187)
LT Plan - 20% Lower All	231	223	-		454	(187)	(182)
LT Plan - 20% Lower LMP - Coal&NG 10% Lower	231	223	-		454	(197)	(182)
LT Plan - 20% Lower LMP - Coal&NG 30% Lower	231	223	-	178	632	(185)	(160)
LT Plan - 40% Lower All	231	223	-		454	(197)	(182)
LT Plan - 40% Lower LMP - Coal&NG 30% Lower	231	223	-		454	(197)	(182)
LT Plan - 40% Lower LMP - Coal&NG 50% Lower	231	223	-	178	632	(185)	(170)
LT Plan - Carbon ACES	231	223	65	178	697	(115)	(165)
LT Plan - Carbon IHS	231	223	-		454	(187)	(182)
LT Plan - No Capacity Price	231	223	65	178	697	(210)	(195)
LT Plan - REC None	231	223	-	178	632	(185)	(170)
LT Plan - REC Ohio Solar	231	223	-	178	632	(185)	(170)
LT Plan - Solar Capacity IHS	231	223	-	178	632	(170)	(164)

Long Term Plan (Yearly Sensitivities)
Capacity Changes from Base
Production Cost Model

Big Rivers Native Load Cost, MISO										
Year	Energy MISO Cost			Capacity MISO Cost				Total MISO Cost		
	MWh	$M	$/MWh	Peak	PRMR	$M	$/MW-Day	MWh	$M	$/MWh
2024	4,409,889	[redacted]	[redacted]	815.0	880.9	[redacted]	[redacted]	4,409,889	[redacted]	[redacted]
2025	4,415,339	[redacted]	[redacted]	817.0	883.8	[redacted]	[redacted]	4,415,339	[redacted]	[redacted]
2026	4,425,681	[redacted]	[redacted]	819.0	886.0	[redacted]	[redacted]	4,425,681	[redacted]	[redacted]
2027	4,427,519	[redacted]	[redacted]	819.0	886.0	[redacted]	[redacted]	4,427,519	[redacted]	[redacted]
2028	4,436,200	[redacted]	[redacted]	820.0	887.1	[redacted]	[redacted]	4,436,200	[redacted]	[redacted]
2029	4,439,269	[redacted]	[redacted]	821.0	888.2	[redacted]	[redacted]	4,439,269	[redacted]	[redacted]
2030	4,443,020	[redacted]	[redacted]	822.0	889.2	[redacted]	[redacted]	4,443,020	[redacted]	[redacted]
2031	4,448,003	[redacted]	[redacted]	823.0	890.3	[redacted]	[redacted]	4,448,003	[redacted]	[redacted]
2032	4,462,278	[redacted]	[redacted]	825.0	892.5	[redacted]	[redacted]	4,462,278	[redacted]	[redacted]
2033	4,462,294	[redacted]	[redacted]	826.0	893.6	[redacted]	[redacted]	4,462,294	[redacted]	[redacted]
2034	4,466,493	[redacted]	[redacted]	827.0	894.6	[redacted]	[redacted]	4,466,493	[redacted]	[redacted]
2035	4,470,695	[redacted]	[redacted]	828.0	895.7	[redacted]	[redacted]	4,470,695	[redacted]	[redacted]
2036	4,477,410	[redacted]	[redacted]	829.0	896.8	[redacted]	[redacted]	4,477,410	[redacted]	[redacted]
2037	4,479,154	[redacted]	[redacted]	830.0	897.9	[redacted]	[redacted]	4,479,154	[redacted]	[redacted]
2038	4,482,805	[redacted]	[redacted]	831.0	899.0	[redacted]	[redacted]	4,482,805	[redacted]	[redacted]
2039	4,482,692	[redacted]	[redacted]	832.0	900.1	[redacted]	[redacted]	4,482,692	[redacted]	[redacted]
2040	4,486,504	[redacted]	[redacted]	833.0	901.2	[redacted]	[redacted]	4,486,504	[redacted]	[redacted]
2041	4,482,635	[redacted]	[redacted]	834.0	902.3	[redacted]	[redacted]	4,482,635	[redacted]	[redacted]
2042	4,483,054	[redacted]	[redacted]	835.0	903.4	[redacted]	[redacted]	4,483,054	[redacted]	[redacted]
2043	4,482,822	[redacted]	[redacted]	836.0	904.5	[redacted]	[redacted]	4,482,822	[redacted]	[redacted]

