Big Rivers
ELECTRIC CORPORATION

2023
INTEGRATED RESOURCE PLAN

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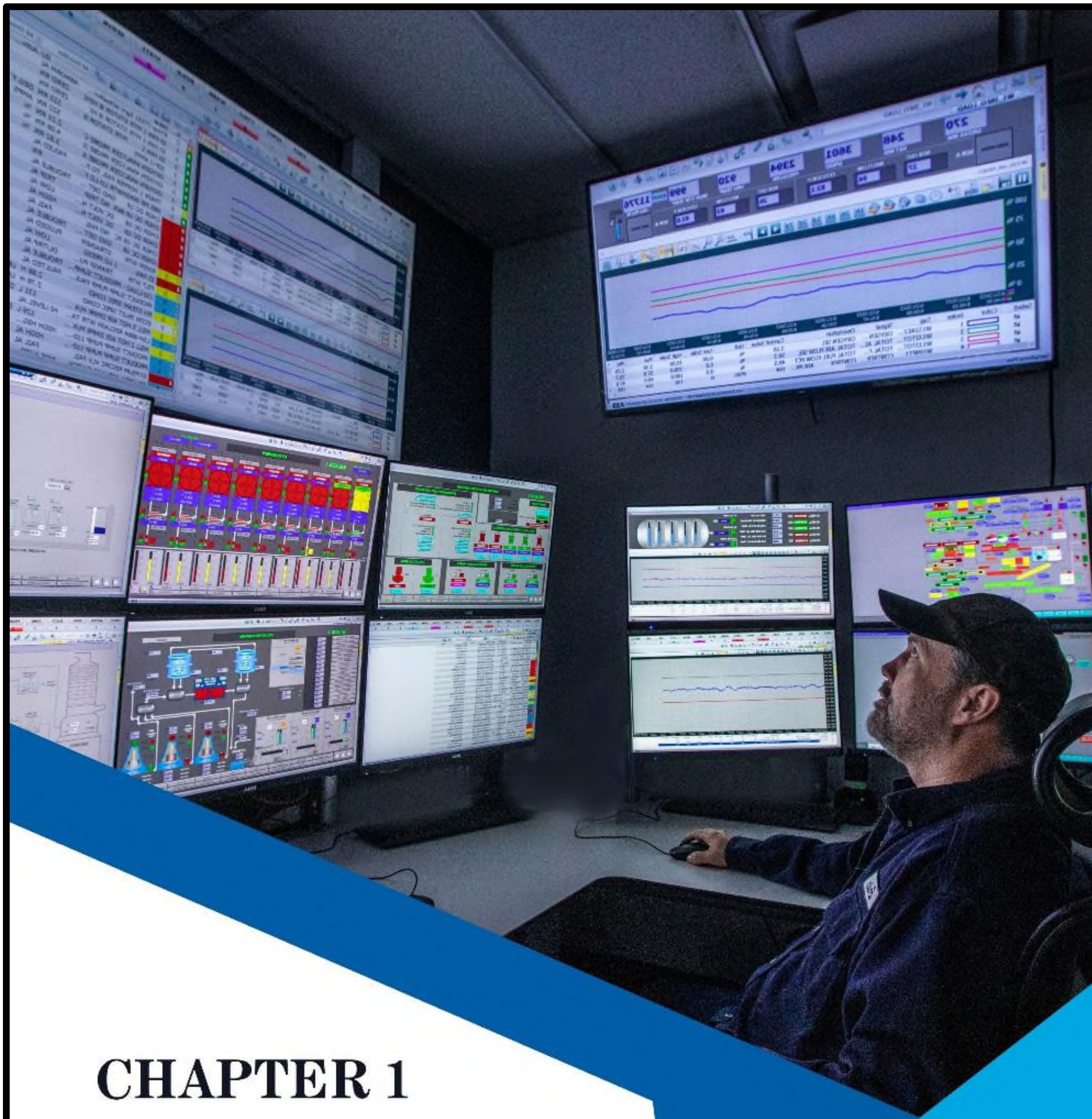

CHAPTER 1

EXECUTIVE SUMMARY

1. EXECUTIVE SUMMARY

Big Rivers Electric Corporation ("Big Rivers" or the "Company") has a responsibility to ensure the safe delivery of reliable, competitive wholesale power to its Member–Owners.[1] Consistent with that obligation, Big Rivers has prepared this Integrated Resource Plan ("IRP" or "2023 IRP") in accordance with 807 KAR 5:058, which requires Big Rivers to triennially file an IRP with the Kentucky Public Service Commission (the "Commission" or "PSC"). This IRP, like those before it, reflects the continuing, in-depth analysis required to ensure future demand is met with a reliable supply of affordable electricity. Big Rivers believes great value is derived not just from this document, but from the process pursued to prepare it, and it is pleased to hereby both satisfy its regulatory requirements and continue to promote a thorough and thoughtful approach to utility resource planning.

In this IRP, Big Rivers first provides a description of its existing system, focusing on its capacity resources, transmission assets, and load served.[2] Next, Big Rivers highlights certain developments and changes that have occurred since its most-recent Integrated Resource Plan filing in 2020, both with respect to the Company in particular, as well as the utility industry at-large; of particular note is the significant uncertainty caused by recent maneuvers of federal environmental authorities to implement new and evolving greenhouse gas guidelines for fossil fuel-

[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."

[2] *See* Chapter 2, IRP Summary.

fired power plants, coupled with expectations of the Midcontinent Independent System Operator ("MISO") to promote a resilient and reliable grid.[3] The IRP then describes the Company's forecasted need for capacity and energy during the relevant planning window,[4] before examining in detail how Big Rivers can and will effectively satisfy the expected need for reliable, affordable power — through demand-side management,[5] evaluation of environmental regulation,[6] effective electric integration,[7] forward-thinking transmission planning,[8] and thorough resource adequacy planning in the context of a regional transmission organization ("RTO").[9] The IRP concludes with an Action Plan, a road map built upon the robust resource planning reflected throughout this IRP.[10]

This IRP comes at a time of many developments and uncertainties in the regulatory and political environment. MISO Tariff changes and federal environmental regulation are among the considerations that power systems and power providers must continually evaluate. The Company faces the challenge of maintaining reliability and controlling costs amidst a changing resource mix. Big

[3] *See* Chapter 3, Developments and Changes Since 2020 IRP.

[4] *See* Chapter 4, Load Forecast.

[5] *See* Chapter 5, Demand-side Management.

[6] *See* Chapter 6, Environmental.

[7] *See* Chapter 7, Electric Integration Analysis.

[8] *See* Chapter 8, Transmission Planning.

[9] *See* Chapter 9, MISO Resource Adequacy Planning.

[10] *See* Chapter 10, Action Plan.

Rivers will meet that challenge with steel in the ground, careful planning, and an ongoing devotion to its Member-Owners' needs.

For Big Rivers, the 2023 IRP highlights a path based on an "all of the above" approach to sustainability and reliability, working to incorporate coal, natural gas, hydropower, and solar energy to increase sustainability while maintaining efficient and reliable baseload electricity for all Member-Owners.

As intended, the Company's 2023 IRP is best viewed as the continuation of a process, representing a snapshot in time of ongoing analyses. Big Rivers' mission to safely deliver competitive and reliable wholesale power and cost-effective shared services to its Member-Owners requires recurrent analysis of multiple factors, including load forecasts, operating performance data, regulatory developments, and available resources. This ongoing analysis is necessary to meet future demand with an adequate and reliable supply of electricity in an efficient and cost-effective manner, while satisfying all applicable state and federal laws. Big Rivers will remain vigilant in seeking and capitalizing on opportunities that fit its mission and goals in the best interest of its Member-Owners.

Going forward, Big Rivers will continue to operate its efficient generating units, monitor energy and capacity markets, and evaluate safe, reliable low-cost generation resources in support of the vital services the Company provides it Member-Owners. Big Rivers must also continue to monitor changes to the MISO Tariff which impact capacity requirements, as well as evaluate and adapt to the ever-changing political and regulatory landscapes that influence the nature and timing of environmental requirements.

CHAPTER 2
IRP SUMMARY

2. IRP SUMMARY

2.1 Overview

This IRP presents Big Rivers' plan for satisfying anticipated power requirements through 2037. It includes the basis for the plan and the actions Big Rivers expects to undertake to meet future load requirements through a portfolio of resources. This IRP considers many different possibilities and issues, including supply and demand resource options; operating, fuel and purchased power costs; environmental regulation; and technology costs associated with various resource plan outcomes. The Company intends that its 2023 IRP provide the Commission and all interested parties with detailed insight into the robust resource planning activities continuously undertaken at Big Rivers.

Big Rivers last filed an IRP with the Commission on September 21, 2020, in Case No. 2020-00299 ("2020 IRP").[11] Commission Staff's report summarizing its review of Big Rivers' 2020 IRP was entered into the case record by Commission order dated November 22, 2021. Commission Staff's report included a number of recommendations, all of which are addressed in this 2023 IRP.[12] The Commission closed Case No. 2020-00299 by order dated May 13, 2022, and established September 29, 2023, as the deadline for filing Big Rivers' 2023 IRP.

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[11] *In the Matter of: The 2020 Integrated Resource Plan of Big Rivers Electric Corporation*, Case No. 2020-00299

[12] *See* Cross-reference table to Big Rivers Responses to Commission Staff's Recommendation from the 2020 IRP, Appendix G.

Pursuant to 807 KAR 5:058 Section 4(2), the individuals responsible for the preparation of this IRP, and who are available to respond to inquiries during the Commission's review of the IRP, are listed in Table 2.1 (a). Like the 2020 IRP, Big Rivers' Load Forecast and Demand Side Management ("DSM") analysis was prepared for the 2023 IRP by Clearspring Energy Advisors, LLC ("Clearspring"). Big Rivers also worked closely with 1898 & Co. ("1898 & Co."), a division of Burns & McDonnell Engineering Company, Inc., in connection with this 2023 IRP.

Consistent with 807 KAR 5:058 Section 4(1), a cross-reference table to the applicable regulatory requirements is presented in Appendix F. A glossary of terms and acronyms used throughout this IRP is provided in Appendix H. Supporting documents, figures, and tables are provided throughout this document and in the appendices, which form an integral part of this 2023 IRP.

Table 2.1(a)

2023 IRP Project Team

Company	*Name*	*Area of Expertise*
Big Rivers Electric Corporation	*Robert Berry*	*President and CEO*
	Nathan Berry	*Chief Operating Officer*
	Erin Murphy	*V. P. Federal and RTO Regulatory Affairs*
	Terry Wright	*Energy Services, Load Forecast*
	Marlene Parsley	*Energy Services*
	Russell Pogue	*Demand Side Management*
	Talina Mathews	*Chief Financial Officer*
	David Blank	*Modeling*
	Jason Burden	*Power Production*
	Michael Mizell	*V. P. Environmental Compliance and Administrative Services*
	Chris Bradley	*VP System Operations*
	Jeff Fulkerson	*Manager of Transmission Planning and Compliance*
	Chris Warren	*Director of Budgets*
	Nicholas Castlen	*Finance*
	Tyson Kamuf	*General Counsel*
	Senthia Santana	*Associate Attorney*
1898 & Co.	*John Christensen*	*Project Manager Resource Planning & Market Analysis*
	Loren Carlisle	*Analyst Power and Utilities*
	Sam McKinney	*Load Analyst Resource Planning & Market Assessments*
Clearspring Energy Advisors, LLC	*Joshua P. Hoyt*	*Demand Side Management*
	Douglas Carlson	*Demand Side Management*
	Matt Sekeres	*Load Forecast*
	Steve Fenrick	*Model Development*

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. Consistent with 807 KAR 5:058 Section 5, the Company's 2023 IRP Plan Summary continues throughout this document, and includes (but is not limited to) a discussion of the key assumptions used to develop the results contained in the IRP,[13] a summary of forecasts of the Company's energy and peak demand,[14] and a summary of the Company's planned resource acquisitions and improvements.[15]

2.2 Description of the Utility

2.2.1 Service Territory and Member-Owners

Big Rivers is a generation and transmission cooperative incorporated June 14, 1961, with headquarters in Owensboro, Kentucky. Big Rivers owns, operates, and maintains electric generation and transmission facilities, and it purchases, transmits, and sells electricity at wholesale. The Company's principal purpose is to satisfy the wholesale electricity requirements of, and provide shared services to, its three distribution cooperative Member-Owners: Jackson Purchase Energy Corporation ("JPEC"), headquartered in Paducah, Kentucky; Kenergy Corp. ("Kenergy"), headquartered in Henderson, Kentucky; and Meade County Rural Electric Cooperative Corporation ("MCRECC"), headquartered in Brandenburg,

[13] *See* Chapter 7 Electric Integration Analysis

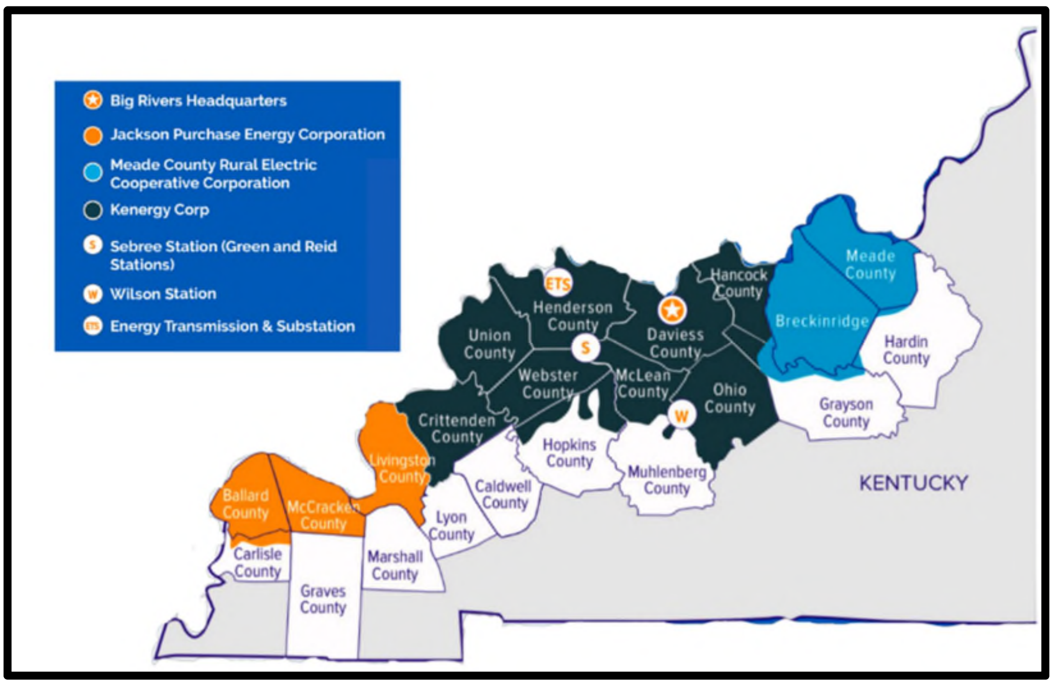
[14] *See* Chapter 4 and Appendix A Long Term Load Forecast Report.

[15] *See* Chapter 10 Action Plan.

Kentucky (JPEC, Kenergy, and MCRECC may be referred to herein collectively as the "Members" or "Member-Owners"). The Members, in turn, provide retail electric service to more than 121,000 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 territories is provided in Figure 2.2.1(a)

Figure 2.2.1(a)

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[16] or from the Regulatory Affairs webpage of Big Rivers' internet site.[17] Also on file with the Commission are wholesale power contracts for Big Rivers' Member-Owners and Commission–approved wholesale power agreements.[18]

2.2.2 RTO Membership / Bilateral Contracts

With Commission approval,[19] Big Rivers became a fully-integrated member of MISO on December 1, 2010. The Company participates in the RTO's real-time and day-ahead energy and capacity markets. Big Rivers provides transmission and ancillary services under the MISO Tariff (https://www.misoenergy.org/legal/tariff/) and serves load in the Southwest Power Pool (https://spp.etariff.biz:8443/viewer/viewer.aspx). Detailed discussion of the Company's MISO participation is contained in Chapter 9, MISO Resource Adequacy, *infra*.

While much of Big Rivers' generating capacity is dedicated to the Company's native load, Big Rivers has capitalized on its available resources both by its participation in MISO and through bilateral power sales contracts. For instance, Big

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[16] www.psc.ky.gov/tariffs/Electric/Big%20Rivers%20Electric%20Corporation/General%20Tariff.pdf

[17] http://www.bigrivers.com/regulatory-affairs/

[18] https://psc.ky.gov/Home/Library?type=Tariffs&folder=Electric%5CBig%20Rivers%20Electric%20Corporation%5CContracts

[19] *See*, *In the Matter of: The Application of the 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, Order (Ky. P.S.C. Nov. 1, 2010).

Rivers has successfully received Commission approval to execute bilateral power contracts with entities in the State of Nebraska, with Owensboro Municipal Utilities, and with the Kentucky Municipal Energy Agency. Detailed discussion of the Company's non-native load obligations is contained in Chapter 4 and Appendix A Long Term Load Forecast Report *infra*.

2.2.3 Capacity Resources

Big Rivers' present total power capacity is 1,114 MW, derived from a variety of generation resources. Big Rivers owns and operates the Robert A. Reid Plant (65 MW), the Robert D. Green Plant (454 MW), and the D. B. Wilson Plant (417 MW), totaling 936 net MW of generating capacity. As discussed in the following subsection, Big Rivers also utilizes 178 MW of contracted hydroelectric capacity from the Southeastern Power Administration ("SEPA").

The "workhorse" of the Company's generating fleet—the D.B. Wilson Station—is located near Centertown, Kentucky. It consists of a single pulverized coal unit with a total rated net generating capacity of 417 MW. It includes a Foster Wheeler boiler, Westinghouse turbine generator, and an upgraded FGD Wheelabrator Air Pollution Control system using limestone as a reagent and which produces market-grade synthetic gypsum. A total of 105 skilled employees are involved in the operation of the Wilson Station, which has proven to be a reliable source of baseload generation for Big Rivers and its Members for many decades.

The Company's Sebree Station, which houses both the Company's Robert A. Reid Plant and Robert D. Green Plant, is located in Sebree, Kentucky. The Green Plant includes two boiler/turbines (231 MW and 223 MW), each converted from coal-fired to natural gas-fired in 2022. The Reid Station includes a combustion turbine ("CT") with 65 MW capacity.

Since 2017, Big Rivers has maintained seven (7) small-scale solar arrays in its Member-Owners' service areas as pilot/education projects, both to gain experience with the technology and to collect data on solar energy generators.[20] The arrays provide retail members, first responders and students the opportunity to experience solar technology first-hand, learning about its construction, capabilities, and costs. Located in McCracken, Marshall, Livingston, Henderson, Daviess, Meade, and Breckinridge Counties, the arrays are rated to produce a combined 165 MWh each year.

Finally, Big Rivers has secured 160 MW of capacity pursuant to a solar power purchase agreement based in Henderson/Webster Counties,[21] which will increase the Company's total generation resource capacity to 1,274 MW in 2025. See Figures 2.2.3(a) and 2.2.3(b) for an overview of Big Rivers' Green, Reid, and Wilson generation facilities.

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

[21] *See In the Matter of: Electronic Application of Big Rivers Electric Corporation for Approval of Solar Power Contracts*, Case No. 2020-00183, Order (Ky. P.S.C. September 28, 2020); *In the Matter of: Electronic Application of Big Rivers Electric Corporation for Approval of Amendment to Power Purchase Agreement*, Case No. 2022-00296, Order (Ky. P.S.C. June 13, 2023).

Figure 2.2.3(a)

Generation Facility Overview – Green and Reid Stations

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.

ROBERT D. GREEN STATION

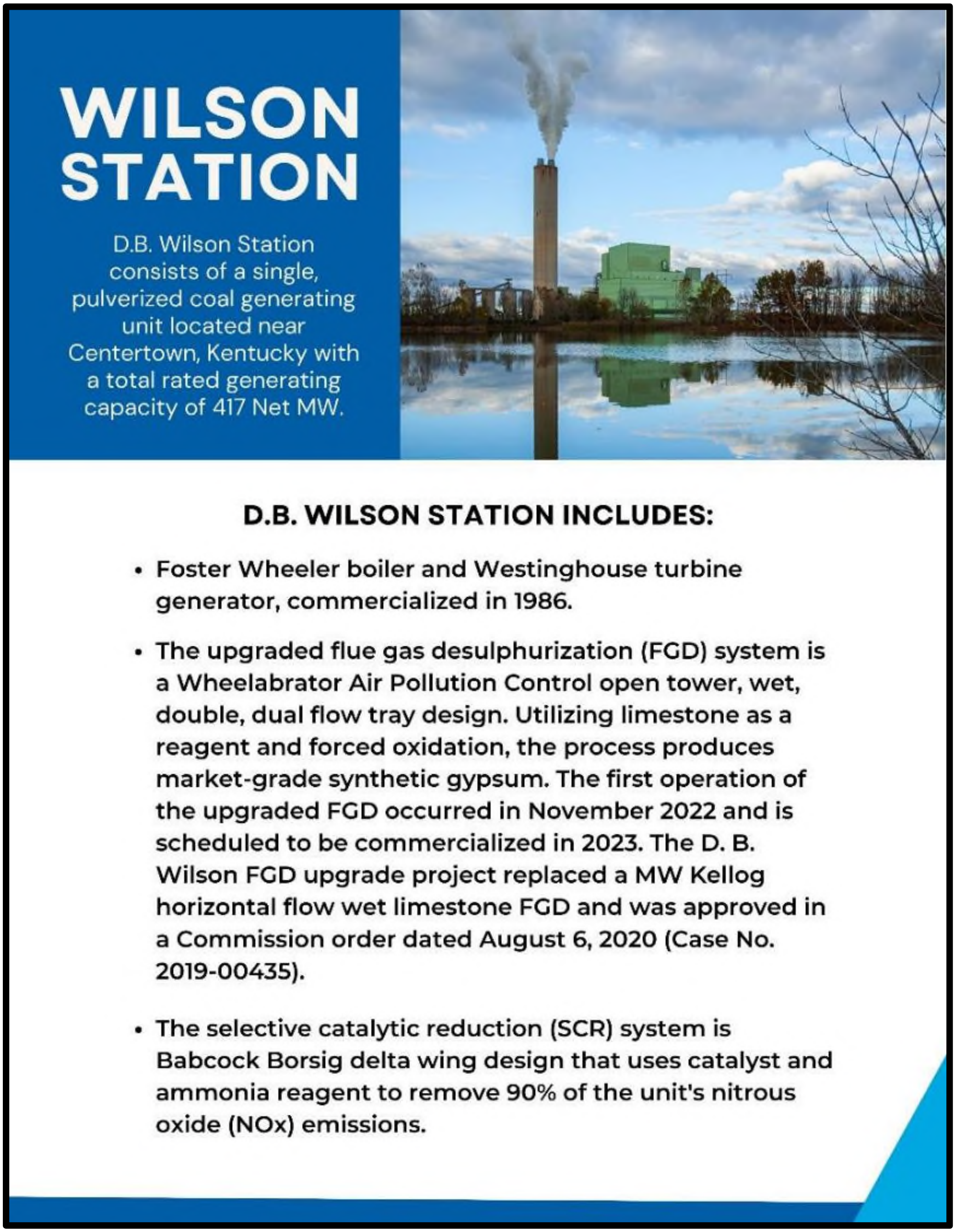
- 231 MW Green Unit 1 has a B&W boiler and GE turbine generator, commercialized in 1979.
- 223 MW Green Unit 2 has a B&W boiler and Westinghouse turbine generator, commercialized in 1981.
- In 2022, Green Units 1 & 2 were converted from coal-fired to natural gas-fired boilers with Forney PAF-II Low NOx Burners.

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.

Figure 2.2.3(b)

Generation Facility Overview – Wilson Station

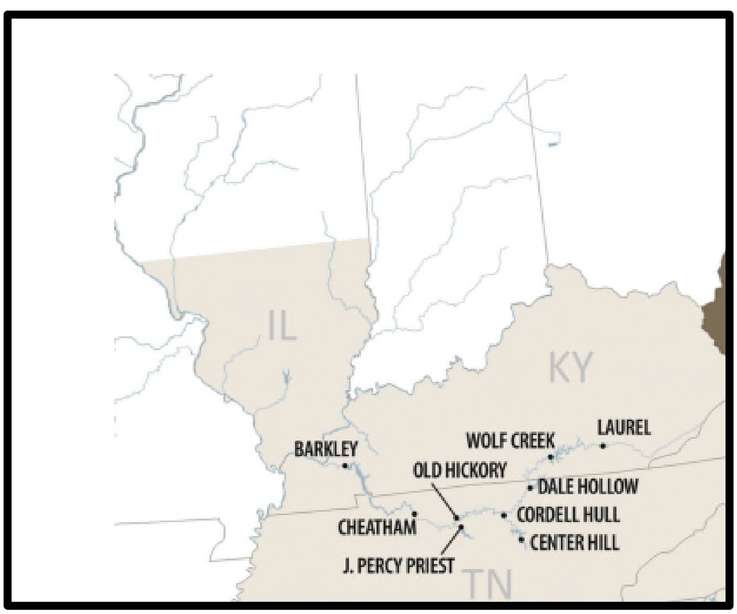


2.2.4 Big Rivers SEPA Cumberland Hydro Capacity Resource

SEPA was created in 1950 by the United States 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. 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 power production projects in the Cumberland System located in Kentucky and Tennessee. The power produced at these projects is delivered to 25 preference entities that serve 208 preference customers in eight (8) states, including Kentucky. Figure 2.2.4(a) is a map of the Cumberland System projects.

Figure 2.2.4(a)
SEPA Cumberland System Map



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

2.2.5 Solar Resources

In addition to the capacity resources above, Big Rivers has contracted to purchase all of the capacity, energy, ancillary services and environmental attributes of a 160 MW solar facility to be located on the Henderson/Webster County from Unbridled Solar, LLC.[22]

2.2.6 Transmission System

Big Rivers owns, operates and maintains 1,338 miles of conductor and twenty-six (26) substations as part of its transmission system, utilized to deliver power to its Member-Owners and third party entities served under bilateral contracts or the MISO Tariff. A **CONFIDENTIAL** map of the transmission system is provided in Figure 2.2.6(a) and a more detailed map is provided in **CONFIDENTIAL** Appendix C. Discussion of Big Rivers' transmission planning is provided in Chapter 8.

[22] *See In that Matter of: Electronic Application of Big Rivers Electric Corporation for Approval of Amendment to Power Purchase Agreement*, Case No. 2022-00296, Order (Ky. P.S.C. June 13, 2023) (amending the original contract approved in Case No. 2020-00183 on Sept. 28, 2020).

Figure 2.2.6(a)

Transmission System Map

[redacted]

2.2.7 Economic Development

Additional large industrial load is likely in the future, as witnessed by the increasing number of requests for information for economic development projects. See table 2.2.7(a) below for details on the number of requests for information in the Big Rivers service territory since 2020.

Table 2.2.7(a)

Requests for Information Since 2020

BREC Service Territory	2020	2021	2022	YTD 2023
RFI's (Request for information)	14	73	71	36
Capital Investment	$2 B	$29.1 B	$38.5 B	$29.8 B
Jobs	2,150	26,123	41,697	20,808
MW's	563	13,004	2,411	4,186

2.2.8 Big Rivers' Member Load and Load Growth

Big Rivers' Members' 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 Chapter 4 and Appendix A – Long Term Load Forecast for more details of class forecasts, as well as the methods and procedures used to develop the forecast.[23]

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 consumers served by Big Rivers' three Members, excluding retail consumers directly served from the transmission system under Big

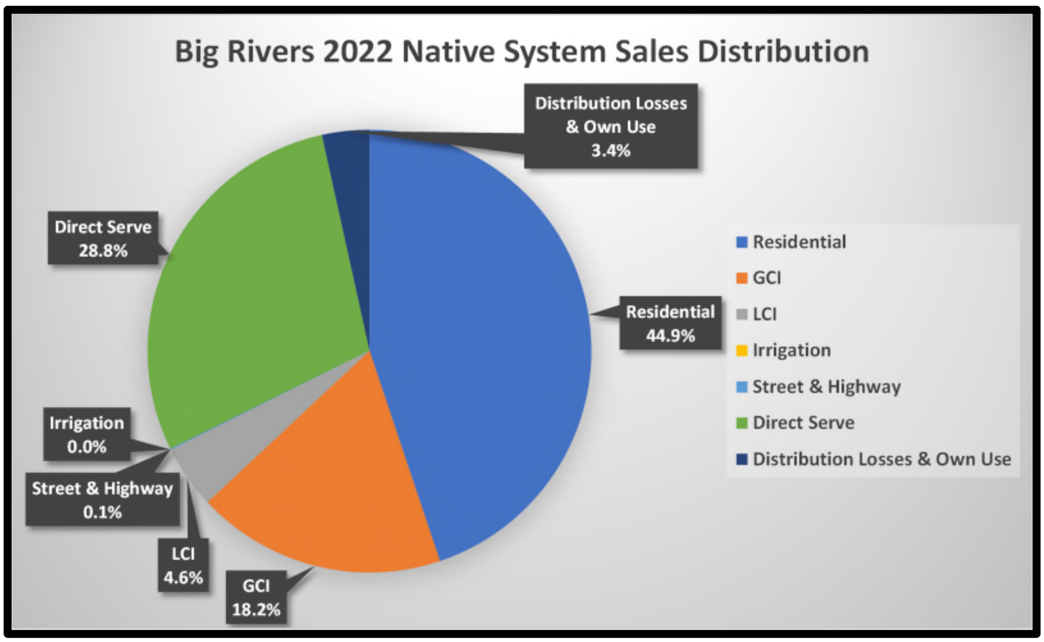
[23] Unless otherwise noted, references to total system energy and peak demand requirements in the 2023 Load Forecast pertain to Big Rivers' Members' native system and Big Rivers' Non-Member load. *See* Appendix A, Long Term Load Forecast.

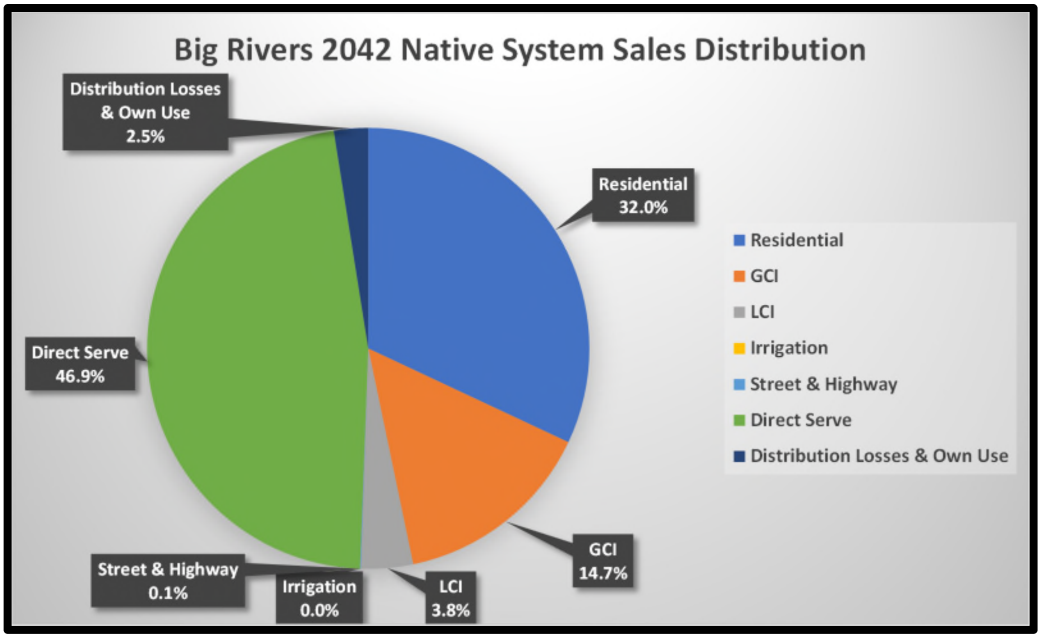
Rivers' Large Industrial Customer ("LIC") tariff or special contracts. There are currently sixteen (16) large industrial consumers. The Large Industrial class contributed 29% of Big Rivers' Member kWh Sales in 2022 and is projected to contribute 47% of Big Rivers' Member kWh Sales in 2042.

A breakdown of actual energy sales for 2022 and projected sales for 2042 by class is presented in Figure 2.2.8(a).

Figure 2.2.8(a)

Class Energy kWH Sales Proportions for Member Load 2022 and 2042





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, which are included in later tables and graphs but not in Figure 2.2.8(a), above. Member system energy and peak demand requirements are projected to reach 4,858 GWh and 896 MW, respectively, by 2042. Annual Member load coincident peak ("CP") projections are presented in Table 2.2.8(a), and Big Rivers' total Member system energy summary is presented in Table 2.2.8(b). Refer to Sections 4.3 (Capacity) and 4.4 (Energy) for details on additional Non-Member sales included in the 2023 Long Term Load Forecast Report. Chapter 4 Load Forecast and Appendix A Long Term Load Forecast Report provide detailed descriptions of the load forecast.

Table 2.2.8(a)

2023 Big Rivers Member CP Load Forecast (kW)

Year	Rural Summer CP	Rural Winter CP	Rural Annual CP	Direct Serve Annual CP	Aux CP	Transmission Losses	**Total Annual CP**
2018	502,549	556,742	556,742	95,530	0	16,382	**668,654**
2019	480,171	490,895	490,895	117,931	0	15,995	**624,821**
2020	460,173	440,685	460,173	105,992	1,756	14,562	**582,483**
2021	487,669	492,854	492,854	96,513	3,046	13,822	**606,235**
2022	510,098	590,652	590,652	99,682	246	16,185	**706,765**
2023	473,447	432,573	473,447	261,127	0	17,601	**752,176**
2024	481,988	484,213	481,988	338,288	0	19,654	**839,930**
2025	482,030	483,438	482,030	359,104	0	20,154	**861,287**
2026	483,992	485,070	483,992	359,104	0	20,201	**863,296**
2027	485,932	486,409	485,932	359,104	0	20,248	**865,283**
2028	488,179	488,028	488,179	359,104	0	20,301	**867,584**
2029	489,348	488,711	489,348	359,104	0	20,329	**868,781**
2030	492,199	490,944	492,199	359,104	0	20,398	**871,701**
2031	494,185	492,406	494,185	359,104	0	20,445	**873,734**
2032	498,436	496,027	498,436	359,104	0	20,547	**878,087**
2033	499,759	496,990	499,759	359,104	0	20,579	**879,441**
2034	501,606	498,509	501,606	359,104	0	20,623	**881,332**
2035	503,602	500,209	503,602	359,104	0	20,671	**883,377**
2036	506,528	502,945	506,528	359,104	0	20,741	**886,373**
2037	508,354	504,790	508,354	359,104	0	20,785	**888,242**
2038	510,032	506,532	510,032	359,104	0	20,825	**889,961**
2039	511,611	508,264	511,611	359,104	0	20,863	**891,577**
2040	513,047	509,905	513,047	359,104	0	20,897	**893,048**
2041	514,533	511,598	514,533	359,104	0	20,933	**894,570**
2042	516,266	513,565	516,266	359,104	0	20,974	**896,344**
Average Annual Growth Rates							
Previous 10 Ye	-0.59%	2.61%	0.88%	-1.23%	-	8.42%	**0.67%**
Previous 5 Yea	0.23%	4.46%	3.21%	-2.71%	-	0.82%	**2.19%**
Next 5 Years	-0.97%	-3.81%	-3.83%	29.22%	-100.00%	4.58%	**4.13%**
Next 10 Years	-0.23%	-1.73%	-1.68%	13.67%	-100.00%	2.42%	**2.19%**
Next 20 Years	0.06%	-0.70%	-0.67%	6.62%	-100.00%	1.30%	**1.20%**

Table 2.2.8(b)

Big Rivers Total Member System Energy Summary (MWh)

Year	Total Rural Requirements	Direct Serve	Aux Load	Transmission Losses	**Total System Energy Requirements**
2018	2,366,988	953,822	0	86,858	**3,407,668**
2019	2,261,069	946,040	4,434	82,848	**3,294,392**
2020	2,164,868	824,695	16,944	77,120	**3,083,627**
2021	2,219,380	781,559	18,367	71,125	**3,090,431**
2022	2,269,586	919,357	6,184	74,851	**3,269,978**
2023	2,291,062	1,569,178	0	92,323	**3,952,563**
2024	2,343,506	2,172,620	0	108,209	**4,624,335**
2025	2,344,105	2,225,127	0	109,482	**4,678,714**
2026	2,354,461	2,225,127	0	109,730	**4,689,319**
2027	2,364,427	2,225,127	0	109,969	**4,699,523**
2028	2,373,176	2,227,894	0	110,245	**4,711,315**
2029	2,380,698	2,225,127	0	110,359	**4,716,184**
2030	2,394,861	2,225,127	0	110,698	**4,730,686**
2031	2,404,797	2,225,127	0	110,936	**4,740,860**
2032	2,425,591	2,227,894	0	111,501	**4,764,986**
2033	2,432,406	2,225,127	0	111,598	**4,769,131**
2034	2,441,782	2,225,127	0	111,822	**4,778,731**
2035	2,451,925	2,225,127	0	112,065	**4,789,118**
2036	2,466,634	2,227,894	0	112,484	**4,807,012**
2037	2,476,201	2,225,127	0	112,647	**4,813,975**
2038	2,485,134	2,225,127	0	112,861	**4,823,122**
2039	2,493,662	2,225,127	0	113,065	**4,831,854**
2040	2,501,574	2,227,894	0	113,321	**4,842,789**
2041	2,509,737	2,225,127	0	113,451	**4,848,315**
2042	2,519,073	2,225,127	0	113,674	**4,857,874**
Average Annual Growth Rates					
Previous 10 Years	-0.23%	-0.52%	-	7.63%	**-0.17%**
Previous 5 Years	0.53%	-0.01%	-	-0.80%	**0.39%**
Next 5 Years	0.82%	19.34%	-100.00%	8.00%	**7.52%**
Next 10 Years	0.67%	9.25%	-100.00%	4.07%	**3.84%**
Next 20 Years	0.52%	4.52%	-100.00%	2.11%	**2.00%**

Member system energy and peak demand requirements are projected to increase at average compound rates of 2.00 % and 1.20%, respectively, per year from 2023 through 2042. Continued increases in employment and number of households, appliance efficiencies, gross regional product ("GRP"), total retail sales, electric vehicle stock, distributed solar generation stock, and decreases in the real price of retail electricity are expected to impact growth in Member energy sales. Increased sales to direct-serve customers will also have positive impacts on Member sales over the near term. Member peak requirements are projected to increase from 752 MW in 2023 to 896 MW (including transmission losses) by the summer of 2042.

2.3 Generator Operations

Big Rivers places emphasis on efficiency, so the Company continues to make strides in generation efficiency improvements to maximize asset value. As wholesale power market prices have dropped recently, 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. Refer to Figure 2.3(a) and Table 2.3(a), which reflect actual heat rate performance based on MISO dispatch.

Figure 2.3(a)

System Net Actual Heat Rate

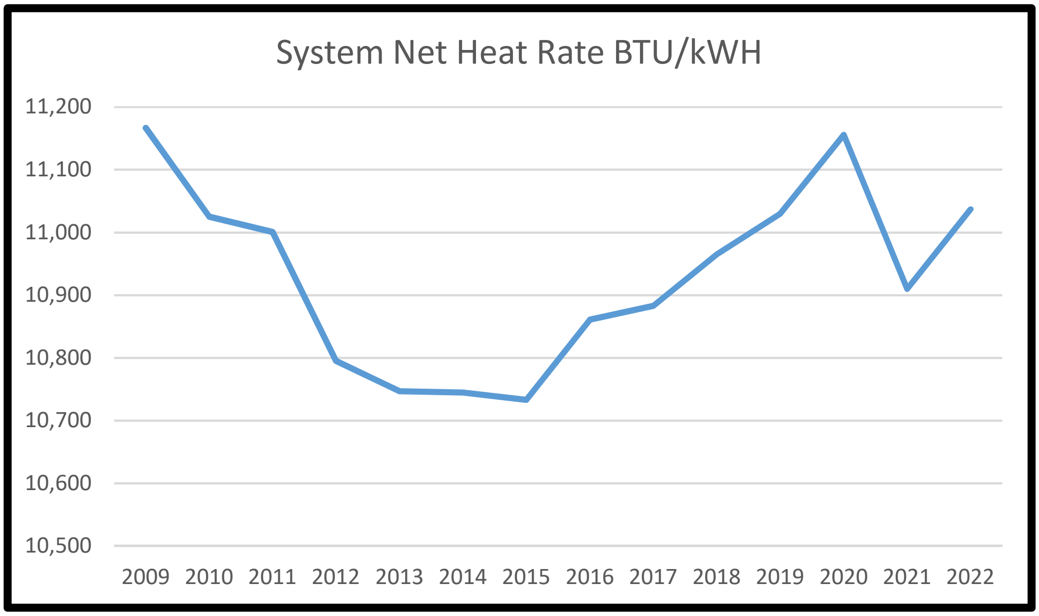


Table 2.3(a)

System Net Actual Heat Rate

Year	BTU/kWH
2009	11,167
2010	11,025
2011	11,001
2012	10,795
2013	10,747
2014	10,745
2015	10,733
2016	10,861
2017	10,883
2018	10,965
2019	11,030
2020	11,156
2021	10,910
2022	11,037

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 lower during pulverizer 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 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 strong. Table 2.3(b) presents the five-year averages (2018-2022) of key performance indicators of Big Rivers' generating units.

Table 2.3(b)

Key Performance Indicators per IEEE[24] Standards

Unit	NAG[25]	Average Net Generation (MWHrs)	Net Heat Rate (BTU/kWH)	Gross Capacity Factor (%)	Gross Output Factor (%)	Equivalent Availability Factor (%)	Equivalent Forced Outage Rate (%)
Green 1	5,275,839	1,055,168	11,166	54.04	79.03	89.55	7.27
Green 2	4,398,415	879,683	11,511	46.54	79.61	91.83	5.39
Wilson 1	12,654,553	2,530,911	10,904	69.73	87.78	80.74	7.9
System	22,328,807	4,465,761	11,086	59.59	83.81	87.38	6.99

Table 2.3(c) is a summary of the operating characteristics of existing Big Rivers resources.

[24] Institute of Electrical and Electronics Engineers.

[25] Net Actual Generation delivered to the grid over the 5 year period 2018-2022

Table 2.3(c)

Operating Characteristics of Existing Big Rivers Resources

Plant	Unit	Location (Kentucky County)	Status	Commercial Operation Date	Type of Facility	Net Dependable Capability (Nameplate)		Fuel Type		Typical Fuel Storage Capability	Expected Retirement Date
						Summer	Winter	Primary	Sec.		
R.D. Green	1	Webster	Existing	December-1979	Steam Turbine	231	231	Gas**			2029***
R.D. Green	2	Webster	Existing	January-1981	Steam Turbine	223	223	Gas**			2029***
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 hours and continued maintenance it should provide reasonably available capacity for a number of years into the future.*

**Green Units were converted to natural gas in 2022

*** Green retirement date referenced in Big Rivers' Application filed in PSC Case No. 2021-00079 on February 28, 2021

2.4 Planning Goals and Objectives

Big Rivers' primary planning goal for its 2023 IRP is to reliably and efficiently provide for its Members' electricity needs over the next fifteen (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. To support this analysis, Big Rivers contracted with 1898 & Co., a division of Burns & McDonnell Engineering Company, Inc.

1898 & Co. has supported multiple investor-owned utilities, municipalities, and cooperatives across different regions of the United States by helping to develop resource plans that meet desired goals and objectives. This includes contemplating new energy and capacity resource buildouts of various technology, which may be comprised of conventional, renewable, or storage assets, along with retirements of older, inefficient existing resources. Big Rivers has a previous relationship with 1898 & Co., which most recently supported Big Rivers in developing, hosting, and evaluating bids for a 2022 All Source Request for Proposals ("RFP") for generation resources, and other Burns & McDonnell divisions continue to provide engineering services to Big Rivers. 1898 & Co. has successfully performed several IRP studies throughout the US, including in MISO within Kentucky, Indiana, Michigan, and surrounding states. 1898 & Co. was chosen for its analytical support of this project due to its in-depth knowledge of the energy utility industry, its team of highly experienced technical professionals and experience with various Production Cost

Modeling Tools, its holistic and integrated approach, and its understanding of MISO Market Resource Adequacy processes.

Big Rivers' vision includes providing services that will allow our Member-Owners to meet future challenges, including the following planning objectives:

- Maintaining a current and reliable load forecast;
- Providing competitively priced power to its Members;
- Maximizing reliability while ensuring safety and minimizing costs, risks, and environmental impacts;
- Identifying potential new supply-side resources;
- Maintaining adequate planning reserve margins;
- Developing and maintain a diversified supply portfolio aligned with anticipated Member-Owner load; and
- Meeting North American Electric Reliability Corporation ("NERC") guidelines and requirements.