	Generation Portfolio Firm Capacity in LT Plan No NGCC Case, MW									
Generation Resource	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
Wilson	393.5	393.5	393.5	393.5	393.5	393.5	393.5	393.5	393.5	393.5
SEPA	178.0	178.0	178.0	178.0	178.0	178.0	178.0	178.0	178.0	178.0
Reid CT	58.5	58.5	58.5	58.5	58.5	58.5	58.5	58.5	58.5	58.5
Green Units, NG	-	-	-	-	-	-	-	-	-	-
Total Solar Facilities	196.7	195.4	194.1	192.8	191.5	190.2	188.9	187.6	186.3	185.0
System	**826.6**	**825.3**	**824.0**	**822.7**	**821.4**	**820.1**	**818.8**	**817.5**	**816.2**	**814.9**

	Generation Portfolio Firm Capacity in LT Plan No NGCC Case, MW									
Generation Resource	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**
Wilson	393.5	393.5	393.5	393.5	393.5	393.5	393.5	393.5	393.5	393.5
SEPA	178.0	178.0	178.0	178.0	178.0	178.0	178.0	178.0	178.0	178.0
Reid CT	58.5	58.5	58.5	58.5	58.5	58.5	58.5	58.5	58.5	58.5
Green Units, NG	-	-	-	-	-	-	-	-	-	-
Total Solar Facilities	183.7	182.4	181.1	179.8	178.5	177.2	175.9	174.6	173.3	172.0
System	**813.6**	**812.3**	**811.0**	**809.7**	**808.4**	**807.1**	**805.8**	**804.5**	**803.2**	**801.9**

Native Load	2024	2025	2026	2027	2028	2029	2030
Energy, MWh	4,409,889	4,415,339	4,425,681	4,427,519	4,436,200	4,439,269	4,443,020
Energy Cost, $M	[redacted]						
Peak Load NCP - MW	815.0	817.0	819.0	819.0	820.0	821.0	822.0
Capacity Requirement, MW	880.9	883.8	886.0	886.0	887.1	888.2	889.2
Capacity Cost, $M	[redacted]						
Total Cost, $M							
Total Cost, $/MWh							
Total Cost, $/MW-Day Capacity							

Native Load Cost Summary	Total Load Cost, $M			Average Load Cost, $M/Yr			Load
	2024-2033	2034-2043	2024-2043	2024-2033	2034-2043	2024-2043	2024-2033
Load Cost	[redacted]						

Generation, MWh							
Generation Resources	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Coal Generation	2,733,136	2,869,889	2,467,334	2,827,130	2,552,853	2,527,428	2,484,284
NG Generation	19,651	23,571	25,917	30,240	27,105	20,609	20,858
Solar Generation	591,843	587,693	584,724	581,756	579,946	575,820	572,852
Hydro Generation	267,000	267,000	267,000	267,000	267,000	267,000	267,000
Total Generation	**3,611,629**	**3,748,152**	**3,344,975**	**3,706,126**	**3,426,904**	**3,390,857**	**3,344,993**
Energy Position	(798,260)	(667,187)	(1,080,706)	(721,393)	(1,009,296)	(1,048,412)	(1,098,027)

Firm Capacity, MW	60	60	60	60	70	70	70
Generation Resources	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Coal Firm Capacity	393.5	393.5	393.5	393.5	393.5	393.5	393.5
NG Firm Capacity	58.5	58.5	58.5	58.5	58.5	58.5	58.5
Solar Firm Capacity	196.7	195.4	194.1	192.8	191.5	190.2	188.9
Hydro Firm Capacity	178.0	178.0	178.0	178.0	178.0	178.0	178.0
Total Firm Capacity	**886.6**	**885.3**	**884.0**	**882.7**	**891.4**	**890.1**	**888.8**
Capacity Position - Reserve MW	71.6	68.3	65.0	63.7	71.4	69.1	66.8
Capacity Position - Reserve %	8.8%	8.4%	7.9%	7.8%	8.7%	8.4%	8.1%