CHAPTER 3

DEVELOPMENTS & CHANGES SINCE 2020 IRP

3. DEVELOPMENTS AND CHANGES SINCE 2020 IRP

As earlier mentioned, the utility resource planning process is inherently continuing in nature, necessarily subject to ongoing review, confirmation, and challenge in light of dynamic internal and external conditions. Recognizing this fact, Section 6 of 807 KAR 5:058 requires each utility's IRP to include a summary of significant changes since the plan most recently filed, describing changes in load forecasts, resource plans, assumptions, and methodologies from the previous plan. Big Rivers provides that information herein, and further identifies notable events and developments that have occurred during the past three (3) years which support or inform this 2023 IRP.

3.1 Changes to Load Forecast

As was the case with respect to Big Rivers' 2020 IRP, Big Rivers chose Clearspring of Madison, Wisconsin, to prepare the 2023 Long–Term Load Forecast and Demand–Side Management/Energy Efficiency 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.

Although Clearspring's Load Forecast from the 2020 IRP is undoubtedly similar to its updated counterpart presented as part of this 2023 IRP, certain differences in assumptions and methodology exist.

- The methodological approach to forecasting electric vehicles and distributed generation outlined in section 2 of this report is new in the 2023 study included in Appendix A Long Term Load Forecast.
- Twenty-year historical weather averages are used as the projected weather value in the baseline forecasts for the 2023 study. The 2020 study used fifteen-year averages. In the 2020 study there were challenges in collecting both the peak data and weather station data needed to create all the weather sensitive modeling variables for a full twenty-year history. These challenges no longer exist in the 2023 study and so the change was made to use twenty-year averages.
- The updated forecast reflects the addition of up to 314 MW of new Large Industrial load:
    - a new steel mill was constructed in the Meade County RECC service territory;
    - a new paper mill is locating in the Kenergy Corporation service territory; and
    - a new crypto currency facility was constructed in the Jackson Purchase Energy Corporation service territory.

3.2 Transmission

Big Rivers operates and maintains a network of 1,338 miles of transmission lines and 26 substations. The Company has completed various project upgrades that are expected to improve reliability for its Members. These upgrades include the continuation of 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 addition to the ARS schemes, Big Rivers has also enhanced system reliability by utilizing steel and ductile iron poles for all new construction projects, adding Remote Control Switches to strategic locations to improve switching response, upgrading many relays to new microprocessor relays, and the installation of Optical Ground Wire ("OPGW") for fiber-optic communication.

In 2022, SERC Reliability Corporation ("SERC"), which is responsible for ensuring the reliability and security of the electric grid across sixteen (16) southeastern and central states including Kentucky, completed a Critical Infrastructure Protection ("CIP") Audit of Big Rivers. The audit included the review of CIP Standards relating to Cyber Security and protection of the Bulk Electric System. The audit was successful, with the SERC CIP audit team noting in its closing statements that Big Rivers had zero Potential Non-Compliance items.

All three (3) Big Rivers member cooperatives also constructed additional upgrades which increased reliability and allowed integration of significant new loads within their respective territories.

3.3 Focused Management Audit

In the final Order of the second rate case Big Rivers filed to address the loss of two aluminum smelters in its service area,[26] the 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 ("Mitigation Plan"). 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 2020 Integrated Resource Plan in September of 2020, Big Rivers filed its Seventh Focused Management Audit Progress Report on October 2, 2020. Previously, the Commission Staff had found that Big Rivers had completed Recommendation Nos. 1, 2, and 4 of the Management Audit. With this Seventh

[26] *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 (Ky. P.S.C. April 25, 2014).

Progress Report, Big Rivers proposed that Recommendation Nos. 3 and 5 were complete as well. On January 12, 2021, Commission Staff replied to Big Rivers' fourth, fifth, and sixth Progress Reports that "[a]ll recommendations have been complete and no further action is required." As such, all of the recommendations are now complete.

3.4 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," and have since upgraded Big Rivers one level in both 2020 and 2022. S&P upgraded Big Rivers one notch in both 2021 and 2022. Fitch upgraded Big Rivers one notch in 2022 to arrive at two notches above investment grade. As of September 2023, Big Rivers is two levels above investment grade with all three rating agencies. Big Rivers continues to meet annually with rating agencies to provide forecasts and information as well as keep them updated on the state of the Company. 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 ("TIER"), the call and refinancing of pollution control bonds which resulted in a significant reduction in annual interest expense, and the approval of the Meade County contract with Nucor Corporation, along with the Pratt Paper and Block Mining contracts are all received as credit positives.

3.5 State Regulatory Events

Since the filing of Big Rivers' 2020 IRP, Big Rivers submitted various filings and participated in multiple cases before the Commission. Below is a brief summary of the results or status of these matters.

The Commission conducted annual reviews of Big Rivers' Member Rate Stability Mechanism ("MRSM"). Big Rivers has several regulatory assets on its books arising out of its successful efforts to mitigate the loss of two large aluminum smelters from the Big Rivers system nearly ten years ago. Big Rivers reduces those assets by at least $17.5M each year. Each year, Big Rivers returns 40% of the margins it earns in excess of a 1.30 TIER to customers in the form of bill credits. The remainder of the margins Big Rivers earns in excess of a 1.30 TIER is deferred into a regulatory liability account. Each year, Big Rivers requests the Commission's authority to utilize that regulatory liability account to further reduce the regulatory assets. The Commission authorized Big Rivers to use $11 million in 2021[27] and $26.7 million in

[27] *See In the Matter of Electronic Application of Big Rivers Electric Corporation for Review of its MRSM Credit for Calendar Year 2020*, Case No. 2021-00061, Order (Ky. P.S.C. June 9, 2021).

2022[28] from the regulatory liability account to further reduce the regulatory assets. The MRSM review case Big Rivers filed in 2023 is still pending.[29]

The Commission has granted a number of Big Rivers' other requests, including granting approval of:

- Three solar power purchase agreements and a subsequent amendment to one of the agreements.[30] Subsequent to the Commission's approval of the solar agreements, AES terminated the Meade County Solar Power Purchase Agreement ("PPA") and the McCracken County Solar PPA due to delays in the MISO interconnection process, among other alleged reasons. The remaining PPA will provide Big Rivers with all of the capacity, energy, ancillary services, and renewable energy credits from a 160 MW solar farm.
- A Retail Agreement for Electric Service between Kenergy and a new large industrial customer, Pratt Paper (KY), LLC and a related wholesale agreement between Kenergy and Big Rivers.[31]

[28] *See In the Matter of: Electronic Application of Big Rivers Electric Corporation for Annual Review of its MRSM Charge for Calendar Year 2021*, Case No. 2022-00028, Order (Ky. P.S.C. July 6, 2022).

[29] *See In the Matter of: Electronic Application of Big Rivers Electric Corporation for Annual Review of its MRSM Charge for Calendar Year 2022*, Case No. 2022-00028, Order (Ky. P.S.C. July 6, 2022).

[30] *See In the Matter of: Electronic Application of Big Rivers Electric Corporation for Approval of Solar Power Contracts*, Case No. 2020-00183, Order (Ky. P.S.C. September 28, 2020).

[31] *See In the Matter of: Electronic Tariff Filing of Big Rivers Electric Corporation and Kenergy Corp. for Approval of a Special Contract with Economic Development Rates with Pratt Paper (KY), LLC*, Case No. 2023-00045, Order (Ky. P.S.C. February 10, 2023).

- A Retail Agreement for Electric Service between JPEC and new large industrial customer, Block Mining, Inc., and a related wholesale agreement between JPEC and Big Rivers.[32]
- An Agreement for Electric Service between Kenergy and Azteca Milling LP to replace the retail electric service agreement between Azteca's predecessor, Valley Grain Products, Incorporated, and Kenergy's predecessor, Henderson Union Electric Cooperative Corp., and a related wholesale agreement between Kenergy and Big Rivers.[33]
- A First Amendment to Amended and Restated Agreement for Electric Service between Kenergy and Aleris Rolled Products, Inc., and a related wholesale agreement between Kenergy and Big Rivers.[34]
- A certificate of public convenience and necessity ("CPCN") to convert Green Station's coal-fired units to burn natural gas.[35]
- A CPCN to construct a new headquarters building in Owensboro, Kentucky.[36]

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[32] *See In the Matter of: Electronic Tariff Filing of Big rivers Electric Corporation and Jackson Purchase Energy Corporation for Approval and Confidential Treatment of a Special Contract and Cost Analysis Information and a Request for Deviation from the Commission's September 24, 1990 Order in Administrative Case No. 327*, Case No. 2021-00282, Order (Ky. P.S.C. October 14, 2021).

[33] TFS 2021-00326.

[34] TFS 2021-00325.

[35] *See In the Matter of: Electronic Application of Big Rivers Electric Corporation for a Certificate of Public Convenience and Necessity Authorizing the Conversion of the Green Station Units to Natural Gas-Fired Units and an Order Approving the Establishing of a Regulatory Asset*, Case No. 2021-00079, Order (Ky. P.S.C. June 11, 2021).

[36] *See In the Matter of: Electronic Application of Big Rivers Electric Corporation for a Certificate of Public Convenience and Necessity Authorizing Construction of a New Headquarters Facility and an Order Authorizing Big Rivers to Sell its Existing Headquarters Facility*, Case No. 2021-00314, Order (Ky. P.S.C. December 7, 2021).

- A CPCN to construct a 161 kV transmission line and related facilities in McCracken County to serve expected load growth associated with Block Mining's new cryptocurrency mining facility, as well as other load growth that is likely to result from such a project.[37]
- A CPCN to construct a 161 kV transmission line and related facilities in Henderson County, Kentucky to serve expected load growth associated with the new Pratt Paper mill, as well as other load growth that is likely to result from such a project.[38]
- A CPCN to construct a new Transmission Operations Center in Owensboro, Kentucky.[39]
- Amendments to power supply contracts with two municipal utilities and a public power district in Nebraska (the City of Wayne, Nebraska, the City of Wakefield, Nebraska, and Northeast Nebraska Public Power District) and a related power hedge contract.[40]
- A Power Purchase and Interconnection Agreement with Southern Star Central Gas Pipeline, Inc. ("Southern Star") that allows Southern Star to utilize power

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[37] *See In the Matter of Electronic Application of Big Rivers Electric Corporation for a Certificate of Public Convenience and Necessity to Construct a 161 KV Transmission line in McCracken County, Kentucky*, Case No. 2021-00275, Order (Ky. P.S.C. January 14, 2022).

[38] *See In the Matter of Electronic Application of Big Rivers Electric Corporation for a Certificate of Public Convenience and Necessity to Construct a 161 KV Transmission line in Henderson County, Kentucky*, Case No. 2022-00012, Order (Ky. P.S.C. June 6, 2022).

[39] *See In the Mater of: Electronic Application of Big Rivers Electric Corporation for a Certificate of Public Convenience and Necessity Authorizing Construction of a New Transmission Operations Center and an Order Authorizing Big Rivers to Dispose of Property*, Case No. 2022-00433, Order (Ky. P.S.C. June 1, 2023).

[40] TFS 2021-00516.

from a new solar facility it has installed for its own use and sell any excess power to Big Rivers pursuant to Big Rivers' Qualifying Facilities tariff ("QF Tariff").[41]

- A new Pole Attachment Tariff.[42]
- Several requests to issue evidences of indebtedness to refinance higher interest debt or for construction projects.[43]

A number of other Commission cases involving Big Rivers are still pending. For example, on September 29, 2021, Big Rivers filed an application requesting that the Commission take all appropriate action to enforce its August 2, 2021, Order in Case No. 2019-00269, in which the Commission ruled on the respective rights and obligations between Big Rivers and Henderson Municipal Power & Light after the termination of agreements under which Big Rivers operated Henderson Municipal Power & Light's ("HMP&L's") Station Two generating facility in exchange for the right to purchase a portion of the power produced by that facility.[44] As of the filing of this IRP, this proceeding was pending.

[41] TFS 2021-00364.

[42] TFS 2023-00066.

[43] *See In the Matter of: Electronic Application of Big Rivers Electric Corporation for Approval to Issue Evidences of Indebtedness*, Case No. 2020-00291; *In the Matter of: Electronic Application of Big Rivers Electric Corporation for Approval to Issue Evidences of Indebtedness*, Case No. 2021-00468; *In the Matter of: Electronic Application of Big Rivers for Approval to Issue Evidences of Indebtedness*, Case No. 2023-00087, Order (Ky. P.S.C. May 15, 2023).

[44] *See In the Matter of: Electronic Application of Big Rivers Electric Corporation for Enforcement of Order*, Case No. 2021-00378 (filed September 29, 2021).

The Commission approved, on a pilot basis, Big Rivers' proposed Large Industrial Customer Standby Service ("LICSS") tariff, which provides a default rate for supplemental, maintenance, and backup power for large industrial customers on the Big Rivers system who install their own generation and do not have a special contract providing such service.[45] Subsequently, Domtar Paper Company, LLC ("Domtar")[46] filed a complaint asking the Commission to approve a rate for Domtar that continued the rates under the terminated Second Amended and Restated Agreement for Retail Electric Service between Kenergy and Domtar until the Commission approves a "permanent" Standby Service tariff. On March 27, 2023, the Commission issued an order directing that the Retail Agreement "shall remain in effect until further order of the Commission." The Commission denied Big Rivers and Kenergy's joint motion for rehearing of the March 27, 2023 order. Big Rivers and Kenergy filed a Complaint and Petition for Declaratory Judgment in the Daviess Circuit Court to vacate and set aside the March 27, 2023, and May 2, 2023, Orders. The Commission filed an original action in the Kentucky Court of Appeals seeking to prohibit the Daviess Circuit Court from hearing the case. Big Rivers proposed its "permanent" LICSS tariff on September 1, 2023.[47] These matters also remain pending as of the filing of this Integrated Resource Plan.

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[45] *See* I*n the Matter of: Electronic Tariff Filing of Big Rivers Electric Corporation and Kenergy Corp. to Implement a New Standby Service Tariff*, Case No. 2021-00289, Order (Ky. P.S.C. March 3, 2022).

[46] *See In the Matter of: Domtar Paper Company, LLC v. Big Rivers Electric Corporation and Kenergy Corp.,* Case No. 2023-00017, Order (Ky. P.S.C. March 27, 2023).

[47] TFS 2023-00391.

On March 1, 2023, Big Rivers submitted a proposed qualified cogeneration and small power production tariff ("QF Tariff") to replace its existing Cogeneration/Small Power Production Sales and Purchases over 100 kW ("QFS") and ("QFP ") tariffs. The Commission's investigation of the proposed QF Tariff continues as of the filing of this IRP.[48]

Big Rivers continues to participate in multiple Commission administrative cases. The following are pending as of the filing of this IRP:

- Investigation of Interconnection and Net Metering Guidelines;[49]
- Investigation of Amendments to the Public Utility Regulatory Policies Act of 1978 and Electrification of Transportation;[50]
- Investigation of Amendments to the Public Utility Regulatory Policies Act of 1978 and Demand Side Practices;[51]
- Investigation into Compliance with Excavator Locate Requests Pursuant to KRS 367.4909 and KRS 367.4917(7);[52] and

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[48] *See In the Matter of Electric Tariff Filing of Big Rivers Corporation for an Approval of Proposed Changes to its Qualified Cogeneration and Small Power Production Facilities Tariffs*, Case No. 2023-00102 (filed March 24, 2023).

[49] *See In the Matter of: Electronic Investigation of Interconnection and Net Metering Guidelines*, Case No. 2020-00302 (filed September 24, 2020).

[50] *See In the Matter of: Electronic Investigation of Amendments to the Public Utility Regulatory Policies Act of 1978 and Electrification of Transportation*, Case No. 2022-00369 (filed November 7, 2022).

[51] *See In the Matter of: Electronic Investigation of Amendments to the Public Utility Regulatory Policies Act of 1978 and Demand Side Practices,* Case No. 2022-00370 (filed November 7, 2022).

[52] *See In the Matter of: Electronic Investigation into Compliance with Excavator Locate Requests Pursuant to KRS 367.4909 and KRS 367.4917(7)*, Case No. 2022-00363 (filed November 16, 2022).

- Investigation of the Fuel Adjustment Clause Regulation 807 KAR 5:056, Purchase Power Costs, and Related Cost Recovery Mechanisms pursuant to Senate Resolution 316 (2022 KY S.R. 316, 2022 Regular Session).[53]

Finally, the Commission initiated semiannual and biennial reviews of the operation of Big Rivers' Fuel Adjustment Clause ("FAC"). In the FAC reviews that have been completed, the Commission approved the operation of Big Rivers' FAC.[54] Two semiannual reviews and a recently opened two-year review of Big Rivers' FAC remain pending.[55]

3.6 Safety Programs

Big Rivers' Board of Directors, 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

[53] See: *In the Matter of: Electronic Investigation of the Fuel Adjustment Clause Regulation 807 KAR 5:056, Purchase Power Costs, and Related Cost Recovery Mechanisms* – Case No. 2022-00190 (filed November 2, 2022).

[54] *See 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 October 31, 2020*, Case No. 2021-00058, Order (Ky. P.S.C. August 2, 2021); *In the Matter of: An Electronic Examination of the Application of the Fuel Adjustment Clause of Big Rivers Electric Corporation from November 1, 2020 through April 30, 2021*, Case No. 2021-00297, Order (Ky. P.S.C. March 24, 2022).

[55] *In the Matter of: An Electronic Examination of the Application of the Fuel Adjustment Clause of Big Rivers Electric Corporation from May 1, 2021 through October 31, 2021*, Case No. 2022-00041 (Filed March 31, 2022; *In the Matter of: An Electronic Examination of the Application of the Fuel Adjustment Clause of Big Rivers Electric Corporation from November 1, 2021 through April 30, 2022*, Case No. 2022-00268 (Filed September 13, 2022)); *In the Matter of: An Electronic Examination of the Application of the Fuel Adjustment Clause of Big Rivers Electric Corporation from November 1, 2020 through October 31, 2022*, Case No. 2023-00013 (Filed September 6, 2023).

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' safety plan also requires that each location at Big Rivers conduct monthly safety meetings to ensure the continued growth in knowledge and employee participation. Decisions are made utilizing safety teams to ensure employees' concerns are taken into consideration. The ideal result of an involved, committed work force is ultimately the total absence of injuries or death.

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 or on Big Rivers' facilities is expected to maintain safety awareness and work safely.

The Company and its employees have achieved the following recent safety milestones:

- Fifty-Seven (57) 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 2023:
  - Transmission: 13 years,
  - Green Station: 1 year,
  - Headquarters: 12 years,
  - Wilson Station: 7 years; and
  - Big Rivers Electric Corporation: 1 year
- Headquarters employees have worked seven years without an Occupational Safety and Health Administration ("OSHA") recordable incident;
- Transmission employees have worked eight years without an OSHA recordable incident;
- Green Station employees have worked one year without an OSHA recordable incident; and
- Big Rivers was awarded the 2016, 2017, 2018, 2019, 2020, 2021 and 2022 Kentucky Employers' Mutual Insurance ("KEMI") Destiny award, recognizing 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 0.8 or below and maintain a loss ratio of 45% or below, which places Big Rivers in an elite group.

3.7 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 2020. Chris Bradley was promoted to Vice President of System Operations in May of 2021. Paul G. Smith Chief Financial Officer ("CFO") and Mark Eacret (Vice President of Energy Services) retired in 2022 and 2023, respectively. In May of 2022, Nathan Berry was promoted to Chief Operating Officer, and Mike Mizell was promoted to the position of Chief Administrative Officer, with responsibility for Human Resources, Procurement and Environmental Compliance. In August of 2022, Big Rivers retained Dr. Talina Mathews as its new CFO. In March 2023, Erin Murphy was retained for the new position of Vice President of Federal and RTO Regulatory Affairs. Finally, in July of 2023, Chief Executive Officer ("CEO") Bob Berry announced his retirement at the end of the year, and as of this filing, Big Rivers' Board is in the process of selecting his successor.

Big Rivers continues to utilize a Pay–for–Performance Plan as part of its Performance Management Process for Non–Bargaining employees, and it has continued to utilize Individual Development Plans for each employee. Since 2019, Big Rivers has conducted annual Leadership Forums, bringing together leaders throughout the organization for a day of learning, fellowship, and teambuilding. Big Rivers continues its succession planning processes 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 its corporate mission.[56]

3.8 Regulatory Climate

This IRP is intended to promote the delivery of reliable and cost-effective power to meet the needs of Big Rivers' Members, including needs pertaining to grid reliability, sustainability, and affordability. As part of that effort, Big Rivers must allow for potential resource adequacy and transmission changes in the MISO Tariff; it must also plan for existing and future state and federal regulatory requirements. Compliance with environmental rules and other obligations requires careful analysis of costs, and Big Rivers will continue to evaluate requirements and opportunities as they are developed and as they become available. Some examples of these considerations subject to ongoing evaluation include:

Obligations:

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

[56] 2023 strategic planning by the board is presently focused on the Executive Search for the CEO position.

Opportunities:

- Inflation Reduction Act ("IRA") and Infrastructure Investment and Jobs Act ("IIJA")
- PACE[57] – the Powering Affordable Clean Energy Program ("PACE"), a part of the Inflation Reduction Act, where the United States Department of Agriculture ("USDA") Rural Development's Rural Utilities Service ("RUS") will forgive up to 40 percent of loans for renewable energy projects that use wind, solar, hydropower, geothermal, or biomass, as well as for renewable energy storage projects. On July 10, 2023, Big Rivers submitted a Letter of Interest ("LOI") for two potential projects which provide benefits to our Members through production of cost-effective renewable energy within our footprint. The RUS is evaluating projects in the order received and anticipates inviting parties to submit full applications as early as September 2023.
- NewERA – The Empowering Rural America Program ("NewERA") program is available only to rural electric cooperatives to make energy efficiency improvements to eligible generation and transmission systems to purchase, build, or deploy renewable energy, zero-emission systems, carbon capture storage systems, or to purchase renewable

[57] https://www.rd.usda.gov/sites/default/files/RD-FS-RUS-PACE_FINAL508.pdf

energy.[58] The NewERA program has total funding of $9.7 billion and no single award can exceed 10% of the total program funding. On September 15, 2023, Big Rivers has submitted a LOI to fund a project that will significantly reduce carbon emissions in our service area. RUS will score all LOIs- and anticipates inviting full applications in the fourth quarter of 2023.

Following the 2023 Regular Session of the Kentucky General Assembly, Kentucky statutory law includes a rebuttable presumption against the retirement by a Kentucky utility of any fossil fuel-fired electric generation unit. KRS 278.264 took effect following an emergency declaration by the General Assembly, in which it declared an emergency existed as to the "retirements of coal-fired electric generating units at an unprecedented rate" and the resulting effect of "compromising the reliability of electric power service and resilience of the electric grid."[59] The implementation of this statute and its impact on utility planning are still developing, and Big Rivers will remain fully compliant with state legal requirements and cognizant of the General Assembly's concerns related to long-term resource planning.

3.9 Other Significant Changes - MISO

In the fall of 2022, MISO began determining resource adequacy on a seasonal basis, rather than annual basis, with the first affected planning year beginning in

[58] https://www.rd.usda.gov/sites/default/files/RD-FS-RUS-NewERA-FINAL508.pdf

[59] 2023 Regular Session, Ky. Senate Bill 4, Section 3.

June of 2023. MISO conducts the annual Planning Resource Auction ("PRA") to demonstrate sufficient resources and allow market participants to sell or buy capacity in each season (summer, fall, winter, and spring) for the upcoming planning year. Resources are accredited for each season, and load requirements are determined for each season. Big Rivers participates in the annual PRA for each season, and this IRP uses the MISO requirements for purposes of its planning analysis

For its thermal resource calculations, MISO moved from an Installed Capacity ("ICAP") approach that takes into account ICAP and Equivalent Forced Outage Rate on demand to determine a Seasonal Accredited Capacity value to an approach that looks at unit performance during the tightest hours in the market. The new approach assigns hours as either Tier 1 Hours or Tier 2 Hours, with Tier 2 Hours given a higher weighting, as these are the hours in each season where MISO's operating margin is the tightest. Tier 2 Hours consist of 65 hours for each season where operating conditions are the tightest and specific conditions are met. These 65 hours make up 70% of our weighting for PY24-25 and 80% of our weighting for all future years, so unit performance is critical during these hours. Notably, MISO uses three (3) years of historical seasonal data in its calculation, allowing a particularly demanding season to be mitigated by that same season in two (2) other years.

3.10 A Focus on Reliability

Ensuring reliability, of course, remains a cornerstone of Big Rivers' planning objectives. James B. Robb, NERC President and CEO, in his testimony before the

Committee on Energy and Natural Resources, United States Senate, Washington, DC on June 1, 2023, stated, "NERC is concerned that the pace of change is overtaking the reliability needs of the system."[60] Mr. Robb emphasized that resource adequacy (capacity) does not guarantee energy sufficiency; instead, Mr. Robb observed that we must shift focus from "capacity on peak" to 24 x 7 energy planning. All generation sources have energy limits and physical constraints, and these limits and constraints must be accurately accounted for in seasonal and long-term planning assessments. Mr. Robb concluded that bulk power system reliability is at an inflection point—NERC assessments demonstrate that the electric grid is operating ever closer to the edge where reliability is at risk. The central challenge is to calibrate the pace of change with the reliability needs of a system that must remain reliable and resilient at all times and under all conditions.

In its 2023 Summer Reliability Assessment,[61] NERC indicated that MISO is expected to have sufficient resources for normal summer peak demand, but it could face challenges in meeting above-normal peak demand if wind generator output is lower than expected. Other reliability issues NERC tracked include:

- Stored supplies of natural gas and coal are at high levels, but the industry is monitoring for potential generator fuel delivery risks.

[60] "The Reliability and Resiliency of Electric Service in the United States in Light of Recent Reliability Assessments and Alerts" at https://www.energy.senate.gov/services/files/D47C2B83-A0A7-4E0B-ABF2-9574D9990C11.

[61] "2023 Summer Reliability Assessment" May 2023 Report at https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2023.pdf

- New environmental rules that restrict power plant emissions will limit the operation of coal-fired generators in 23 states including Nevada, Utah, and several states in the Gulf Coast, mid-Atlantic, and Midwest.
- Low inventories of replacement distribution transformers could slow restoration efforts following hurricanes and severe storms.
- Supply chain issues present maintenance and summer preparedness challenges and are delaying some new resource additions.
- Winter precipitation is expected to improve the water supply for hydro generation in parts of the U.S. West, but low water levels on major reservoirs remain a concern for electricity generation.
- Unexpected tripping of wind and solar Photovoltaic ("PV") resources during grid disturbances continues to be a reliability concern.
- Curtailment of electricity transfers to areas in need during periods of high regional demand is a growing reliability concern.
- In addition to these concerns, resource outages will continue to present challenges in many areas during "near-peak" demand conditions that occur in spring and fall.

Likewise, MISO's CEO, John Bear, has underscored that the grid must remain dependable in the face of rapid fleet changes in the MISO region giving rise to urgent and complex reliability challenges.[62] MISO's January 2023 report emphasizes that as the transition to different generation resources continues, society must decide how to balance reliability, sustainability, and affordability.[63]

Some considerations attendant to the rapid transformation of the generation landscape include the significantly-different attributes of the replacement resources from those of the replaced resources; the emerging technologies which show promise for addressing challenges, but are not yet commercially viable at scale; and the impact of extreme weather events, which have become more frequent and severe.[64] For example, the extreme cold during Winter Storm Elliott on December 23-24, 2022, led MISO to take emergency actions, including manually dispatching generation, calling an emergency to cut LMRs, and making costly resource commitments which resulted in very high costs: $350M in real time congestion and $30M in uplift payments.[65]

Additionally, the growth of electric vehicles and increasing use of electricity in homes and businesses is likely to exert new pressures on the grid in hours of the day and seasons of the year that rarely posed risks in the past. According to Mr. Bear, MISO's Response to the Reliability Imperative Report is part of MISO's effort to help

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[62] "MISO Regional Reliability Imperative – January 2023" at "A Message from John Bear, CEO". https://cdn.misoenergy.org/MISO%20Response%20to%20the%20Reliability%20Imperative504018.pdf

[63] Id. at page 4.

[64] Winter Storm Elliott in December 2022, Winter Storm Uri in February 2021, Hurricane Ida in August 2021, and Hurricanes Laura, Delta, and Zeta in the same and fall of 2020.

[65] https://cdn.misoenergy.org/20230628%20Markets%20Committee%20of%20the%20BOD%20Item%2004a%20IMM%20State%20of%20the%20Market%20Presentation629360.pdf

facilitate a planning process for all the region's entities to collaboratively address relevant challenges, while also balancing the priorities of reliability, sustainability, and affordability.

Temporal issues present challenges as well, as retirement decisions and regulatory changes can create conflict within practical modeling and planning cycles. MISO's generator interconnection queue, for example, consists of more than 1400 active projects totaling over 240 GW. More than half of these are solar projects that still must go through the Interconnection queue, the timelines for which continue to slide.

Accelerated retirement within the MISO footprint and the addition of large quantities of solar can create or exacerbate resource planning challenges. Large quantities of solar will also likely lead to significant changes in ramping needs, given the fluctuating timing of increased and decreased solar output. The average hourly wind output grew 23 percent over 2021, and served an average of 23.8 percent of hourly load in the Midwest, up from 18.5 percent in 2020. However, wind fluctuations have grown significantly as well, leading to more congestion and increased operational uncertainty. As recently as July 2023, MISO's Independent Market Monitor ("IMM"), David B. Patton, Ph.D., recommended that MISO more accurately model marginal accreditation from intermittent resources, which would cause the model to forego some wind and solar when it needs resources for reliability. He described the "more realistic" case being one where capacity previously presumed to be provided by intermittent resources is replaced by gas, hybrid resources, and batteries.[66]

Additionally, as described in section 3.9 above, MISO received approval from FERC in 2021 to establish seasonal capacity requirements; MISO is currently making further changes to capacity accreditation for thermal and non-thermal resources, known as Direct Loss of Load ("Direct-LOL"). MISO intends to begin implementing Direct-LOL as early as Planning Year 2025/2026. MISO is additionally working to establish Reliability Based Demand Curves (where MISO will procure additional planning reserves beyond the Planning Reserve Margin);[67] and to add a 3-year Opt-Out provision to Fixed Resource Adequacy Plans (offering the option to commit resources for the upcoming planning year plus 2 years).[68, 69] None of these changes are anticipated to increase the summer capacity value of existing resources, but the actual impact of any proposed change is unknown.

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[66] From Presentation to MISO Market Subcommittee "Summary of 2022 MISO State of the Market Report" by Potomac Economics as MISO's Independent Market Monitor ("IMM") (July 13, 2023) at Slide 28, https://cdn.misoenergy.org/20230713%20MSC%20Item%2006%20IMM%20State%20of%20the%20Market%20Recommendations629500.pdf

[67] "Reliability-Based Demand Curve(s),"Resource Adequacy Subcommittee, RASC-2019-8 (Feb. 28-Mar. 1, 2023) https://cdn.misoenergy.org/20230228-0301%20RASC%20Item%2006a%20Reliability%20Based%20Demand%20Curves%20(RASC-2019-8)628029.pdf

[68] https://www.misoenergy.org/events/2023/resource-adequacy-subcommittee-rasc---july-11-2023/

[69] https://cdn.misoenergy.org/20230808%20RASC%20Item%2002%20Reliability%20Based%20Demand%20Curves%20Presentation%20(RASC-2019-8)629793.pdf

CHAPTER 4
LOAD FORECAST

4. LOAD FORECAST

4.1 Load Forecast Introduction

Clearspring Energy Advisors, LLC, which prepared Big Rivers' 2020 Long Term Load Forecast, was again selected by Big Rivers and its Members to prepare this 2023 electric load forecast through 2042. 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 (Jackson Purchase Energy Corporation, Kenergy Corporation, and Meade County RECC), and Clearspring in preparing this study to ensure accurate and useful load forecast results. This chapter includes summary results of the load forecast, and Appendix A Long Term Load Forecast contains more detailed aspects of the analysis.

4.2 Big Rivers' Native System

The table below provides the total Rural energy requirements, Direct Serve (Large Industrial) 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 (2018-2022) and the forecasts for the next 20 years.

Table 4.2(a)

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
2018	2,366,988	953,822	556.7	95.5	48.5%	58.2%
2019	2,261,069	946,040	490.9	117.9	52.6%	60.2%
2020	2,164,868	824,695	460.2	106.0	53.6%	60.3%
2021	2,219,380	781,559	492.9	96.5	51.4%	58.2%
2022	2,269,586	919,357	590.7	99.7	43.9%	52.8%
2023	2,291,062	1,569,178	473.4	261.1	55.2%	60.0%
2024	2,343,506	2,172,620	482.0	338.3	55.4%	62.7%
2025	2,344,105	2,225,127	482.0	359.1	55.5%	62.0%
2026	2,354,461	2,225,127	484.0	359.1	55.5%	62.0%
2027	2,364,427	2,225,127	485.9	359.1	55.5%	62.0%
2028	2,373,176	2,227,894	488.2	359.1	55.3%	61.8%
2029	2,380,698	2,225,127	489.3	359.1	55.5%	62.0%
2030	2,394,861	2,225,127	492.2	359.1	55.5%	62.0%
2031	2,404,797	2,225,127	494.2	359.1	55.6%	61.9%
2032	2,425,591	2,227,894	498.4	359.1	55.4%	61.8%
2033	2,432,406	2,225,127	499.8	359.1	55.6%	61.9%
2034	2,441,782	2,225,127	501.6	359.1	55.6%	61.9%
2035	2,451,925	2,225,127	503.6	359.1	55.6%	61.9%
2036	2,466,634	2,227,894	506.5	359.1	55.4%	61.7%
2037	2,476,201	2,225,127	508.4	359.1	55.6%	61.9%
2038	2,485,134	2,225,127	510.0	359.1	55.6%	61.9%
2039	2,493,662	2,225,127	511.6	359.1	55.6%	61.9%
2040	2,501,574	2,227,894	513.0	359.1	55.5%	61.7%
2041	2,509,737	2,225,127	514.5	359.1	55.7%	61.9%
2042	2,519,073	2,225,127	516.3	359.1	55.7%	61.9%
Average Annual Growth Rates						
Previous 10 Years	-0.23%	-0.52%	0.88%	-1.23%	-1.12%	-0.86%
Previous 5 Years	0.53%	-0.01%	3.21%	-2.71%	-2.59%	-1.77%
Next 5 Years	0.82%	19.34%	-3.83%	29.22%	4.84%	3.26%
Next 10 Years	0.67%	9.25%	-1.68%	13.67%	2.36%	1.58%
Next 20 Years	0.52%	4.52%	-0.67%	6.62%	1.20%	0.79%

4.3 Non-Coincident Peak

The Big Rivers non-coincident peak ("NCP") is defined as the Big Rivers Native CP demand plus Non-Member sales at their peak load values. The table below displays the annual peak NCP forecast for the total system.

Table 4.3(a)
Total System NCP

Year	Total Annual Big River's CP	Non-Member Sales	Total NCP
2018	668,654	64,608	733,262
2019	624,821	341,253	966,074
2020	582,483	346,820	929,303
2021	606,235	356,940	963,175
2022	706,765	365,780	1,072,545
2023	752,176	344,230	1,096,406
2024	839,930	345,700	1,185,630
2025	861,287	345,700	1,206,987
2026	863,296	345,700	1,208,996
2027	865,283	100,000	965,283
2028	867,584	100,000	967,584
2029	868,781		868,781
2030	871,701		871,701
2031	873,734		873,734
2032	878,087		878,087
2033	879,441		879,441
2034	881,332		881,332
2035	883,377		883,377
2036	886,373		886,373
2037	888,242		888,242
2038	889,961		889,961
2039	891,577		891,577
2040	893,048		893,048
2041	894,570		894,570
2042	896,344		896,344

4.4 Energy

Big Rivers total system energy requirements include Native system energy requirements plus the Non-Member energy requirements which are described more fully in the Appendix A Long Term Load Forecast Report. The following table provides the total system energy requirements.

Table 4.4(a)[70]

Total System Energy Summary

Year	Total Rural Requirements	Direct Serve & Aux Sales	Transmission Losses	Non-Member Requirements	**Total System Energy Requirements**
2018	2,366,988	953,822	86,858	359,615	**3,767,283**
2019	2,261,069	950,475	82,848	1,591,431	**4,885,823**
2020	2,164,868	841,639	77,120	1,565,152	**4,648,780**
2021	2,219,380	799,926	71,125	2,004,399	**5,094,831**
2022	2,269,586	925,541	74,851	2,210,824	**5,480,803**
2023	2,291,062	1,569,178	92,323	2,106,933	**6,059,496**
2024	2,343,506	2,172,620	108,209	2,106,933	**6,731,268**
2025	2,344,105	2,225,127	109,482	2,106,933	**6,785,647**
2026	2,354,461	2,225,127	109,730	2,106,933	**6,796,252**
2027	2,364,427	2,225,127	109,969	1,080,851	**5,780,374**
2028	2,373,176	2,227,894	110,245	784,825	**5,496,140**
2029	2,380,698	2,225,127	110,359	324,681	**5,040,865**
2030	2,394,861	2,225,127	110,698	0	**4,730,686**
2031	2,404,797	2,225,127	110,936	0	**4,740,860**
2032	2,425,591	2,227,894	111,501	0	**4,764,986**
2033	2,432,406	2,225,127	111,598	0	**4,769,131**
2034	2,441,782	2,225,127	111,822	0	**4,778,731**
2035	2,451,925	2,225,127	112,065	0	**4,789,118**
2036	2,466,634	2,227,894	112,484	0	**4,807,012**
2037	2,476,201	2,225,127	112,647	0	**4,813,975**
2038	2,485,134	2,225,127	112,861	0	**4,823,122**
2039	2,493,662	2,225,127	113,065	0	**4,831,854**
2040	2,501,574	2,227,894	113,321	0	**4,842,789**
2041	2,509,737	2,225,127	113,451	0	**4,848,315**
2042	2,519,073	2,225,127	113,674	0	**4,857,874**
Average Annual Growth Rates					
Previous 10 Years	-0.36%	4.50%	7.19%	-	5.85%
Previous 5 Years	-0.65%	10.47%	1.23%	-	9.97%
Next 5 Years	0.82%	19.18%	8.00%	-	1.07%
Next 10 Years	0.67%	9.18%	4.07%	-	-1.39%
Next 20 Years	0.52%	4.48%	2.11%	-	-0.60%

[70] Total non-member energy utilized in EnCompass differs from the load forecast (see footnote on Table 7.1.6(a) due to the following factors: 1) OMU energy is the total value prior to any allocations of energy from OMU's share of the SEPA Hydro system and based off an hourly load profile curve, and 2) KYMEA is modeled as a call option in the model which results in a reduced obligation to KYMEA as fuel prices and market conditions vary over time.

4.5 Class Forecasts

Consistent with Commission regulation, this IRP includes historical and forecasted information regarding loads, disaggregated by customer class where available. This information is more fully described in Appendix A Long Term Load Forecast, particularly at Section 3 thereof.

4.6 Uncertainties

Loads can be influenced by factors that are inherently difficult to predict, such as weather and the economy, in addition to regulatory and other mindful pushes toward the electrification of transportation and home appliances. That said, the study considers many of these issues and includes alternate growth scenarios for extreme and mild weather, as well as optimistic and pessimistic economic expectations that are more fully described in Appendix A Long Term Load Forecast Section 6.

4.7 Forecast Development

Clearspring used econometric equations developed as part of the modeling process to develop monthly forecasts for each of Big Rivers' Member systems. The modeled classes are calculated using the estimated equations along with forecasted values for economic, demographic, and weather variables.

The amount of energy required by each system is greater than the sum of the retail energy sales. System own-use and energy losses are forecasted 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. 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.

4.8 Model Development

Various economic and demographic variables are used in the econometric models developed for the 2023 load forecast. The key economic and demographic assumptions for these variables are listed below.

- Real residential electricity prices are projected to [redacted] through the forecast period.
- Air conditioning saturation levels increase slowly through history until capping out at full saturation levels.

- 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 [redacted] through the forecast period.
- Real GRP is projected to [redacted] through the forecast period.
- Real total retail sales are projected to [redacted] through the forecast period.
- Inflation is projected at an average annual rate of 2.1% through the forecast period.
- Cooling degree days, heating degree days, and peak day weather conditions are based on a prior twenty-year average.

Clearspring employs the econometric forecasting approach in the study. This is the same approach used in prior IRP applications. The econometric approach includes several variables that are econometrically estimated to determine their impacts on loads. The econometric approach has a rich history in load forecasting and, in Clearspring's opinion, is a transparent and accurate method that can quantify the impacts of expected variable changes. As a response to Staff's first Recommendation on Load for the 2020 IRP, Appendix A Long Term Load Forecast

Section 8.3 describes a research paper produced by Lawrence Berkeley National Laboratory showing no significant performance advantages in forecasting accuracy to employing SAE models versus econometric methods.

CHAPTER 5
DEMAND SIDE MANAGEMENT

5. DEMAND-SIDE MANAGEMENT

5.1 Demand-Side Management

The 2023 Demand-Side Management Potential Study (the ["DSM Study"] or the ["2023 DSM Study"]) presents results from the evaluation of opportunities for energy efficiency programs in Big Rivers Members' service territories. Of course, as a wholesale power provider, opportunities for demand-side management require cooperation between Big Rivers and its Member-Owners who ultimately implement the programming. Estimates of technical potential, economic potential, achievable potential, and program potential are provided for the period spanning 2024-2033 for the residential and non–residential (commercial/industrial or "C&I") sectors served under the Rural Delivery Service schedule. Results from a program potential scenario 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 2023 DSM Study.

5.1.1 Member Load Research

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.

Big Rivers is currently experiencing growth in large industrial loads. To improve daily forecasting efforts for the industrial loads, Big Rivers Energy Services personnel are moving to individual load forecasts provided by each large industrial to include the total load, load breakdowns by processes, behind the meter generation, and net load positions. Receiving individual load forecasts from the large industrials will help provide a more accurate hour-by-hour total load forecast to purchase power in the MISO Day-Ahead Market. To enhance the individual large industrial forecast process and to ensure internet security, Big Rivers Information Technology personnel are creating a web-based interface that will allow each individual large industrial to provide their load forecast via the internet instead of sending spreadsheets through email. This process will also provide daily reports that will automatically populate the loaded forecasts into the forecasting process workbooks for a cleaner and more secure process.

5.2 Market Potential Study - Energy Efficiency

The 2023 DSM 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 Big Rivers Members' service territories from 2024 through 2033. The study had five primary objectives:

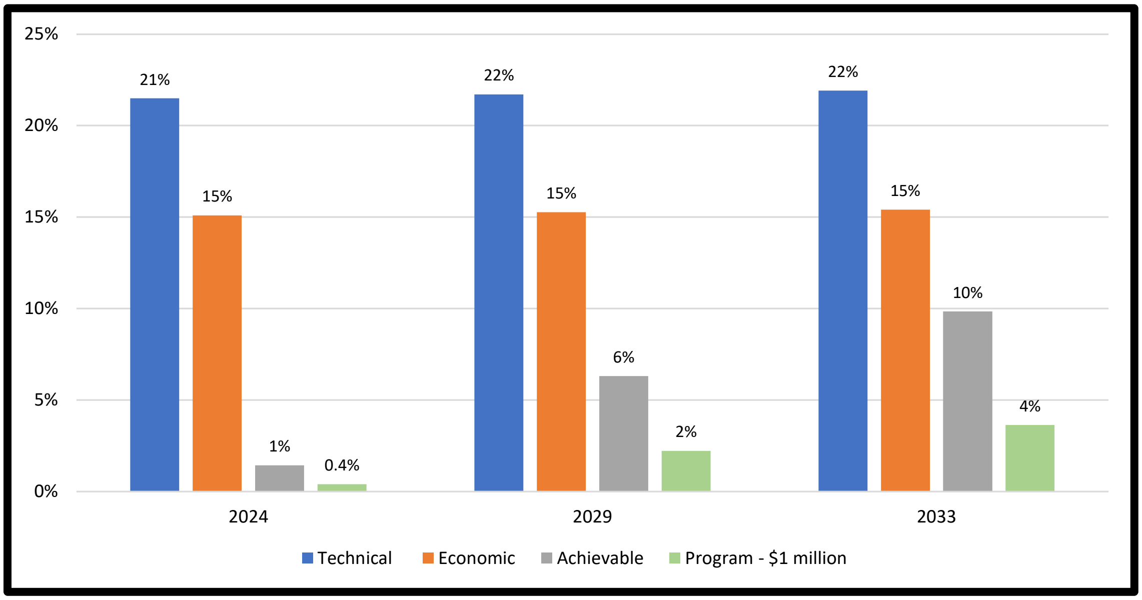
- Develop databases of energy efficiency and demand response measures in the residential and non–residential sectors to reflect current industry knowledge of energy efficiency and demand response. This ensures Big Rivers' 2023 IRP analyzed measures that take into account known codes and standards and aligns with the market and demographics of Big Rivers' Members' customers.
- Evaluate 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' and its Members.