Long Term Plan (No NGCC)
Cost to Serve Load
Production Cost Model

Native Load	2031	2032	2033	2034	2035	2036	2037
Energy, MWh	4,448,003	4,462,278	4,462,294	4,466,493	4,470,695	4,477,410	4,479,154
Energy Cost, $M	[redacted]						
Peak Load NCP - MW	823.0	825.0	826.0	827.0	828.0	829.0	830.0
Capacity Requirement, MW	890.3	892.5	893.6	894.6	895.7	896.8	897.9
Capacity Cost, $M	[redacted]						
Total Cost, $M							
Total Cost, $/MWh							
Total Cost, $/MW-Day Capacity							

Native Load Cost Summary	Cost, NPV 2024$, $M		Load Cost , Avg. NPV 2024$, $M/Yr		
	2034-2043	2024-2043	2024-2033	2034-2043	2024-2043
Load Cost	[redacted]				

Generation, MWh							
Generation Resources	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**
Coal Generation	2,784,755	2,592,145	2,947,703	2,564,024	3,023,207	2,931,524	3,221,210
NG Generation	19,209	13,536	18,736	15,898	13,154	11,095	8,201
Solar Generation	569,884	568,050	563,947	560,979	558,011	556,154	552,075
Hydro Generation	267,000	267,000	267,000	267,000	267,000	267,000	267,000
Total Generation	**3,640,848**	**3,440,731**	**3,797,386**	**3,407,902**	**3,861,372**	**3,765,772**	**4,048,485**
Energy Position	(807,155)	(1,021,547)	(664,908)	(1,058,591)	(609,323)	(711,638)	(430,669)

Firm Capacity, MW	80	80	80	80	90	90	90
Generation Resources	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**
Coal Firm Capacity	393.5	393.5	393.5	393.5	393.5	393.5	393.5
NG Firm Capacity	58.5	58.5	58.5	58.5	58.5	58.5	58.5
Solar Firm Capacity	187.6	186.3	185.0	183.7	182.4	181.1	179.8
Hydro Firm Capacity	178.0	178.0	178.0	178.0	178.0	178.0	178.0
Total Firm Capacity	**897.5**	**896.2**	**894.9**	**893.6**	**902.3**	**901.0**	**899.7**
Capacity Position - Reserve MW	74.5	71.2	68.9	66.6	74.3	72.0	69.7
Capacity Position - Reserve %	9.1%	8.6%	8.3%	8.1%	9.0%	8.7%	8.4%

Long Term Plan (No NGCC)
Cost to Serve Load
Production Cost Model

Native Load	2038	2039	2040	2041	2042	2043
Energy, MWh	4,482,805	4,482,692	4,486,504	4,482,635	4,483,054	4,482,822
Energy Cost, $M	[redacted]					
Peak Load NCP - MW	831.0	832.0	833.0	834.0	835.0	836.0
Capacity Requirement, MW	899.0	900.1	901.2	902.3	903.4	904.5
Capacity Cost, $M	[redacted]					
Total Cost, $M	[redacted]					
Total Cost, $/MWh	[redacted]					
Total Cost, $/MW-Day Capacity	[redacted]					

Native Load Cost Summary
Load Cost

Generation, MWh							
Generation Resources	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**Average**
Coal Generation	3,113,733	3,341,784	3,174,213	3,370,675	2,919,582	3,374,527	**2,891,057**
NG Generation	5,893	6,061	2,520	1,693	1,133	784	**14,293**
Solar Generation	549,107	546,139	544,257	540,202	537,234	534,266	**562,747**
Hydro Generation	267,000	267,000	267,000	267,000	267,000	267,000	**267,000**
Total Generation	**3,935,732**	**4,160,983**	**3,987,990**	**4,179,570**	**3,724,949**	**4,176,577**	**3,735,097**
Energy Position	(547,073)	(321,709)	(498,514)	(303,065)	(758,105)	(306,245)	**(723,091)**

Firm Capacity, MW	90	90	90	100	100	100	
Generation Resources	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**Average**
Coal Firm Capacity	393.5	393.5	393.5	393.5	393.5	393.5	**393.5**
NG Firm Capacity	58.5	58.5	58.5	58.5	58.5	58.5	**58.5**
Solar Firm Capacity	178.5	177.2	175.9	174.6	173.3	172.0	**184.3**
Hydro Firm Capacity	178.0	178.0	178.0	178.0	178.0	178.0	**178.0**
Total Firm Capacity	**898.4**	**897.1**	**895.8**	**904.5**	**903.2**	**901.9**	**894.8**
Capacity Position - Reserve MW	67.4	65.1	62.8	70.5	68.2	65.9	**68.7**
Capacity Position - Reserve %	8.1%	7.8%	7.5%	8.5%	8.2%	7.9%	**8.3%**

Long Term Plan (No NGCC)
Cost to Serve Load
Production Cost Model

Net Cost (Revenue), $M							
Generation Resources	2024	2025	2026	2027	2028	2029	2030
System Net Cost	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Cost to Serve Load	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Cost to Serve Load Summary	Total Cost to Serve Load, $M			Average Cost to Serve Load, $M/Yr			Cost to Se
	2024-2033	2034-2043	2024-2043	2024-2033	2034-2043	2024-2043	2024-2033
Load Cost	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Long Term Plan (No NGCC)
Cost to Serve Load
Production Cost Model

Net Cost (Revenue), $M							
Generation Resources	2031	2032	2033	2034	2035	2036	2037
System Net Cost	[redacted]						
Cost to Serve Load	[redacted]						

Cost to Serve Load Summary	rve Load, NPV 2024$, $M		Cost to Serve Load, Avg. NPV 2024$, $M/Yr		
	2034-2043	2024-2043	2024-2033	2034-2043	2024-2043
Load Cost	[redacted]				

Long Term Plan (No NGCC)
Cost to Serve Load
Production Cost Model

Net Cost (Revenue), $M						
Generation Resources	2038	2039	2040	2041	2042	2043
System Net Cost	[redacted]					
Cost to Serve Load						