- Evaluate the potential for achievable savings through DSM programs over a ten-year funding window (2024-2033).
- Estimate the potential savings over that same 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 a $1.0 million incentive budget.

Figure 5.2(a) provides the technical, economic, achievable and program potential for residential and non-residential sectors in the Big Rivers service territory. By 2033 technical potential is approximately 22% of sales. The economic potential is approximately 15% of forecasted sales in 2033, achievable potential tops out at 10%, and the program potential $1 million scenario is approximately 4% of forecasted sales by 2033. Chapters 3 and 4 of the 2023 DSM Potential Study in Appendix B provide sector level details including program potential details.

Figure 5.2(a)

Electric Efficiency Potential Savings Summary (% of Retail MWh Sales)



Tables 5.2(a) and 5.2(b) provide the energy and demand potential.

Table 5.2(a)

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

2024-2033 Program Term

Potential	Residential	Non-Res (C&I)
Technical	296,037	216,489
Economic	213,006	147,314
Achievable	108,886	121,046
Program ($1m)	23,110	61,508
Note: Cumulative Annual Impact		

Table 5.2(b)

Energy Efficiency Potential (Cumulative Annual) Demand Savings (MW) 2024-2033 Program Term

Potential	Residential	Non-Res
Technical	49	48
Economic	29	32
Achievable	15	26
Program ($1m)	3	13
Note: Cumulative Annual Impact		

Table 5.2(c) shows the TRC benefit–cost ratio based on the net present value of benefits and costs of the program scenarios. The cost–effectiveness ratio indicates that the program potential scenario is cost–effective. The program evaluation was based on savings identified in the achievable analysis from key end–use categories rather than specific measure programs.

Table 5.2(c)

Program Potential Cost-Effectiveness (TRC Test) 2024-2033 Program Term

Potential	TRC Test Ratio
Program ($1m)	3.1

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 a $1.0 million annual funding scenario. The residential sector ended up with 43% of the budget, and the non–residential sector received 57% of the budget. The results for ten years of the program potential are presented below. The $1.0 million funding program potential constitutes 0.4% of forecasted retail MWh sales over the 10–year timeframe and rises to 4.0% across the 10–year timeframe.

Table 5.2(d) provides the estimates of cumulative annual program potential for energy and summer peak demand. The $1.0 million program potential is just over 84,600 MWhs by 2033. Summer peak demand program potential is 16.0 MWs for the same period.

Table 5.2(d)

Program Potential Summary

2024-2033 Program Term

Program Potential	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Annual Energy (MWh)	8,462	16,924	25,385	33,847	42,309	50,771	59,233	67,694	76,156	84,618
Demand (MW)	1.6	3.2	4.8	6.4	8.0	9.6	11.2	12.8	14.4	16.0

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.

5.3 Residential Energy Efficiency Program Potential

The program potential assessment involved estimating potential savings across specific end–use categories. Table 5.3(a) provides a summary of the program potential for the $1 million incentive scenario for the residential segment. The heating, ventilation, and air conditioning ("HVAC") program opportunities provide the most potential energy savings over the next ten (10) years, followed by water heating.

Table 5.3(a)

$1 Million Program Scenario – Residential Energy and Demand Savings by End-Use 2024-2033 Program Term

	Category	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Energy (MWh)	HVAC	1,050	2,099	3,149	4,198	5,248	6,298	7,347	8,397	9,446	10,496
	Water Heating	891	1,781	2,672	3,562	4,453	5,344	6,234	7,125	8,016	8,906
	Appliance	269	539	808	1,077	1,347	1,616	1,886	2,155	2,424	2,694
	Lighting	51	103	154	206	257	309	360	411	463	514
	Other	50	100	150	200	250	300	350	400	450	500
	Total	2,311	4,622	6,933	9,244	11,555	13,866	16,177	18,488	20,799	23,110
Demand (MW)	Category	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
	HVAC	0.2	0.4	0.6	0.8	1.0	1.2	1.4	1.6	1.9	2.1
	Water Heating	0.0	0.1	0.1	0.2	0.2	0.3	0.3	0.4	0.4	0.4
	Appliance	0.1	0.1	0.2	0.2	0.3	0.3	0.4	0.4	0.5	0.5
	Lighting	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
	Other	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1
	Total	0.3	0.6	1.0	1.3	1.6	1.9	2.2	2.6	2.9	3.2

Note: MISO Summer Peak

Note: Cumulative Annual Impact

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

Table 5.4(a) 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 HVAC category.

Table 5.4(a)

**$1 Million Program Scenario –
Non-Residential Energy and Demand Savings by End-Use
2024-2033 Program Term**

	Category	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Energy (MWh)	HVAC	1,359	2,717	4,076	5,435	6,793	8,152	9,510	10,869	12,228	13,586
	Water Heating	120	240	360	480	600	721	841	961	1,081	1,201
	Lighting	1,367	2,733	4,100	5,466	6,833	8,199	9,566	10,932	12,299	13,665
	Appliance	2,192	4,385	6,577	8,770	10,962	13,154	15,347	17,539	19,732	21,924
	Other	1,113	2,226	3,339	4,453	5,566	6,679	7,792	8,905	10,018	11,132
	Total	6,151	12,302	18,452	24,603	30,754	36,905	43,056	49,207	55,357	61,508
	Category	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Demand (MW)	HVAC	0.2	0.5	0.7	0.9	1.2	1.4	1.7	1.9	2.1	2.4
	Water Heating	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1
	Lighting	0.3	0.5	0.8	1.1	1.4	1.6	1.9	2.2	2.5	2.7
	Appliance	0.6	1.3	1.9	2.6	3.2	3.9	4.5	5.1	5.8	6.4
	Other	0.1	0.2	0.3	0.4	0.6	0.7	0.8	0.9	1.0	1.1
	Total	1.3	2.6	3.8	5.1	6.4	7.7	8.9	10.2	11.5	12.8

Note: MISO Summer Peak

Note: Cumulative Annual Impact

5.5 Market Potential – Demand Response

The 2023 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 2023 IRP provides a brief overview of the results of the demand response analysis. Section 5 of the 2023 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, 2023 DSM Study.

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[71].

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 nineteen 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 5.5(a) provides the results of the evaluations.

[71] Responsive to 807 KAR 5:058 Section 7 (2) (e)

Table 5.5(a)

Demand Response Programs Evaluation Results

Program	Sector	Type	Direct Control	TRC	UCT	PCT
Air Conditioner Cycling (25%)	Residential	Load Management	Yes	1.6	0.7	2.2
Air Conditioner Cycling (50%)	Residential	Load Management	Yes	3.3	1.5	2.2
Air Conditioner Control (100%)	Residential	Load Management	Yes	6.5	2.9	2.2
Water Heater Cycling (25%)	Residential	Load Management	Yes	0.3	0.1	2.2
Water Heater Cycling (50%)	Residential	Load Management	Yes	0.5	0.2	2.2
Water Heater Control (100%)	Residential	Load Management	Yes	0.9	0.4	2.2
Level 2 EV Charger	Residential	Load Management	Yes	1.2	1.1	1.3
Battery Storage	Residential	Load Management	Yes	0.4	1.0	2.8
Residential Load Control	Residential	Load Management	Yes	5.5	3.4	1.6
DLC (Customer Ownership)	Non-Residential	Load Management	Yes	2.1	1.2	1.2
DLC (Utility Ownership)	Non-Residential	Load Management	Yes	2.1	1.8	1.5
Battery Storage	Non-Residential	Load Management	Yes	0.9	2.4	5.9
Fleet Charging (Off-Peak)	Non-Residential	Load Management	Yes	2366.0	3.4	600.0
Peak Time Rebate	All	Load Management	No	49.5	2.3	121.9
Residential TOU	Residential	Dynamic Pricing	No	18.7	30.8	13.7
Residential CPP	Residential	Dynamic Pricing	No	41.1	67.9	68.6
Non-Residential TOU	Non-Residential	Dynamic Pricing	No	10.5	53.1	30.4
Non-Residential CPP	Non-Residential	Dynamic Pricing	No	37.8	191.7	199.3
Plug-In EV TOU	All	Dynamic Pricing	No	0.1	10	0.1

Notes: ("DLC") = Direct Load Control, ("TOU") = Time of Use, ("CPP") = Critical Peak Pricing

5.6 Conclusions for Demand Response

Forward capacity prices in MISO have seen a significant rise when compared to the past decade. Consequently, the cost/benefit of demand response programs has risen. As a result of the current higher outlook for capacity cost, the following programs did pass the TRC test.

- Air conditioning Cycling and Control
- Level 2 Charger Control
- Residential Load Control
- Non-Residential Load Control
- Fleet Charging Control
- Peak-Time Rebate
- Time-of-Use and Critical Peak Pricing

5.7 DSM Recommendation

Big Rivers and its Member-Owners should continue evaluating energy efficiency and formal demand response programs deemed cost-effective. Energy efficiency programs are being 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. The existing DSM-14 Low- Income Weatherization Support Program – Pilot has seen no activity since March 31, 2021 and should be re-evaluated by Big Rivers. It is yet unknown how MISO's seasonal capacity implementation will impact future avoided cost assumptions. Big Rivers will focus its efforts on continuing to evaluate energy efficiency and DR programs that offer peak demand reductions and energy reductions that benefit Member Cooperatives and retail members. As capacity tightens in the region, the value of capacity should increase, and at that time, all programs are likely to realize increased cost effectiveness. 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 cost, and
- Monitor the opportunity of new technologies that may provide peak demand reduction benefits at a lower cost than current programs evaluated.

CHAPTER 6
ENVIRONMENTAL

6. ENVIRONMENTAL

As a generation and transmission cooperative in the business of producing, selling, and buying electric power, Big Rivers necessarily devotes a significant amount of effort to the evaluation of existing and anticipated environmental regulations. Indeed, it may be impossible to overstate the influence of environmental regulation on the Company and its strategic assets, in particular the generation portfolio it has built and will build to serve its Members-Owners. In light of a complex and ever-evolving framework of state and federal rules, Big Rivers chooses each day to seek and act on the best available information, remaining focused on compliance and responsibility, reliability, and cost-effectiveness.

Big Rivers' generation portfolio is varied by design. It includes the natural gas-fired Green Units 1 and 2, the coal-fired Wilson Unit, and the natural gas-fired Reid combustion turbine. Big Rivers has also contracted for 178 MWs of hydroelectric capacity from SEPA, as well as 160 MWs of solar generation presently scheduled to come on-line in 2025. Demolition work continues on six retired coal-fired units (R.A. Reid 1, K.C. Coleman 1, 2 & 3, and HMP&L Station Two) and is scheduled to be completed by the end of 2023.

In this Chapter, the Company describes areas of existing and contemplated environmental oversight that impact the IRP process, chiefly those concerning the emissions and wastes that can accompany utility-scale power production. While this Chapter necessarily reflects an uncertain regulatory future created by the rules and proposed rules outlined herein, it underscores that Big Rivers remains at-the-ready to effectively address the legal, political, and technological challenges undoubtedly before it.

6.1 Greenhouse Gas Rules

On May 23, 2023, the U.S. Environmental Protection Agency announced proposed new greenhouse gas ("GHG") emissions standards for fossil fuel-fired electric generating units ("EGUs") (the "Proposed GHG Rule").[72] The Proposed GHG Rule is EPA's latest of several attempts to regulate the impact of greenhouse gases (particularly carbon) on the environment; this rule's predecessors, namely the Affordable Clean Energy Rule and the Clean Power Plan, were subject to multiple legal challenges and, consequently, neither rule went fully into effect.

Initially, on October 23, 2015, EPA, under the administration of President Obama issued the final version of the Clean Power Plan ("CPP"). The CPP attempted to regulate carbon through a process known as "generation shifting," which was designed to shift electricity production from coal-fired plants to natural gas-fired plants and renewables. Almost immediately, the CPP was challenged in court by over 150 entities including 27 states, 24 trade associations, 37 rural electric cooperatives, and three labor unions. On December 1, 2015, Congress formally issued a disapproval of the CPP pursuant to the Congressional Review Act, and on February

[72] New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule.

9, 2016, the United States Supreme Court issued a stay of the implementation of the CPP.

On June 19, 2019, EPA, under the administration of President Trump, simultaneously repealed the CPP and issued its replacement, the Affordable Clean Energy ("ACE") rule. Unlike the generation shifting focus of the CPP, the ACE rule was designed to establish emission guidelines for states to use when developing State Implementation plans ("SIP") to limit carbon dioxide ("CO_2") from coal-fired units. On January 19, 2021, at the request of EPA under the Biden administration, the ACE rule was vacated by the D.C. Circuit Court of Appeals and returned to EPA for further proceedings consistent with the court's decision.

Most recently, on May 23, 2023, EPA issued the Proposed GHG Rule. Unlike the CPP or the ACE rules, this proposed rule attempts to regulate carbon through the Clean Air Act. Specifically, EPA concludes in the proposed rule that technologies such as carbon capture and sequestration/storage ("CCS") and low Greenhouse Gas Hydrogen ("Green Hydrogen") co-firing are the "best system of emission reduction" ("BSER") for the purpose of improving emissions performance. Section 111 of the Clean Air Act requires the application of BSER to EGUs, taking into account costs, energy requirements and other statutory factors.

In the proposed rule, EPA concludes that both CCS and Green hydrogen co-firing will be commercially available by 2030, despite the fact that neither technology is currently in operation at any electric generating unit in the United States.

Further, the proposed rule establishes performance standards for existing coal-fired plants, new and reconstructed combustion turbines, and existing combustion turbines. For existing coal-fired units that are anticipated to be retired after 2040, the proposed rule requires the units have CCS in service and operating by January 1, 2030. For existing combustion turbines (larger than 300MW), the proposed rule requires either the use of Green hydrogen co-firing (30% by 2032 and 96% by 2038) or CCS to be placed in service by 2035. Finally, for newly constructed baseload (more than 50% capacity factor) combustion turbines, the proposed rule requires either the use of Green hydrogen co-firing (10% at startup, 30% by 2032 and 96% by 2038) or the use of CCS to be placed in service by 2035.

Since the publication of the rule, EPA has received over one million comments, many of which are focused on the assertion that neither CCS nor Green hydrogen co-firing is currently available or affordable. In the proposed rule itself, EPA acknowledges its reliance on an assumption that both technologies will become commercially viable by 2030 based on anticipated investments and advancements spurred by the Inflation Reduction Act and the Infrastructure Investment and Jobs Act. EPA recently closed the comment period for the proposed rule and anticipates publishing a final rule in the near future.

There will be significant litigation regarding the Proposed GHG Rule, and it is not now known whether or when the rule will become applicable law, and if so, when and in what manner. In light of the lack of certainty regarding the status of the new rule, combined with the exceptionally high costs of implementation (assuming implementation eventually becomes technologically feasible or financially viable), Big Rivers does not believe the Proposed GHG Rule and its contemplated BSER technology (either CCS or Green hydrogen co-firing) should presently have significant impacts on long term resource planning. Big Rivers will continue to monitor the status of the proposed rule and will modify its planning as warranted by new developments.

6.2 Clean Air Regulations – Cross State Air Pollution Rule

EPA implemented the Cross State Air Pollution Rule ("CSAPR") on January 1, 2015, to replace the Clean Air Interstate Rule ("CAIR") that was previously vacated by federal courts on July 11, 2008. CSAPR requires fossil fuel-fired EGUs at coal–, gas–, and oil–fired facilities in 22 states to reduce both sulfur dioxide ("SO_2") and oxides of nitrogen ("NOx") emissions to help downwind states attain fine particle and/or ozone compliance with the National Ambient Air Quality Standards ("NAAQS"). Under the original structure of CSAPR, EPA set a pollution limit (emission budget) for each of the covered states. 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; they can also 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. Since its inception in 2015, CSAPR has undergone numerous changes resulting in significant impacts to Big Rivers' operation of its units and causing uncertainty about the status of operations in the near future, as described below.

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 NOx annual, and 50 percent (50%) for NOx seasonal, as compared to Phase 1 allocations. Phase 2 NOx allowances issued under CSAPR are surrendered at a rate of one allowance for each ton of NOx 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 previous flue gas desulphurization ("FGD") system, Wilson Station had operated under an $S0_2$ allocation deficit annually since 2017. With the upgrade of the FGD system by using the recycled Coleman Station FGD/absorber system, Wilson Station can now operate well within its annual emission allowance. Additionally, Big Rivers maintains a bank of approximately 43,602 SO_2 allowances as of August 2023.

On September 7, 2016, EPA revised the CSAPR ozone season NOx program by finalizing an update to CSAPR for the 2008 ozone NAAQS, known as the CSAPR Update. The CSAPR Update ozone season NOx program largely replaced the original CSAPR ozone season NOx program as of May 1, 2017. The CSAPR Update further reduced summertime NOx 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 CSAPR Update would have effectively ended 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 allowed significant contribution to continue beyond downwind attainment deadlines and therefore remanded the rule to EPA. In response, on March 15, 2021, EPA issued its Final Revised CSAPR Rule Update. The goal of this final update is to reduce emission of nitrogen oxides from power plants in twelve (12) (out of the original twenty-two) states by setting a new level of allowances for seasonal NOx in those states. EPA found that emissions from these remaining states (which include Kentucky) were still significantly contributing to compliance efforts in the downwind states. Therefore, EPA issued new Federal Implementation Plans ("FIPS") for those states, revising each state's emission budgets for the 2021-2024 ozone seasons. In doing so, EPA also rejected pending State Implementation Plan applications from these twelve (12) states, finding that the applications did not sufficiently address the seasonal NOx issues. EPA's denials of these SIP applications are currently subject to litigation in several Federal Courts of Appeal.

The new FIP issued by EPA created a new category of Group 3 allowances for use in the twelve (12) states. Starting in 2021, EGUs in the impacted states were issued Group 3 allowances for the ozone season. Existing Group 2 banked allowances held by EGUs in these states were converted to Group 3 allowances at an 8:1 ratio resulting in a significant reduction in existing banked allowances.

6.3 Coal Combustion Residuals

Coal Combustion Residuals 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 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; it also requires 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 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, EPA subsequently issued what it called a "Holistic Approach to Closure" under a new series of proposed rules ("Part A" and "Part B") in November 2019 and March 2020. Among other things, Part A:

- Established a new deadline of April, 2021, by which all unlined surface impoundments and those surface impoundments that failed the location restriction for placement above the uppermost aquifer must stop receiving waste and begin closure or retrofit.

- Established 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.
- Changed the classification of compacted–soil–lined or clay–lined surface impoundments from "lined" to "unlined".
- Revised the coal ash regulations to specify that all unlined surface impoundments are required to retrofit or close.

Part B included 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.

Big Rivers operates, or has operated, three facilities that utilize ash ponds (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 United States Court of Appeals in August, 2018. On May 18, 2023, EPA issued a proposed rule outlining the future treatment of such "legacy ponds." In this proposed rule, EPA found that, in addition to CCR products in regulated impoundments covered by the 2015 Rule, many power plants had also disposed of CCR products in areas outside of the regulated impoundments. The proposed 2023 rule refers to these areas as CCR Management Units and includes coal ash in surface impoundments and landfills that were closed prior to the effective date of the 2015 CCR Rule (so-called Legacy Ponds) as well as other areas where CCR was placed directly on the land. Big Rivers is currently reviewing the details of the proposed rule and is involved with various trade industry groups in litigation challenging the proposed rule.

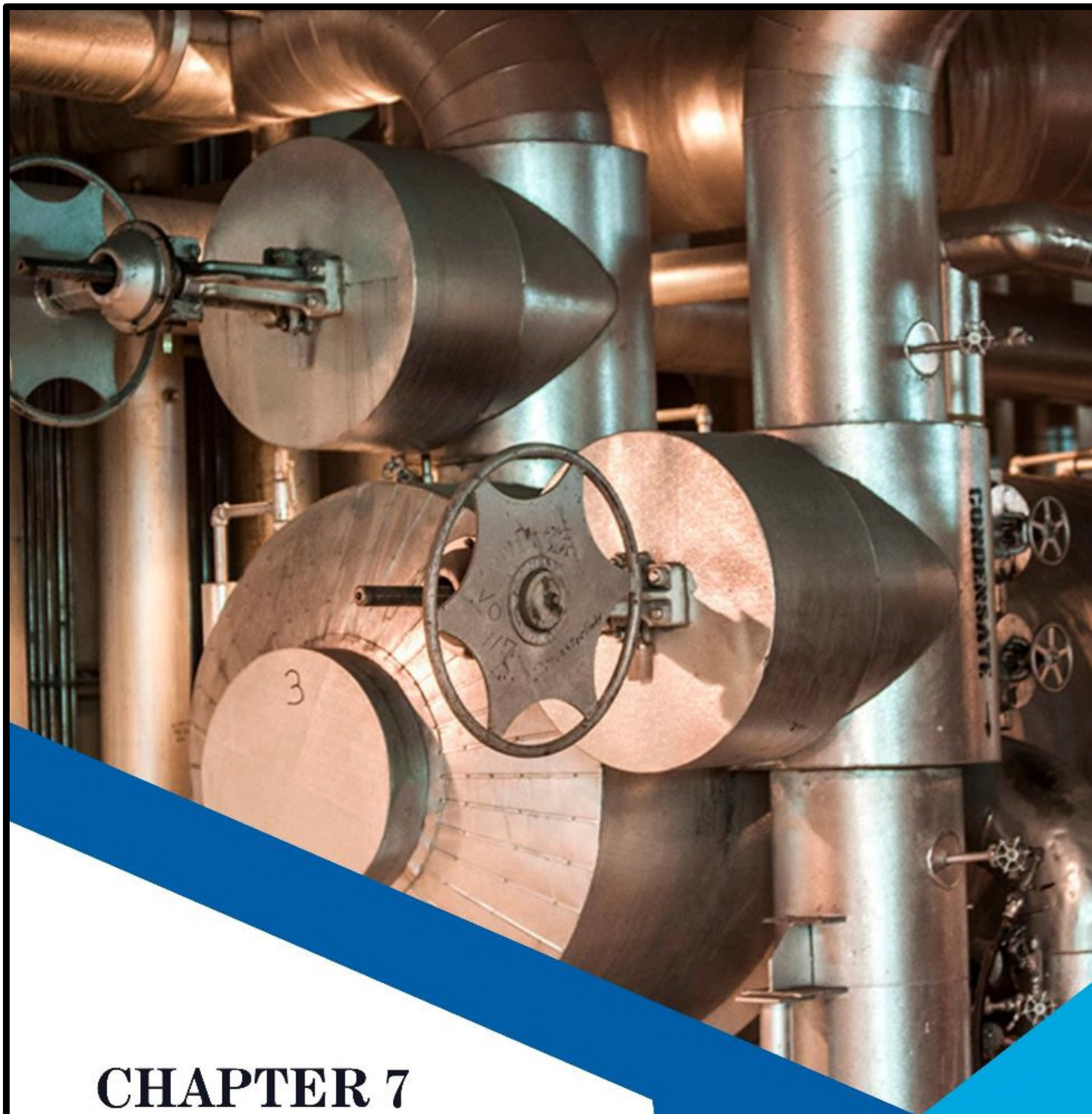
In its 2020 ECP filing with the Commission, Big Rivers received approval of its plans to close the ash ponds at Coleman Station, Green Station, and Station Two pursuant to the current or expected requirements of the CCR Rule. The Commission's August 6, 2020, Order approved Big Rivers' plan for the Green and Station Two ash ponds and conditionally approved Big Rivers' plan for the Coleman ash pond pending a final rule from EPA regarding the treatment of such legacy ponds. As of September 1, 2023, construction closure activities are ongoing at both the Green Station ash pond and the Station Two ash pond. Closure of the Green Station ash pond should be complete by the end of 2023, and closure of the Station Two ash pond should be complete by April of 2024. Both closures will be in full regulatory compliance with the 2015 CCR Rule and subsequent regulatory guidance.

Big Rivers also operates two special waste landfills, one located at the Green Station and one located at the 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 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. Installation of the final cover system will be completed by the end of 2023.

Finally, Big Rivers continues to maintain a publicly-accessible website (https://www.bigrivers.com/environmental-services/big-rivers-electric-corporation-ccr-rule-compliance-and-data-information/) that is populated with the reports and studies required to date.

6.4 Environmental Study & Monitoring

As reflected above, Big Rivers closely and continuously analyzes developments in the environmental compliance realm. As part of that activity, it likewise continuously evaluates plans and opportunities to achieve timely compliance with applicable environmental laws and regulations. As the tumultuous legal history of environmental regulation has illustrated, these plans must remain flexible, as they are subject to change through ongoing legal and political developments. Big Rivers will continue to monitor these developments and will make all necessary and appropriate adjustments to satisfy new compliance limits and schedules.



CHAPTER 7
ELECTRIC INTEGRATION ANALYSIS

7. ELECTRIC INTEGRATION ANALYSIS

Big Rivers continually evaluates its generation portfolio to ensure it is positioned to adequately meet capacity needs. Each IRP cycle is an opportunity for Big Rivers to challenge assumptions, identify uncertainties, and weigh risks, ultimately resulting in a plan to meet the energy requirements of Big Rivers' system. As earlier stated, Big Rivers' primary planning goal for its 2023 IRP is to reliably and efficiently provide for its Members' electricity needs over the next fifteen (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. Big Rivers engaged 1898 & Co., a division of Burns & McDonnell Engineering Company, Inc., to provide additional expertise and considered analysis.

7.1 Power Planning Model (EnCompass)

1898 & Co. utilized the EnCompass Power System Optimization Software, Version 6.2.2, by Anchor Power Solutions to optimize the Big Rivers fleet of energy and capacity resources through the defined study period. EnCompass is an industry standard chronological unit commitment and dispatch model with extensive presence throughout the power industry. The model employs Mixed Integer Programming to determine the optimal solution to capacity expansion, resource commitment, and economic dispatch problems with the application of real-world constraints like emission targets, generation and transmission limitations, mandatory portfolio targets and renewable energy availability.

The analysis objective is to minimize the net present value ("NPV") of capital and production costs considering, among other things, customer reliability needs and environmental regulation. Capital and production costs include compliance costs associated with existing generation, investments into capacity expansion, operation and maintenance costs, market cost of energy to serve native Member load, and the market revenues for energy sold from generation.

EnCompass was used for expansion planning and production cost modeling. The capacity expansion mode determines the recommended mix of generation resources expected to achieve a least-cost dispatch of existing and new generating assets to meet electric load along with regulatory and reliability requirements. Expansion planning is typically conducted on a simplified dispatch horizon; in the case of Big Rivers' 2023 IRP, EnCompass was used to simulate a typical two-day week (one on-peak day, one off-peak day), fifty-two (52) weeks a year. Then a detailed economic dispatch mode (Production Cost Analysis) was utilized on an hourly basis for each year of the study period.

7.1.1 Modeling Overview

Big Rivers developed its Base Case using inputs, constraints, and assumptions based on the best information available at the time this IRP was prepared. This IRP includes a 15-year planning horizon (2024-2038), as required by Commission regulation. Multiple scenarios with multiple input variables were analyzed during portfolio development. Big Rivers started with assumptions previously developed in connection with Big Rivers' 2019-2033 Long-Term Financial Plan and, with the assistance of key subject matter experts and third-party consultants, developed several new and revised assumptions, including the following updated inputs as of mid-2023:

- Member energy and demand load forecast
- Natural Gas commodity price forecast at Henry Hub
- MISO Indiana Hub energy market forecast
- Unit cost and performance projections for new and existing generation resources.
- Market purchases and demand response as resource alternatives for both energy and capacity additions

This analysis assumes the following regarding Big Rivers' existing or approved generation resources:

- Wilson remains coal-fired and in operation throughout the planning period.
- The Green units have the option to either retire in June 2029 or continue operations for the next 20 years from 2023.
- The Reid combustion turbine to remain operational throughout the study period and be dispatched when economically viable.
- Big Rivers to continue the existing SEPA contract.
- The Unbridled Solar Facility modeled as a Power Purchase Agreement operational in June of 2024.[73]

[73] In-service estimate for solar has been delayed to 2025 at the time of this IRP filing.

Consistent with the Big Rivers 2020 IRP, which indicated the need for a new combined cycle gas turbine ("NGCC"), diverse technologies were evaluated in this IRP. The following thermal resource alternatives were evaluated:

- 635 MW natural gas combined cycle
- 21 MW blocks of Wartsila reciprocating engines.
- 237 MW simple cycle combustion turbine(s) fueled by natural gas.
- 105 MW Aeroderivative fueled by natural gas.

In addition to the thermal options, the analysis also considered the following intermittent resource options:

- 100 MW Utility scale solar.
- 100 MW Utility Scale onshore wind projects.
- 50 MW x 200 MWh Utility Scale standalone/paired Li-Ion storage

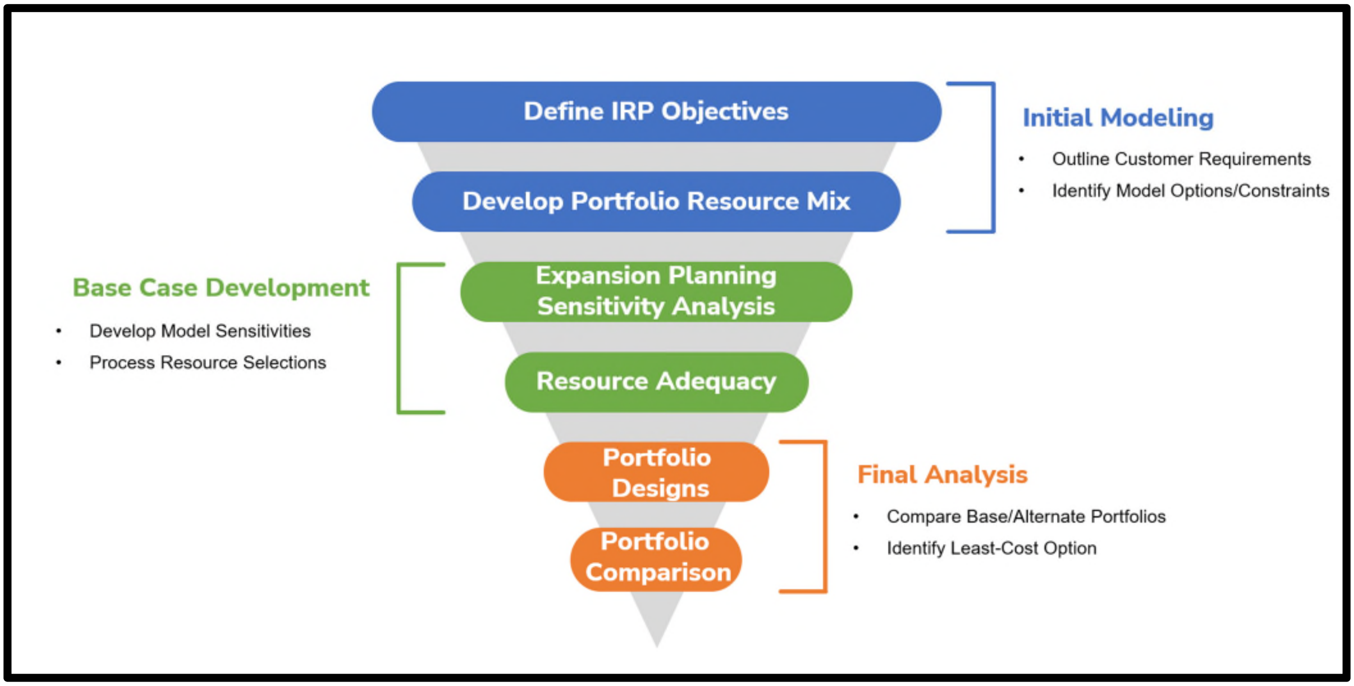
Finally, limited interaction with the MISO market for capacity was considered to fill any remaining capacity gaps as needed.

The EnCompass model was used to ensure compliance with the new MISO Seasonal Planning Reserve Margin Requirements ("PRMR"). Consistent with how MISO operates, the EnCompass model was built to ensure that all of Big Rivers' Load is purchased at market price for Big Rivers' load node, and the generation resources are economically dispatched against the market price at their respective generator pricing nodes. The model was developed to allow for economic market capacity purchases from the regional system at prices consistent with past market conditions and forward projections of Cost of New Entry. This enables the model to select the market as a least-cost option for small capacity needs to meet the seasonal reserve margin without having to potentially over-build a large, new asset.

It bears noting that the EnCompass Model results included in this IRP do not represent a commitment by Big Rivers to a specific course of action. Additionally, it is important to understand that changes to the inputs, constraints and assumptions that impact this IRP result can, and do, occur rapidly, especially with the current uncertainty around environmental requirements and commodity prices. Consequently, Big Rivers has run sensitivities to the Base Case to evaluate the impact of changing inputs on the model determination of the least-cost option. National trends and risk factors were considered when creating sensitivities with multi-variable inputs. For example, changes to carbon inputs, commodity prices, and implied market heat rates result in varying energy prices.

Big Rivers developed a total of nine (9) sensitivities on the resource portfolios, six (6) for expansion planning plus three (3) additional sensitivities in production cost modeling, designed to focus on the impact of changing one variable without subjecting that analysis to additional uncertainty. 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 ran sensitivities involving changes to the load forecast, commodity (and Locational Marginal Price or ("LMP"), by association) pricing, capital costs, PRMR, and carbon adders. This approach allowed for the exploration of several possible futures. Figure 7.1.1 (a) illustrates the approach taken to refine resource selection and arrive at an economic and reliable portfolio, cognizant of environmental regulation and related contingencies.

Figure 7.1.1(a)
Portfolio Selection Process



7.1.2 Pre-IRP Position

At the commencement of expansion planning in connection with this IRP, Big Rivers' existing fleet was modeled to assess any energy or capacity shortfalls, verify costs, and establish a preliminary model for testing purposes. The capacity and energy positions below were developed using base assumptions, discussed in later sections. Figure 7.1.2 (a) and Figure 7.1.2(b) show Big Rivers' summer and winter capacity positions respectively, and Figure 7.1.2(c) shows Big Rivers' energy position.

Figure 7.1.2(a)[74]

Preliminary Summer Capacity Position

[redacted]

From a long-term planning perspective, without taking any action, Big Rivers has sufficient capacity to meet its obligations under MISO's seasonal resource adequacy construct throughout both the 15-year and 27-year planning horizons.

[74] Note that in figures 7.1.2(a), (b), and (c) the OMU and KYMEA allocations are not net out of Wilson, but in later figures they will not be shown in this manner and will instead be reflected as the Member-Only capacity and energy positions.

While only summer and winter seasons are shown here, Big Rivers' position in the spring and fall are equally sufficient.

Figure 7.1.2(b)

Preliminary Winter Capacity Position

[redacted]

Pre-IRP Economic Energy Dispatch

As Figure 7.1.2(c) shows, while Big Rivers has an existing portfolio of resources sufficient to meet capacity requirements, [redacted]

[redacted] From a resource adequacy perspective, this analysis aims to meet both the energy and capacity requirements efficiently and economically.

Figure 7.1.2(c)

Pre-IRP Economic Energy Dispatch

[redacted]

7.1.3 Assumptions: Budgeting and Finance

Table 7.1.3 (a) shows the financial input assumptions for the Encompass model. The Debt Ratio represents the percentage of the total capital project costs to be financed with long-term debt. Big Rivers utilizes a TIER requirement instead of a Return on Equity ("ROE") requirement for establishing base rates. The discount rate used in the NPV calculation was 5.50% and the approved TIER is 1.30.

Table 7.1.3(a)

Financial and Budgeting Assumptions

Metric	Value
Debt Ratio	100%
Debt Rate	5.50%
Return on Equity	0%
General Escalation	2.85%
Tax Rate	0%
Discount Rate	5.50%

The general escalation rate was applied to all costs including capital, operating, and maintenance expenditures.

7.1.4 Assumptions: Resource Options

Table 7.1.4(a) shows the generation resources that are currently operating and the alternative resource options made available within the model. The heat rates for the existing thermal resources and the new combined cycle vary on a capacity block basis, as shown in Table 7.1.4(b) and Table 7.1.4(c). These resources were modeled in EnCompass and used to help determine the optimal least-cost portfolio to serve as the Base Case.

Table 7.1.4(a)

Existing and Alternative Generation Resources for Big Rivers' IRP

Resource Options for EnCompass Model

Name	First Available Year	Max Capacity (MW)	Heat Rate (Btu/kWh)	Forced Outage Rate (%)	Minimum Uptime (hours)	Minimum Downtime (hours)	Ramp Up Rate (MW/min)	Ramp Down Rate (MW/min)
Existing (Currently Operating) Big Rivers Assets								
Green Unit 1	In Service	231	**Table 7.1.4(b)**	14	24	24	3	3
Green Unit 2	In Service	223	**Table 7.1.4(b)**	14	24	24	3	3
Reid	In Service	65	**Table 7.1.4(b)**	10	24	24	3	3
Wilson	In Service	412	**Table 7.1.4(b)**	6.5	24	24	2.5	2.5
New/Potential Big Rivers Assets								
Unbridled Solar	2024	160	NA	NA	NA	NA	NA	NA
BREC CC	2029	635	**Table 7.1.4(c)**	1	1	1.5	47	47
Reciprocating Engine	2023	21	8295	3	1	1	25	25
Simple Cycle Gas Turbine	2023	237	9905	3	1	1	25	25
Solar PV	2023	100	NA	NA	NA	NA	NA	NA
Onshore Wind	2024	100	NA	NA	NA	NA	NA	NA
4-Hour Li-Ion BESS	2022	50	NA	NA	NA	NA	NA	NA
Aeroderivative	2024	105	9124	3	1	1	25	25

Table 7.1.4(b)

Heat Rates for Thermal Resource Loading Level

Resource Blocks for EnCompass Model

Resource	Block 1		Block 2		Block 3		Block 4		Block 5		Block 6	
	MW	HR	MW	HR	MW	HR	MW	HR	MW	HR	MW	HR
Green 1	65	[redacted]	100	[redacted]	133	[redacted]	166	[redacted]	200	[redacted]	231	[redacted]
Green 2	65	[redacted]	100	[redacted]	133	[redacted]	166	[redacted]	200	[redacted]	223	[redacted]
Reid	20	[redacted]	29	[redacted]	38	[redacted]	47	[redacted]	56	[redacted]	65	[redacted]
Wilson	150	[redacted]	200	[redacted]	250	[redacted]	325	[redacted]	375	[redacted]	412	[redacted]

Table 7.1.4(c)

Monthly Heat Rates for New Combined Cycle Resource Blocks

BREC Combined Cycle Resource Blocks										
Month	Max		Block 2		Block 3		Block 4		Block 5	
	MW	HR	MW	HR	MW	HR	MW	HR	MW	HR
Jan	620	[redacted]	424	[redacted]	473	[redacted]	522	[redacted]	571	[redacted]
Feb	620	[redacted]	424	[redacted]	473	[redacted]	522	[redacted]	571	[redacted]
March	620	[redacted]	424	[redacted]	473	[redacted]	522	[redacted]	571	[redacted]
April	635	[redacted]	408	[redacted]	465	[redacted]	522	[redacted]	578	[redacted]
May	635	[redacted]	408	[redacted]	465	[redacted]	522	[redacted]	578	[redacted]
June	590	[redacted]	385	[redacted]	436	[redacted]	487	[redacted]	538	[redacted]
July	590	[redacted]	385	[redacted]	436	[redacted]	487	[redacted]	538	[redacted]
Aug	590	[redacted]	385	[redacted]	436	[redacted]	487	[redacted]	538	[redacted]
Sept	635	[redacted]	408	[redacted]	465	[redacted]	522	[redacted]	578	[redacted]
Oct	635	[redacted]	408	[redacted]	465	[redacted]	522	[redacted]	578	[redacted]
Nov	635	[redacted]	408	[redacted]	465	[redacted]	522	[redacted]	578	[redacted]
Dec	620	[redacted]	424	[redacted]	473	[redacted]	522	[redacted]	571	[redacted]

For Big Rivers' existing resources, Wilson Unit 1 was modeled on the assumption that it would continue operation as a coal-fired unit for the duration of the study period, with and without 90% Carbon Capture Sequestration. Both Green Units were modeled with two options: (i) retire in 2029, to be replaced by a new natural gas combined cycle power plant (635 MW); and (ii) continue operating Green Station from 2023 for 20 years. The Reid CT was modeled to remain natural gas-fired. Big Rivers' SEPA entitlement was modeled as status quo through the study period. The Unbridled Solar Facility, which is currently under development, was modeled as beginning operations in 2024. A new potential solar facility was modeled as selectable at any period within the study. This same approach was taken for the potential wind and storage facilities. The wind and solar resources were selectable in 100 MW blocks, meaning the model could optimize around the total number of MW block additions. The new natural gas combined cycle power plant (635 MW), both with and without 90% CCS, was modeled assuming Big Rivers would own and operate the facility near the existing Green Station Facility. Four other thermal alternatives were modeled with the intent to provide further alternatives in place of a new combined cycle power plant. These options would include a 237 MW simple cycle gas turbine power plant, an alternative combined cycle gas turbine power plant available later in the study period, 21 MW blocks of Wartsila reciprocating engines, and a 105 MW Aeroderivative.

Big Rivers utilized the 2023-2037 Long-term Financial Plan as the starting point for developing the forecast for the fixed operation and maintenance ("O&M") production costs for the existing fleet.[75] Table 7.1.4(d) and Table 7.1.4(e) show the total fixed and variable cost for the existing fleet, including both retirement scenarios and the planned Unbridled Solar Project, respectively.[76]

[75] As Green 1 and 2 were being considered for retirement, the inventory and decommission costs were analyzed within the retirement timeframe. This assumes that the gas lateral would tie into a new combined cycle facility, minimal capital expenditures at retirement, and fixed costs would only be applicable during plant operation for the first 5 months of the retirement year.

[76] Note that Unbridled Solar is a PPA option that is set to expire in [redacted]

Table 7.1.4(d)

Fixed Cost for Existing Big Rivers Resources

Fixed Cost for EnCompass Model						
	Wilson	Green 1 - 2029	Green 2 - 2029	Green 1 - 2043	Green 2 - 2043	Reid
Year	Total Cost	Total Cost	Total Cost	Total Cost	Total Cost	Total Cost
	Nominal $000	Nominal $000	Nominal $000	Nominal $000	Nominal $000	Nominal $000
2023	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2024	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2025	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2026	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2027	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2028	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2029	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2030	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2031	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2032	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2033	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2034	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2035	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2036	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2037	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2038	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2039	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2040	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2041	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2042	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2043	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2044	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2045	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2046	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2047	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2048	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2049	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2050	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Table 7.1.4(e)

Variable Cost for Existing/Planned Big Rivers Resources

Variable Cost For EnCompass Model		
	Wilson	Unbridled
Year	Total Cost	Total Cost
	$/MWh	$/MWh
2023	[redacted]	$38.10
2024		$38.10
2025		$38.10
2026		$38.10
2027		$38.10
2028		$38.10
2029		$38.10
2030		$38.10
2031		$38.10
2032		$38.10
2033		$38.10
2034		$38.10
2035		$38.10
2036		$38.10
2037		$38.10
2038		$38.10
2039		$38.10
2040		$38.10
2041		$38.10
2042		$38.10
2043		$38.10
2044		$38.10
2045		
2046		
2047		
2048		
2049		
2050		

The price volume forecast for Big Rivers' SEPA entitlement is based on the best available information. 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. This termination option was not studied in this IRP, as the SEPA allocation provides firm, dispatchable, and clean capacity and energy to Big Rivers which would not be easily replaced by new resources. The accredited capacity allotment for the SEPA contract is set at an annual value of 178 MW based on historical performance. See Table 7.1.4(f) for the SEPA volume cost projection included in the model.

Table 7.1.4(f)

SEPA Volume and Cost

BREC SEPA Allocation for EnCompass Model							
Date	Economic Max Capacity (MW)	Economic Firm Capacity (MW)	Energy (MWh)	Demand Rate ($/kW/Month)	Demand Rate ($000/Year)	TVA Transmission Paid to SEPA ($000)	Total ($000)
2024	[redacted]	178.0	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2025	[redacted]	178.0	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2026	[redacted]	178.0	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2027	[redacted]	178.0	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2028	[redacted]	178.0	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2029	[redacted]	178.0	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2030	[redacted]	178.0	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2031	[redacted]	178.0	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2032	[redacted]	178.0	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2033	[redacted]	178.0	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2034	[redacted]	178.0	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2035	[redacted]	178.0	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2036	[redacted]	178.0	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

For new solar and wind facilities, annual production profiles were pulled from vetted third-party assumptions specific to the Big Rivers' geographic area. The MISO Effective Load Carrying Capability ("ELCC") projections for these resources were taken from MISO Direct-LOL results using the latest planning year (2023/2024) results from the non-thermal evaluation and the 2022 Regional Resource Assessment ("RRA").[77] As a starting point, initial Capital and O&M cost for new/potential

[77] 20230117-18 RASC Item 14b Non-Thermal Resource Accreditation (RASC-2020-4, RASC-2019-2) Presentation627472.pdf (misoenergy.org)

resources were forecasted using the cost curves from the 2022 National Renewable Energy Laboratory ("NREL") Annual Technology Baseline and the Energy Information Administration's ("EIA") public technology assessment. See Table 7.1.4(g) and 7.1.4 (h) for renewable capacity factors and ELCC inputs for the Encompass model. Table 7.1.4(i) is a summary of renewable generation and storage costs.