Cost to Serve Load Summary
Load Cost

Long Term Plan (No NGCC)
Cost to Serve Load
Production Cost Model

Big Rivers Native Load Cost, MISO - Base Case										
Year	Energy MISO Cost			Capacity MISO Cost				Total MISO Cost		
	MWh	$M	$/MWh	Peak, MW	PRMR	$M	$/MW-Day	MWh	$M	$/MWh
2021	3,330,269	[redacted]	[redacted]		666.7	[redacted]	[redacted]	3,330,269	[redacted]	[redacted]
2022	4,384,110	[redacted]	[redacted]		882.6	[redacted]	[redacted]	4,384,110	[redacted]	[redacted]
2023	4,395,839	[redacted]	[redacted]		879.8	[redacted]	[redacted]	4,395,839	[redacted]	[redacted]
2024	4,409,889	[redacted]	[redacted]	815.0	880.9	[redacted]	[redacted]	4,409,889	[redacted]	[redacted]
2025	4,415,339	[redacted]	[redacted]	817.0	883.8	[redacted]	[redacted]	4,415,339	[redacted]	[redacted]
2026	4,425,681	[redacted]	[redacted]	819.0	886.0	[redacted]	[redacted]	4,425,681	[redacted]	[redacted]
2027	4,427,519	[redacted]	[redacted]	819.0	886.0	[redacted]	[redacted]	4,427,519	[redacted]	[redacted]
2028	4,436,200	[redacted]	[redacted]	820.0	887.1	[redacted]	[redacted]	4,436,200	[redacted]	[redacted]
2029	4,439,269	[redacted]	[redacted]	821.0	888.2	[redacted]	[redacted]	4,439,269	[redacted]	[redacted]
2030	4,443,020	[redacted]	[redacted]	822.0	889.2	[redacted]	[redacted]	4,443,020	[redacted]	[redacted]
2031	4,448,003	[redacted]	[redacted]	823.0	890.3	[redacted]	[redacted]	4,448,003	[redacted]	[redacted]
2032	4,462,278	[redacted]	[redacted]	825.0	892.5	[redacted]	[redacted]	4,462,278	[redacted]	[redacted]
2033	4,462,294	[redacted]	[redacted]	826.0	893.6	[redacted]	[redacted]	4,462,294	[redacted]	[redacted]
2034	4,466,493	[redacted]	[redacted]	827.0	894.6	[redacted]	[redacted]	4,466,493	[redacted]	[redacted]
2035	4,470,695	[redacted]	[redacted]	828.0	895.7	[redacted]	[redacted]	4,470,695	[redacted]	[redacted]
2036	4,477,410	[redacted]	[redacted]	829.0	896.8	[redacted]	[redacted]	4,477,410	[redacted]	[redacted]
2037	4,479,154	[redacted]	[redacted]	830.0	897.9	[redacted]	[redacted]	4,479,154	[redacted]	[redacted]
2038	4,482,805	[redacted]	[redacted]	831.0	899.0	[redacted]	[redacted]	4,482,805	[redacted]	[redacted]
2039	4,482,692	[redacted]	[redacted]	832.0	900.1	[redacted]	[redacted]	4,482,692	[redacted]	[redacted]
2040	4,486,504	[redacted]	[redacted]	833.0	901.2	[redacted]	[redacted]	4,486,504	[redacted]	[redacted]
2041	4,482,635	[redacted]	[redacted]	834.0	902.3	[redacted]	[redacted]	4,482,635	[redacted]	[redacted]
2042	4,483,054	[redacted]	[redacted]	835.0	903.4	[redacted]	[redacted]	4,483,054	[redacted]	[redacted]
2043	4,482,822	[redacted]	[redacted]	836.0	904.5	[redacted]	[redacted]	4,482,822	[redacted]	[redacted]

Long Term Plan (No NGCC)
Load Cost
Production Cost Model

Fuel Oil Start Fuel	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Delivered Price, $/MMBtu	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Wilson Usage, MMBtu	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Wilson Cost, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Green 1 Usage, MMBtu	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Green 1 Cost, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Green 2 Usage, MMBtu	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Green 2 Cost, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

NG Price, $/MMBtu	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Green NG Usage, MMBtu	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Green NG Cost, $M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Long Term Plan (No NGCC)
Start Fuel
Production Cost Model

Fuel Oil Start Fuel	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Delivered Price, $/MMBtu	[redacted]										
Wilson Usage, MMBtu	[redacted]										
Wilson Cost, $M	[redacted]										
Green 1 Usage, MMBtu	[redacted]										
Green 1 Cost, $M	[redacted]										
Green 2 Usage, MMBtu	[redacted]										
Green 2 Cost, $M	[redacted]										

NG Price, $/MMBtu	[redacted]										
Green NG Usage, MMBtu	[redacted]										
Green NG Cost, $M	[redacted]										

Long Term Plan (No NGCC)
Start Fuel
Production Cost Model

Appendix H
Acronyms and Glossary

ACE	Affordable Clean Energy Rule
ACES	Alliance for Cooperative Energy Services
ACP	Auction Clearing Prices
APA	Asset Purchase Agreement
ARS	Automatic Restoration and Sectionalizing
B&W	Babcock & Wilcox Enterprises, Inc.
BPM	Business Practice Manual
BREC	Big Rivers Electric Corporation
BTU	British Thermal Unit
C&I	Commercial and Industrial
CAA	Clean Air Act
CAA	Community Action Agencies
CAIR	Clean Air Interstate Rule
CCR	Coal Combustion Residuals
CDD	Cooling Degree Day
CEO	Chief Executive Officer
CFO	Chief Financial Officer
Clearspring	Clearspring Energy Advisors, LLC
Commission	Kentucky Public Service Commission
CPCN	Certificate of Public Convenience and Necessity
CP	Coincident Peak
CPP	Clean Power Plan, or alternatively, Critical Peak Pricing
CROs	Control Room Operators
CSAPR	Cross State Air Pollution Rule
DOE	U. S. Department of Energy
DR	Demand Response
DSI	Dry Sorbent Injection
DSM	Demand-Side Management
ECP	Environmental Compliance Plan
EE	Energy Efficiency
EFORd	Unit Forced Outage Rate
EHV	Extra High Voltage
EIA	U. S. Department of Energy Information Administration
EGU	Electric Generating Units
ELCC	Effective Load Carrying Capability
ELG	Effluent Limitation Guidelines
EPA	Environmental Protection Agency