In early 2023, Big Rivers also evaluated a 100 MW solar and 50 MW, 4-hour battery storage facility under the Inflation Reduction Act's PACE program. Big Rivers submitted a Letter of Interest for this project in July 2023. For this IRP, this was modeled as a pair solar + storage resource, with the solar component having a 21% capacity factor and the storage component having a 90% round trip efficiency. This was modeled with the assumption that construction would be complete by 2028, with a total project estimate of [redacted]. Big Rivers requested the full loan limit from the PACE program of $100M with 4.5% financing for 30 years and 40% loan forgiveness taken as a reduction of capital expenditures upon the commercial operation date ("COD"). Big Rivers anticipates separate financing for the remainder of the project.

Table 7.1.4(g)

Wind and Solar Performance Metrics

Renewable Options for EnCompass Model				
Technology	**First Available Year**	**Max Capacity (MW)**	**Capacity Factor (%)**	**Effective Load Carrying Capability**
Solar PV	2023	100	21%	**Table 7.1.4(h)**
Onshore Wind	2024	100	28%	**Table 7.1.4(h)**

Table 7.1.4(h)

Renewable and Storage Effective Load Carrying Capability

Effective Load Carrying Capability for EnCompass Model												
Year	**Wind**				**Solar**				**4-Hour Storage**			
	Spring	**Summer**	**Fall**	**Winter**	**Spring**	**Summer**	**Fall**	**Winter**	**Spring**	**Summer**	**Fall**	**Winter**
2023	13%	7%	7%	15%	50%	50%	50%	50%	98%	98%	98%	98%
2024	13%	7%	7%	15%	50%	50%	50%	50%	98%	98%	98%	98%
2025	13%	7%	7%	15%	50%	50%	50%	50%	98%	98%	98%	98%
2026	14%	7%	7%	15%	50%	40%	6%	1%	98%	98%	98%	98%
2027	14%	8%	8%	14%	33%	37%	6%	1%	98%	98%	98%	98%
2028	15%	8%	8%	14%	30%	35%	6%	1%	98%	98%	98%	98%
2029	15%	8%	8%	14%	28%	32%	6%	1%	98%	95%	95%	95%
2030	16%	8%	9%	13%	26%	29%	6%	1%	95%	88%	88%	88%
2031	16%	9%	9%	13%	23%	26%	6%	1%	88%	85%	85%	85%
2032	17%	9%	10%	13%	21%	24%	6%	1%	85%	83%	83%	83%
2033	17%	9%	10%	12%	19%	21%	5%	1%	83%	80%	80%	80%
2034	18%	10%	10%	12%	16%	18%	5%	1%	80%	78%	78%	78%
2035	18%	10%	11%	11%	14%	15%	5%	1%	78%	75%	75%	75%
2036	19%	10%	11%	11%	11%	12%	5%	1%	75%	75%	75%	75%
2037	19%	10%	11%	11%	9%	10%	5%	1%	75%	75%	75%	75%
2038	20%	11%	12%	10%	7%	7%	5%	1%	75%	75%	75%	75%
2039	20%	11%	12%	10%	4%	4%	5%	1%	75%	75%	75%	75%
2040	20%	11%	12%	10%	2%	4%	5%	1%	75%	75%	75%	75%
2041	20%	11%	12%	10%	2%	4%	5%	1%	75%	75%	75%	75%
2042	20%	11%	12%	10%	2%	4%	5%	1%	75%	75%	75%	75%
2043	20%	11%	12%	10%	2%	4%	5%	1%	75%	75%	75%	75%
2044	20%	11%	12%	10%	2%	4%	5%	1%	75%	75%	75%	75%
2045	20%	11%	12%	10%	2%	4%	5%	1%	75%	75%	75%	75%
2046	20%	11%	12%	10%	2%	4%	5%	1%	75%	75%	75%	75%
2047	20%	11%	12%	10%	2%	4%	5%	1%	75%	75%	75%	75%
2048	20%	11%	12%	10%	2%	4%	5%	1%	75%	75%	75%	75%
2049	20%	11%	12%	10%	2%	4%	5%	1%	75%	75%	75%	75%
2050	20%	11%	12%	10%	2%	4%	5%	1%	75%	75%	75%	75%

Table 7.1.4(i)

Renewable and Storage Project Cost

	Solar PV		Onshore Wind		4-Hour Li-Ion BESS	
Year	Overnight Capital cost	Fixed O&M	Overnight Capital cost	Fixed O&M	Overnight Capital cost	Fixed O&M
	Nominal $	$/kW-Yr	Nominal $	$/kW-Yr	Nominal $	$/kW-Yr
2023	[redacted]					
2024	[redacted]					
2025	[redacted]					
2026	[redacted]					
2027	[redacted]					
2028	[redacted]					
2029	[redacted]					
2030	[redacted]					
2031	[redacted]					
2032	[redacted]					
2033	[redacted]					
2034	[redacted]					
2035	[redacted]					
2036	[redacted]					
2037	[redacted]					
2038	[redacted]					
2039	[redacted]					
2040	[redacted]					
2041	[redacted]					
2042	[redacted]					
2043	[redacted]					
2044	[redacted]					
2045	[redacted]					
2046	[redacted]					
2047	[redacted]					
2048	[redacted]					
2049	[redacted]					
2050	[redacted]					

For new natural gas resources, Big Rivers utilized both EIA and NREL data for estimated overnight capital, and fixed and variable O&M costs for new resources. See Table 7.1.4(j) for a summary of the thermal operating costs. Big Rivers also used both historical Henry Hub and forward New York Mercantile Exchange ("NYMEX") cost curves to develop a blended natural gas pricing forecast. Vendor estimates were taken for the delivered natural gas cost to the generating facility.

Table 7.1.4(j)

Thermal Generation Project Cost

Year	Simple Cycle Gas Turbine			Combined Cycle Gas Turbine			Reciprocating Engine			Aeroderivative		
	Overnight Capital cost	Fixed O&M	Variable O&M	Overnight Capital cost	Fixed O&M	Variable O&M	Overnight Capital cost	Fixed O&M	Variable O&M	Overnight Capital cost	Fixed O&M	Variable O&M
	Nominal $/kW	$/kW-Yr	$/MWh	Nominal $/kW	$/kW-Yr	$/MWh	Nominal $/kW	$/kW-Yr	$/MWh	Nominal $/kW	$/kW-Yr	$/MWh
2023	[redacted]											
2024												
2025												
2026												
2027												
2028												
2029												
2030												
2031												
2032												
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2044												
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2047												
2048												
2049												
2050												

Big Rivers did not include every resource option listed in the NREL and EIA reports for the 2023 IRP modeling process. Many of the new generation options could be dismissed without analysis for varying reasons. Advanced Nuclear, Biomass, and advanced storage options were dismissed due to their high costs and technology maturity risk during the planning period. The 2020 IRP did not consider wind due to the lack of viable locations for wind energy and pricing basis risk between strong wind regionals and the Big Rivers service territory. In order to retest its 2020 IRP wind-related assumptions, wind energy was, however, included in the present analysis, using production assumptions consistent with rural Kentucky generation profile data.

Energy efficiency and demand response were also evaluated as a part of this IRP. Clearspring developed a potential DSM program based on assumptions of a 10-year annual investment projected to cost $1M per year nominally.[78] This program would have a 10-year investment horizon but would be active through the study period. Peak and energy reductions were created by following the Member load shape as a percent of peak load during the 10-year payment horizon. After the payment period the energy and peak savings were held constant. Table 7.1.4(k) provides a summary of the programs annual spend, peak, and energy reductions.

[78] See Section 5.3 Residential Energy Efficiency Program Potential, and Appendix B Demand-Side Management Potential Study Chapters 3 & 4.

Table 7.1.4(k)

Big Rivers' DSM Program

Energy Efficiency and Demand Response			
Year	Energy Efficiency Program		
	Annual Spend ($000)	Annual Energy Reduction (MWh)	Annual Peak Reduction (MW)
NPV	$9,195	-	-
2024	$1,028	9,076	1.71
2025	$1,058	18,152	3.43
2026	$1,088	27,228	5.14
2027	$1,119	36,305	6.86
2028	$1,151	45,381	8.57
2029	$1,183	54,457	10.29
2030	$1,217	63,533	12.00
2031	$1,252	72,609	13.71
2032	$1,287	81,686	15.43
2033	$1,324	90,762	17.14
2034	$0	90,762	17.14
2035	$0	90,762	17.14
2036	$0	90,762	17.14
2037	$0	90,762	17.14
2038	$0	90,762	17.14
2039	$0	90,762	17.14
2040	$0	90,762	17.14
2041	$0	90,762	17.14
2042	$0	90,762	17.14
2043	$0	90,762	17.14
2044	$0	90,762	17.14
2045	$0	90,762	17.14
2046	$0	90,762	17.14
2047	$0	90,762	17.14
2048	$0	90,762	17.14
2049	$0	90,762	17.14
2050	$0	90,762	17.14

7.1.5 Assumptions: Commodity and Market Price Forecasts

Commodity prices were developed using the best currently available data in conjunction with statistical analysis.

- **Coal Prices:** Coal pricing inputs for years 2023-2024 consist of actual coal pricing, plus transportation costs, from current active term contracts in place. Transportation logistics comprised of both trucking and barging operations, with contracts to expire in conjunction with coal contracts. The commodity price was then added to the transportation cost to determine a total delivered dollar/MMBtu cost. Upon completion of the current Big Rivers' contracts which are due to expire December 31, 2024, pricing for years 2025-2034, was based off market pricing as of May 2023. Market pricing was determined by taking the average pricing for Illinois basin, low chlorine, 11,500 Btu coal. Transportation costs were calculated under the assumption coal would be shipped via truck and/or barge from West Kentucky coal mines. As before, the market pricing and transportation costs were added to provide an estimated total delivered dollar/MMBtu cost. For years [redacted] was applied for every year thereafter to reflect anticipated but uncertain inflation in both commodity and transportation pricing.

- **Natural Gas Prices:** 1898 & Co. developed forward natural gas price forecasts based on historical Henry Hub Prices, forward prices from NYMEX, and the Reference Case EIA forecast. Historical and Spot pricing was used up to Spring 2023 present day, and NYMEX futures were used between Spring 2023 and Winter 2024. The mid-term gas price (for 2025 – 2026) was a blended average between EIA and S&P Henry Hub Futures. Finally, the long-term forecast was based on the EIA reference case. Confidence bands were taken at 10, 25, 50, 75, and 90 percent confidence intervals. 50 percent would serve as the base case, while 10 and 90 percent would serve as the low and high gas forecasts.

Figure 7.1.5(a) shows a visual representation of these forecasts. Additional details on forecast development can be found in section 7.2.2.2.

Figure 7.1.5(a)

Henry Hub Natural Gas Price Forecast

[redacted]

- **Energy Market Prices:** Energy market price forecasts were developed using the National Database by Horizon Energy. The National Database was used to develop energy prices based on the resource mix projected by MISO under their Future 1 Scenario from MISO Transmission Expansion Plan 2021 ("MTEP21"). The EnCompass model was used to develop an hourly LMP forecast for the Indy Hub from present to 2050. The commodity forecasts mentioned above were used as inputs in the National Database model. Around-The-Clock Indy Hub LMP's served as the basis for development of the Western Kentucky area LMP's. Average annual energy pricing for each future along with the high and low natural gas scenarios are shown in Figure 7.1.5(b).

Analysis of historical LMP's were used to determine on-peak and off-peak basis differentials between Indy Hub and BREC load and generator nodes.

Figure 7.1.5(b)

Around the Clock Locational Marginal Price

[redacted]

- **<u>Capacity Prices:</u>** Capacity price forecasts were based upon the MISO 2021 Cost of New Entry or ("CONE") filing. MISO establishes capacity pricing based on Local Resource Zones.[79] Capacity Prices for Zone 6 were used in this analysis and escalated throughout the study period to provide accurate capacity pricing should the model find it more economic then resource additions. Table 7.1.5(a) shows the nominal cost of capacity throughout the study period on a seasonal basis from the MISO 2023/2024 planning year value of $23.03 $/kW-Season.[80]

[79] See Chapter 9 MISO Resource Adequacy Planning, Figure 9.2(a) MISO Local Resource Zone Map
[80] https://cdn.misoenergy.org/20221012%20RASC%20Item%2004c%20CONE%20Update626542.pdf

Table 7.1.5 (a)

MISO Cost of New Entry Forecast

CONE -- Zone 6	
Year	**$/kW-season**
2024	[redacted]
2025	
2026	
2027	
2028	
2029	
2030	
2031	
2032	
2033	
2034	
2035	
2036	
2037	
2038	
2039	
2040	
2041	
2042	
2043	
2044	
2045	
2046	
2047	
2048	
2049	

7.1.6 Assumptions: Load Forecast Summary

As previously noted in this IRP, Clearspring (who prepared Big Rivers' 2020 Long Term Load Forecast) was again selected by Big Rivers and its Members to prepare a 2023 electric load forecast through 2042. Seasonal PRMR were implemented in accordance with MISO's Business Practice Manual.[81]

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

- **Load Forecast:** Table 7.1.6(a) shows Big Rivers' annual Member load forecasts along with the requirements to serve non-Member load.

Table 7.1.6(a)

Member and Non-Member Load Included in the Base Case[82], [83]

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

- **Capacity Reserve Margin:** On August 31, 2022, FERC accepted MISO's proposal to move to seasonal resource adequacy requirements, rather than

[82] Total energy excludes station service load at Big Rivers-owned generation stations

[83] Total non-member energy utilized in EnCompass differs from the load forecast (see footnote on Table 4.4(a) due to the following factors: 1) OMU energy is the total value prior to any allocations of energy from OMU's share of the SEPA Hydro system and based off an hourly profile curve, and 2) KYMEA is modeled as a call option in the model which results in a reduced obligation to KYMEA as fuel prices and market conditions vary over time.

a single requirement based on summer peak. For Local Resource Zone 6 the seasonal PRMR is as follows:

- Summer 2023 – 7.4%
- Fall 2023 – 14.9%
- Winter 2023/2024 – 25.5%
- Spring 2024 – 24.5%

7.2 Big Rivers System Expansion Planning Analysis

EnCompass was also used to perform Expansion Planning analysis across the base assumptions with six (6) different single-variable sensitivities discussed further in Section 7.2.2 to inform portfolio development. All resource options were considered in this step to establish consistent portfolio selections across each sensitivity.

7.2.1 Assumptions: Inputs and Constraints

Big Rivers and 1898 & Co. developed the IRP expansion planning model with inputs and constraints using the best currently available information. The inputs, constraints, and justification for the Base Case assumptions are further explained below.

- **Generation Commit**: All coal and natural gas fired generation units were modeled as economically committed according to startup characteristics and production costs. These characteristics include minimum up-time, minimum down-time, ramp rates and startup costs.

- **<u>Generation Dispatch</u>:** All coal and natural gas fired generation units were modeled as economically dispatched within specific operating parameters provided for each unit such as maximum and minimum capacity, heat rates, unit outage rates, and planned outages. The solar and wind units were modeled with a fixed hourly generation profile drawn from the National Database by Horizon Energy for renewable alternatives based in Kentucky. The SEPA volumes were modeled pursuant to the contract terms at the monthly minimum and maximum volumes and annual volume offtake.
- **<u>Generation Selection:</u>** All new resource alternatives were evaluated based on project feasibility, i.e. the earliest reasonable COD for each alternative based on expectations for permitting and transmission interconnection. EnCompass was configured to allow the selection of resource alternatives in incremental steps over the study period For example, in 2029 EnCompass could consider adding up to 300 MW of 4-hour Li-Ion based Storage (see Table 7.2.1(a)). In future years, EnCompass could continue to add up to 300 MW of 4-hour Li-Ion based storage up to a maximum of 600 MW added (see Table 7.2.1(b)). This approach to constraining the model is a typical practice in resource planning to liberally set limits around resource types in order to keep the model from exhibiting issues with solving to the size of the computational problem. See Table 7.2.1(a) for a summary of the selection timeline for resource alternatives, and 7.2.1(b) for a table of Cumulative Alternative Resource Selection Constraints.

Annual Maximum Project Capacity for EnCompass Model									
Year	4-Hour Storage	Wind	Solar PV	Recip 4x5MW	Combustion Turbine	Aeroderivative	Big Rivers CC	Big Rivers DSM	PACE 4-Hou Storage
2024								1	
2025									
2026									
2027			200						
2028		200	200						50
2029	300	200	200	630	711	630	635		
2030	300	200	200	630	711	630	635		
2031	300	200	200	630	711	630	635		
2032	300	200	200	630	711	630	635		
2033	300	200	200	630	711	630	635		
2034	300	200	200	630	711	630	635		
2035	300	200	200	630	711	630	635		
2036	300	200	200	630	711	630	635		
2037	300	200	200	630	711	630	635		
2038	300	200	200	630	711	630	635		
2039	300	200	200	630	711	630	635		
2040	300	200	200	630	711	630	635		
2041	300	200	200	630	711	630	635		
2042	300	200	200	630	711	630	635		
2043	300	200	200	630	711	630	635		
2044	300			630	711	630	635		
2045	300			630	711	630	635		
2046	300			630	711	630	635		
2047	300			630	711	630	635		
2048	300			630	711	630	635		
2049	300			630	711	630	635		
2050	300			630	711	630	635		

Cumulative Maximum Project Capacity for EnCompass Model

Year	4-Hour Storage	Wind	Solar PV	Recip 4x5MW	Combustion Turbine	Aeroderivative	Big Rivers CC	Big Rivers DSM	PACE 4-Hour Storage
2024								1	
2025									
2026									
2027			200						
2028		200	400						50
2029	300	400	600	630	711	630	635		
2030	600	600	800	630	711	630	635		
2031	600	800	1000	630	711	630	635		
2032	600	1000	1200	630	711	630	635		
2033	600	1200	1400	630	711	630	635		
2034	600	1400	1600	630	711	630	635		
2035	600	1600	1800	630	711	630	635		
2036	600	1800	2000	630	711	630	635		
2037	600	2000	2200	630	711	630	635		
2038	600	2200	2400	630	711	630	635		
2039	600	2400	2600	630	711	630	635		
2040	600	2600	2800	630	711	630	635		
2041	600	2800	3000	630	711	630	635		
2042	600	3000	3200	630	711	630	635		
2043	600	3200	3400	630	711	630	635		
2044	600			630	711	630	635		
2045	600			630	711	630	635		
2046	600			630	711	630	635		
2047	600			630	711	630	635		
2048	600			630	711	630	635		
2049	600			630	711	630	635		
2050	600			630	711	630	635		

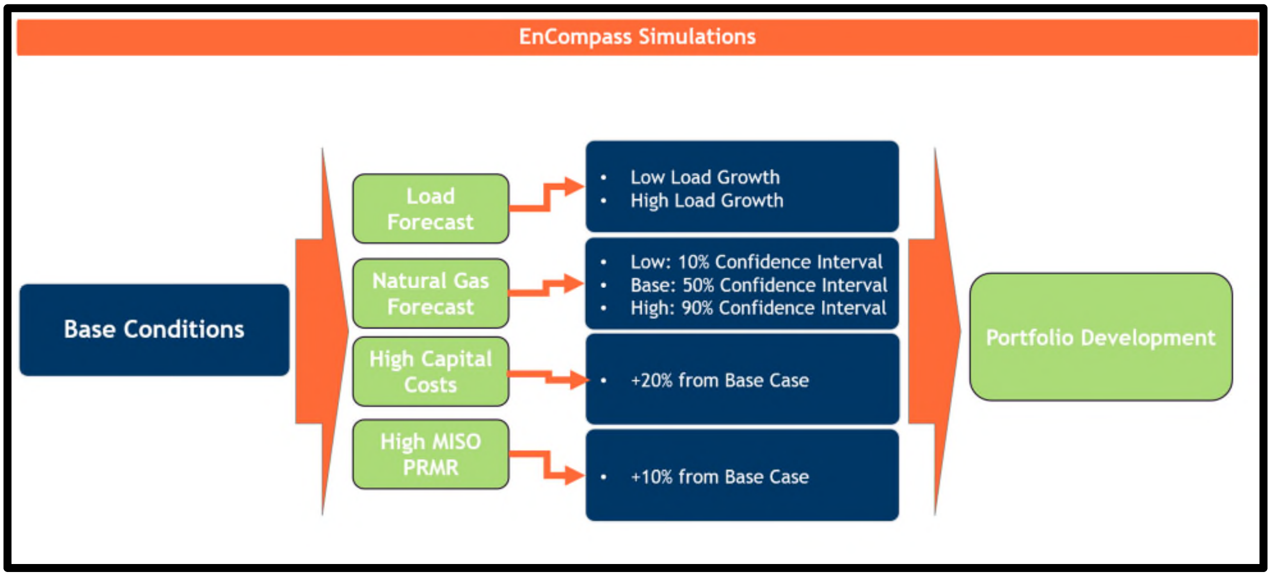
- **Production Fixed Costs:** The production fixed costs that were utilized are provided in Table 7.1.4(d) for existing resources and Table 7.1.4(j) for new resource alternatives. These costs were based on projections from the 2023-2037 long-term financial plan, Big Rivers' self-build bids from the All-Source RFP, as well as EIA and NREL estimates for resource alternatives.
- **Production non-Fuel Variable Costs and Generator Operating Parameters:** The production non-fuel variable cost and generator operating parameters (i.e., heat rate, outage rate, etc.) can be seen in Tables 7.1.4(a), Table 7.1.4(b), Table 7.1.4(c), Table 7.1.4(e), and Table 7.1.4(j).

7.2.2 Base Case and Sensitivity Analysis

A Base Case and Six (6) model sensitivities were analyzed using the EnCompass Model. The focus of the sensitivity analysis is to determine the optimal resource selection across a range of inputs – varying one at a time – to assess the impacts to the least-cost resource plan selected by the modeling tool. The sensitivities were conducted by varying load forecasts, natural gas pricing, capital costs, and MISO PRMR. The resources chosen in the expansion planning across these sensitivities were used to inform the development of the Base Portfolio and Alternative Portfolios. Figure 7.2.2(a) is a visual representation of the sensitivity analysis approach taken by Big Rivers and 1898 & Co.

Figure 7.2.2(a)

EnCompass Expansion Planning Sensitivity Analysis



7.2.2.1 Load Forecast

Clearspring developed Base, High, and Low load growth forecasts used in the EnCompass Model, and a summary of this report can be found in Technical Appendix E.

7.2.2.2 Natural Gas Forecast

As described in Section 7.1.5, a natural gas commodity forecast was developed for a Base, High, and Low case using a combination of publicly available data from S&P Global[84] historical Henry Hub prices, forward NYMEX projections, and the Reference Case EIA forecast.[85] Historical and Spot pricing was used up to present day. Given the uncertainty surrounding commodity prices, the NYMEX projections

84 https://www.capitaliq.spglobal.com

85 https://www.eia.gov/outlooks

were used as a near term (18 month) forward projection. The next 18-month period was blended linearly between the EIA long-term forecast and the near-term NYMEX forward projections. The remaining period was composed of the EIA Reference Case natural gas forecast, following NYMEX trading cost curve.

Confidence bands were developed using the EIA Base, High Oil/Gas Supply, Low Oil/Gas Supply, High Economic Growth, and Low Economic Growth forecasts. Using statistical analysis of these five (5) forecasts, confidence bands were developed between 10 and 90 percent to provide a range of possible price variation. Following consultation between Big Rivers and 1898 & Co., the Low, Base, and High forecasts were set at the 10, 50, and 90 percent confidence intervals, respectively, as seen in Figure 7.1.5(a).

7.2.2.3 Capital Costs

Possible continued disruptions in supply chains, in concert with potential for high inflation, may result in higher costs of capital for new resource construction. To study the effects of this economic uncertainty, the capital costs for new projects were increased by 20% for all resource alternatives. Though a project may be economic under base case conditions, the higher capital costs allow for further insight into the economic feasibility of project construction over time, given continued market uncertainty.

7.2.2.4 MISO Peak Reserve Margin Requirements

A key reason for the selection of new resources in capacity expansion planning is to meet the Planning Reserve Margin Requirements set forth by MISO. Given that these requirements change annually due to external factors, a sensitivity was conducted to assess the optimal resource mix and portfolio risk if these margins were to increase. Consequently, the base seasonal PRMR was increased by 10 percent annually through the entire study horizon to assess the corresponding resource selection.

7.2.3 Expansion Planning Results

The optimal plan from the EnCompass model under base case conditions resulted in (i) the retirement of Green 1 and 2 in June of 2029, and (ii) Big Rivers adding a new 635 MW natural gas combined cycle located near Green Station 1 and 2 following the Green station's retirement. As described previously, Big Rivers keeps the Wilson unit as a coal-fired station, keeps the Reid CT Available as a natural gas peaking unit, and stays in the SEPA contract. Table 7.2.3(a) shows the optimal resource additions and selection of Green's retirement across base conditions and six sensitivities.

Table 7.2.3(a)

Summary of Alternative Resource Selections

Year	Base Conditions	Low Load	High Load	Low Gas	High Gas	+20% High CapEx	+10% High PRMR
2024			DSM Program	DSM Program			DSM Program
2028			PACE Solar (100MW) PACE Storage 4-hr (50MW)				
2029 Retirements	Green 1 & 2	Green 1 & 2	Green 1 & 2	Green 1 & 2	Green 1 & 2	Green 1 & 2	Green 1 & 2
2029	BREC CC (~600MW)	BREC CC (~600MW)	BREC CC (~600MW) Wind (100 MW)	1x 7FA CT (237 MW)	BREC CC (~600MW) Wind (200 MW)	BREC CC (~600MW)	BREC CC (~600MW) Wind (100 MW)
2030				1x 7FA CT (237 MW)	Wind (200 MW)		
2031					Wind (200 MW)		
2032					Wind (200 MW)		
2033					Wind (200 MW)		
2034					Wind (200 MW)		

The results from the expansion planning analysis can be summarized into the following key themes:

- The retirement of Green Station 1 and 2 was consistently selected across all cases.
- The new natural gas combined cycle was selected across six of the seven cases.
- The addition of two 237 MW combustion turbines was selected in 2029 and 2030 in the Low Gas case.
- The demand response program was selected in the High Load, Low Gas, and High PRMR cases.
- The solar plus storage project with PACE financing was selected in the High Load case.
- 1200 MW of wind was added in the High Gas case.

7.3 Portfolio Development

Three Portfolios were developed for further study using the Production Cost Modeling in EnCompass.

7.3.1 Base & Alternative Portfolio Designs

The Base Portfolio was comprised of the following Expansion Planning results:

- The retirement of Green Station 1 and 2 in May of 2029.
- A 635 MW natural gas combined cycle is constructed in June of 2029.
- Reid continues operation throughout the study period.
- Wilson remains coal-fired throughout the study period.
- The SEPA contract continues.
- The Unbridled 20-year PPA contract commences in 2024.
- The PACE qualified solar plus storage comes online in 2028.

In addition to the Base Portfolio, Table 7.3.1(a) shows a summary of the two alternative portfolios that were also developed to provide a reasonable comparison to the Base Portfolio.

Table 7.3.1(a)

Big Rivers Resource Portfolios

Year	Base Portfolio	Alt Portfolio	Aggressive Carbon Reduction Portfolio
2028	PACE Solar (100MW) PACE Storage 4-hr (50MW)	PACE Solar (100MW) PACE Storage 4-hr (50MW)	PACE Solar (100MW) PACE Storage 4-hr (50MW)
2029 Retirements	Green 1 & 2	Green 1 & 2	Green 1 & 2
June 2029	BREC CC (~600MW)	2x 7FA CT (~450 MW)	BREC CC (600 MW)
2030		Wind (200 MW)	
2031		Wind (200 MW)	
2032		Wind (200 MW)	Wilson Carbon Capture BREC CC Carbon Capture Wind (200 MW)
2033		Wind (100 MW)	
2036			Wind (100 MW)
2040			Wind (100 MW)

The PACE solar plus storage project was included across all Portfolios. The proposed PACE project, a 100 MW solar installation connected to a 50 MW battery storage system in McCracken County, will use an interconnection that is currently being studied in the MISO Transmission Expansion Plan for 2023, with approval anticipated in December 2023. The proposed project would interconnect to Big Rivers' existing 161 kV transmission system and will include an expanded interconnection with a neighboring system that will reduce transmission congestion and provide increased resilience along the MISO/TVA seam. Big Rivers has requested the full loan eligibility amount of $100 million through the PACE program, and it anticipates financing the remainder of the project. The proposed project would serve populations deemed distressed or disadvantaged, as 76% of Big Rivers' service area population meets the PACE Program definitions of Energy Communities or Disadvantaged Communities.

The economic retirement of Green Units 1 and 2 was selected across all sensitivities and was included in all of the portfolios as a 2029 retirement. The high and low natural gas cases varied the most significantly from the base case during expansion planning. The Alternative Portfolio takes into consideration the substitution of the combined cycle resource with two combustion turbine resources. Upon review of the low gas sensitivity results, it was concluded that the addition of the CTs was primarily for capacity reserves and not for energy production. To build a complete Portfolio with sufficient energy for Big Rivers' Member load, additional wind resources were added to the Alternative Portfolio to meet the long-term energy needs on an annual basis.

Recent proposed rules from EPA have also placed uncertainty around long-term planning. Future environmental regulations are uncertain, and to assess the impacts of environmental regulation without planning for a specific rule, an Aggressive Carbon Reduction ("ACR") Portfolio was also constructed. The Wilson coal unit and the new combined cycle unit were modeled to be retrofitted with 90 percent carbon capture sequestration technology in 2032. Due to the operational changes to the units as a result of retrofitting, additional wind resources were added to the ACR Portfolio to meet the long-term energy needs of Big Rivers' Members on an annual basis.

7.3.2 Assumptions: Carbon Capture and Sequestration

Specific Assumptions for the ACR Portfolio were developed using the latest projections from EIA's public technology assessment, developed by Sargent & Lundy, along with EPA estimates for carbon capture technologies. The objective was to source the latest available data on all performance and financing metrics related to outfitting both the Wilson coal unit and the natural gas combined cycle unit with 90% carbon capture sequestration. The total net capital expense for the Wilson coal unit and the new combined cycle unit calculated to [redacted] respectively. The Wilson costs were assumed to qualify for NewERA financing including and a 25% grant and 0% loan financing that is factored into this capital expense estimate. Transportation, storage, and carbon capture tax credits were also factored into the ACR Portfolio during analysis in the Production Cost Optimization study as follows, using 2032 dollars, subject to inflation:

- Transportation costs: [redacted]Ton
- Storage costs: [redacted]
- 45Q Tax Credits: $85/Ton[86]

Placing Carbon Capture and Sequestration technology on both the Wilson coal unit and the new combined cycle unit are expected to have impacts on the net plant output, which in turn will result in increased plant heat rates. Table 7.3.2(a) contains

[86] Greenhouse Gas Standards and Guidelines for Fossil Fuel-Fired Power Plants | US EPA

a summary of the impacts of carbon capture technology on the unit performance characteristics of both the Wilson coal unit and the new combined cycle unit.

Table 7.3.2(a)

Summary of Carbon Capture Technology[87]

Carbon Capture Input Metrics for EnCompass Model		
Metric	**BREC CC with 90% Carbon Capture**	**Wilson with 90% Carbon Capture**
Max Capacity (MW)	[redacted]	
Capacity Penalty (%)		
Heat Rate Penalty (%)		
Carbon Release Rate (Ton/MWh)		
Capital Cost ($000)		
FOM ($000)		
VOM ($/MWh)		
45Q Tax Credits ($/MWh)		

7.3.3 DSM Expansion Planning on Portfolios

Following the development of the Base Portfolio, the Alternate Portfolio, and the ACR Portfolio, the Big Rivers demand response program was again tested for selection as a part of the sensitivity analysis. The DSM program was made available as a resource alternative in each portfolio through six (6) sensitivities, as with the expansion planning analysis discussed above. Table 7.3.3(a) shows the circumstances under which the DSM program was selected. It was chosen consistently as load reduction under a high load sensitivity across all portfolio buildouts, and under high

[87] Costs for carbon capture technology are in nominal dollars for a 2032 implementation year, fixed and variable O&M are escalated post implementation.

PRMR in the ACR Portfolio. Consistent with the expansion planning analysis, the DSM program is not seen as a viable resource alternative for the Big Rivers fleet.

Figure 7.3.3(a)

Summary of DSM Project Selection

Sensitivity	Base Portfolio	Alt Portfolio	ACR Portfolio
Base			
Low Load			
High Load	✓	✓	✓
Low Gas			
High Gas			
High CapEx			
High PRMR			✓

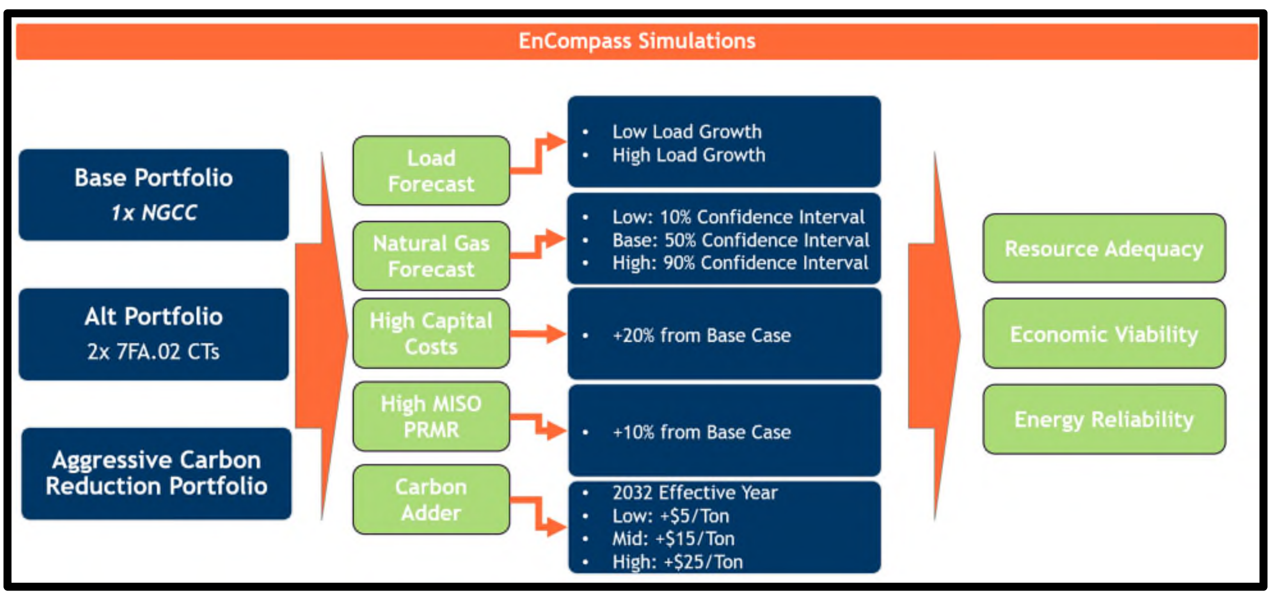
7.4 Portfolio Production Cost Analysis

EnCompass was also used to perform hourly production cost analysis for all three Portfolios – Base, Alternate, and ACR – under base assumptions across the original six expansion planning sensitivities, plus three carbon adder sensitivities. Each project portfolio was run through all nine sensitivities and evaluated on a resource adequacy, emission, and net present value basis. A 15-year and full study period NPV was taken from each EnCompass simulation to assess both the near- and long-term impacts of project additions. Figure 7.4(a) is a visual representation of the portfolio sensitivity analysis.

As previously noted, the likelihood of and extent to which carbon emission dispatch adders may be required/enforced remains significantly uncertain. Environmental, political, and economic impacts on carbon emission regulations remain difficult to predict. To provide a proxy of potential future developments related to carbon emission dispatch adders, 1898 & Co. developed market LMP forecast at three different carbon emission dispatch adder levels – $5, $15, and $25 per ton – starting in 2032 and continuing through the remainder of the study period with escalation. These different levels would serve as the low, mid, and high carbon adder cases. Once energy prices were established under these constraints, they were re-input into the EnCompass model to study their effects on the selected portfolios.

Figure 7.4(a)

EnCompass Portfolio Sensitivity Analysis



7.4.1 Base Portfolio

The retirement of Green Station 1 and 2 and the addition of the new combustion turbine meet both energy and capacity requirements on a seasonal and annual basis. Figure 7.4.1(a) and Figure 7.4.1(b) show the capacity positions of the Base Case portfolio in the summer and winter seasons. Table 7.4.1(a) shows the capacity surplus/deficit of Big Rivers' fleet expressed as a percentage seasonally and Table 7.4.1(b) shows the capacity position by fuel type. [redacted]. Figure 7.4.1(c) shows that the annual energy position of the Base Case from COD of the new combined cycle unit throughout the study period (a 22-year timeframe) results in an average capacity factor of 94.7%. This, in turn, results in increased economic benefits while continuing to meet the reliability needs of Big Rivers' Member-Owners. Table 7.4.1(c) shows the energy generation of the Big Rivers fleet by fuel type.

Figure 7.4.1(a)[88]

Base Case Summer Capacity Position

[redacted]

[88] Figures 7.4.1(a), 7.4.1(b) and 7.4.1(c) reflect reduced capacity on Wilson and lower load obligation to show modeling of Non-Member sales through their existing term for both Summer Capacity and Winter Capacity positions. While not shown in the charts below, the Energy requirements of the modeling include Non-Member sales. These sales are excluded from the reporting for clarity with regard to Member load obligations.

Figure 7.4.1(b)

Base Case Winter Capacity Position

[redacted]

Table 7.4.1(a)

Big Rivers Capacity Position Relative to PRMR

Year	Spring	Summer	Fall	Winter
	%	%	%	%
2024	[redacted]	[redacted]	[redacted]	[redacted]
2025	[redacted]	[redacted]	[redacted]	[redacted]
2026	[redacted]	[redacted]	[redacted]	[redacted]
2027	[redacted]	[redacted]	[redacted]	[redacted]
2028	[redacted]	[redacted]	[redacted]	[redacted]
2029	[redacted]	[redacted]	[redacted]	[redacted]
2030	[redacted]	[redacted]	[redacted]	[redacted]
2031	[redacted]	[redacted]	[redacted]	[redacted]
2032	[redacted]	[redacted]	[redacted]	[redacted]
2033	[redacted]	[redacted]	[redacted]	[redacted]
2034	[redacted]	[redacted]	[redacted]	[redacted]
2035	[redacted]	[redacted]	[redacted]	[redacted]
2036	[redacted]	[redacted]	[redacted]	[redacted]
2037	[redacted]	[redacted]	[redacted]	[redacted]
2038	[redacted]	[redacted]	[redacted]	[redacted]
2039	[redacted]	[redacted]	[redacted]	[redacted]
2040	[redacted]	[redacted]	[redacted]	[redacted]
2041	[redacted]	[redacted]	[redacted]	[redacted]
2042	[redacted]	[redacted]	[redacted]	[redacted]
2043	[redacted]	[redacted]	[redacted]	[redacted]
2044	[redacted]	[redacted]	[redacted]	[redacted]
2045	[redacted]	[redacted]	[redacted]	[redacted]
2046	[redacted]	[redacted]	[redacted]	[redacted]
2047	[redacted]	[redacted]	[redacted]	[redacted]
2048	[redacted]	[redacted]	[redacted]	[redacted]
2049	[redacted]	[redacted]	[redacted]	[redacted]
2050	[redacted]	[redacted]	[redacted]	[redacted]

Year	Hydroelectric	Solar PV	Coal	Natural Gas	Sto
	MW	MW	MW	MW	M
2023	158	160	412	520	
2024	158	160	412	520	
2025	164	159	412	520	
2026	169	158	412	520	
2027	150	158	412	520	
2028	155	257	412	520	
2029	161	256	412	700	
2030	167	255	412	700	
2031	172	254	412	700	
2032	172	254	412	700	
2033	172	253	412	700	
2034	172	252	412	700	
2035	172	251	412	700	
2036	172	251	412	700	
2037	172	250	412	700	
2038	172	249	412	700	
2039	172	248	412	700	
2040	172	248	412	700	
2041	172	247	412	700	
2042	172	246	412	700	

Figure 7.4.1(c)

Base Case Energy Position

[redacted]

Table 7.4.1(c)

Generation by Fuel Type

Generation by Fuel Type for EnCompass Model							
Year	Firm Purchase From Utilities	Firm Purchase From Non-Utilities	Hydroelectric	Solar PV	Coal	Natural Gas	Storage
	GWh	GWh	GWh	GWh	GWh	GWh	GWh
2023	0	0	313	197	3,093	40	0
2024	0	0	313	197	3,093	40	0
2025	0	0	310	323	2,392	14	0
2026	0	0	311	321	1,140	11	0
2027	0	0	270	320	586	6	0
2028	0	0	264	503	568	0	67
2029	0	0	270	501	664	2,979	66
2030	0	0	267	499	741	4,963	63
2031	0	0	265	498	981	4,879	60
2032	0	0	269	497	1,614	4,847	61
2033	0	0	267	494	2,136	4,909	59
2034	0	0	267	493	2,210	5,005	56
2035	0	0	270	492	2,512	4,967	47
2036	0	0	266	491	2,525	5,019	47
2037	0	0	267	488	2,510	5,045	47
2038	0	0	272	487	2,866	5,107	48
2039	0	0	266	485	2,458	5,079	40
2040	0	0	267	485	2,787	5,114	38
2041	0	0	268	482	2,532	5,182	38
2042	0	0	265	481	2,967	5,212	40

7.4.2 Alternative Portfolio

The first alternative to the base case is comprised of two 237 MW combustion turbines in place of the new NGCC. These unit additions would provide adequate capacity positions to meet the MISO PRMR shown in Figure 7.4.2(a) and Figure 7.4.2(b). However, the peaking units would not provide base load energy and, as a result, would operate at a lower (~0.3%) capacity factor through the same study horizon as the natural gas combined cycle unit. This in turn would require additional project development to meet the energy requirements of Big River's Member-Owners. To fill the remaining shortfall, approximately 700 MW of wind was added between the 2030 and 2033 study years. Figure 7.4.2(c) demonstrates the wind energy production necessary to meet the portfolio energy requirements under this Alternative Portfolio. These project additions result in higher capital spend and higher NPV estimate. Big Rivers considers wind not economically feasible, as there were no wind resources proposed in our recent all source RFP, and the intermittent operation of wind remote to Big Rivers' load brings the risk of congestion costs which are hard to quantify and/or hedge. Also, the supply of wind energy as a non-dispatchable resource is challenging. Some hours are extremely long at times of low market prices, and others are short when prices are high.

Figure 7.4.2(a)[89]

Alternative Case Summer Capacity Position

[redacted]

[89] Figures 7.4.2(a), 7.4.2(b) and 7.4.2(c) reflect reduced capacity on Wilson and lower load obligation to show modeling of Non-Member sales through their existing term for both Summer Capacity and Winter Capacity positions. While not shown in the charts below, the Energy requirements of the modeling include Non-Member sales. These sales are excluded from the reporting for clarity with regard to Member load obligations.

Figure 7.4.2(b)

Alternative Case Winter Capacity Position

[redacted]

Figure 7.4.2(c)

Alternative Case Energy Position

[redacted]

7.4.3 Aggressive Carbon Reduction Portfolio

The portfolio buildout for the ACR Portfolio case initially followed the same resource mix as the Base Portfolio case with the additional 90% carbon capture equipment addition in 2032. After the initial simulation, the capacity position was met in the summer peaking season but resulted in a shortfall in the winter months. This was due to the maximum capacity reduction of the Wilson coal unit and the new natural gas combined cycle unit. From 2032 through the remainder of the study period, a capacity shortfall was projected in the winter season. To fill this shortfall, wind additions were made during periods of deficit until the PRMR was met as demonstrated in Figure 7.4.3(b). The timing of these wind additions can be referenced in Table 7.3.1(a).

The combination of increased capital expenditures for carbon capture technology and additional wind projects resulted in the highest NPV of the three cases studied. The energy position of this portfolio adequately meets the needs of Big Rivers Members during the 45 Q tax credit period. These tax credits were estimated to begin following the carbon capture equipment implementation in 2032 and to continue for 12 years. These tax credits became a crucial part of meeting energy requirements, as once they expire, the portfolio is at an increased market risk beginning in 2044, as shown in Figure 7.4.3(c). After the credits expire, both the Wilson unit and the new natural gas combined cycle unit are no longer economically viable with the carbon capture equipment. Starting in 2044, the Wilson unit no longer dispatches, and the capacity factor for the natural gas combined cycle falls by approximately 87%.

Figure 7.4.3(a)[90]

ACR Case Summer Capacity Position

[redacted]

[90]Figures 7.4.3(a), 7.4.3(b) and 7.4.3(c) reflect reduced capacity on Wilson and lower load obligation show modeling of Non-Member sales through their existing term for both Summer Capacity and Winter Capacity positions. While not shown in the charts below, the Energy requirements of the modeling include Non-Member sales. These sales are excluded from the reporting for clarity with regard to Member load obligations.

Figure 7.4.3(b)

ACR Case Winter Capacity Position

[redacted]

Figure 7.4.3(c)

ACR Case Energy Position

[redacted]

7.4.4 Summary Evaluation

Big Rivers' mission remains unchanged: to safely deliver low-cost, reliable wholesale power and the cost-effective shared services desired by its Member-Owners. The economic expansion and production cost modeling approach reflected herein allows for insightful results to assist Big Rivers in accomplishing its mission. Table 7.4.4(a) and Table 7.4.4(b) show the NPV comparison for each portfolio on a 15- and 27-year basis, respectively, in all sensitivities. In comparison to the two (2) alternative portfolios, the Base Portfolio provided the least-cost resource mix while still meeting customer reliability in seven (7) of the nine (9) cases on a 15-year NPV basis, and in all cases on a 27-year NPV basis.

Table 7.4.4(a)

15-Year Portfolio NPV Comparison

Sensitivity	Base Portfolio (Base)	Alt No. 1 (S1)	Aggressive Carbon Reduction Portfolio (S2)
Base	[redacted]		
Low Load			
High Load			
Low Gas			
High Gas			
High CapEx			
High PRMR			
Low CO2			
Mid CO2			
High CO2			

Based on a 15-year planning horizon, it can be observed from Table 7.4.4(a) that the Base Portfolio provides the least-cost resource mix across seven of the nine sensitivities. The ACR Portfolio provides the least cost mix in the remaining two cases in which mid- and high-carbon adders are implemented, primarily as a consequence of the significant twelve-year 45Q tax benefits.

Table 7.4.4(b)

27-Year Portfolio NPV Comparison

Sensitivity	Base Portfolio (Base)	Alt No. 1 (S1)	Aggressive Carbon Reduction Portfolio (S2)
Base	[redacted]		
Low Load			
High Load			
Low Gas			
High Gas			
High CapEx			
High PRMR			
Low CO2			
Mid CO2			
High CO2			

Conducting a full study horizon NPV (2024 – 2050), however, the Base Portfolio provides the least-cost resource mix across all sensitivities. This is due to the high capital cost in 2032 for the implementation of carbon capture equipment and ending the 45Q tax credits after their 12-year term. The full study period NPV demonstrates the risk of a long-term investment in carbon capture and sequestration prematurely, before full understanding of any future environmental regulations are known. The Base Portfolio offers the least-cost option under both planning horizons leaving open the potential for carbon capture and sequestration at the appropriate time.

CHAPTER 8
TRANSMISSION PLANNING

8. TRANSMISSION PLANNING

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

8.1 MISO Transmission Planning

As a member of MISO, Big Rivers participates in MISO's coordinated short–term 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 cost-effective transmission infrastructure that is sufficiently stout to meet reliability needs, enable a competitive energy market, support policy goals, and allow opportunities for stakeholders to participate and provide input on the transmission system. The Guiding Principles of the MISO Transmission Expansion Planning process follow:

- MISO regional expansion planning process should: develop transmission plans that will ensure a reliable and resilient transmission system that can respond to the operational needs of the MISO region
- Make the benefits of an economically efficient electricity market available to customers by identifying solutions to transmission issues that are informed by near-term and long-range needs and provide reliable access to electricity at the lowest total electric system cost.
- Support federal, state, and local energy policy and member goals by planning for access to a changing resource mix.
- 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.
- Analyze system scenarios and make the results available to federal, state, and local energy policy makers and other stakeholders to provide context and to inform choices.
- Coordinate planning processes with neighbors and work to eliminate barriers to reliable and efficient operations.

8.2 Transmission Transfer Capability

Big Rivers routinely assesses its transmission system's ability to transfer power into and out of Big Rivers' local balancing area. Additionally, Big Rivers performs transfer capability studies as a participant in MISO and SERC seasonal assessments. 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.

With respect to the optimization and expansion of the existing Big Rivers transmission facilities during the period from 2021 through 2023, Big Rivers constructed and placed in service approximately 42 miles of new transmission line to serve five new delivery point substations to its Members. The new delivery points required Big Rivers to complete the following capital projects:

- The Brandenburg Steel Mill load addition required building 3 greenfield switching/substations, two 345 kV transmission lines, one 161kV transmission line, one 69kV transmission line, and installing a Static Synchronous Compensator to support their electrical demand for daily operations.
- The Henderson Paper Mill load addition required building two new greenfield Switching / Substation stations and a new 161kV line to supply power to the new paper mill.
- The new crypto load required Big Rivers to build one new greenfield substation and a new 161kV transmission line to supply power at the new substation.

Big Rivers reviews facility rating methodology and practices on an annual basis. As part of this review, rating assumptions are evaluated for opportunities to optimize existing facility ratings. Between 2020 and 2021, Big Rivers provided Ambient Adjusted Ratings ("AAR") to MISO through a coordinated automated format. This ensures that Big Rivers' transmission facilities are efficiently utilized within real-time operations. In 2021 FERC issued Order 881, which will revises the regulatory policies for determining future AAR transmission line ratings. The new regulations aim to improve the efficiency, reliability, and transparency of the transmission grid and to lower costs for consumers. Big Rivers is working with MISO on implementation of FERC Order 881 across the MISO footprint.

The ongoing effort to complete other transmission system improvements is a continuous process. A list of completed and planned improvements to the Big Rivers system is presented in Table 8.2(a) and Planned System Additions Table 8.2(b).

Table 8.2(a)

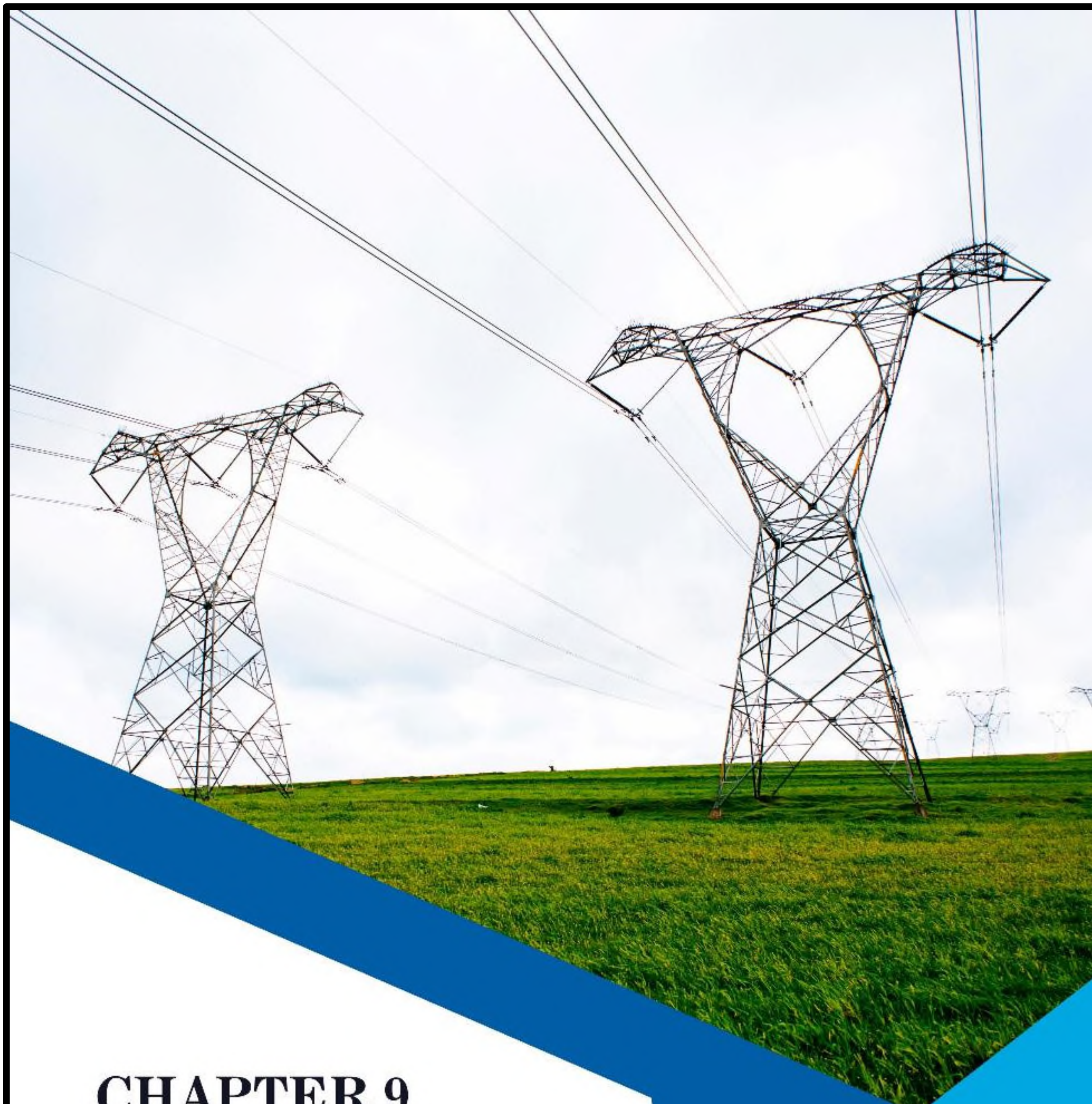
Completed Transmission System Additions (2021 – 2023)

Project Description	Year
West Brandenburg 69 kV Line	2021
Easton Road 69 kV Line	2021
OPGW Installation	2021
Redmon Road, Otter Creek, and BSM Substations	2022
Redmon Road – Otter Creek 345 kV Line	2022
Otter Creek – BSM 345 kV Line	2022
Otter Creek – Meade County 161 kV Line	2022
Buttermilk Falls – BSM 69 kV Line	2022
Wilson –Sacramento 69 kV Line	2022
REHV Transformer #1 and #2 Replacement	2022
OPGW Installation	2022
West Paducah, South Henderson, HPM Substations	2023
McCracken Co. – West Paducah 161 kV Line	2023
South Henderson to HPM 161 kV Line	2023
McCracken – Shell 69 kV Line Upgrade	2023
OPGW Installation	2023

Table 8.2(b)

Planned Transmission System Additions (2024-2038)

Project Description	Year
[redacted]	
New Transmission Operation Center	2025
[redacted]	



CHAPTER 9
MISO RESOURCE ADEQUACY PLANNING

9. MISO RESOURCE ADEQUACY PLANNING

Following receipt of the Commission's permission in Case No. 2010-00043,[91] 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, reserve requirements, sources of energy, demand-side resources, and projected needs for new generation and transmission facilities.

9.1 Consideration of MISO Planning Reserve Margins in this IRP

MISO's annual Loss of Load Expectation (LOLE) study[92] sets the system-wide Planning Reserve Margin and the zonal Local Reliability Requirements for load serving entities within the MISO footprint. MISO's seasonal construct accepted by FERC in September 2022 introduces seasonal requirements to the Planning Resource Auction to account for the unique risk profile of each season. Big Rivers used the MISO Planning Reserve Margin ("PRM") Unforced Capacity ("UCAP") Planning Reserve Margin of 7.4% for summer, 14.9% for fall, 25.5% for winter, and 24.5% for

[91] *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 (Ky. P.S.C. November 1, 2010). Subsequent to this proceeding, MISO changed its name from Midwest Independent Transmission System Operator, Inc., to Midcontinent Independent System Operator, Inc.

[92] *MISO Planning Year 2023-2024 Loss of Load Expectation Study Report included as Appendix E*

spring in this IRP analysis and expansion planning was designed to meet the MISO requirements over the analysis period. The MISO Planning Reserve Margin requirement as determined by the Loss of Load Expectation Study "LOLE") 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 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 MISO 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 well as participation in the annual Planning Resource Auction. As the MISO market evolves, Big Rivers will continue to evaluate the proper reserve margin target by continuing participation in MISO Stakeholder groups such as Resource Adequacy Subcommittee, Loss of Load Expectation Working Group, and other groups, to ensure Big Rivers' participation in the MISO market provides optimum value to its Members.

9.2 MISO Footprint

Figure 9.2(a)

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

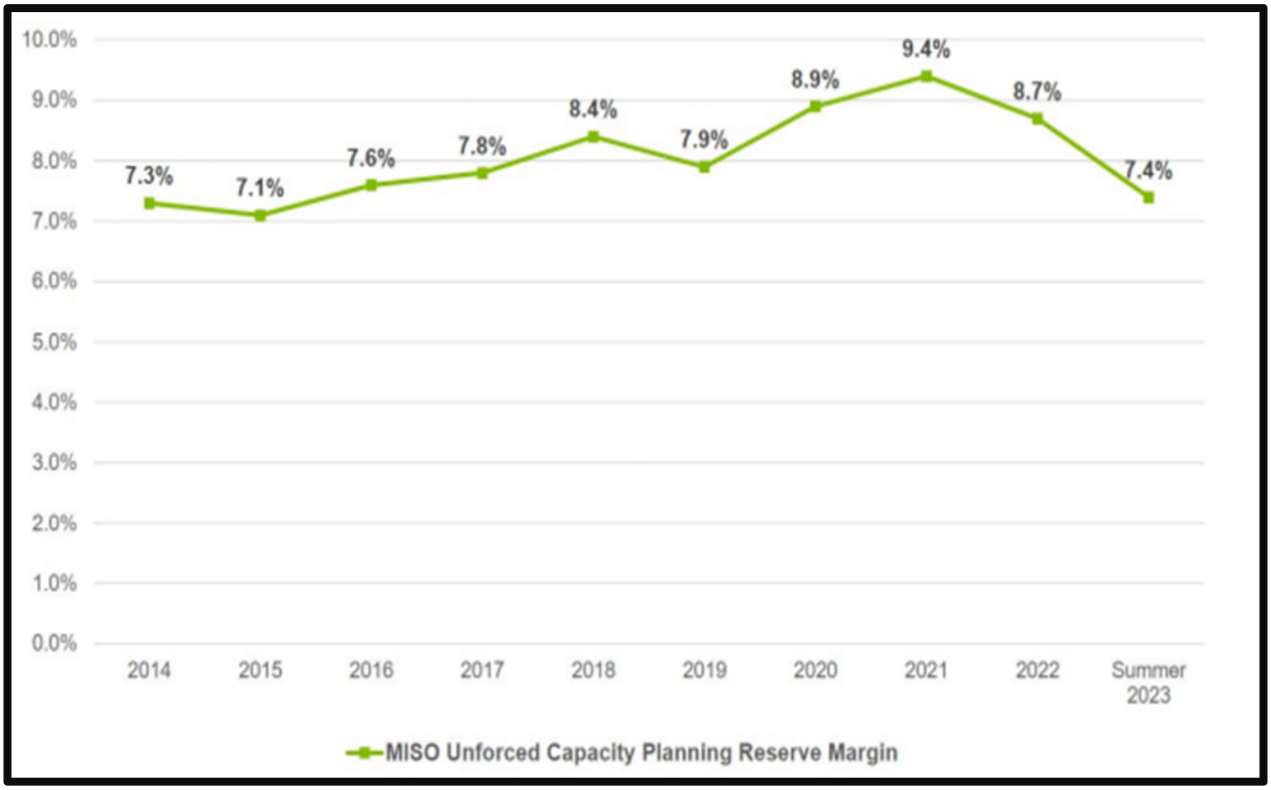
Big Rivers is located in MISO's regional zone 6, along with entities in Indiana, as shown in The MISO Local Resource Zone Map above.

9.3 Comparison of PRM Targets across 10 Years

Figure 9.3(a) below compares the PRM UCAP values over the last 10 planning years. The last endpoint shows the Planning Year 2023-2024 summer PRM value of 7.4%.

Figure 9.3(a)

Capacity Planning Reserve Margin History



CHAPTER 10
ACTION PLAN

10. ACTION PLAN

For Big Rivers, the 2023 IRP highlights a path based on an "all of the above" approach to sustainability and reliability, working to incorporate coal, natural gas, hydropower, and solar energy to increase sustainability while maintaining efficient and reliable baseload electricity for all Member-Owners.

Big Rivers' mission to safely deliver low-cost, reliable wholesale power to its Member-Owners is an ongoing effort, necessitating robust analysis of existing and potential load and resources. Big Rivers will leverage its access to wholesale power markets to maximize Member value while ensuring sufficient steel in the ground to minimize risk and promote reliability.

This triennial IRP filing incorporates the best information available at the time of analysis, and as circumstances change, plans will be adjusted. This plan is not a commitment for certain actions now or at any future date.

Big Rivers' most-recent Financial Plan, which was approved by its Board in December 2022, included projected Member rates as shown in Table 10(a) below. The variables impacting Big Rivers' future rates are complex. Big Rivers' base plan (least cost option) for meeting its Members' load requirements under the base case scenario is to continue operating through 2029 with substantially the same approach as employed today. However, many variables can impact Big Rivers' Members' rates.

As noted above, significant analysis has occurred surrounding the optimum use of Big Rivers' existing and potential assets in the future. Greater clarity on the future of the power market, coal and natural gas pricing, and environmental regulations will be paramount to Big Rivers' decision-making process. Big Rivers exists solely to safely and reliably serve its Members at the lowest reasonable cost, and management will continue to focus on the best options for the Members in the years to come.

Table 10(a)

Actual and Projected Big Rivers' Wholesale Rates

Actual and Projected Big Rivers' Forecasted Wholesale Member Rates
Approved by Board of Directors December 2022

Year	cents/KWh	Year	cents/KWh
[redacted]			

10.1 Action Plan Detail

Big Rivers' 2023 IRP analysis reflects a beginning base portfolio to include Wilson on coal, Reid CT, Green 1 and Green 2 on gas, continuing the SEPA hydropower contract, and the addition of the Unbridled solar power purchase agreement. Big Rivers will continue to monitor the regulatory landscape, including any opportunities to advance the projects proposed via PACE and NewERA programs with federal funding awards, and will pursue incentivized projects which bring value to our Member-Owners.

The Base Case includes all existing Big Rivers resources continuing in service through at least 2029. It also includes the addition of the 100 MW solar plus 50 MW storage project related to Big Rivers' PACE letter of intent submitted in June 2023, anticipated to be online no earlier than 2028, and the addition of a ~600 MW Combined Cycle generator located near the Company's Sebree plant location. At the appropriate time in advance of adding these generators, Big Rivers will submit to the Commission the required requests for Certificates of Public Convenience and Necessity. Consistent with its mission to evaluate for changing circumstances, Big Rivers will:

- Continue to operate existing efficient generating units;
- Continue to support Economic Development in the Big Rivers footprint;
- Continue to monitor energy and capacity markets and fuel futures to evaluate the identification of safe, reliable, dispatchable and low-cost generation resources to reduce risk, consistent with the needs and desires of Big Rivers' Member-Owners;
- Continue to monitor changes in MISO Tariff provisions which impact capacity accreditation and load planning reserve requirements;

- Constantly evaluate off-system sales activity to ensure low-risk and high value to Members to the extent it supports Big Rivers' mission and core business.
- Along with Members, continue to evaluate opportunities for energy efficiency and demand response programs looking for reductions in cost or increases in the value of avoided cost.
- Continue to monitor the political landscape for changes that may impact the nature and/or timing of environmental requirements, leveraging incentives as they become available which bring value to Big Rivers' Members.
- Continue MISO Generator Interconnection Agreement process to ensure cost and ability to interconnect a NGCC unit.

APPENDICES

Appendix A

Long Term Load Forecast Report

2023 Load Forecast Report

PREPARED FOR:

BIG RIVERS ELECTRIC CORPORATION

PREPARED BY:

CLEARSPRING ENERGY ADVISORS

JULY 2023

2023 Big Rivers Electric Corporation
Load Forecast Study

July 25, 2023

Prepared By:

Clearspring Energy Advisors LLC

1050 Regent St., Suite L3

Madison, WI 53715

Confidentiality Statement

TABLE OF CONTENTS

1 Introduction and System Summary

1.1 Project Overview

The 2023 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 2023 electric load forecast through 2042. 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

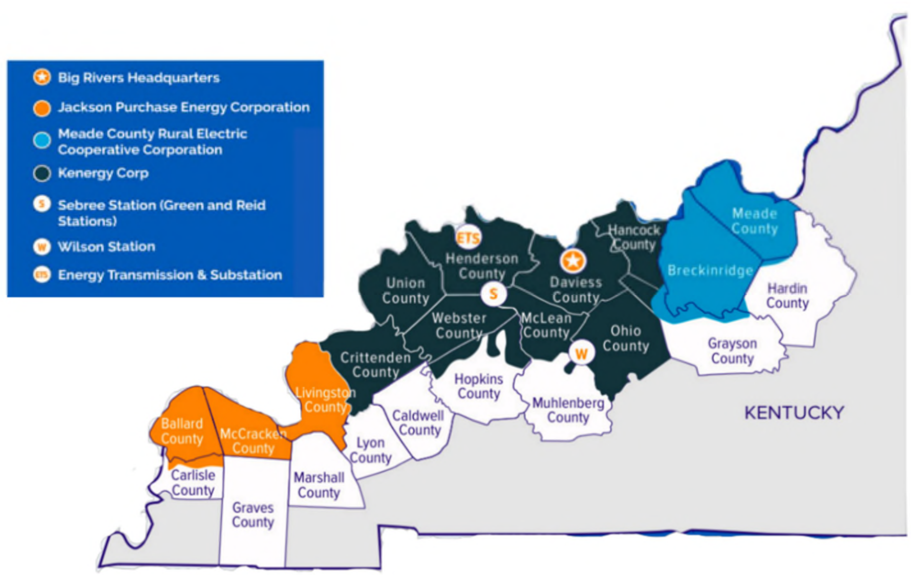
Name	Company	Role
Marlene Parsley	Big Rivers Electric Corporation	Project Manager
Terry Wright	Big Rivers Electric Corporation	Project Manager
Russ Pogue	Big Rivers Electric Corporation	DSM Study
Travis Spiceland	Jackson Purchase Energy Corporation	Load Forecast Representative
Meredith Kendall	Jackson Purchase Energy Corporation	Load Forecast Representative
Steve Thompson	Kenergy Corporation	Load Forecast Representative
Travis Siewert	Kenergy Corporation	Load Forecast Representative
Rob Stumph	Kenergy Corporation	Load Forecast Representative
Anna Swanson	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 USDA Rural Utilities Service ("RUS") loan applications. Clearspring and Big Rivers staff will continue to be available for any RUS questions or follow up requests. 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 participate 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 120,000 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 (2018-2022) and the forecasts for the next 20 years.

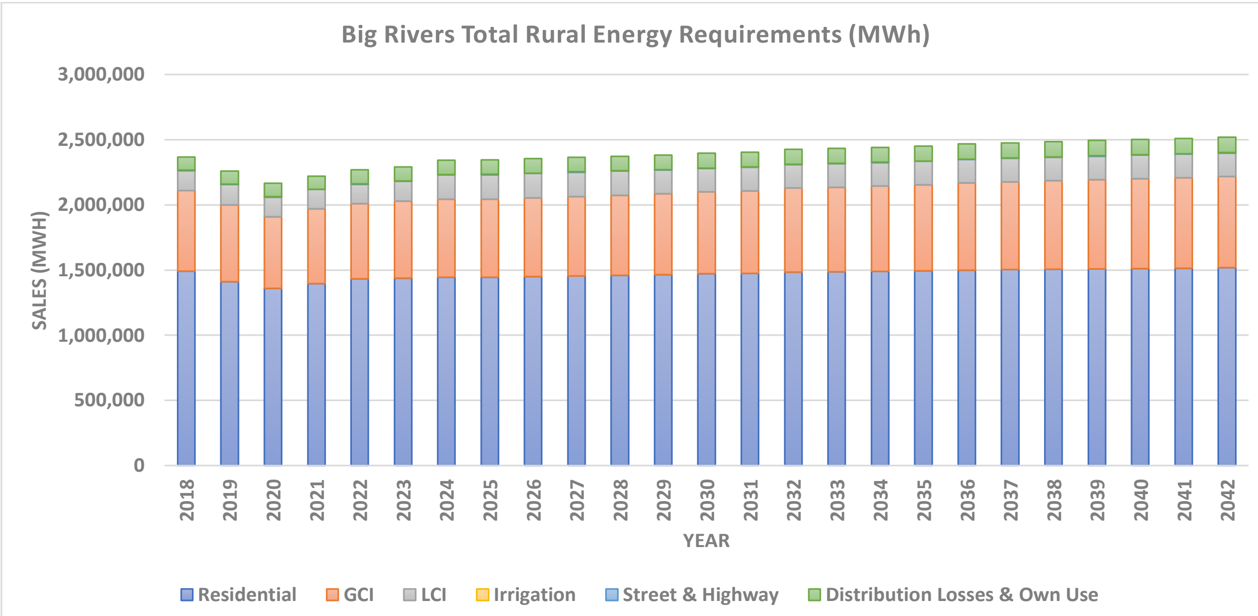
Native System Summary[1]

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
2018	2,366,988	953,822	556.7	95.5	48.5%	58.2%
2019	2,261,069	946,040	490.9	117.9	52.6%	60.2%
2020	2,164,868	824,695	460.2	106.0	53.6%	60.3%
2021	2,219,380	781,559	492.9	96.5	51.4%	58.2%
2022	2,269,586	919,357	590.7	99.7	43.9%	52.8%
2023	2,291,062	1,569,178	473.4	261.1	55.2%	60.0%
2024	2,343,506	2,172,620	482.0	338.3	55.4%	62.7%
2025	2,344,105	2,225,127	482.0	359.1	55.5%	62.0%
2026	2,354,461	2,225,127	484.0	359.1	55.5%	62.0%
2027	2,364,427	2,225,127	485.9	359.1	55.5%	62.0%
2028	2,373,176	2,227,894	488.2	359.1	55.3%	61.8%
2029	2,380,698	2,225,127	489.3	359.1	55.5%	62.0%
2030	2,394,861	2,225,127	492.2	359.1	55.5%	62.0%
2031	2,404,797	2,225,127	494.2	359.1	55.6%	61.9%
2032	2,425,591	2,227,894	498.4	359.1	55.4%	61.8%
2033	2,432,406	2,225,127	499.8	359.1	55.6%	61.9%
2034	2,441,782	2,225,127	501.6	359.1	55.6%	61.9%
2035	2,451,925	2,225,127	503.6	359.1	55.6%	61.9%
2036	2,466,634	2,227,894	506.5	359.1	55.4%	61.7%
2037	2,476,201	2,225,127	508.4	359.1	55.6%	61.9%
2038	2,485,134	2,225,127	510.0	359.1	55.6%	61.9%
2039	2,493,662	2,225,127	511.6	359.1	55.6%	61.9%
2040	2,501,574	2,227,894	513.0	359.1	55.5%	61.7%
2041	2,509,737	2,225,127	514.5	359.1	55.7%	61.9%
2042	2,519,073	2,225,127	516.3	359.1	55.7%	61.9%
Average Annual Growth Rates						
Previous 10 Years	-0.23%	-0.52%	0.88%	-1.23%	-1.12%	-0.86%
Previous 5 Years	0.53%	-0.01%	3.21%	-2.71%	-2.59%	-1.77%
Next 5 Years	0.82%	19.34%	-3.83%	29.22%	4.84%	3.26%
Next 10 Years	0.67%	9.25%	-1.68%	13.67%	2.36%	1.58%
Next 20 Years	0.52%	4.52%	-0.67%	6.62%	1.20%	0.79%

[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 5.

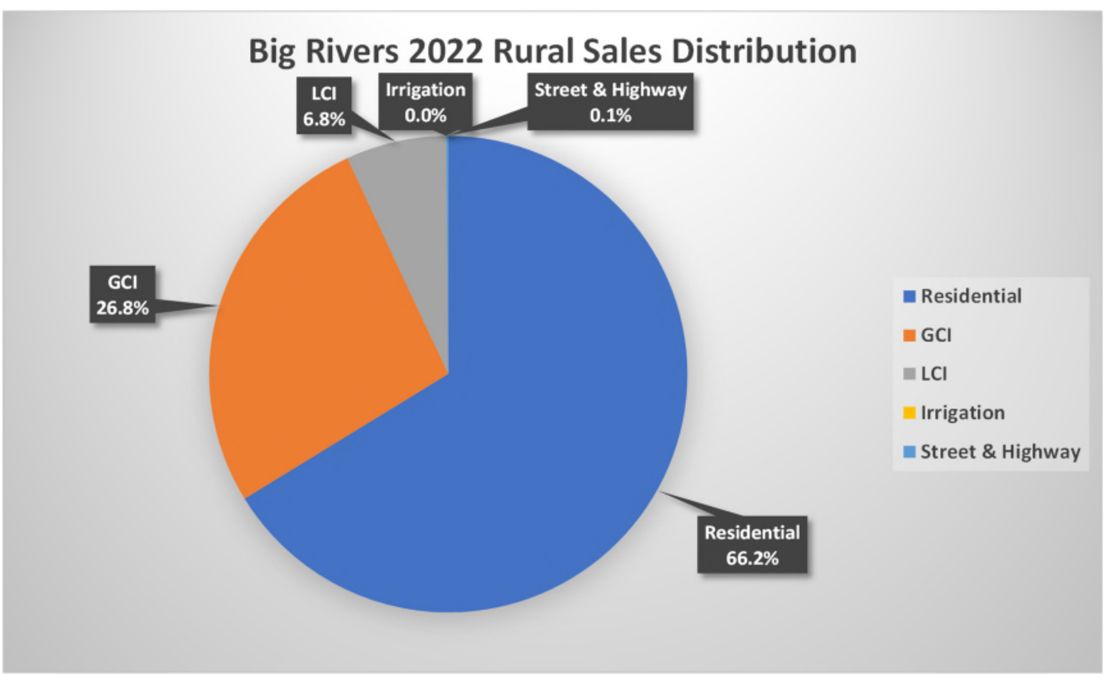
The following graph provides the Native system Rural energy requirements forecast.

Rural Energy Requirements



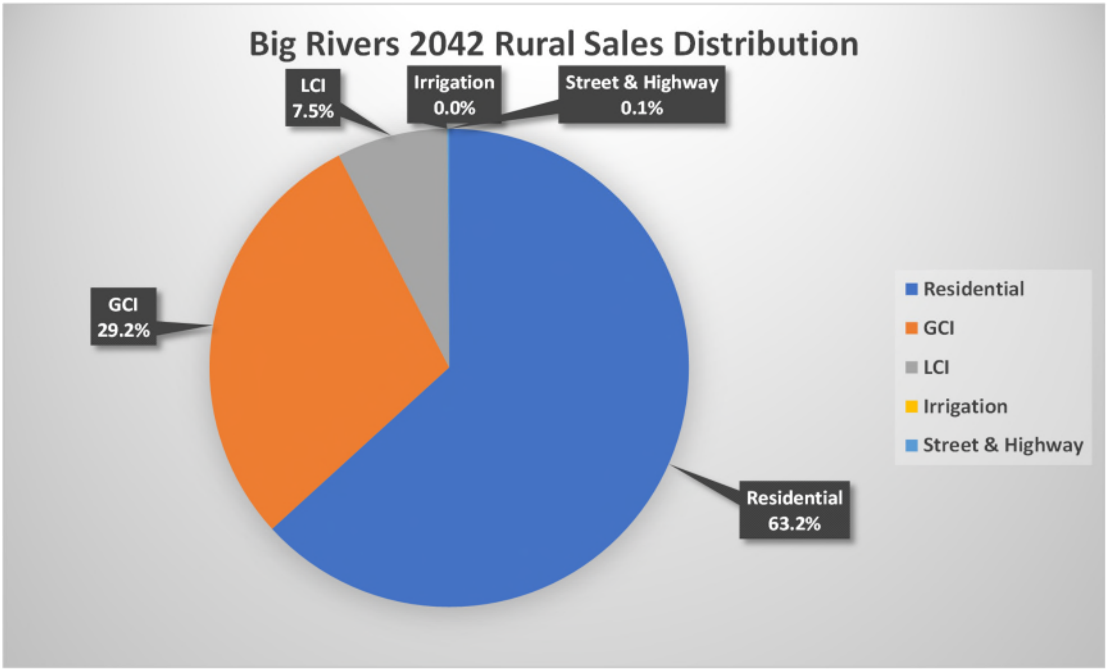
The figure below provides the Native system Rural sales distribution by class for 2022.

2022 Rural Sales by Class Distribution



The figure below provides the Native system Rural sales distribution forecasted by class for 2042.

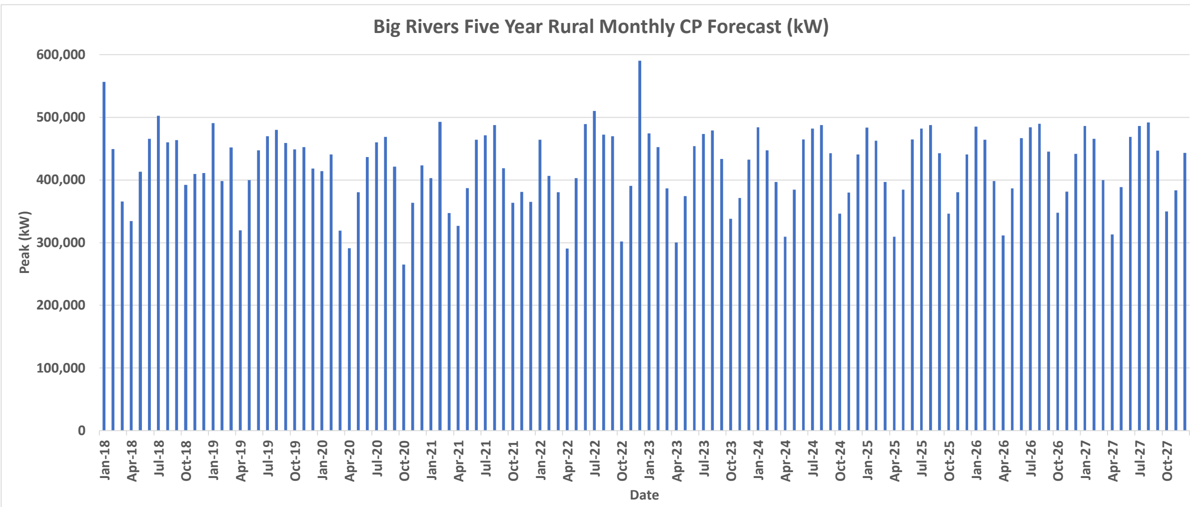
2042 Rural Sales by Class Distribution



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.

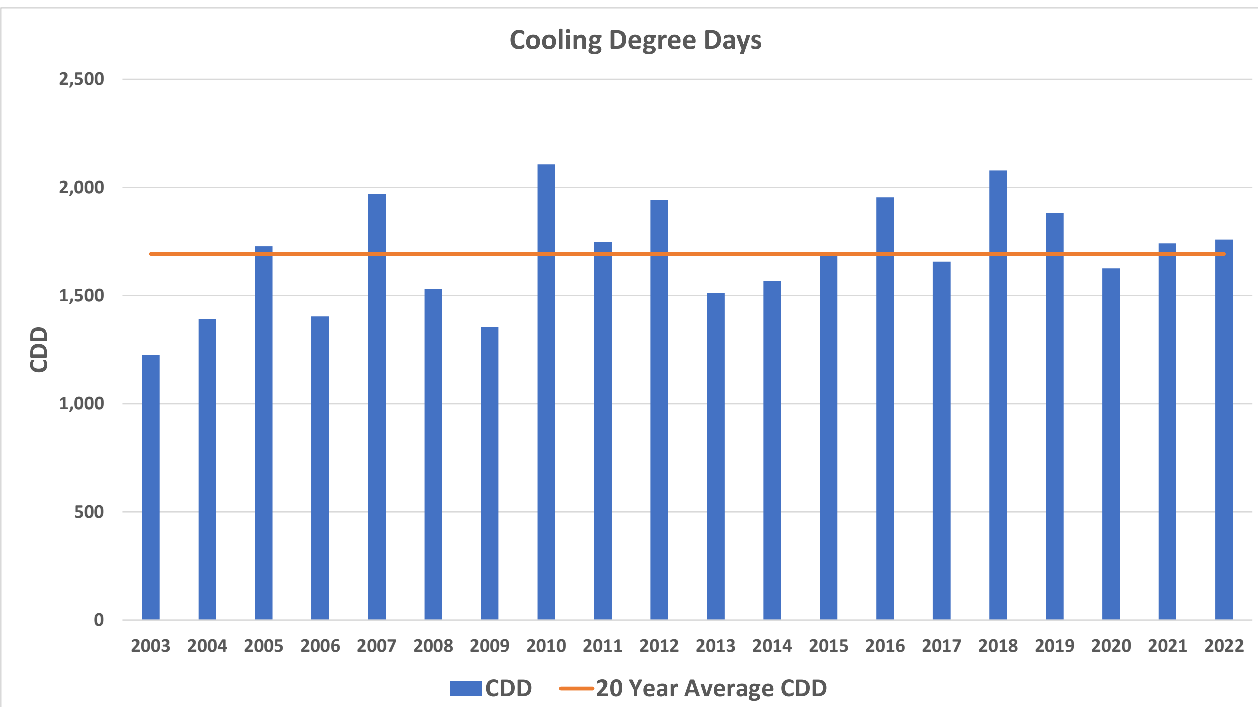
Monthly Rural Peak Forecast



1.4 2022 Weather Conditions

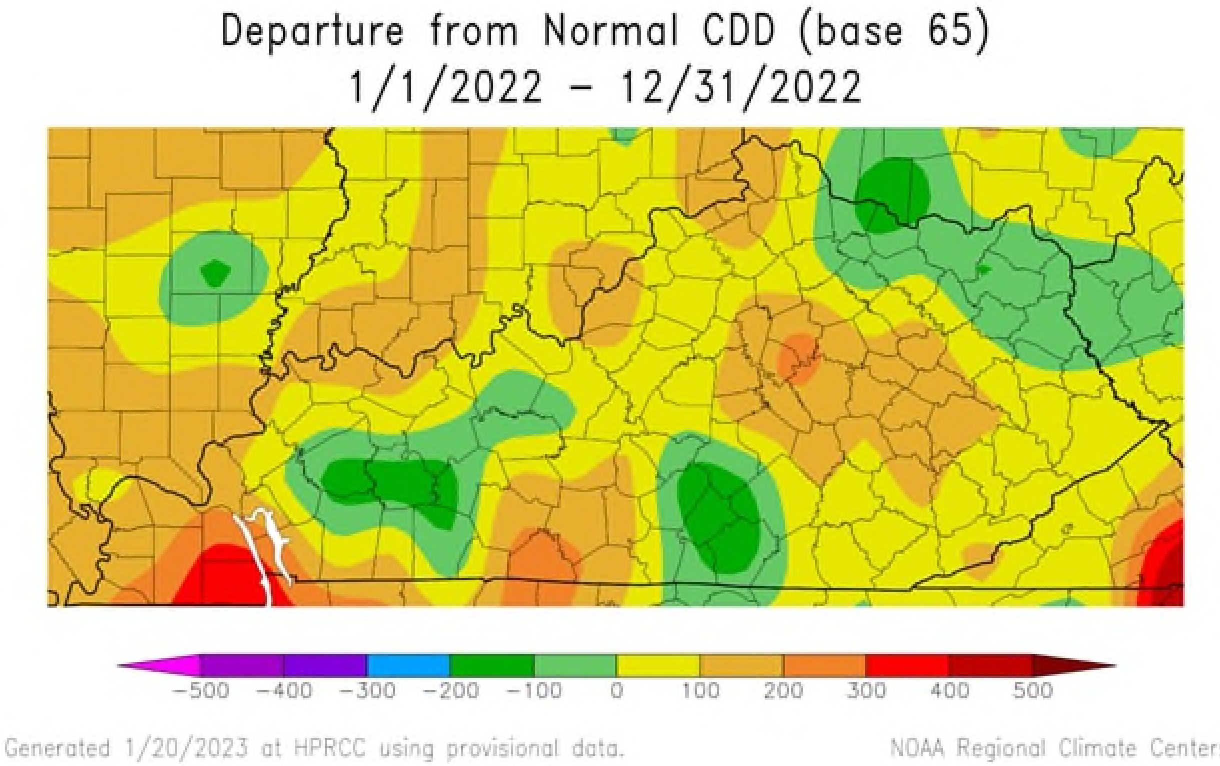
The forecast contains an assumption of a "normal" weather scenario for each class. Clearspring Energy compiled historical weather observations to enable the estimation of weather impacts on sales and peak loads. Weather variables such as cooling degree days (CDD), heating degree days (HDD), and peak 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 twenty years of CDDs for Big Rivers along with the 20-year average CDD.

Cooling Degree Days for Last 20 Years



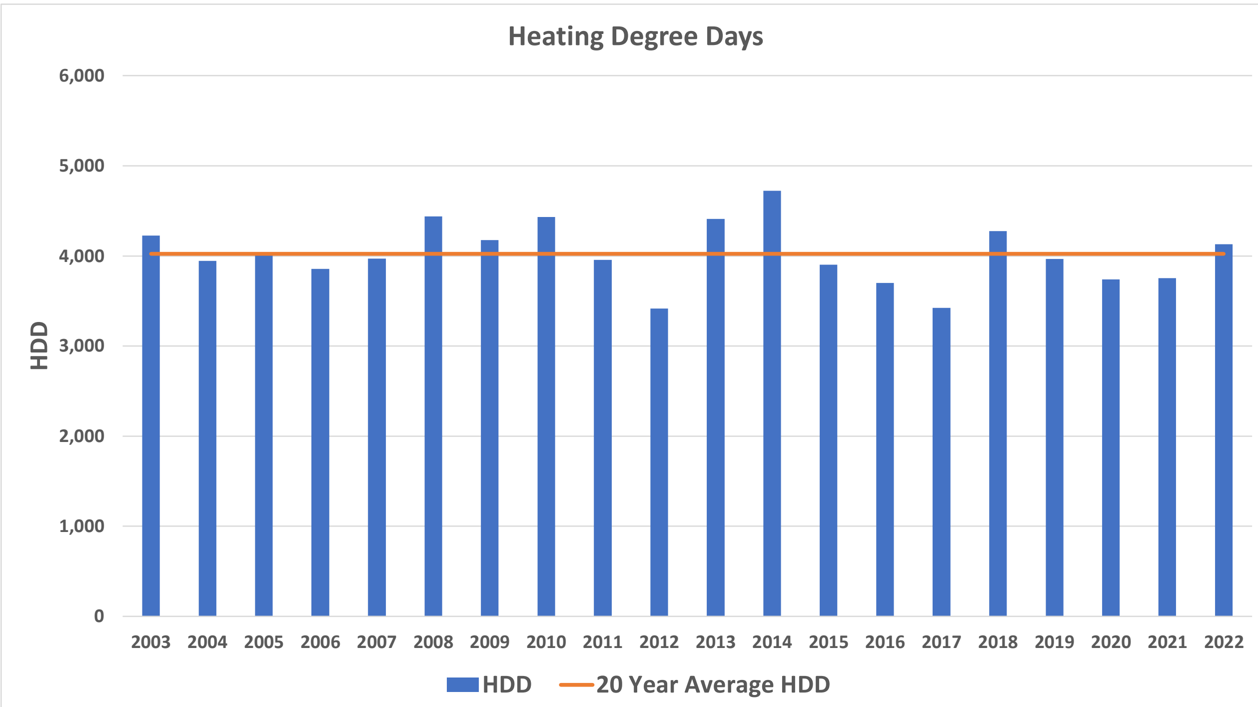
The figure below provides the CDD deviation in 2022 from a 30-year normal amount for the entire state of Kentucky, showing the distribution of weather conditions across the full service territory. The map shows some isolated pockets of mild summer CDD amounts. However, most of the service territory experienced a slightly hotter-than-normal summer season.