Appendix H
Acronyms and Glossary

ES	Environmental Surcharge
FAC	Fuel Adjustment Clause
FGD	Flue Gas Desulphurization
GADS	Generator Availability Data System
GCI	General Commercial and Industrial
GDP	Gross Domestic Product
GKS	Generation Knowledge Service
GWH	Gigawatt Hours
HDD	Heating Degree Day
HMP&L	Henderson Municipal Power and Light
HPRCC	High Plaines Regional Climate Center
HRI	Heat Rate Improvement
HVAC	Heating, Ventilation, and Air Conditioning
ICAP	Installed Capacity
IHS	IHS Markit
IRP	Integrated Resource Plan
JPEC	Jackson Purchase Energy Corporation
Kenergy	Kenergy Corp.
KEMI	Kentucky Employers' Mutual Insurance
KIUC	Kentucky Industrial Utility Customers
KU	Kentucky Utilities Company
kV	Kilovolt
kW	Kilowatt
kWH	Kilowatt Hour
KYMEA	Kentucky Municipal Energy Agency
LFE	Load Forecast Errors
LCI	Large Commercial and Industrial
LIC	Large Industrial Customer
LICX	Large Industrial Customer Expansion
LMP	Locational Marginal Price
LOLE	Loss of Load Expectation
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 (also Meade County RECC)

Appendix H
Acronyms and Glossary

Members	Collectively: JPEC, Kenergy, MCRECC
MECT	Module E Capacity Tracking Tool
MISO	Midcontinent Independent System Operator, Inc.
Mitigation Plan	Load Concentration Analysis and Mitigation Plan
MMBtu	One Million British Thermal Units
Moody's	Moody's Investor Services
MRCC	Midwest Regional Climate Center
MRSM	Member Rate Stability Mechanism
MW	Megawatt
NAAQS	National Ambient Air Quality Standards
NERC	North American Electric Reliability Corporation
NG	Natural Gas
NGCC	Natural Gas Combined Cycle
NGCT	Natural Gas Combustion Turbine
NCP	Non Coincident Peak
NERC	North American Electric Reliability Corporation
NOx	Nitrogen Oxides
NPV	Net Present Value
Nucor	Nucor Corporation
O&M	Operation and Maintenance
OEM	Original Equipment Manufacturers
OMU	Owensboro Municipal Utilities
OSHA	United States Department of Labor Occupational Safety and Health Administration
PCT	Participant Cost Tests
PPA	Power Purchase Agreement
PRA	Planning Resource Auction
PRM	Planning Reserve Margin
PSC	Kentucky Public Service Commission
PTR	Peak Time Rebates
Reid CT	Reid Station Combustion Turbine
REC	Renewable Energy Certificate
SCR	Selective Catalytic Reduction
SEPA	Southeastern Power Administration
SERC	Southeast Electric Reliability Corporation
SERVM	Strategic Energy and Risk Valuation Model
SO2	Sulfur Dioxide

Appendix H
Acronyms and Glossary

SPP	Southwest Power Pool
Station Two	William L. Newman Station Two
TIER	Times Interest Earned Ratio
TRC	Total Resources Cost
TVA	Tennessee Valley Authority
UCAP	Unforced Capacity
UCT	Utility Cost Test
XEFORd	Unit Forced Outage Rate

Appendix I
Figures and Tables Listing

Appendix I
Figures and Tables Listing

Appendix I
Figures and Tables Listing