Kentucky 2022 CDD Deviations



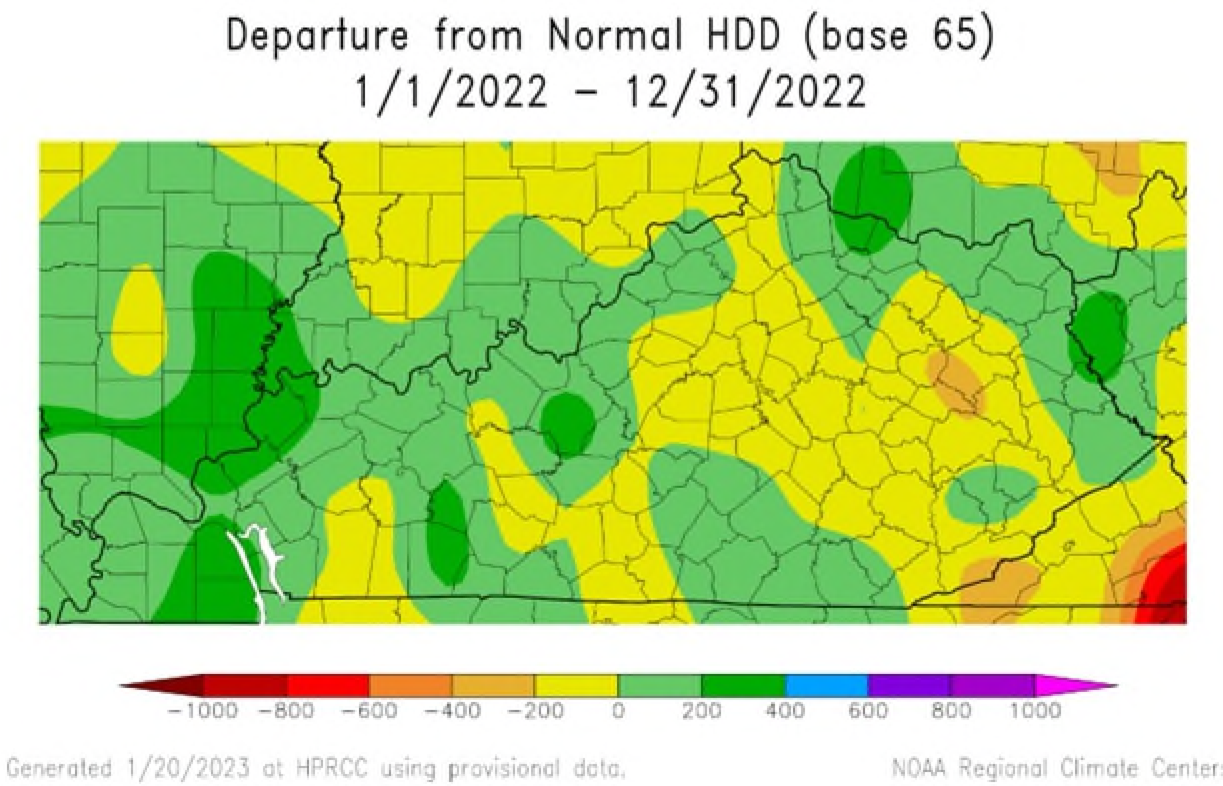
The figure below displays the last twenty years of HDDs for Big Rivers along with the 20-year average HDD.

Heating Degree Days for Last 20 Years



The figure below provides the HDD deviation in 2022 from a 30-year normal amount for the entire state of Kentucky. The map shows mostly average winter HDD amounts during 2022.

Kentucky 2022 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.

Prior to forecasting Residential and GCI use per consumer models, historical usage for electric vehicles and distributed generation are removed from the historical modeling dataset. These two sectors are forecasted independently using data from publicly available sources. The results for each of these two sectors are then aggregated with the results from the econometric models to create the final class forecasts.

Forecasts for the LCI and Direct Serve commercial loads have been prepared based on input from the cooperatives and historical values. 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.

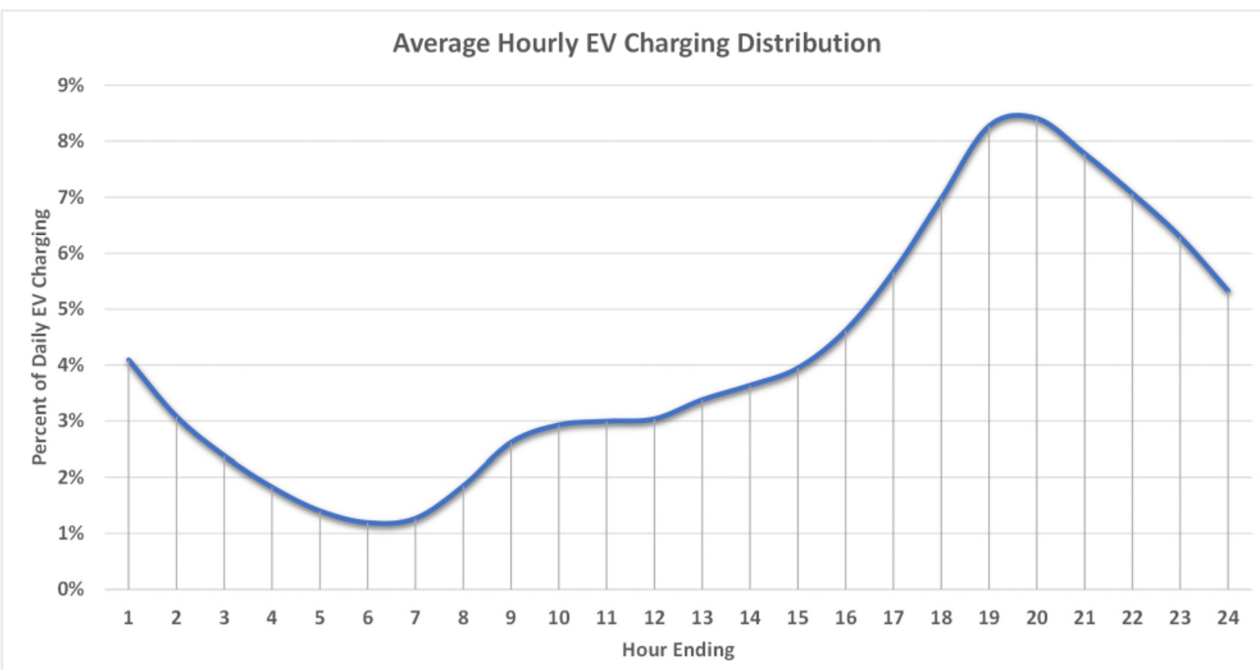
2 Electric Vehicle and Distributed Generation Forecast

2.1 Electric Vehicle Forecast

The electric vehicle (EV) forecast is produced by first isolating the estimated historical contribution of EV charging to Residential and GCI energy and peak load. Historical and projected annual EV energy charging values are derived from statewide vehicle registration data and regional projections created by the Energy Information Administration (EIA) Annual Energy Outlook.

The EV charging annual energy values are then fit to monthly and hourly contributions using estimated load shapes obtained by the Department of Energy Alternative Fuels Data Center. Ten years of monthly system peaking times are assessed to determine the likelihood of each hour of the day becoming the system peak hour, with each occurrence given a ten percent weighting. Big Rivers coincident peak projections from EV charging are then created using the hourly load shapes during the likely peaking hours each month. While slightly different seasonal shapes are used for the forecast, the figure below shows the average daily load shape used for EV charging.

Electric Vehicle Load Shape



The table below shows the estimated historical contributions for the last five years, and the twenty-year forecast for Residential EV charging energy, GCI EV charging energy, additional associated distribution losses, and Big River's coincident peak contributions.

Electric Vehicle Forecast

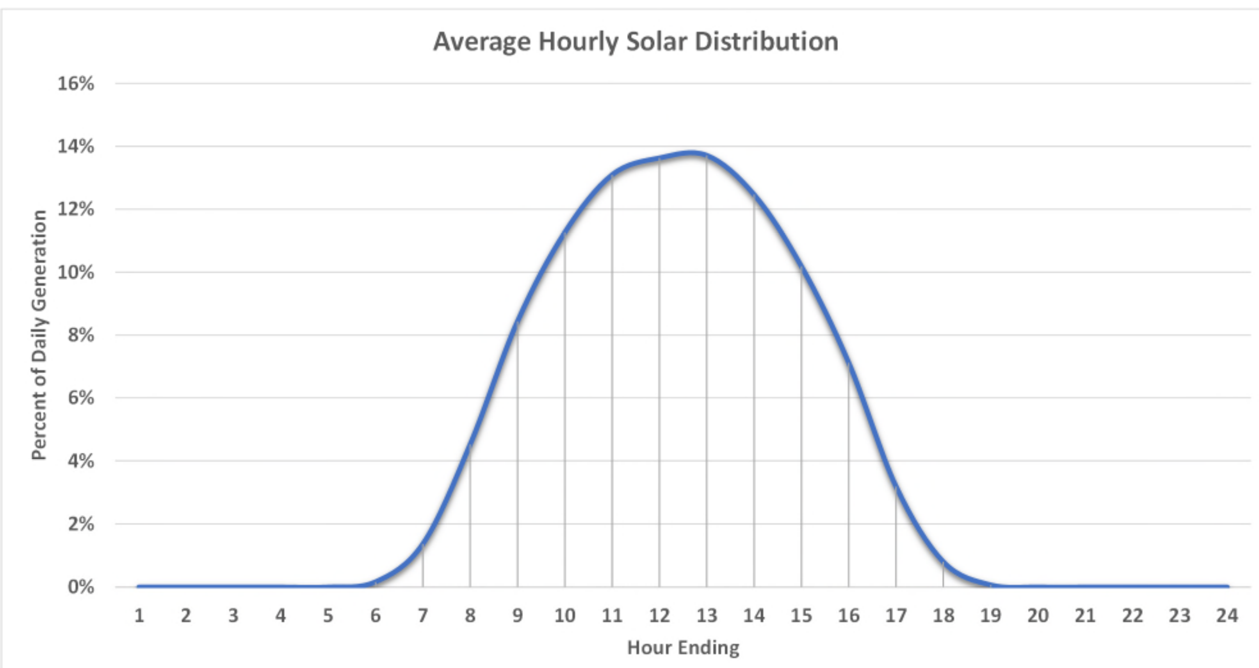
Big Rivers Rural System Electric Vehicle Forecast					
Year	Residential Energy (MWh)	Commercial Energy (MWh)	Distribution Losses (MWh)	Total Energy (MWh)	Rural Coincident Peak Contribution (kW)
2018	315	129	19	463	55
2019	431	176	28	635	75
2020	547	223	37	808	109
2021	849	346	53	1,248	103
2022	1,723	704	118	2,545	209
2023	2,792	1,140	185	4,117	557
2024	3,947	1,612	262	5,820	787
2025	5,169	2,111	343	7,623	1,031
2026	6,453	2,635	428	9,516	1,287
2027	7,753	3,166	514	11,434	1,546
2028	9,040	3,691	600	13,331	1,802
2029	10,327	4,217	685	15,229	2,059
2030	11,634	4,750	772	17,156	2,320
2031	12,947	5,287	859	19,093	2,581
2032	14,258	5,822	946	21,026	2,843
2033	15,581	6,362	1,034	22,976	3,106
2034	16,913	6,906	1,122	24,941	3,372
2035	18,240	7,448	1,210	26,898	3,637
2036	19,571	7,992	1,298	28,861	3,902
2037	20,912	8,539	1,387	30,839	4,169
2038	22,255	9,088	1,476	32,819	4,437
2039	23,604	9,638	1,566	34,808	4,706
2040	24,949	10,188	1,655	36,792	4,974
2041	26,275	10,729	1,743	38,747	5,239
2042	27,586	11,264	1,830	40,680	5,500
Average Annual Growth Rates					
Previous 10 Years	-	-	-	-	-
Previous 5 Years	50.73%	50.73%	48.74%	50.63%	36.28%
Next 5 Years	35.09%	35.09%	34.29%	35.06%	49.28%
Next 10 Years	23.53%	23.53%	23.16%	23.51%	29.86%
Next 20 Years	14.87%	14.87%	14.70%	14.87%	17.78%

2.2 Distributed Generation Forecast

The distributed generation (DG) forecast is produced by first isolating the estimated historical contribution of DG to Residential and GCI energy and peak load. Historical DG installed capacity amounts are obtained directly from Big Rivers for each of the three distribution Members. Forecasted annual DG amounts are derived from the EIA Annual Energy Outlook.

The DG annual energy values are then fit to monthly and hourly contributions using estimated load shapes obtained by the National Renewable Energy Laboratory (NREL). Ten years of monthly system peaking times are assessed to determine the likelihood of each hour of the day becoming the system peak hour, with each occurrence given a ten percent weighting. Big Rivers coincident peak projections from DG are then created using the hourly load shapes during the likely peaking hours each month. While different DG load shapes are used for each calendar month in the forecast, the figure below shows the average daily load shape used for DG.

Distributed Generation Load Shape



The table below shows the estimated historical contributions for the last five years, and the twenty-year forecast for Residential DG energy, GCI DG energy, additional associated distribution losses, and Big River's coincident peak contributions. Note that the values displayed are negative because they represent a reduction in Big Rivers' energy requirements.

Distributed Generation Forecast

Big Rivers Rural System Distributed Generation Forecast					
Year	Residential Energy (MWh)	Commercial Energy (MWh)	Distribution Losses (MWh)	Total Energy (MWh)	Rural Coincident Peak Contribution (kW)
2018	-1,204	-851	-89	-2,144	-6
2019	-2,584	-1,827	-201	-4,611	-14
2020	-3,649	-2,580	-285	-6,515	-1,435
2021	-5,956	-4,211	-451	-10,618	-64
2022	-6,955	-4,984	-559	-12,497	-77
2023	-7,722	-5,600	-612	-13,934	-3,046
2024	-8,318	-6,213	-668	-15,199	-3,322
2025	-8,912	-6,637	-715	-16,264	-3,555
2026	-9,523	-7,115	-765	-17,402	-3,804
2027	-10,156	-7,516	-812	-18,485	-4,040
2028	-10,810	-7,814	-856	-19,480	-4,258
2029	-11,487	-8,196	-905	-20,588	-4,500
2030	-12,174	-8,437	-947	-21,559	-4,712
2031	-12,905	-8,803	-998	-22,707	-4,963
2032	-13,658	-9,057	-1,044	-23,759	-5,193
2033	-14,483	-9,417	-1,098	-24,998	-5,464
2034	-15,368	-9,731	-1,154	-26,252	-5,738
2035	-16,267	-9,869	-1,201	-27,337	-5,975
2036	-17,209	-10,232	-1,261	-28,702	-6,273
2037	-18,198	-10,593	-1,323	-30,114	-6,582
2038	-19,200	-10,922	-1,384	-31,507	-6,887
2039	-20,287	-11,417	-1,457	-33,161	-7,248
2040	-21,426	-11,876	-1,531	-34,833	-7,614
2041	-22,593	-12,253	-1,602	-36,448	-7,966
2042	-23,857	-12,699	-1,680	-38,236	-8,357
Average Annual Growth Rates					
Previous 10 Years	-	-	-	-	-
Previous 5 Years	58.64%	59.06%	56.06%	58.68%	-22.26%
Next 5 Years	7.87%	8.57%	7.76%	8.14%	120.51%
Next 10 Years	6.98%	6.16%	6.45%	6.64%	52.27%
Next 20 Years	6.36%	4.79%	5.66%	5.75%	26.37%

After the Residential, GCI, and load factor models are run without the presence of EV charging and DG usage, the forecast results for EV charging and DG are added back into each associated area. All class and system forecast data presented in the later sections of this report represent the final forecast with EV and DG included.

3 ENERGY FORECAST RESULTS

3.1 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.

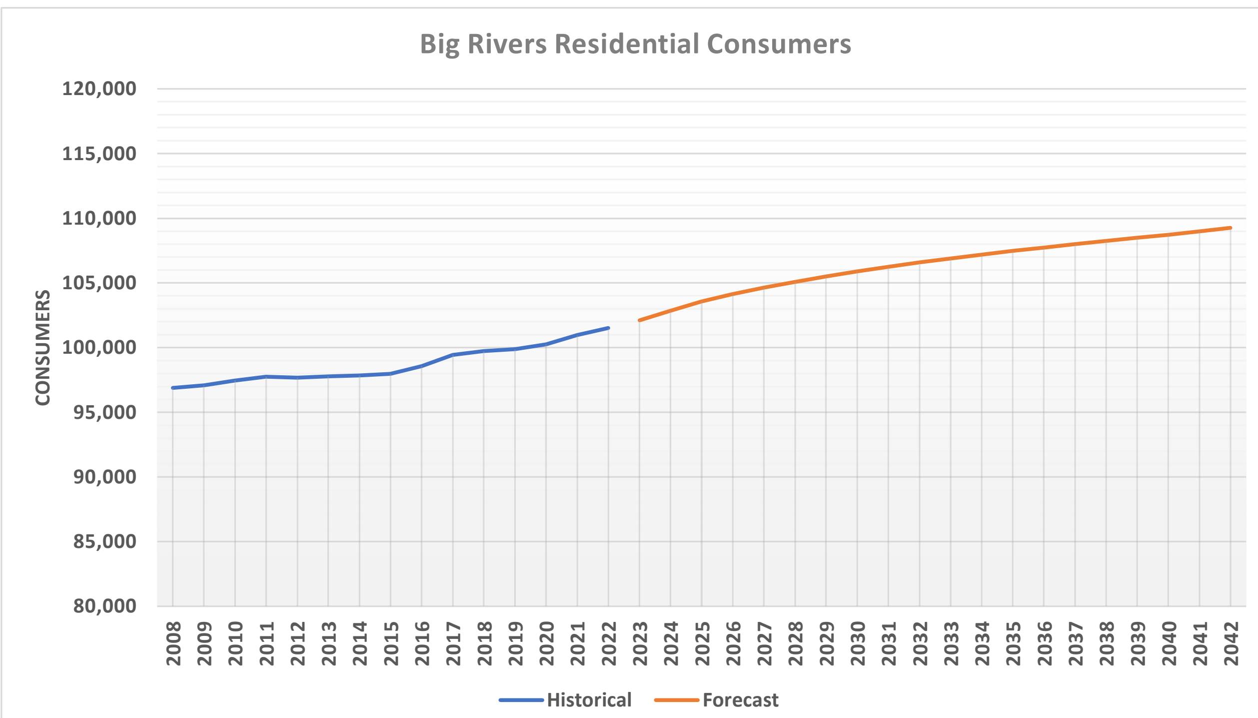
Historical and Projected Residential Consumers, Use per Consumer, and Sales

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
2018	99,724	0.27%	14,955	10.34%	1,491,338	10.64%
2019	99,871	0.15%	14,126	-5.54%	1,410,779	-5.40%
2020	100,257	0.39%	13,564	-3.98%	1,359,904	-3.61%
2021	100,954	0.69%	13,822	1.90%	1,395,391	2.61%
2022	101,506	0.55%	14,093	1.96%	1,430,495	2.52%
2023	102,118	0.60%	14,086	-0.05%	1,438,426	0.55%
2024	102,864	0.73%	14,059	-0.19%	1,446,158	0.54%
2025	103,563	0.68%	13,962	-0.69%	1,445,944	-0.01%
2026	104,147	0.56%	13,928	-0.24%	1,450,553	0.32%
2027	104,633	0.47%	13,905	-0.16%	1,454,971	0.30%
2028	105,087	0.43%	13,891	-0.10%	1,459,775	0.33%
2029	105,504	0.40%	13,889	-0.01%	1,465,364	0.38%
2030	105,888	0.36%	13,894	0.03%	1,471,171	0.40%
2031	106,248	0.34%	13,882	-0.08%	1,474,949	0.26%
2032	106,580	0.31%	13,923	0.29%	1,483,909	0.61%
2033	106,891	0.29%	13,903	-0.14%	1,486,097	0.15%
2034	107,185	0.28%	13,895	-0.05%	1,489,378	0.22%
2035	107,467	0.26%	13,891	-0.03%	1,492,870	0.23%
2036	107,737	0.25%	13,912	0.15%	1,498,803	0.40%
2037	108,000	0.24%	13,911	0.00%	1,502,402	0.24%
2038	108,251	0.23%	13,909	-0.02%	1,505,605	0.21%
2039	108,493	0.22%	13,905	-0.03%	1,508,589	0.20%
2040	108,734	0.22%	13,900	-0.04%	1,511,367	0.18%
2041	108,984	0.23%	13,895	-0.04%	1,514,309	0.19%
2042	109,252	0.25%	13,892	-0.02%	1,517,731	0.23%
Average Annual Growth Rates						
Previous 10 Years	0.39%		-0.63%		-0.24%	
Previous 5 Years	0.41%		0.78%		1.20%	
Next 5 Years	0.61%		-0.27%		0.34%	
Next 10 Years	0.49%		-0.12%		0.37%	
Next 20 Years	0.37%		-0.07%		0.30%	

3.1.1 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 0.6% 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 in the later years of the forecast.

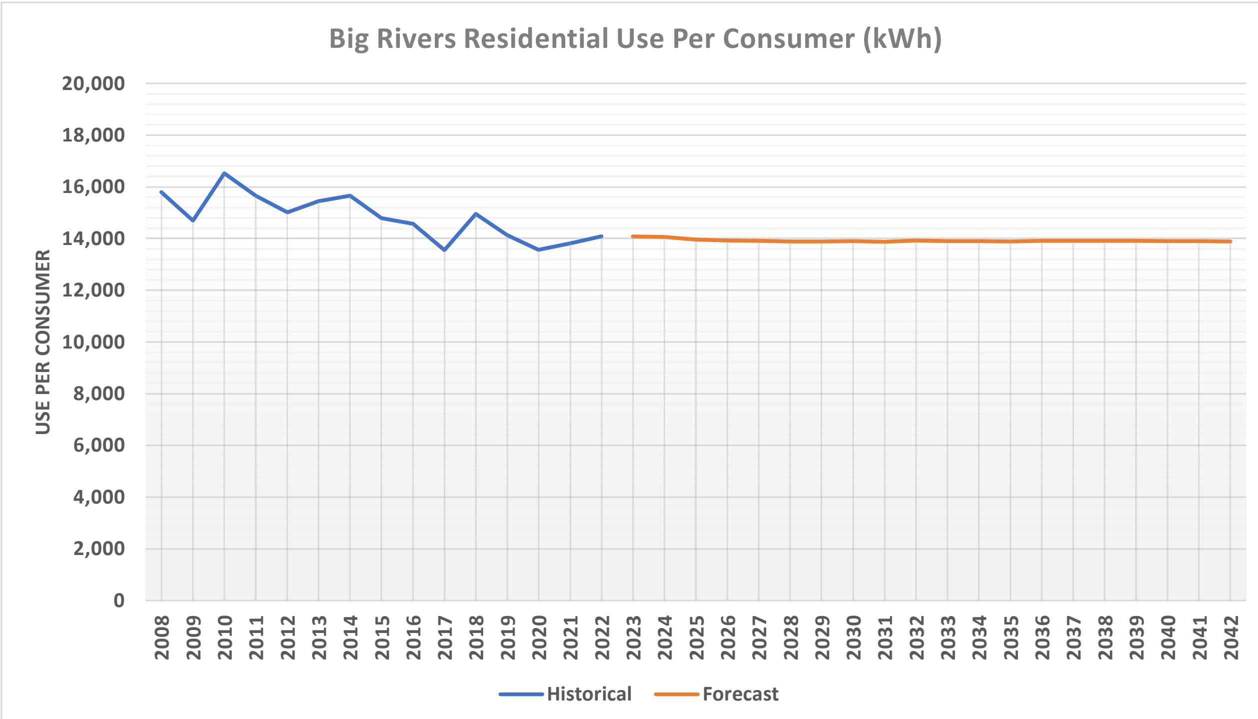
Residential Consumers



3.1.2 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 192 observations from January 2007 to December 2022. The models use electricity prices, alternate fuel prices, cooling and heating degree days, appliance saturation levels, and appliance efficiencies as explanatory variables. Explanatory variable values are projected in future years using 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 five years of the forecast at an average annual rate of -0.3%. 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 fifteen 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 and increases to electric vehicle charging. This results in relatively flat usage per consumer during 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



3.2 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.

3.2.1 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.

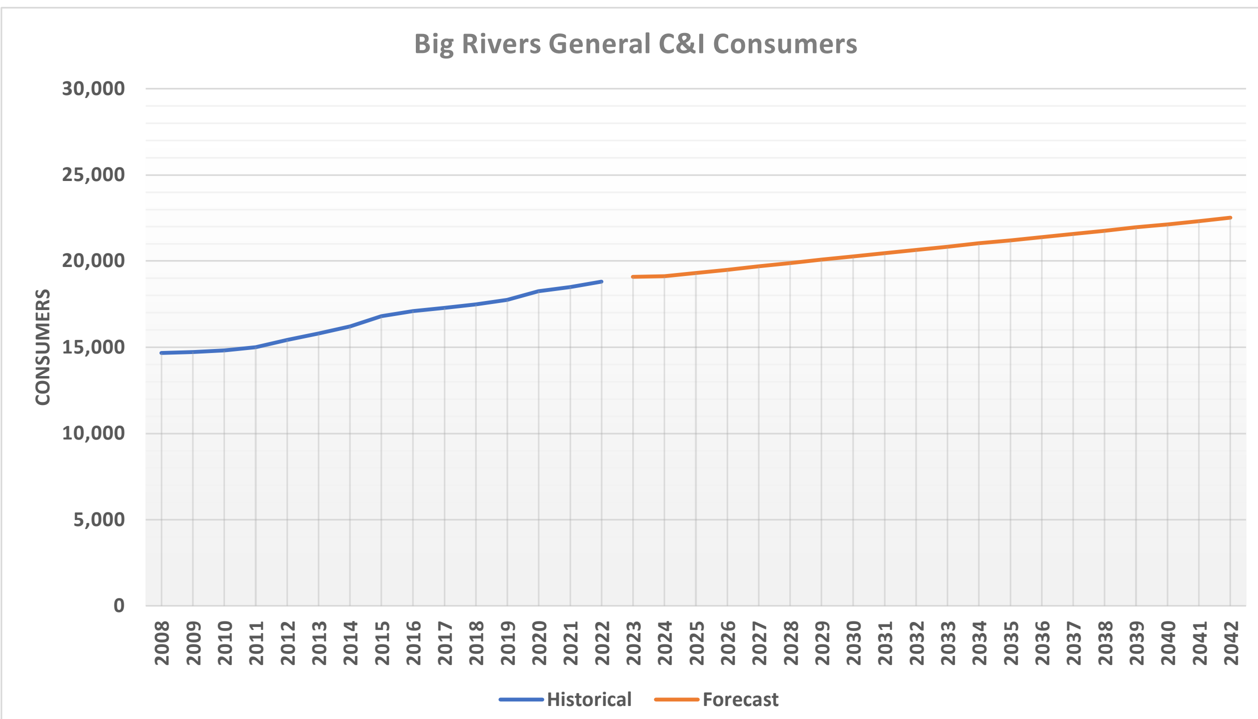
Historical and Projected GCI Consumers, Use per Consumer, and Sales

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
2018	17,482	1.11%	35,358	1.84%	618,143	2.97%
2019	17,749	1.53%	33,201	-6.10%	589,282	-4.67%
2020	18,262	2.89%	30,057	-9.47%	548,908	-6.85%
2021	18,502	1.32%	30,995	3.12%	573,487	4.48%
2022	18,815	1.69%	30,798	-0.64%	579,464	1.04%
2023	19,096	1.50%	30,967	0.55%	591,349	2.05%
2024	19,124	0.15%	31,203	0.76%	596,736	0.91%
2025	19,302	0.93%	30,955	-0.79%	597,500	0.13%
2026	19,505	1.05%	30,903	-0.17%	602,749	0.88%
2027	19,702	1.01%	30,851	-0.17%	607,821	0.84%
2028	19,896	0.99%	30,850	0.00%	613,805	0.98%
2029	20,089	0.97%	30,878	0.09%	620,295	1.06%
2030	20,278	0.94%	30,968	0.29%	627,982	1.24%
2031	20,467	0.93%	30,961	-0.02%	633,667	0.91%
2032	20,653	0.91%	31,207	0.80%	644,527	1.71%
2033	20,839	0.90%	31,135	-0.23%	648,826	0.67%
2034	21,024	0.89%	31,130	-0.02%	654,474	0.87%
2035	21,209	0.88%	31,150	0.06%	660,644	0.94%
2036	21,394	0.87%	31,258	0.35%	668,727	1.22%
2037	21,579	0.86%	31,246	-0.04%	674,242	0.82%
2038	21,764	0.86%	31,223	-0.07%	679,545	0.79%
2039	21,951	0.86%	31,192	-0.10%	684,683	0.76%
2040	22,138	0.85%	31,143	-0.16%	689,438	0.69%
2041	22,326	0.85%	31,097	-0.15%	694,269	0.70%
2042	22,517	0.85%	31,076	-0.07%	699,737	0.79%
Average Annual Growth Rates						
Previous 10 Years	2.00%		-2.23%		-0.27%	
Previous 5 Years	1.70%		-2.37%		-0.71%	
Next 5 Years	0.93%		0.03%		0.96%	
Next 10 Years	0.94%		0.13%		1.07%	
Next 20 Years	0.90%		0.04%		0.95%	

3.2.1.1 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), total retail sales, and total employment within the counties served and are aligned with each distribution cooperatives 2022 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.

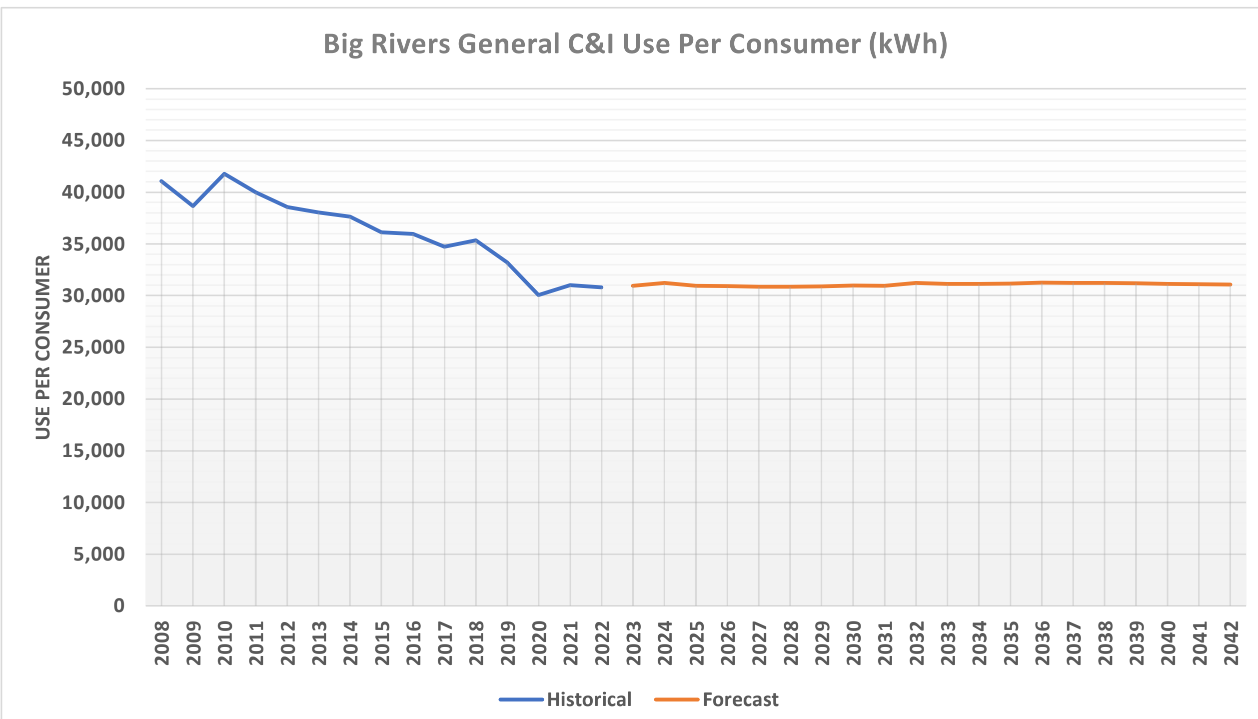
GCI Consumers



3.2.1.2 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



3.2.2 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 2022 the Big Rivers LCI class contained 29 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
2018	30	4.65%	5,114	-0.56%	153,431	4.07%
2019	30	0.83%	5,131	0.32%	155,205	1.16%
2020	30	-0.83%	4,987	-2.81%	149,601	-3.61%
2021	29	-2.78%	5,103	2.33%	148,832	-0.51%
2022	29	-0.57%	5,056	-0.92%	146,626	-1.48%
2023	30	1.72%	5,095	0.77%	150,305	2.51%
2024	33	11.86%	5,671	11.31%	187,146	24.51%
2025	33	0.00%	5,671	0.00%	187,146	0.00%
2026	33	0.00%	5,671	0.00%	187,146	0.00%
2027	33	0.00%	5,671	0.00%	187,146	0.00%
2028	33	-1.01%	5,654	-0.30%	184,693	-1.31%
2029	32	-2.04%	5,618	-0.63%	179,788	-2.66%
2030	32	0.00%	5,618	0.00%	179,788	0.00%
2031	32	0.00%	5,618	0.00%	179,788	0.00%
2032	32	0.00%	5,618	0.00%	179,788	0.00%
2033	32	0.00%	5,618	0.00%	179,788	0.00%
2034	32	0.00%	5,618	0.00%	179,788	0.00%
2035	32	0.00%	5,618	0.00%	179,788	0.00%
2036	32	0.00%	5,618	0.00%	179,788	0.00%
2037	32	0.00%	5,618	0.00%	179,788	0.00%
2038	32	0.00%	5,618	0.00%	179,788	0.00%
2039	32	0.00%	5,618	0.00%	179,788	0.00%
2040	32	0.00%	5,618	0.00%	179,788	0.00%
2041	32	0.00%	5,618	0.00%	179,788	0.00%
2042	32	0.00%	5,618	0.00%	179,788	0.00%
Average Annual Growth Rates						
Previous 10 Years	2.13%		-1.28%		0.82%	
Previous 5 Years	0.23%		-0.34%		-0.11%	
Next 5 Years	2.62%		2.32%		5.00%	
Next 10 Years	0.99%		1.06%		2.06%	
Next 20 Years	0.49%		0.53%		1.02%	

3.2.3 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 sixteen[2] consumers in 2022. The Direct Serve class is expected to add one additional consumer in 2023, and one in 2024. One of the Direct Serve consumers only partially contributes energy to the Big Rivers energy requirements. Beginning in 2025, this load is projected to fully count towards the Big Rivers energy requirements.

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 2022 would be eighteen.

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
2018	21	4.17%	45,783	-0.46%	953,822	3.69%
2019	21	0.80%	45,050	-1.60%	946,040	-0.82%
2020	19	-7.94%	42,657	-5.31%	824,695	-12.83%
2021	16	-17.67%	49,103	15.11%	781,559	-5.23%
2022	16	3.14%	56,001	14.05%	919,357	17.63%
2023	17	5.08%	90,967	62.44%	1,569,178	70.68%
2024	18	4.35%	120,701	32.69%	2,172,620	38.46%
2025	18	0.00%	123,618	2.42%	2,225,127	2.42%
2026	18	0.00%	123,618	0.00%	2,225,127	0.00%
2027	18	0.00%	123,618	0.00%	2,225,127	0.00%
2028	18	0.00%	123,772	0.12%	2,227,894	0.12%
2029	18	0.00%	123,618	-0.12%	2,225,127	-0.12%
2030	18	0.00%	123,618	0.00%	2,225,127	0.00%
2031	18	0.00%	123,618	0.00%	2,225,127	0.00%
2032	18	0.00%	123,772	0.12%	2,227,894	0.12%
2033	18	0.00%	123,618	-0.12%	2,225,127	-0.12%
2034	18	0.00%	123,618	0.00%	2,225,127	0.00%
2035	18	0.00%	123,618	0.00%	2,225,127	0.00%
2036	18	0.00%	123,772	0.12%	2,227,894	0.12%
2037	18	0.00%	123,618	-0.12%	2,225,127	-0.12%
2038	18	0.00%	123,618	0.00%	2,225,127	0.00%
2039	18	0.00%	123,618	0.00%	2,225,127	0.00%
2040	18	0.00%	123,772	0.12%	2,227,894	0.12%
2041	18	0.00%	123,618	-0.12%	2,225,127	-0.12%
2042	18	0.00%	123,618	0.00%	2,225,127	0.00%
Average Annual Growth Rates						
Previous 10 Years	-1.95%		1.46%		-0.52%	
Previous 5 Years	-3.87%		4.02%		-0.01%	
Next 5 Years	1.86%		17.16%		19.34%	
Next 10 Years	0.92%		8.25%		9.25%	
Next 20 Years	0.46%		4.04%		4.52%	

3.3 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
2018	107	3.20%	28,965	-7.23%	3,111	-4.26%
2019	106	-1.01%	28,640	-1.12%	3,045	-2.12%
2020	110	3.68%	27,662	-3.41%	3,050	0.15%
2021	119	7.86%	25,332	-8.42%	3,012	-1.23%
2022	124	4.48%	24,202	-4.46%	3,007	-0.18%
2023	125	0.60%	24,272	0.29%	3,034	0.90%
2024	125	0.00%	24,272	0.00%	3,034	0.00%
2025	125	0.00%	24,272	0.00%	3,034	0.00%
2026	125	0.00%	24,272	0.00%	3,034	0.00%
2027	125	0.00%	24,272	0.00%	3,034	0.00%
2028	125	0.00%	24,272	0.00%	3,034	0.00%
2029	125	0.00%	24,272	0.00%	3,034	0.00%
2030	125	0.00%	24,272	0.00%	3,034	0.00%
2031	125	0.00%	24,272	0.00%	3,034	0.00%
2032	125	0.00%	24,272	0.00%	3,034	0.00%
2033	125	0.00%	24,272	0.00%	3,034	0.00%
2034	125	0.00%	24,272	0.00%	3,034	0.00%
2035	125	0.00%	24,272	0.00%	3,034	0.00%
2036	125	0.00%	24,272	0.00%	3,034	0.00%
2037	125	0.00%	24,272	0.00%	3,034	0.00%
2038	125	0.00%	24,272	0.00%	3,034	0.00%
2039	125	0.00%	24,272	0.00%	3,034	0.00%
2040	125	0.00%	24,272	0.00%	3,034	0.00%
2041	125	0.00%	24,272	0.00%	3,034	0.00%
2042	125	0.00%	24,272	0.00%	3,034	0.00%
Average Annual Growth Rates						
Previous 10 Years	3.11%		-4.35%		-1.38%	
Previous 5 Years	3.61%		-4.97%		-1.54%	
Next 5 Years	0.12%		0.06%		0.18%	
Next 10 Years	0.06%		0.03%		0.09%	
Next 20 Years	0.03%		0.01%		0.04%	

3.4 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 use per consumer forecasts were derived from three years of historical class averages.

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 below 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
2018	5	12.50%	15,618	-38.60%	70	-30.93%
2019	5	11.11%	22,742	45.61%	114	61.79%
2020	5	0.00%	10,043	-55.84%	50	-55.84%
2021	5	0.00%	16,704	66.33%	84	66.33%
2022	5	0.00%	26,082	56.14%	130	56.14%
2023	5	0.00%	18,625	-28.59%	93	-28.59%
2024	5	0.00%	18,625	0.00%	93	0.00%
2025	5	0.00%	18,625	0.00%	93	0.00%
2026	5	0.00%	18,625	0.00%	93	0.00%
2027	5	0.00%	18,625	0.00%	93	0.00%
2028	5	0.00%	18,625	0.00%	93	0.00%
2029	5	0.00%	18,625	0.00%	93	0.00%
2030	5	0.00%	18,625	0.00%	93	0.00%
2031	5	0.00%	18,625	0.00%	93	0.00%
2032	5	0.00%	18,625	0.00%	93	0.00%
2033	5	0.00%	18,625	0.00%	93	0.00%
2034	5	0.00%	18,625	0.00%	93	0.00%
2035	5	0.00%	18,625	0.00%	93	0.00%
2036	5	0.00%	18,625	0.00%	93	0.00%
2037	5	0.00%	18,625	0.00%	93	0.00%
2038	5	0.00%	18,625	0.00%	93	0.00%
2039	5	0.00%	18,625	0.00%	93	0.00%
2040	5	0.00%	18,625	0.00%	93	0.00%
2041	5	0.00%	18,625	0.00%	93	0.00%
2042	5	0.00%	18,625	0.00%	93	0.00%
Average Annual Growth Rates						
Previous 10 Years	0.00%		-11.46%		-11.46%	
Previous 5 Years	4.56%		0.50%		5.09%	
Next 5 Years	0.00%		-6.51%		-6.51%	
Next 10 Years	0.00%		-3.31%		-3.31%	
Next 20 Years	0.00%		-1.67%		-1.67%	

3.5 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 (2018 to 2022) 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**
2018	1,491,338	618,143	153,431	70	3,111	97,684	3,211	**2,366,988**
2019	1,410,779	589,282	155,205	114	3,045	99,557	3,087	**2,261,069**
2020	1,359,904	548,908	149,601	50	3,050	100,542	2,814	**2,164,868**
2021	1,395,391	573,487	148,832	84	3,012	94,909	3,666	**2,219,380**
2022	1,430,495	579,464	146,626	130	3,007	105,760	4,103	**2,269,586**
2023	1,438,426	591,349	150,305	93	3,034	103,804	4,051	**2,291,062**
2024	1,446,158	596,736	187,146	93	3,034	106,266	4,073	**2,343,506**
2025	1,445,944	597,500	187,146	93	3,034	106,290	4,098	**2,344,105**
2026	1,450,553	602,749	187,146	93	3,034	106,764	4,121	**2,354,461**
2027	1,454,971	607,821	187,146	93	3,034	107,220	4,142	**2,364,427**
2028	1,459,775	613,805	184,693	93	3,034	107,614	4,161	**2,373,176**
2029	1,465,364	620,295	179,788	93	3,034	107,945	4,179	**2,380,698**
2030	1,471,171	627,982	179,788	93	3,034	108,598	4,195	**2,394,861**
2031	1,474,949	633,667	179,788	93	3,034	109,056	4,211	**2,404,797**
2032	1,483,909	644,527	179,788	93	3,034	110,016	4,225	**2,425,591**
2033	1,486,097	648,826	179,788	93	3,034	110,330	4,238	**2,432,406**
2034	1,489,378	654,474	179,788	93	3,034	110,764	4,250	**2,441,782**
2035	1,492,870	660,644	179,788	93	3,034	111,234	4,262	**2,451,925**
2036	1,498,803	668,727	179,788	93	3,034	111,915	4,273	**2,466,634**
2037	1,502,402	674,242	179,788	93	3,034	112,359	4,284	**2,476,201**
2038	1,505,605	679,545	179,788	93	3,034	112,773	4,295	**2,485,134**
2039	1,508,589	684,683	179,788	93	3,034	113,170	4,305	**2,493,662**
2040	1,511,367	689,438	179,788	93	3,034	113,539	4,315	**2,501,574**
2041	1,514,309	694,269	179,788	93	3,034	113,919	4,326	**2,509,737**
2042	1,517,731	699,737	179,788	93	3,034	114,353	4,337	**2,519,073**
Average Annual Growth Rates								
Previous 10 Years	-0.24%	-0.27%	0.82%	-11.46%	-1.38%	-1.29%	15.28%	**-0.23%**
Previous 5 Years	1.20%	-0.71%	-0.11%	5.09%	-1.54%	-0.40%	6.87%	**0.53%**
Next 5 Years	0.34%	0.96%	5.00%	-6.51%	0.18%	0.27%	0.19%	**0.82%**
Next 10 Years	0.37%	1.07%	2.06%	-3.31%	0.09%	0.40%	0.29%	**0.67%**
Next 20 Years	0.30%	0.95%	1.02%	-1.67%	0.04%	0.39%	0.28%	**0.52%**

3.6 Total Native System Energy

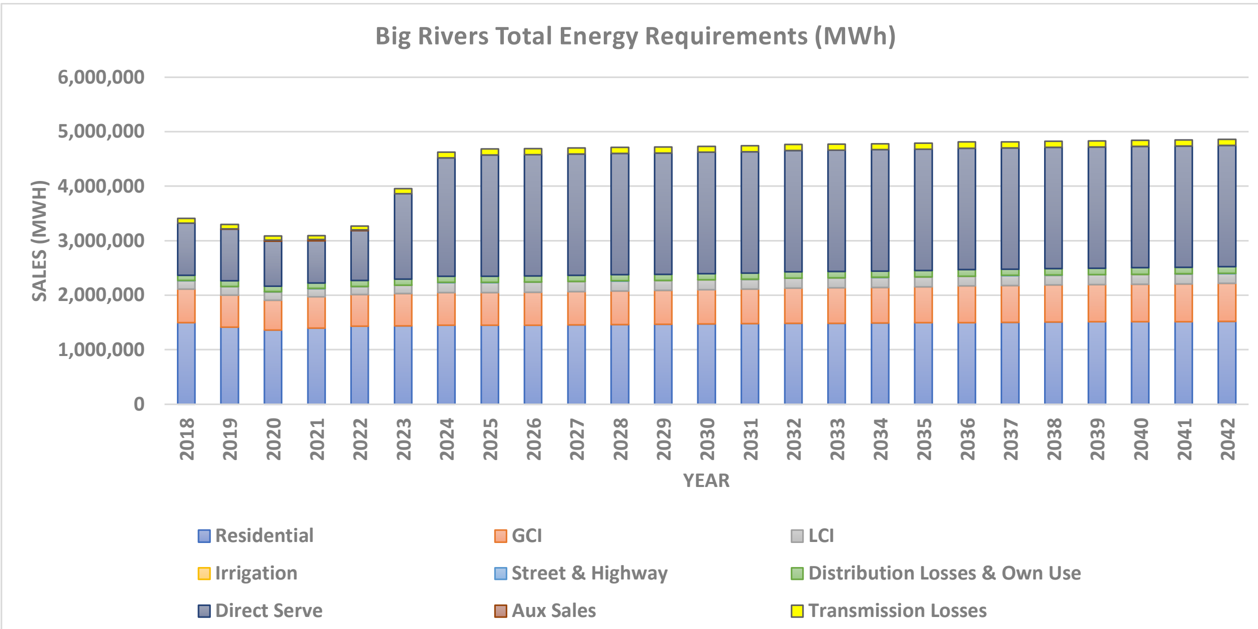
The total system Native energy requirements consists of the Rural system requirements, Direct Serve energy, auxiliary load for certain retired units which has diminished to an immaterial amount, and transmission losses. Transmission losses were 2.29% in 2022 and are forecasted at 2.34% beginning in February 2023 for the remainder of the forecast. The table below shows each component of the Native system energy requirements.

Total Native System Energy Summary

Big Rivers Total Native System Energy Summary (MWh)					
Year	Total Rural Requirements	Direct Serve	Aux Load	Transmission Losses	**Total System Energy Requirements**
2018	2,366,988	953,822	0	86,858	**3,407,668**
2019	2,261,069	946,040	4,434	82,848	**3,294,392**
2020	2,164,868	824,695	16,944	77,120	**3,083,627**
2021	2,219,380	781,559	18,367	71,125	**3,090,431**
2022	2,269,586	919,357	6,184	74,851	**3,269,978**
2023	2,291,062	1,569,178	0	92,323	**3,952,563**
2024	2,343,506	2,172,620	0	108,209	**4,624,335**
2025	2,344,105	2,225,127	0	109,482	**4,678,714**
2026	2,354,461	2,225,127	0	109,730	**4,689,319**
2027	2,364,427	2,225,127	0	109,969	**4,699,523**
2028	2,373,176	2,227,894	0	110,245	**4,711,315**
2029	2,380,698	2,225,127	0	110,359	**4,716,184**
2030	2,394,861	2,225,127	0	110,698	**4,730,686**
2031	2,404,797	2,225,127	0	110,936	**4,740,860**
2032	2,425,591	2,227,894	0	111,501	**4,764,986**
2033	2,432,406	2,225,127	0	111,598	**4,769,131**
2034	2,441,782	2,225,127	0	111,822	**4,778,731**
2035	2,451,925	2,225,127	0	112,065	**4,789,118**
2036	2,466,634	2,227,894	0	112,484	**4,807,012**
2037	2,476,201	2,225,127	0	112,647	**4,813,975**
2038	2,485,134	2,225,127	0	112,861	**4,823,122**
2039	2,493,662	2,225,127	0	113,065	**4,831,854**
2040	2,501,574	2,227,894	0	113,321	**4,842,789**
2041	2,509,737	2,225,127	0	113,451	**4,848,315**
2042	2,519,073	2,225,127	0	113,674	**4,857,874**
Average Annual Growth Rates					
Previous 10 Years	-0.23%	-0.52%	-	7.63%	**-0.17%**
Previous 5 Years	0.53%	-0.01%	-	-0.80%	**0.39%**
Next 5 Years	0.82%	19.34%	-100.00%	8.00%	**7.52%**
Next 10 Years	0.67%	9.25%	-100.00%	4.07%	**3.84%**
Next 20 Years	0.52%	4.52%	-100.00%	2.11%	**2.00%**

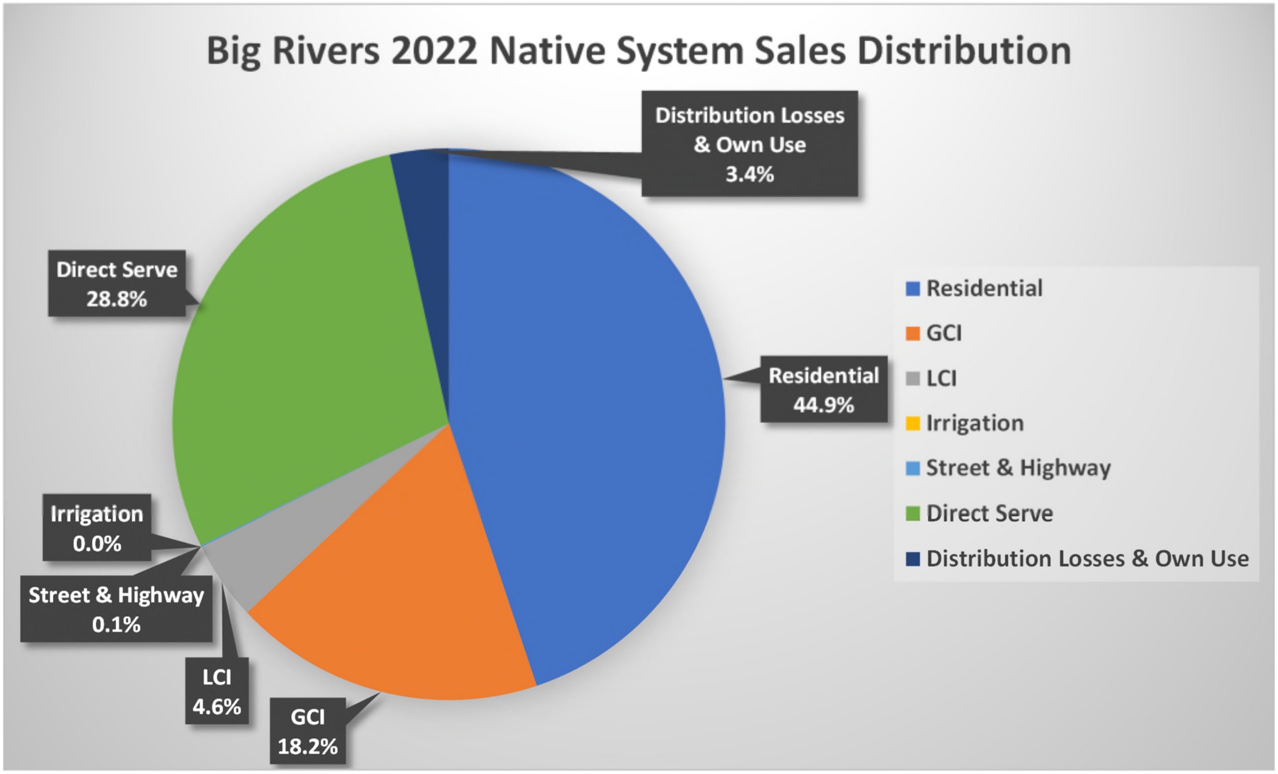
The following graph provides the class components that comprise the total energy requirements for the Big Rivers Native system.

Total Native Energy Forecast



The figure below provides the Native sales[3] distribution by each contributing component for 2022.

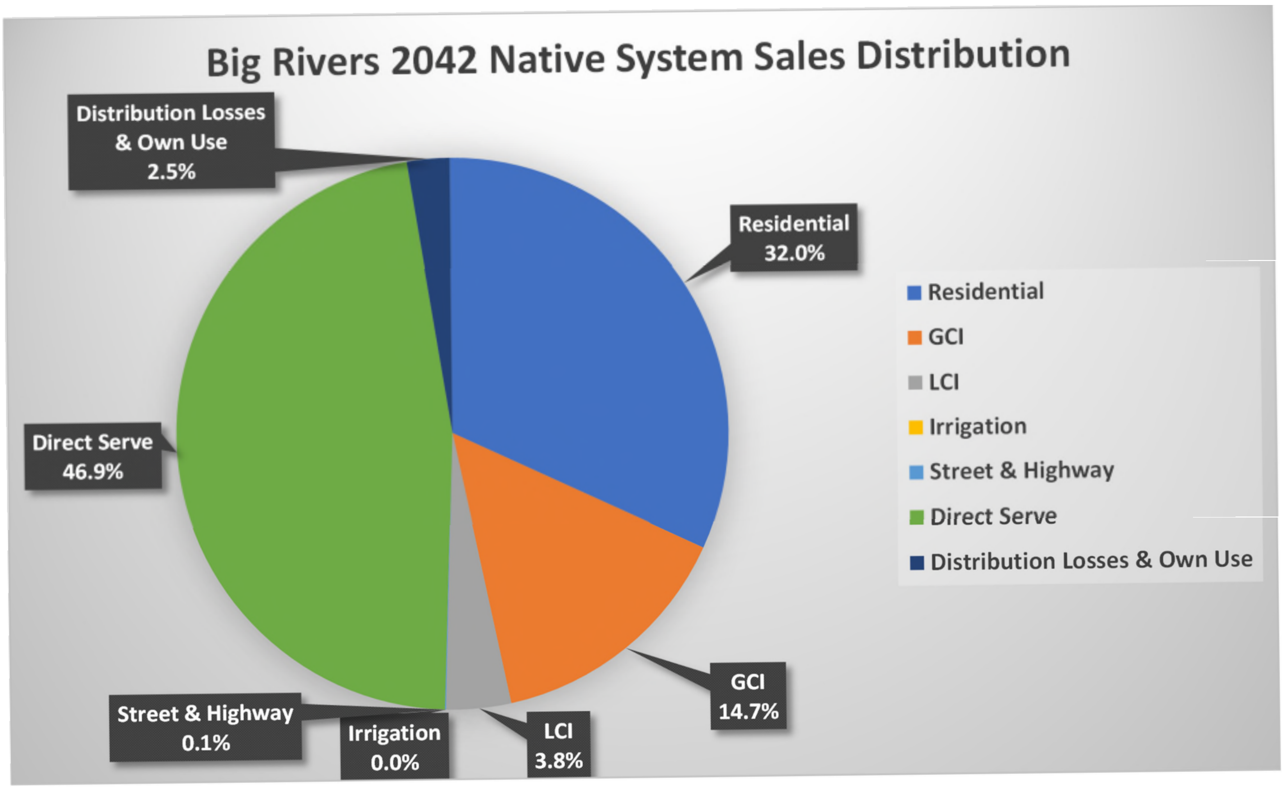
2022 Native System Sales by Class Distribution



[3] Transmission losses are not included in Big Rivers sales figures.

The figure below provides the Native sales distribution by each contributing component for 2042. The largest change in the class distribution is within the Direct Serve class. The Direct Serve class contributed 28.8% of sales in 2022 and is projected to contribute 46.9% in 2042.

2042 Native System Sales by Class Distribution



3.7 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)[4],
- Kentucky Municipal Energy Agency (KYMEA)[5],
- Nebraska Entities[6], and
- Short Term Bilateral Capacity[7].

[4] OMU load is not net of their allocation of Southeastern Power Administration Cumberland system hydropower and a future purchase of renewable power.
[5]KYMEA is a block sale of power and the volume will vary based on economic conditions.
[6] 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. The remaining amount of Nebraska Load is met through forward and spot purchases in the SPP Market.
[7] Short Term bilateral capacity with no associated energy.

Non-Member Energy Sales

Non-Member Sales Under Contract as of 2023	
Calendar Year	MWH
2023	2,106,933
2024	2,106,933
2025	2,106,933
2026	2,106,933
2027	946,757
2028	784,825
2029	324,681

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 & Aux Sales	Transmission Losses	Non-Member Requirements	**Total System Energy Requirements**
2018	2,366,988	953,822	86,858	359,615	**3,767,283**
2019	2,261,069	950,475	82,848	1,591,431	**4,885,823**
2020	2,164,868	841,639	77,120	1,565,152	**4,648,780**
2021	2,219,380	799,926	71,125	2,004,399	**5,094,831**
2022	2,269,586	925,541	74,851	2,210,824	**5,480,803**
2023	2,291,062	1,569,178	92,323	2,106,933	**6,059,496**
2024	2,343,506	2,172,620	108,209	2,106,933	**6,731,268**
2025	2,344,105	2,225,127	109,482	2,106,933	**6,785,647**
2026	2,354,461	2,225,127	109,730	2,106,933	**6,796,252**
2027	2,364,427	2,225,127	109,969	946,757	**5,646,280**
2028	2,373,176	2,227,894	110,245	784,825	**5,496,140**
2029	2,380,698	2,225,127	110,359	324,681	**5,040,865**
2030	2,394,861	2,225,127	110,698	0	**4,730,686**
2031	2,404,797	2,225,127	110,936	0	**4,740,860**
2032	2,425,591	2,227,894	111,501	0	**4,764,986**
2033	2,432,406	2,225,127	111,598	0	**4,769,131**
2034	2,441,782	2,225,127	111,822	0	**4,778,731**
2035	2,451,925	2,225,127	112,065	0	**4,789,118**
2036	2,466,634	2,227,894	112,484	0	**4,807,012**
2037	2,476,201	2,225,127	112,647	0	**4,813,975**
2038	2,485,134	2,225,127	112,861	0	**4,823,122**
2039	2,493,662	2,225,127	113,065	0	**4,831,854**
2040	2,501,574	2,227,894	113,321	0	**4,842,789**
2041	2,509,737	2,225,127	113,451	0	**4,848,315**
2042	2,519,073	2,225,127	113,674	0	**4,857,874**
Average Annual Growth Rates					
Previous 10 Years	-0.36%	4.50%	7.19%	-	5.85%
Previous 5 Years	-0.65%	10.47%	1.23%	-	9.97%
Next 5 Years	0.82%	19.18%	8.00%	-	0.60%
Next 10 Years	0.67%	9.18%	4.07%	-	-1.39%
Next 20 Years	0.52%	4.48%	2.11%	-	-0.60%

4 PEAK DEMAND

4.1 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, auxiliary contribution, 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 Calendar Year CP Demands

Big Rivers Coincident Peak (kW)							
Year	Rural Summer CP	Rural Winter CP	Rural Annual CP	Direct Serve Annual CP	Aux CP	Transmission Losses	**Total Annual CP**
2018	502,549	556,742	556,742	95,530	0	16,382	**668,654**
2019	480,171	490,895	490,895	117,931	0	15,995	**624,821**
2020	460,173	440,685	460,173	105,992	1,756	14,562	**582,483**
2021	487,669	492,854	492,854	96,513	3,046	13,822	**606,235**
2022	510,098	590,652	590,652	99,682	246	16,185	**706,765**
2023	473,447	432,573	473,447	261,127	0	17,601	**752,176**
2024	481,988	484,213	481,988	338,288	0	19,654	**839,930**
2025	482,030	483,438	482,030	359,104	0	20,154	**861,287**
2026	483,992	485,070	483,992	359,104	0	20,201	**863,296**
2027	485,932	486,409	485,932	359,104	0	20,248	**865,283**
2028	488,179	488,028	488,179	359,104	0	20,301	**867,584**
2029	489,348	488,711	489,348	359,104	0	20,329	**868,781**
2030	492,199	490,944	492,199	359,104	0	20,398	**871,701**
2031	494,185	492,406	494,185	359,104	0	20,445	**873,734**
2032	498,436	496,027	498,436	359,104	0	20,547	**878,087**
2033	499,759	496,990	499,759	359,104	0	20,579	**879,441**
2034	501,606	498,509	501,606	359,104	0	20,623	**881,332**
2035	503,602	500,209	503,602	359,104	0	20,671	**883,377**
2036	506,528	502,945	506,528	359,104	0	20,741	**886,373**
2037	508,354	504,790	508,354	359,104	0	20,785	**888,242**
2038	510,032	506,532	510,032	359,104	0	20,825	**889,961**
2039	511,611	508,264	511,611	359,104	0	20,863	**891,577**
2040	513,047	509,905	513,047	359,104	0	20,897	**893,048**
2041	514,533	511,598	514,533	359,104	0	20,933	**894,570**
2042	516,266	513,565	516,266	359,104	0	20,974	**896,344**
Average Annual Growth Rates							
Previous 10 Ye	-0.59%	2.61%	0.88%	-1.23%	-	8.42%	**0.67%**
Previous 5 Yea	0.23%	4.46%	3.21%	-2.71%	-	0.82%	**2.19%**
Next 5 Years	-0.97%	-3.81%	-3.83%	29.22%	-100.00%	4.58%	**4.13%**
Next 10 Years	-0.23%	-1.73%	-1.68%	13.67%	-100.00%	2.42%	**2.19%**
Next 20 Years	0.06%	-0.70%	-0.67%	6.62%	-100.00%	1.30%	**1.20%**

4.2 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 2023	
Calendar Year	MW
2023	344.2
2024	345.7
2025	345.7
2026	345.7
2027	100
2028	100

4.3 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 Big River's CP	Non-Member Sales	Total NCP
2018	668,654	64,608	733,262
2019	624,821	341,253	966,074
2020	582,483	346,820	929,303
2021	606,235	356,940	963,175
2022	706,765	365,780	1,072,545
2023	752,176	344,230	1,096,406
2024	839,930	345,700	1,185,630
2025	861,287	345,700	1,206,987
2026	863,296	345,700	1,208,996
2027	865,283	100,000	965,283
2028	867,584	100,000	967,584
2029	868,781		868,781
2030	871,701		871,701
2031	873,734		873,734
2032	878,087		878,087
2033	879,441		879,441
2034	881,332		881,332
2035	883,377		883,377
2036	886,373		886,373
2037	888,242		888,242
2038	889,961		889,961
2039	891,577		891,577
2040	893,048		893,048
2041	894,570		894,570
2042	896,344		896,344

5 DSM IMPACTS

Clearspring was selected by Big Rivers to complete a Demand-Side Management ("DSM") potential study in 2023 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 DSM spending in the future so additional future DSM impacts are set to zero.

An alternate load forecast scenario has been developed that is derived from the Big Rivers DSM potential study that outlines the projected impacts of a $1,000,000 DSM spending scenario. 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 this spending scenario on total energy requirements and peak demand.

DSM Scenario Impacts

Big Rivers DSM Scenario						
Year	Total Energy Requirements - Base Forecast (MWh)	Impact of DSM Scenario on Energy (MWh)	Total Energy Requirements - DSM Scenario (MWh)	Total CP Forecast - Base Forecast (kW)	Impact of DSM Scenario on Peak (kW)	Total CP Forecast - DSM Scenario (kW)
2018	3,407,668		3,407,668	668,654		668,654
2019	3,294,392		3,294,392	624,821		624,821
2020	3,083,627		3,083,627	582,483		582,483
2021	3,090,431		3,090,431	606,235		606,235
2022	3,269,978		3,269,978	706,765		706,765
2023	3,952,563	0	3,952,563	752,176	0	752,176
2024	4,624,335	9,076	4,615,259	839,930	1,714	838,216
2025	4,678,714	18,152	4,660,562	861,287	3,428	857,859
2026	4,689,319	27,228	4,662,090	863,296	5,143	858,154
2027	4,699,523	36,305	4,663,219	865,283	6,857	858,426
2028	4,711,315	45,381	4,665,934	867,584	8,571	859,013
2029	4,716,184	54,457	4,661,727	868,781	10,285	858,496
2030	4,730,686	63,533	4,667,154	871,701	11,999	859,701
2031	4,740,860	72,609	4,668,251	873,734	13,714	860,020
2032	4,764,986	81,686	4,683,300	878,087	15,428	862,659
2033	4,769,131	90,762	4,678,368	879,441	17,142	862,299
2034	4,778,731	90,762	4,687,969	881,332	17,142	864,190
2035	4,789,118	90,762	4,698,355	883,377	17,142	866,235
2036	4,807,012	90,762	4,716,250	886,373	17,142	869,231
2037	4,813,975	90,762	4,723,213	888,242	17,142	871,100
2038	4,823,122	90,762	4,732,360	889,961	17,142	872,818
2039	4,831,854	90,762	4,741,092	891,577	17,142	874,435
2040	4,842,789	90,762	4,752,027	893,048	17,142	875,905
2041	4,848,315	90,762	4,757,552	894,570	17,142	877,428
2042	4,857,874	90,762	4,767,112	896,344	17,142	879,201

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 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

6.1 Weather Scenarios

Weather is one of the critical components to explain year-to-year variation in load. Because of this, “severe” or 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 twenty-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 twenty 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
2018		2,366,988			556,742			502,549	
2019		2,261,069			490,895			480,171	
2020		2,164,868			440,685			460,173	
2021		2,219,380			492,854			487,669	
2022		2,269,586			590,652			510,098	
2023	2,147,395	2,291,062	2,453,968	368,591	432,573	556,126	428,432	473,447	544,583
2024	2,200,341	2,343,506	2,505,700	422,307	484,213	565,179	437,103	481,988	553,031
2025	2,202,173	2,344,105	2,504,782	422,112	483,438	570,862	437,560	482,030	552,271
2026	2,213,084	2,354,461	2,514,395	424,015	485,070	571,774	439,716	483,992	553,792
2027	2,223,536	2,364,427	2,523,705	425,650	486,409	572,438	441,816	485,932	555,361
2028	2,232,608	2,373,176	2,531,991	427,500	488,028	563,666	444,158	488,179	557,349
2029	2,240,288	2,380,698	2,539,242	428,369	488,711	573,408	445,364	489,348	558,332
2030	2,254,465	2,394,861	2,553,303	430,705	490,944	575,288	448,197	492,199	561,122
2031	2,264,571	2,404,797	2,562,971	432,329	492,406	576,318	450,210	494,185	562,990
2032	2,284,853	2,425,591	2,584,265	435,837	496,027	571,197	454,260	498,436	567,479
2033	2,291,872	2,432,406	2,590,790	436,958	496,990	580,475	455,620	499,759	568,686
2034	2,301,238	2,441,782	2,600,122	438,539	498,509	581,734	457,435	501,606	570,532
2035	2,311,266	2,451,925	2,610,347	440,243	500,209	583,270	459,368	503,602	572,584
2036	2,325,505	2,466,634	2,625,542	442,823	502,945	577,275	462,119	506,528	575,742
2037	2,334,793	2,476,201	2,635,395	444,561	504,790	587,952	463,841	508,354	577,702
2038	2,343,473	2,485,134	2,644,585	446,199	506,532	589,709	465,428	510,032	579,496
2039	2,351,743	2,493,662	2,653,377	447,816	508,264	591,472	466,917	511,611	581,189
2040	2,359,408	2,501,574	2,661,545	449,340	509,905	584,465	468,271	513,047	582,729
2041	2,367,289	2,509,737	2,670,006	450,895	511,598	594,922	469,667	514,533	584,335
2042	2,376,246	2,519,073	2,679,748	452,683	513,565	597,037	471,277	516,266	586,237

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 Native System Weather Scenarios									
Year	Energy (MWh)			Winter CP Demand (kW)			Summer CP Demand (kW)		
	Mild	Base	Extreme	Mild	Base	Extreme	Mild	Base	Extreme
2018		3,407,668			668,654			626,212	
2019		3,294,392			624,821			619,553	
2020		3,083,627			570,433			582,483	
2021		3,090,431			606,235			601,789	
2022		3,269,978			706,765			663,208	
2023	3,805,464	3,952,563	4,119,360	686,610	752,124	878,638	706,082	752,176	825,016
2024	4,477,739	4,624,335	4,790,416	753,057	816,447	898,953	793,969	839,930	912,675
2025	4,533,382	4,678,714	4,843,241	774,172	836,967	927,180	815,752	861,287	933,211
2026	4,544,554	4,689,319	4,853,085	776,120	838,638	928,114	817,960	863,296	934,769
2027	4,555,257	4,699,523	4,862,617	777,795	840,010	928,794	820,110	865,283	936,375
2028	4,567,379	4,711,315	4,873,935	779,689	841,668	918,718	822,508	867,584	938,411
2029	4,572,409	4,716,184	4,878,527	780,579	842,367	929,788	823,743	868,781	939,418
2030	4,586,927	4,730,686	4,892,924	782,970	844,653	931,712	826,644	871,701	942,275
2031	4,597,275	4,740,860	4,902,824	784,634	846,151	932,767	828,705	873,734	944,187
2032	4,620,876	4,764,986	4,927,461	788,226	849,858	926,430	832,853	878,087	948,784
2033	4,625,229	4,769,131	4,931,310	789,373	850,844	937,023	834,245	879,441	950,020
2034	4,634,820	4,778,731	4,940,865	790,992	852,400	938,312	836,103	881,332	951,910
2035	4,645,089	4,789,118	4,951,336	792,737	854,140	939,886	838,082	883,377	954,011
2036	4,662,502	4,807,012	4,969,728	795,379	856,942	932,653	840,900	886,373	957,245
2037	4,669,179	4,813,975	4,976,983	797,158	858,830	944,679	842,663	888,242	959,252
2038	4,678,067	4,823,122	4,986,394	798,836	860,615	946,479	844,288	889,961	961,089
2039	4,686,535	4,831,854	4,995,397	800,492	862,388	948,284	845,812	891,577	962,822
2040	4,697,217	4,842,789	5,006,593	802,052	864,068	940,016	847,199	893,048	964,399
2041	4,702,453	4,848,315	5,012,424	803,645	865,802	951,817	848,628	894,570	966,044
2042	4,711,625	4,857,874	5,022,400	805,475	867,816	953,982	850,277	896,344	967,991

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: “pessimistic” or low economic growth and “optimistic” or 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 2023. 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 2042 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
2018		2,366,988			556,742			502,549	
2019		2,261,069			490,895			480,171	
2020		2,164,868			440,685			460,173	
2021		2,219,380			492,854			487,669	
2022		2,269,586			590,652			510,098	
2023	2,277,835	2,291,062	2,304,310	427,956	432,573	437,199	470,475	473,447	476,424
2024	2,304,890	2,343,506	2,382,256	478,626	484,213	489,814	473,790	481,988	490,216
2025	2,280,437	2,344,105	2,408,131	472,726	483,438	494,196	468,667	482,030	495,468
2026	2,265,420	2,354,461	2,444,198	469,185	485,070	501,058	465,400	483,992	502,732
2027	2,249,876	2,364,427	2,480,125	465,343	486,409	507,657	462,080	485,932	510,027
2028	2,233,038	2,373,176	2,515,030	461,751	488,028	514,589	459,018	488,179	517,703
2029	2,214,896	2,380,698	2,548,909	457,257	488,711	520,574	454,909	489,348	524,297
2030	2,202,798	2,394,861	2,590,153	454,198	490,944	528,248	452,337	492,199	532,744
2031	2,186,616	2,404,797	2,627,144	450,404	492,406	535,139	448,927	494,185	540,322
2032	2,180,019	2,425,591	2,676,431	448,537	496,027	544,451	447,514	498,436	550,468
2033	2,160,653	2,432,406	2,710,615	444,240	496,990	550,894	443,427	499,759	557,451
2034	2,143,441	2,441,782	2,747,908	440,426	498,509	557,992	439,778	501,606	565,073
2035	2,126,776	2,451,925	2,786,327	436,752	500,209	565,340	436,234	503,602	572,918
2036	2,113,813	2,466,634	2,830,347	433,944	502,945	573,925	433,441	506,528	581,908
2037	2,096,264	2,476,201	2,868,777	430,339	504,790	581,547	429,667	508,354	589,699
2038	2,078,045	2,485,134	2,906,745	426,622	506,532	589,101	425,741	510,032	597,376
2039	2,059,317	2,493,662	2,944,555	422,874	508,264	596,693	421,697	511,611	605,003
2040	2,039,959	2,501,574	2,981,904	419,030	509,905	604,228	417,511	513,047	612,516
2041	2,020,692	2,509,737	3,019,811	415,205	511,598	611,873	413,344	514,533	620,142
2042	2,002,188	2,519,073	3,059,475	411,576	513,565	619,905	409,337	516,266	628,134

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 Native System Economic Scenarios

Year	Energy (MWh)			Winter CP Demand (kW)			Summer CP Demand (kW)		
	Low	Base	High	Low	Base	High	Low	Base	High
2018		3,407,668			668,654			626,212	
2019		3,294,392			624,821			619,553	
2020		3,083,627			570,433			582,483	
2021		3,090,431			606,235			601,789	
2022		3,269,978			706,765			663,208	
2023	3,929,332	3,952,563	3,975,815	744,305	752,124	759,954	747,572	752,176	756,783
2024	4,550,418	4,624,335	4,698,389	807,252	816,447	825,655	826,051	839,930	853,839
2025	4,555,511	4,678,714	4,802,285	818,875	836,967	855,107	838,106	861,287	884,547
2026	4,517,350	4,689,319	4,862,000	811,830	838,638	865,552	831,083	863,296	895,661
2027	4,478,648	4,699,523	4,921,572	804,476	840,010	875,729	824,006	865,283	906,808
2028	4,441,310	4,711,315	4,983,078	797,378	841,668	886,247	817,194	867,584	918,345
2029	4,397,262	4,716,184	5,037,573	789,357	842,367	895,795	809,310	868,781	928,775
2030	4,362,089	4,730,686	5,102,590	782,806	844,653	907,072	802,999	871,701	941,101
2031	4,322,735	4,740,860	5,163,252	775,501	846,151	917,548	795,830	873,734	952,538
2032	4,295,769	4,764,986	5,239,597	770,169	849,858	930,502	790,706	878,087	966,604
2033	4,250,581	4,769,131	5,294,291	762,351	850,844	940,519	782,844	879,441	977,432
2034	4,210,173	4,778,731	5,355,263	755,026	852,400	951,207	775,431	881,332	988,913
2035	4,170,324	4,789,118	5,417,387	747,844	854,140	962,150	768,125	883,377	1,000,624
2036	4,136,726	4,807,012	5,488,452	741,550	856,942	974,360	761,587	886,373	1,013,505
2037	4,093,511	4,813,975	5,547,381	734,438	858,830	985,584	754,046	888,242	1,025,161
2038	4,052,072	4,823,122	5,609,043	727,213	860,615	996,739	746,349	889,961	1,036,699
2039	4,010,110	4,831,854	5,670,544	719,956	862,388	1,007,933	738,531	891,577	1,048,186
2040	3,969,851	4,842,789	5,734,891	712,600	864,068	1,019,067	730,567	893,048	1,059,555
2041	3,924,991	4,848,315	5,793,172	705,264	865,802	1,030,315	722,623	894,570	1,071,041
2042	3,883,259	4,857,874	5,856,570	698,129	867,816	1,041,958	714,844	896,344	1,082,902

7 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 20-year normal amounts in each year.

The weather normalized values are calculated using econometric models that identify 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
2013	2,374,921	2,371,974	484,077	481,532	472,452	491,756
2014	2,415,564	2,353,606	616,023	532,703	481,155	481,478
2015	2,325,204	2,332,339	566,553	513,425	504,990	498,614
2016	2,330,037	2,311,958	484,768	476,389	486,690	485,846
2017	2,209,837	2,279,288	474,971	510,612	504,269	473,606
2018	2,366,988	2,286,546	556,742	460,987	502,549	490,584
2019	2,261,069	2,244,669	490,895	472,251	480,171	483,235
2020	2,164,868	2,207,443	440,685	442,727	460,173	469,297
2021	2,219,380	2,245,472	492,854	448,816	487,669	493,313
2022	2,269,586	2,246,531	590,652	465,836	510,098	478,918

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

Native System Weather Normalized

Big Rivers Native System Weather Normalization						
Year	Energy (MWh)		Winter CP Demand (kW)		Summer CP Demand (kW)	
	Actual	Normalized	Actual	Normalized	Actual	Normalized
2013	3,431,215	3,428,216	605,121	597,336	617,356	636,928
2014	3,436,352	3,373,444	750,485	666,007	611,785	619,391
2015	3,339,047	3,346,353	698,949	644,951	629,640	623,131
2016	3,318,766	3,300,280	612,568	609,350	621,295	620,432
2017	3,207,660	3,278,803	606,671	643,125	634,184	602,751
2018	3,407,668	3,325,135	668,654	587,958	626,212	613,932
2019	3,294,392	3,277,573	624,821	605,687	619,553	622,696
2020	3,083,627	3,127,297	570,433	572,528	582,483	591,842
2021	3,090,431	3,117,147	606,235	570,700	601,789	607,565
2022	3,269,978	3,246,384	706,765	579,024	663,208	631,297

8 FORECAST METHODOLOGY

The load forecast process began with discussions with Clearspring Energy to solicit feedback from Big Rivers and representatives of each of the Member systems. 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)[8], electric vehicle and distributed generation projections from the EIA, electric vehicle load shapes from the Department of Energy Alternative Fuels Data Center[9], distributed generation load shapes from the National Renewable Energy Laboratory (NREL)[10], monthly and daily weather data from the Midwest Regional Climate Center (MRCC)[11] and High Plains Regional Climate Center (HPRCC)[12], 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 2022.

8.1 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.

[8] https://www.eia.gov/outlooks/aeo/
[9] https://afdc.energy.gov/vehicles/electric.html
[10] https://pvwatts.nrel.gov/
[11] https://mrcc.illinois.edu/
[12] https://hprcc.unl.edu/

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). Weighted averages were calculated using customized member system county weights based on the service territory of 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 twenty-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 and High Plains Regional Climate Center
Alternative Fuel Prices and Appliance Energy Efficiency	Energy Information Administration
Electric Vehicle Data	Energy Information Administration and Alternative Fuels Data Center
Distributed Generation Data	Energy Information Administration and National Renewable Energy Laboratory
End-Use Appliance Saturations	Big Rivers Survey Reports

8.2 Key Economic and Demographic Assumptions

Various economic and demographic variables are used in the econometric models developed for the 2023 load forecast. The key economic and demographic assumptions for these variables are listed below.

- Real residential electricity prices are projected to [redacted] through the forecast period.
- Air conditioning saturation levels increase slowly through history until capping out at full saturation levels.
- 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 [redacted] through the forecast period.
- Real GRP is projected to [redacted] through the forecast period.
- Real total retail sales are projected to [redacted] through the forecast period.
- Inflation is projected at an average annual rate of 2.1% through the forecast period.
- Cooling degree days, heating degree days, and peak day weather conditions are based on a prior twenty-year average.

8.3 Model Development

Clearspring employs the econometric forecasting approach in the study. This is the same approach used in the prior IRP application. The econometric approach includes several variables that are econometrically estimated to calculate their impacts on loads. The econometric approach has a rich history in load forecasting and, in Clearspring's opinion, is a transparent and accurate method that can quantify the impacts of expected variable changes.

A research paper produced by the Lawrence Berkeley National Laboratory (LBNL) titled "Load Forecasting in Electric Utility Integrated Resource Planning" examined the results of utilities that employed the econometric and SAE approaches. In examining the LBNL calculations on forecasting average annual growth rate errors, there appear to be no significant performance advantages in forecasting accuracy to employing SAE models versus econometric methods.

According to the LBNL study, the econometric approach did have considerably lower bias in regards to forecasting peak demand average annual growth rates, and the econometric approach had slightly better performance when measured by mean absolute average error. The econometric approach is more widely used within the electric utility forecasting industry as illustrated by the LBNL study containing more utilities using the econometric approach and provides a more transparent understanding of the specific variables and their impacts to calculate the forecast.

The table below summarizes the LBNL findings found on pages 11 through 15 of the report. In the tables below, we include PacifiCorp for both SAE and econometric models because the company used both forecast methods to determine results. Regarding energy forecasting, SAE produced an average error of 1.4%, whereas the econometric method produced an average error of 1.2%. In forecasting demand, SAE produced an error of 1.2% versus the econometric average of 0.2%. If we look at the mean absolute errors of the two methodologies, SAE and the econometric approach have the same mean absolute error rate of 1.4% and the econometric approach is slightly better than SAE for demand, 1.1% versus 1.2%.

Modeling Technique Comparison

Modeling Technique Comparison		
Utility	Energy Growth Average Annual Growth Rate Error	Demand Growth Average Annual Growth Rate Error
SAE		
Colorado PSC	2.2%	2.6%
Idaho Power	1.5%	1.0%
PacifiCorp	0.6%	0.0%
SAE Average	**1.4%**	**1.2%**
Econometric		
Avista	1.8%	1.4%
LADWP	0.6%	-1.5%
Nevada Power	2.2%	2.5%
NW	-0.6%	NA
PacifiCorp	0.6%	0.0%
Puget Sound	1.9%	0.3%
Seattle	0.9%	0.5%
Sierra Pacific	2.3%	-1.7%
Econometric Average	**1.2%**	**0.2%**
Econometric Mean Absolute Percentage Error	**1.4%**	**1.1%**

Making conclusions on such a small sample should be done with caution, however; based on this sample used by LBNL, the econometric approach has less bias than SAE as measured by the average error rates for both energy and demand. In looking at mean average percentage error, the econometric approach matches SAE on energy and does slightly better regarding demand.

In the LBNL research, we noticed that the three utilities that used SAE models are much larger in size than the utilities that used the econometric approach. Larger utilities with more load diversity tend to be easier to forecast accurately in terms of average percent error. Despite this advantage in the LBNL sample, the SAE method is either the same or worse than the econometric approach in terms of percent errors or mean absolute percentage errors. To Clearspring’s knowledge, there is no evidence that a SAE model will produce a more accurate forecast than a well-specified econometric model. Our forecasts incorporate end-use components such as heating and air conditioning survey saturations and efficiency projections and we empirically estimated the impacts of those end-use components econometrically.

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 sizes, 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 criteria 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.

8.4 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 forecasts created assume no impact from any future potential service territory acquisitions and no impact from any wholesale or retail competition. The forecasts also assume no impact from new environmental requirements other than any impact indirectly assumed through any third party variables used in the modeling process.

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 forecasted 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.

8.5 Changes in Methodology From 2020 Load Forecast

The 2020 and 2023 load forecasts were both conducted by Clearspring Energy Advisors, LLC. The following list documents changes to the methodological approach used in the two studies.

1. The methodological approach to forecasting electric vehicles and distributed generation outlined in section 2 of this report is new in the 2023 study.
2. Twenty-year historical weather averages are used as the projected weather value in the baseline forecasts for the 2023 study. The 2020 study used fifteen-year averages. In the 2020 study there were challenges in collecting both the peak data and weather station data needed to create all the weather sensitive modeling variables for a full twenty-year history. These challenges no longer exist in the 2023 study and so the change was made to use twenty-year averages.
3. There is one Direct Serve consumer that is currently served as partial requirement that is expected to transition to full requirement in the forecast period. In the 2023 study, the modeling database was revised to include this customer's full load.

9 TRACKING ANALYSIS

9.1 TRACKING 2013 THROUGH 2020 FORECASTS TO ACTUAL VALUES

The following section provides a tracking analysis comparing portions of the 2013, 2015, 2017, and 2020 load forecasts to actual values. The table below shows the total consumer forecast from each of the prior four forecasts. The forecasted consumer values have been consistently over-projected in the 2013, 2015, and 2017 forecasts. The three forecasts over-projected 2022 actual consumer counts by an average of 1.16%. The 2020 forecast was very close to actual consumer counts in 2022. This forecast under-projected consumer counts by only 0.02%.

Total Consumer Tracking Analysis

Comparison of Consumer Forecasts										
'ear	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	2020 Forecast Compared to Actual	2023 Load Forecast
2008	111,691									
2009	111,940									
2010	112,410									
2011	112,885									
2012	113,250									
2013	113,717	113,562	-0.14%							
2014	114,208	114,545	0.30%							
2015	114,934	115,658	0.63%	114,864	-0.06%					
2016	115,852	116,753	0.78%	115,694	-0.14%					
2017	116,898	117,815	0.78%	116,511	-0.33%	116,843	-0.05%			
2018	117,369	118,818	1.23%	117,529	0.14%	117,809	0.38%			
2019	117,782	119,796	1.71%	118,538	0.64%	118,737	0.81%			
2020	118,684	120,784	1.77%	119,523	0.71%	119,781	0.92%	118,667	-0.01%	
2021	119,625	121,772	1.79%	120,465	0.70%	120,701	0.90%	119,616	-0.01%	
2022	120,496	122,734	1.86%	121,386	0.74%	121,568	0.89%	120,474	-0.02%	
2023		123,678		122,313		122,434		121,218		121,391
2024		124,582		123,206		123,299		121,886		122,169
2025		125,473		124,067		124,197		122,470		123,046
2026		126,366		124,910		125,044		122,883		123,832
2027				125,712		125,822		123,157		124,516
2028				126,511		126,786		123,391		125,164
2029						127,688		123,579		125,773
2030						128,589		123,723		126,346
2031						129,438		123,830		126,894
2032						130,286		123,901		127,413
2033						131,134		123,947		127,910
2034						131,983		123,976		128,389
2035						132,831		123,991		128,856
2036						133,680		123,997		129,311
2037								124,003		129,758
2038								124,014		130,195
2039								124,033		130,624
2040										131,052
2041										131,491
2042										131,949

The following table provides a breakdown of the 2020 and 2023 forecasted consumer values by Residential and GCI class. The 2020 forecast study over-projected 2022 Residential consumers by 161. The GCI consumer count for 2022 was under-projected by 174 in the 2020 forecast study.

Consumer Tracking Analysis by Class

Comparison of Consumer Forecasts by Class								
Year	Residential Actual	2020 Residential Load Forecast	2020 Forecast Compared to Actual	2023 Residential Load Forecast	GCI Actual	2020 GCI Load Forecast	2020 Forecast Compared to Actual	2023 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				17,290			
2018	99,724				17,482			
2019	99,871				17,749			
2020	100,257	100,314	0.06%		18,262	18,188	-0.41%	
2021	100,954	101,044	0.09%		18,502	18,406	-0.52%	
2022	101,506	101,667	0.16%		18,815	18,641	-0.92%	
2023		102,180		102,118		18,872		19,096
2024		102,616		102,864		19,104		19,124
2025		102,990		103,563		19,314		19,302
2026		103,193		104,147		19,524		19,505
2027		103,256		104,633		19,734		19,702
2028		103,282		105,087		19,942		19,896
2029		103,263		105,504		20,150		20,089
2030		103,200		105,888		20,357		20,278
2031		103,101		106,248		20,562		20,467
2032		102,970		106,580		20,765		20,653
2033		102,815		106,891		20,966		20,839
2034		102,644		107,185		21,166		21,024
2035		102,460		107,467		21,365		21,209
2036		102,269		107,737		21,562		21,394
2037		102,079		108,000		21,759		21,579
2038		101,894		108,251		21,954		21,764
2039		101,718		108,493		22,149		21,951
2040				108,734				22,138
2041				108,984				22,326
2042				109,252				22,517

The following table compares the 2013, 2015, 2017 and 2020 forecasts to actual energy values for the Native system. The four forecasts over-projected 2020 energy values by an average of 14.2%. Actual values in 2021 were over-projected by an average of 14.3% across the forecasts, and 2022 values were over-projected by an average of 16.7%. Comparing the prior forecasts to weather normalized energy values explains some of the fluctuation in the comparisons of these three years. Other reasons for past over-projections include delayed construction of a large Direct Serve load and possible drops in load due to the 2020 COVID-19 pandemic.

Total Native Energy Tracking Analysis

Comparison of Native Energy Forecasts (GWh)											
ear	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	2020 Forecast Compared to Actual	2023 Load Forecast
2008											
2009											
2010											
2011											
2012	3,290	3,305									
2013	3,385	3,382	3,350	-1.04%							
2014	3,382	3,320	3,408	0.77%							
2015	3,272	3,279	3,384	3.42%	3,318	1.40%					
2016	3,245	3,227	3,373	3.93%	3,413	5.17%					
2017	3,130	3,199	3,394	8.44%	3,452	10.30%	3,259	4.13%			
2018	3,321	3,240	3,416	2.87%	3,469	4.46%	3,343	0.67%			
2019	3,212	3,195	3,437	7.02%	3,486	8.55%	3,433	6.90%			
2020	3,007	3,049	3,460	15.08%	3,496	16.28%	3,473	15.52%	3,302	9.81%	
2021	3,019	3,045	3,485	15.42%	3,514	16.38%	3,475	15.09%	3,330	10.28%	
2022	3,195	3,172	3,511	9.89%	3,536	10.67%	3,479	8.88%	4,384	37.21%	
2023			3,537		3,560		3,481		4,396		3,860
2024			3,562		3,581		3,490		4,409		4,516
2025			3,589		3,602		3,495		4,416		4,569
2026			3,616		3,624		3,502		4,425		4,580
2027			3,644		3,642		3,509		4,427		4,590
2028					3,669		3,521		4,437		4,601
2029					3,691		3,526		4,439		4,606
2030					3,714		3,535		4,443		4,620
2031					3,737		3,544		4,448		4,630
2032					3,760		3,557		4,458		4,653
2033					3,782		3,562		4,463		4,658
2034					3,805		3,572		4,467		4,667
2035							3,581		4,471		4,677
2036							3,593		4,475		4,695
2037									4,479		4,701
2038									4,483		4,710
2039									4,487		4,719
2040											4,729
2041											4,735
2042											4,744

The following table provides a breakdown of the 2020 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 1.9% high during the 2020-2022 forecast period. The GCI forecast was an average of 10.7% high during the 2020-2022 forecast period compared to weather normalized actual values. The drop in GCI load corresponds directly with the timing of the 2020 COVID-19 impact, and this could have been a major contributing factor for these deviations between projected and actual load.

Energy Tracking Analysis by Class

Comparison of Class Energy Forecasts (GWh)													
Year	Residential Actual	Residential Weather Normalization	2020 Residential Load Forecast	2020 Forecast Compared to Actual	2020 Forecast Compared to Weather Normalization	2023 Residential Load Forecast	GCI Actual	GCI Weather Normalization	2020 GCI Load Forecast	2020 Forecast Compared to Actual	2020 Forecast Compared to Weather Normalization	2023 GCI Load Forecast
2008	1,529	1,509					603	601				
2009	1,427	1,449					569	578				
2010	1,611	1,490					619	591				
2011	1,530	1,516					600	596				
2012	1,466	1,480					595	594				
2013	1,510	1,506					601	601				
2014	1,532	1,480					610	601				
2015	1,448	1,450					607	610				
2016	1,436	1,423					615	608				
2017	1,348	1,403					600	612				
2018	1,491	1,433					618	598				
2019	1,411	1,399					589	584				
2020	1,360	1,392	1,424	4.71%	2.28%		549	556	621	13.11%	11.74%	
2021	1,395	1,414	1,432	2.61%	1.28%		573	577	630	9.88%	9.15%	
2022	1,430	1,410	1,439	0.59%	2.02%		579	574	639	10.29%	11.27%	
2023			1,442			1,438			647			591
2024			1,444			1,446			655			597
2025			1,447			1,446			662			598
2026			1,449			1,451			668			603
2027			1,446			1,455			673			608
2028			1,446			1,460			680			614
2029			1,444			1,465			687			620
2030			1,441			1,471			693			628
2031			1,439			1,475			700			634
2032			1,439			1,484			709			645
2033			1,437			1,486			716			649
2034			1,434			1,489			722			654
2035			1,432			1,493			729			661
2036			1,430			1,499			735			669
2037			1,428			1,502			741			674
2038			1,425			1,506			747			680
2039			1,423			1,509			753			685
2040						1,511						689
2041						1,514						694
2042						1,518						700

The following table compares the 2013, 2015, 2017, and 2020 forecasts to actual peak values for the Native system. The four forecasts over-projected 2020 peak values by an average of 13.9%. The 2021 actual values were over-projected by an average of 10.1% across the four forecasts, and 2022 values were over-projected by an average of 1.8%. 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, 2020 was over-projected by an average of 12.1%, 2021 was over-projected by 9.8%, and 2022 was over-projected by 14.0%. The over-projection of peak on the 2020 load forecast for year 2022 is attributable to a delay in a new Direct Serve load.

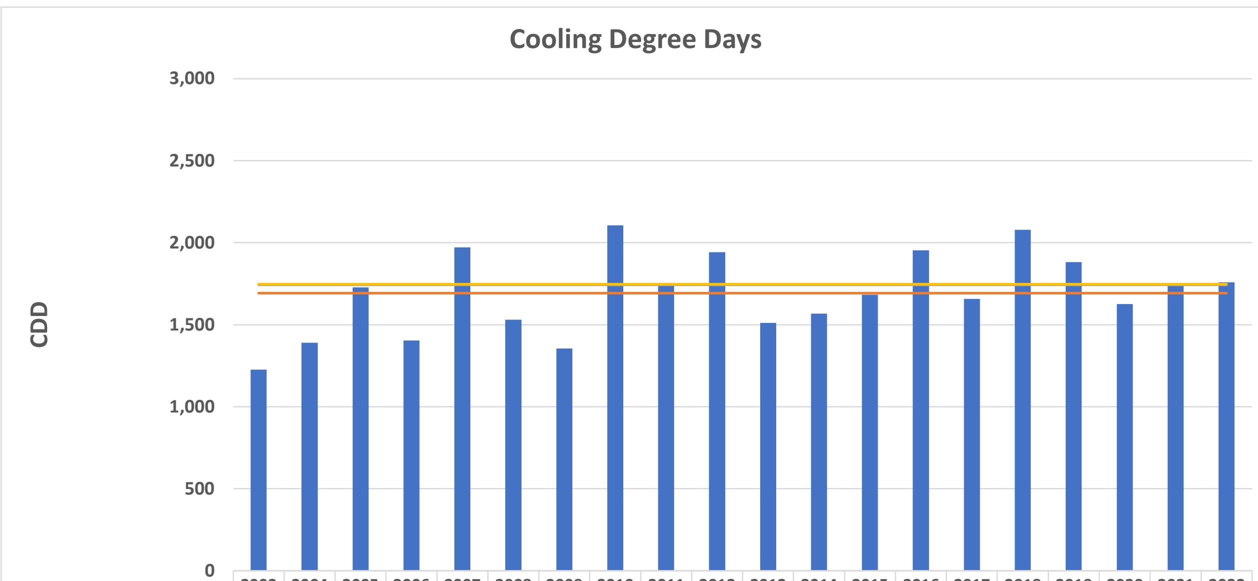
Native Peak Tracking Analysis

Comparison of Native Peak Forecasts (MW)

	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	2020 Forecast Compared to Actual	2023 Load Forecast
2008	618	621									
2009	673	621									
2010	662	626									
2011	659	646									
2012	661	627									
2013	617	637	632	2.37%							
2014	750	666	635	-15.39%							
2015	699	645	635	-9.15%	661	-5.43%					
2016	621	620	637	2.53%	683	9.93%					
2017	634	643	642	1.23%	691	8.96%	648	2.18%			
2018	669	614	645	-3.54%	693	3.64%	660	-1.29%			
2019	625	623	649	3.87%	695	11.23%	673	7.71%			
2020	582	592	653	12.11%	697	19.66%	676	16.05%	627	7.59%	
2021	606	608	658	8.54%	701	15.63%	678	11.84%	632	4.27%	
2022	707	631	663	-6.19%	704	-0.39%	679	-3.93%	832	17.78%	
2023			668		707		680		835		752
2024			673		711		681		836		840
2025			678		715		682		838		861
2026			683		720		683		840		863
2027					724		685		840		865
2028					729		686		841		868
2029					734		688		843		869
2030					740		689		843		872
2031					745		691		844		874
2032					750		693		846		878
2033					755		695		847		879
2034					761		696		848		881
2035							698		849		883
2036							700		850		886
2037									851		888
2038									851		890
2039									852		892
2040											893
2041											895
2042											896

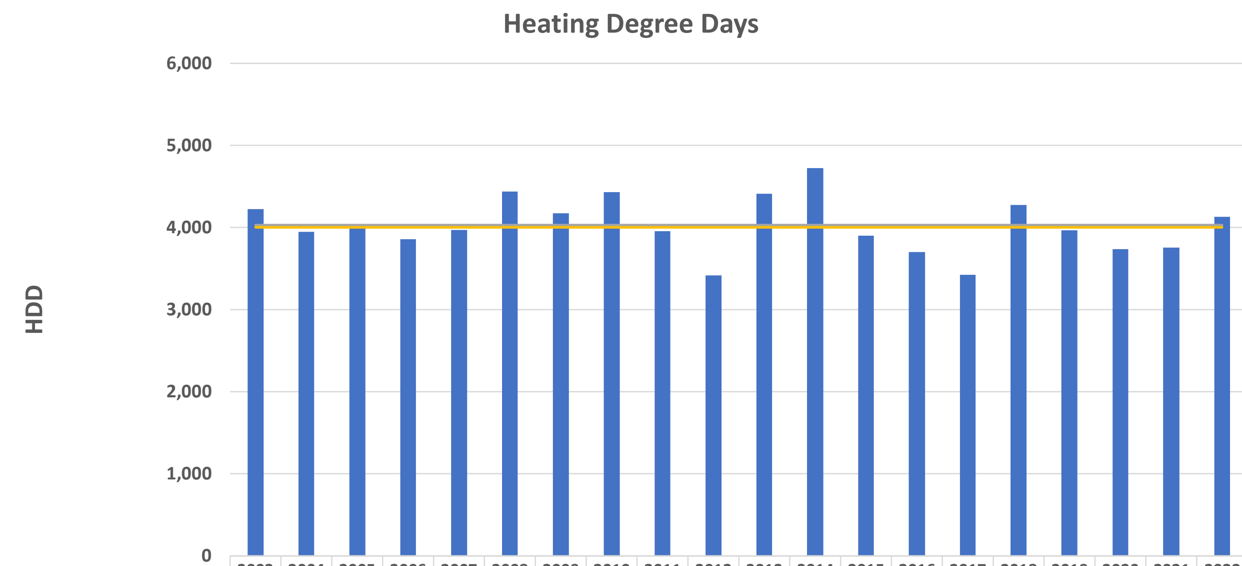
The historical weather normalized values in this section were completed using twenty-year average values as the definition for normal weather. This is consistent with the normal weather definition used throughout the forecast. If the time span used to define normal weather is shortened to a ten-year average, the normal CDD values would be slightly higher and the normal HDD values would be slightly lower. If a fifteen-year average is used, the normal CDD values would be slightly higher and the HDD values would be nearly identical at a difference of only six HDDs. Differences at these amounts would cause very little change to the energy forecast and in most cases a change in the time span used to define normal weather 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 twenty years as well as the ten, fifteen, and twenty-year averages.

Cooling Degree Day Normal Values



	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
CDD	1,225	1,391	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	1,627	1,741	1,759
20 Year Average CDD	1,693	1,693	1,693	1,693	1,693	1,693	1,693	1,693	1,693	1,693	1,693	1,693	1,693	1,693	1,693	1,693	1,693	1,693	1,693	1,693
15 Year Average CDD	1,743	1,743	1,743	1,743	1,743	1,743	1,743	1,743	1,743	1,743	1,743	1,743	1,743	1,743	1,743	1,743	1,743	1,743	1,743	1,743
10 Year Average CDD	1,746	1,746	1,746	1,746	1,746	1,746	1,746	1,746	1,746	1,746	1,746	1,746	1,746	1,746	1,746	1,746	1,746	1,746	1,746	1,746

Heating Degree Day Normal Values

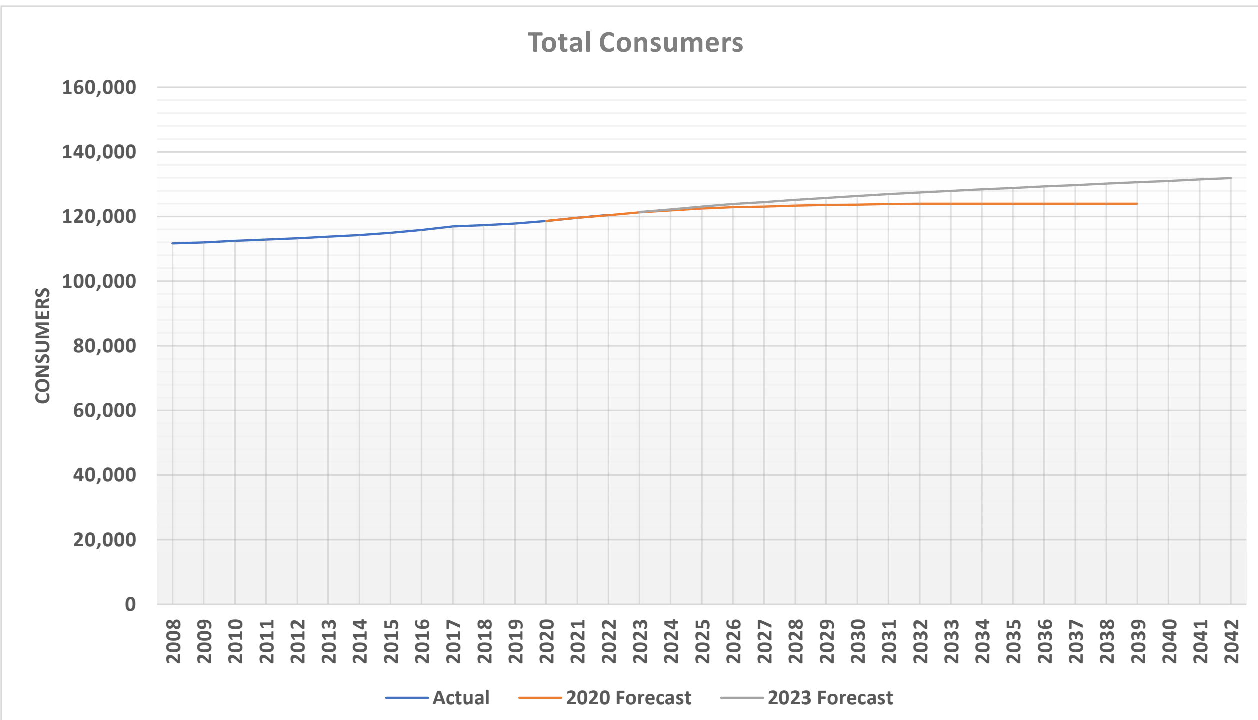


	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
HDD	4,226	3,945	4,027	3,858	3,970	4,437	4,175	4,432	3,955	3,416	4,410	4,722	3,903	3,699	3,423	4,277	3,966	3,738	3,755	4,129
20 Year Average HDD	4,023	4,023	4,023	4,023	4,023	4,023	4,023	4,023	4,023	4,023	4,023	4,023	4,023	4,023	4,023	4,023	4,023	4,023	4,023	4,023
15 Year Average HDD	4,029	4,029	4,029	4,029	4,029	4,029	4,029	4,029	4,029	4,029	4,029	4,029	4,029	4,029	4,029	4,029	4,029	4,029	4,029	4,029
10 Year Average HDD	4,002	4,002	4,002	4,002	4,002	4,002	4,002	4,002	4,002	4,002	4,002	4,002	4,002	4,002	4,002	4,002	4,002	4,002	4,002	4,002

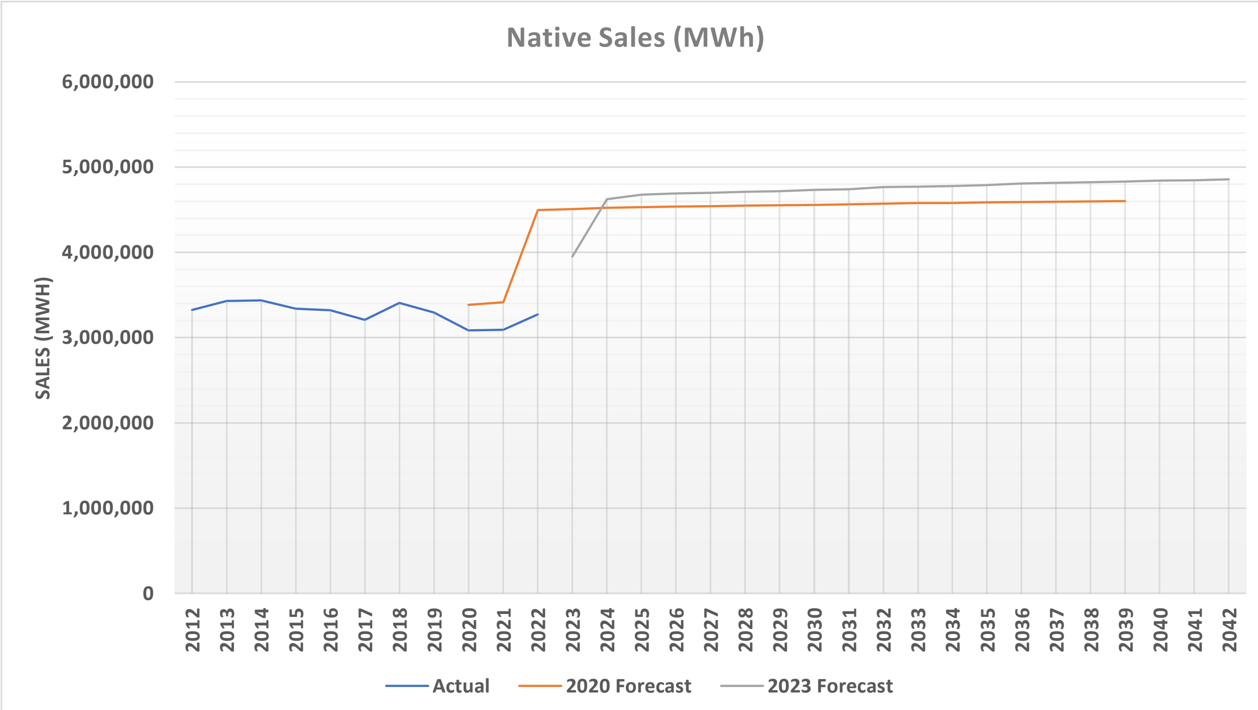
9.2 Comparisons to the 2020 Forecast By Class

The following figures display comparisons to the 2020 Load Forecast results. Comparisons are shown for Rural totals, total system load, and comparisons for each separate class.

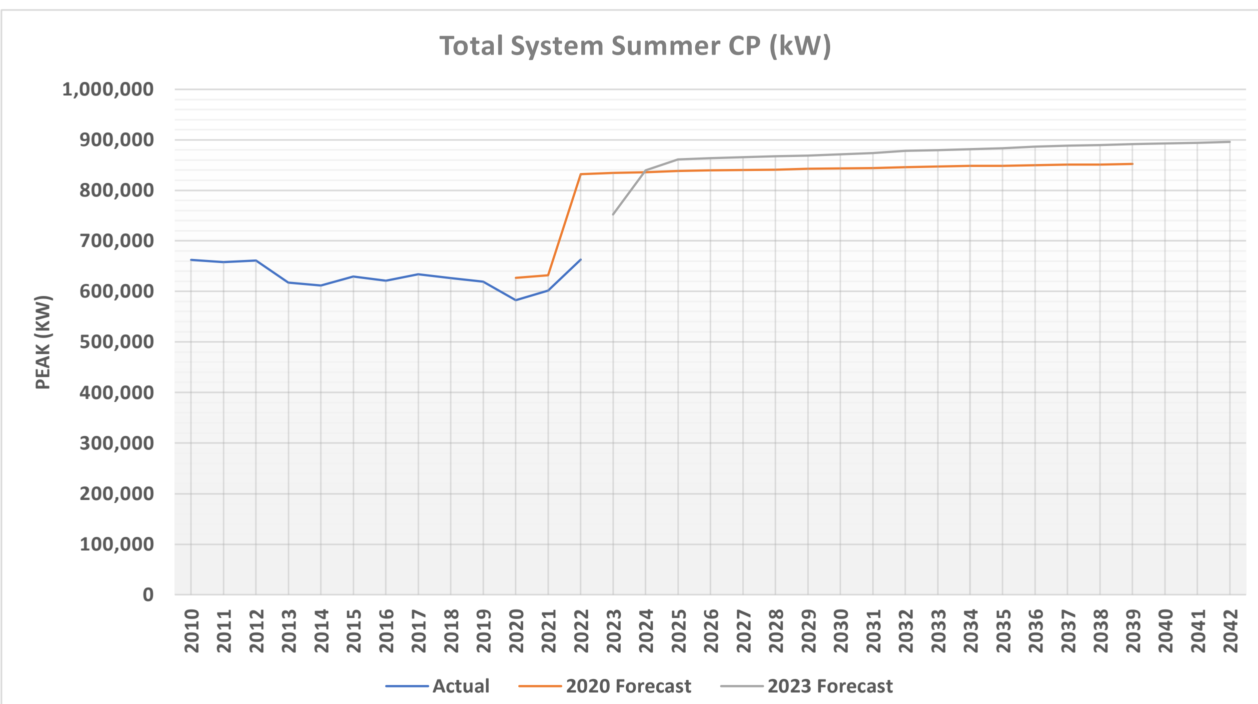
2020 Forecast Total Consumers Comparison



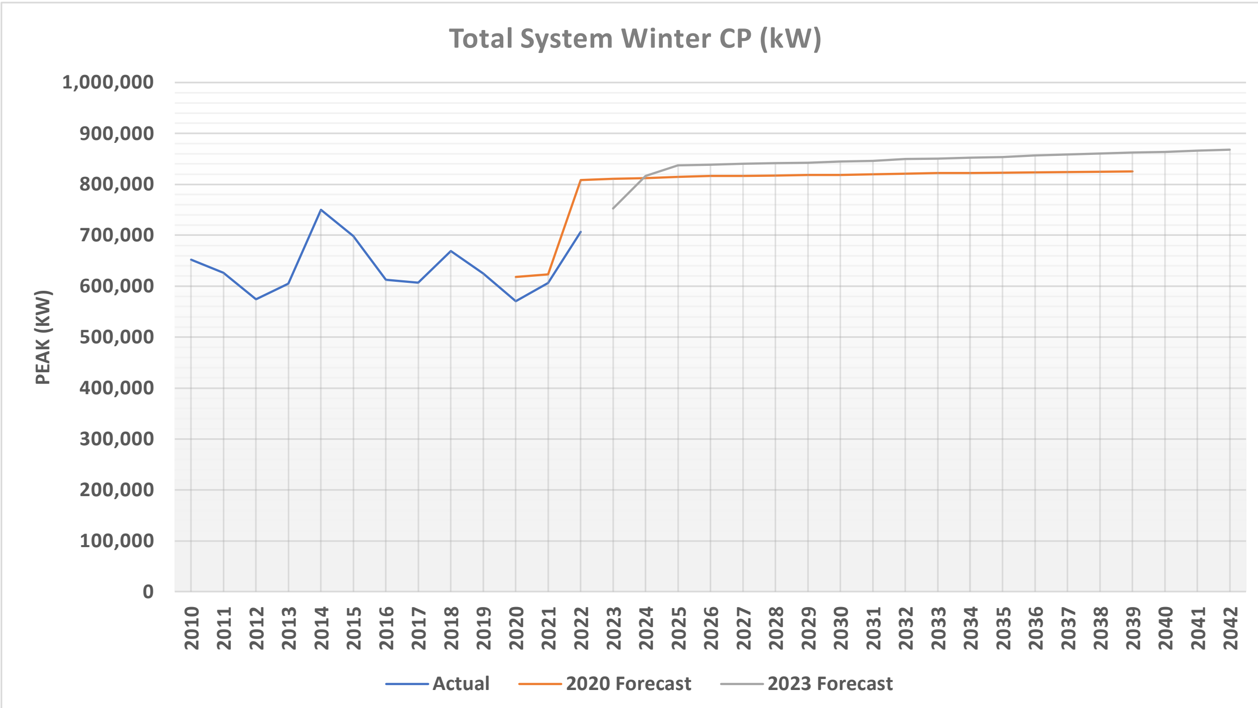
2020 Forecast Native Sales Comparison



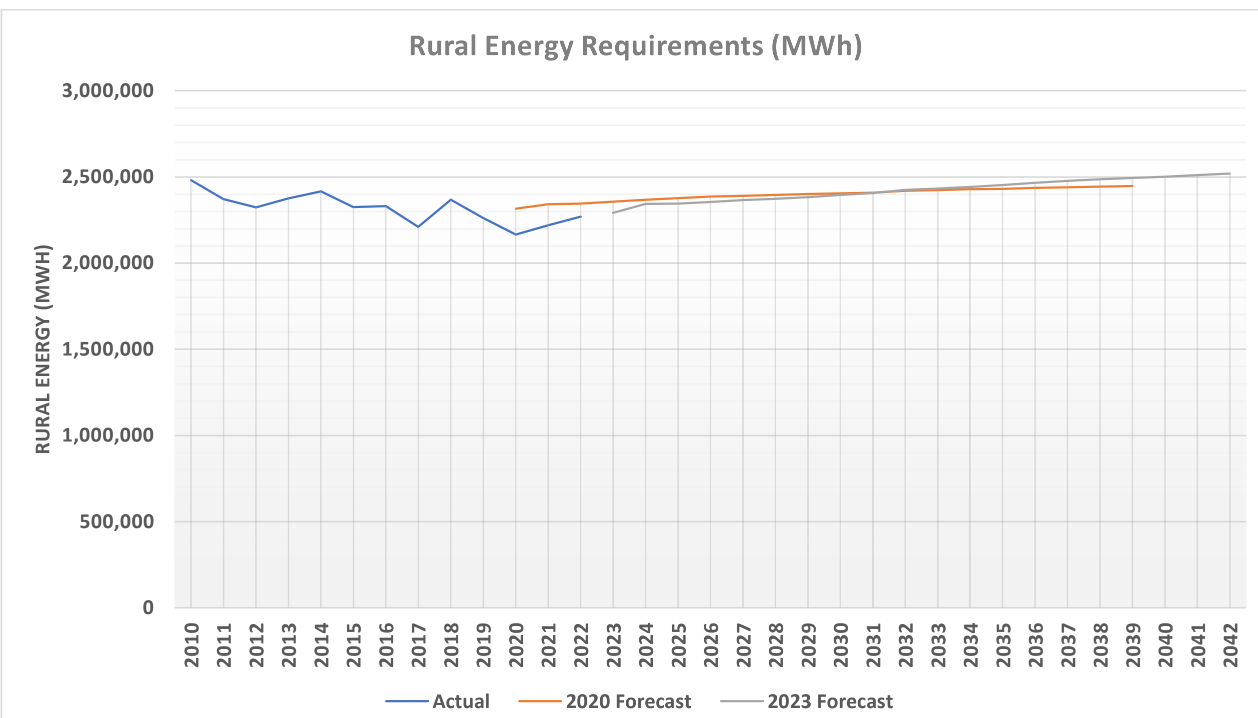
2020 Forecast Summer CP Comparison



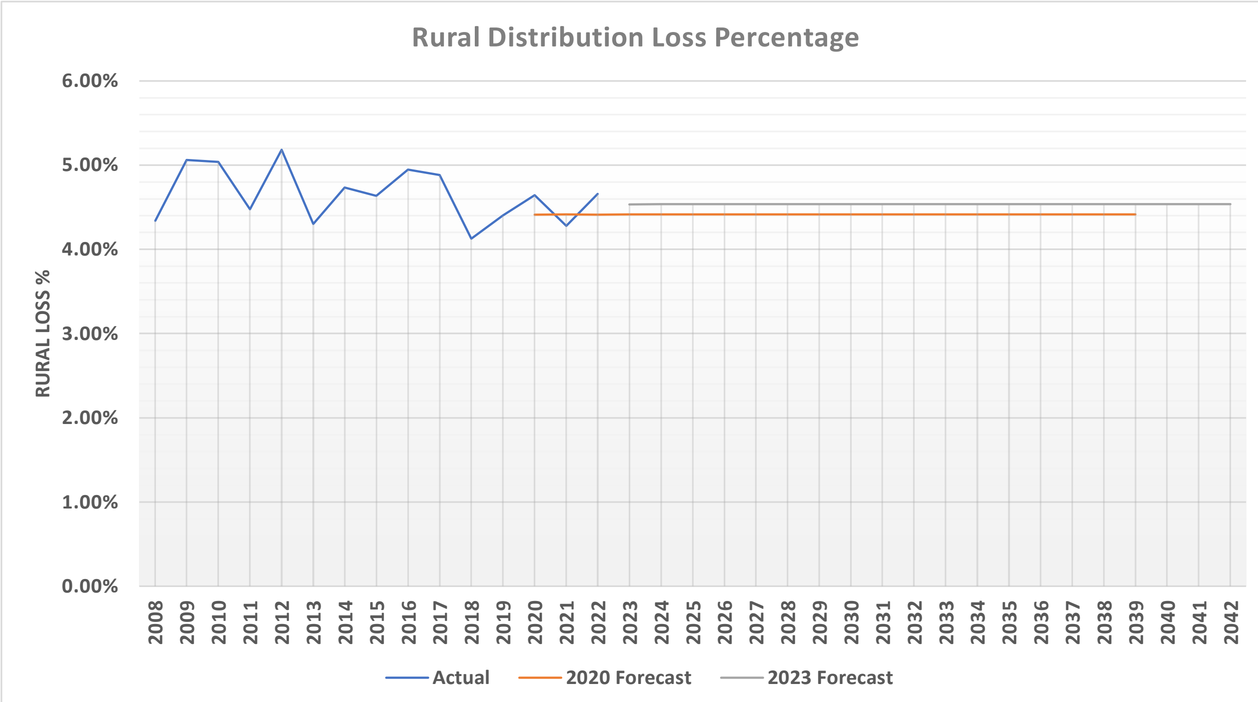
2020 Forecast Winter CP Comparison



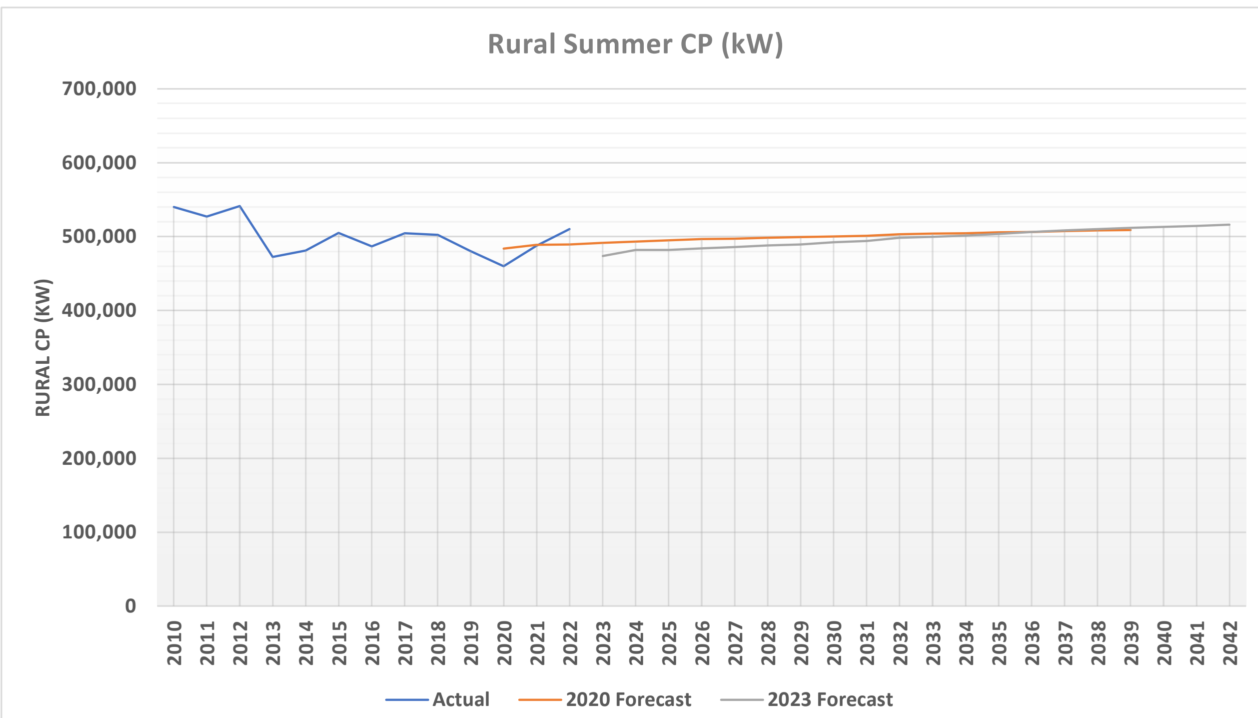
2020 Forecast Rural Energy Requirements Comparison



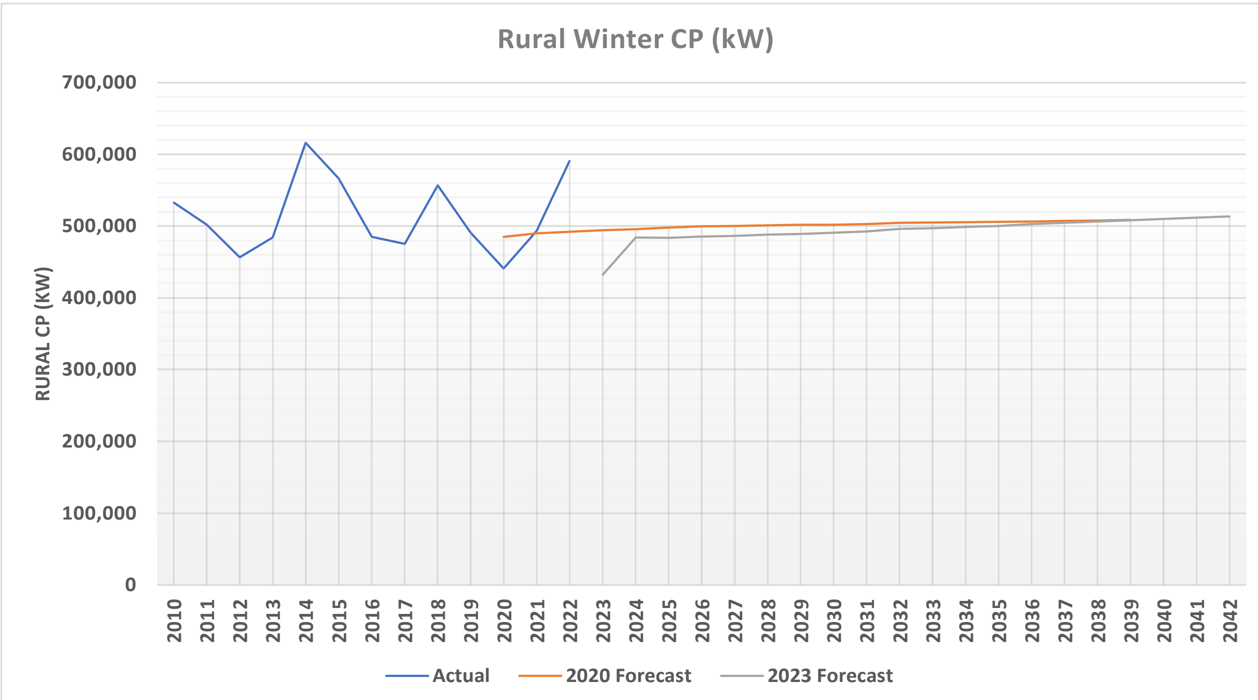
2020 Forecast Distribution Loss Comparison



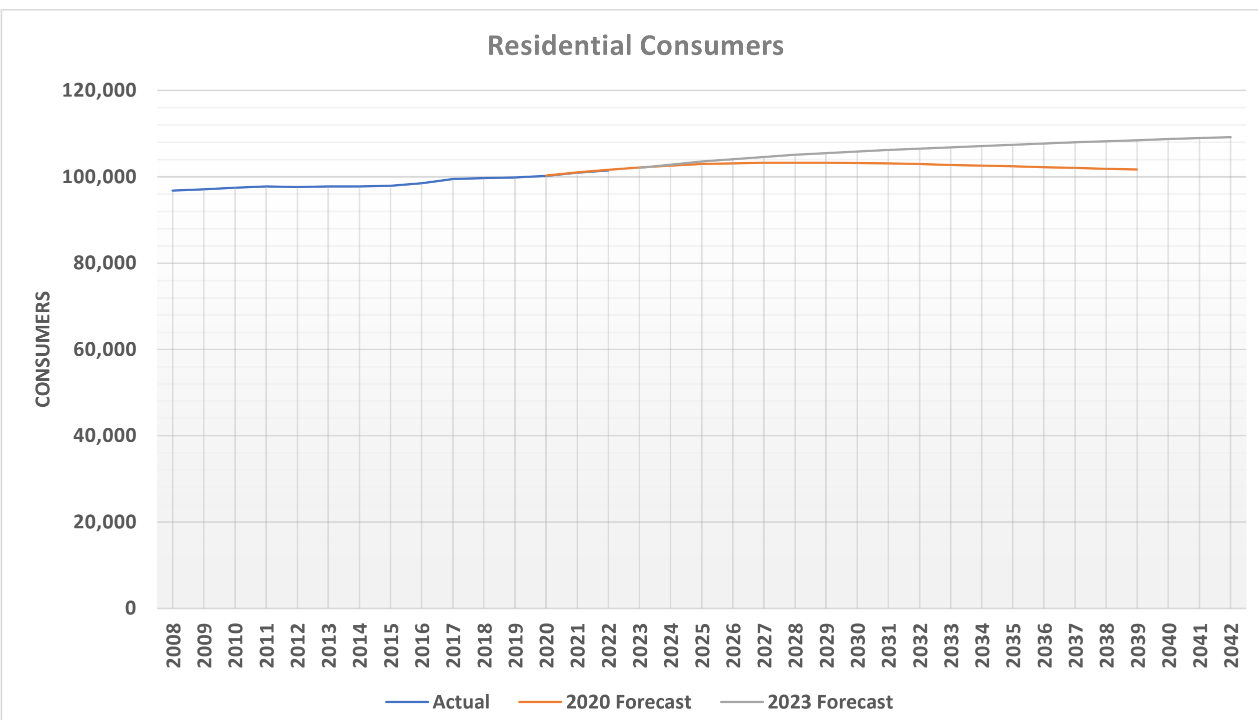
2020 Forecast Rural Summer CP Comparison



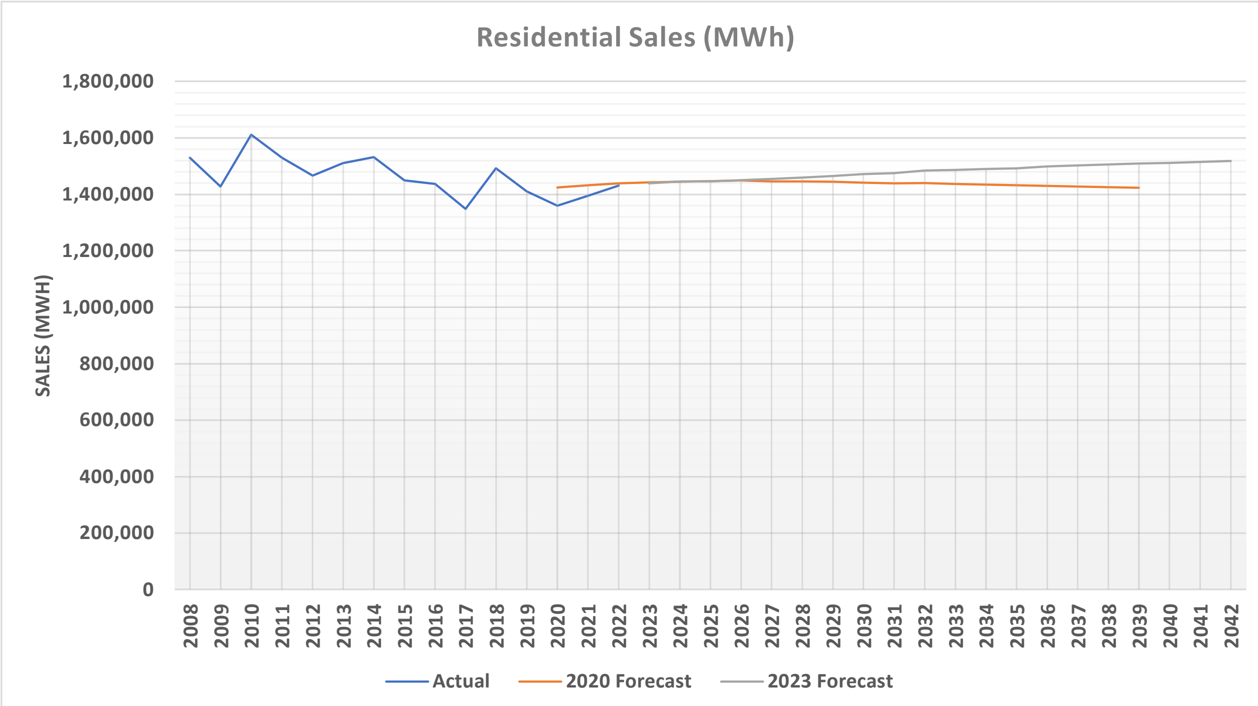
2020 Forecast Rural Winter CP Comparison



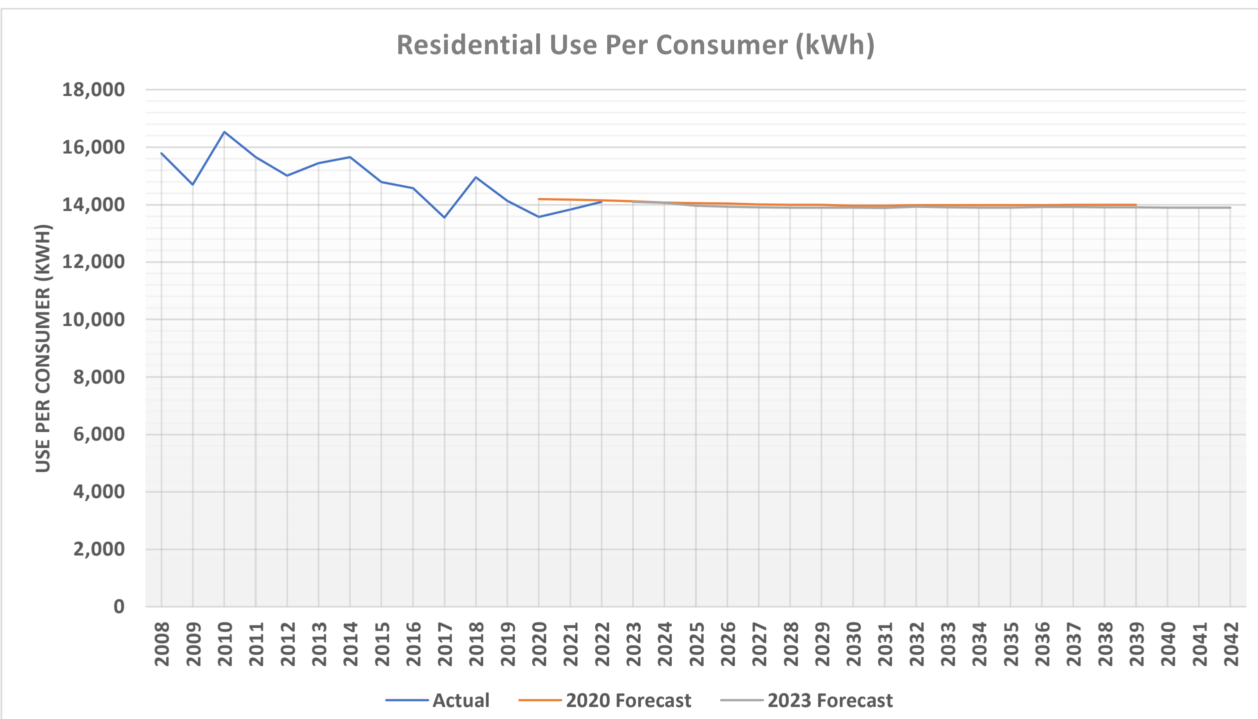
2020 Forecast Residential Consumers Comparison



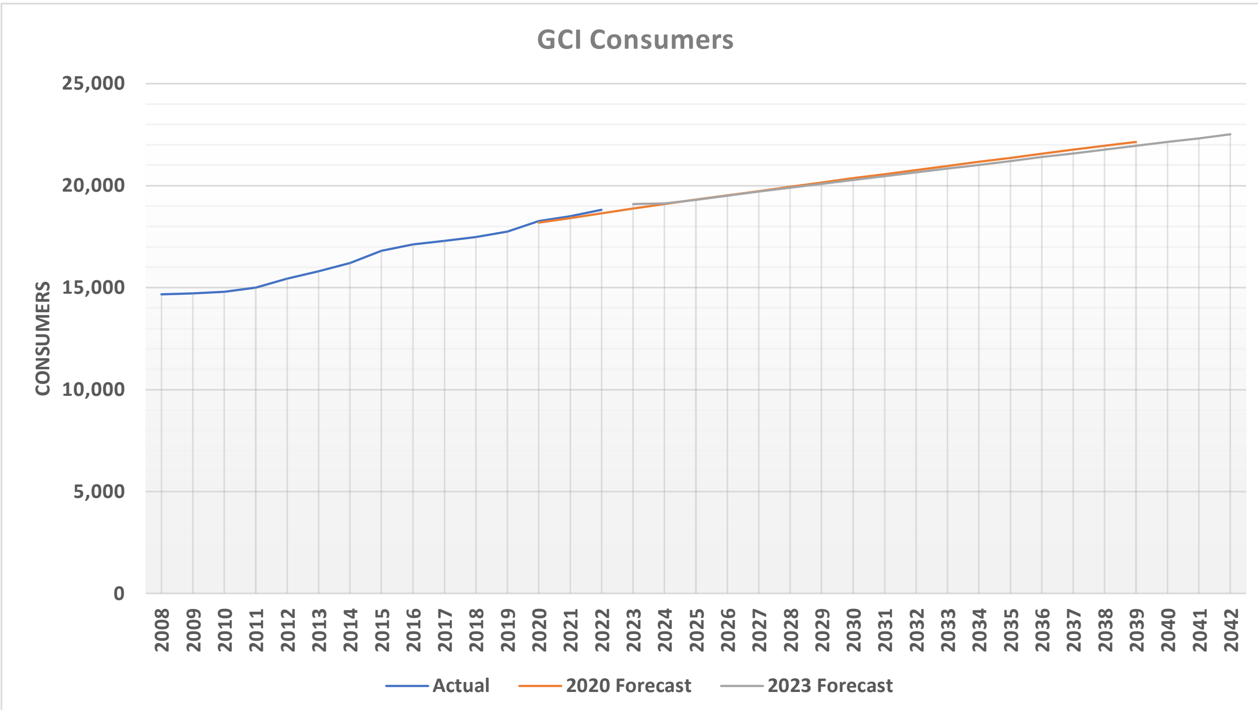
2020 Forecast Residential Sales Comparison



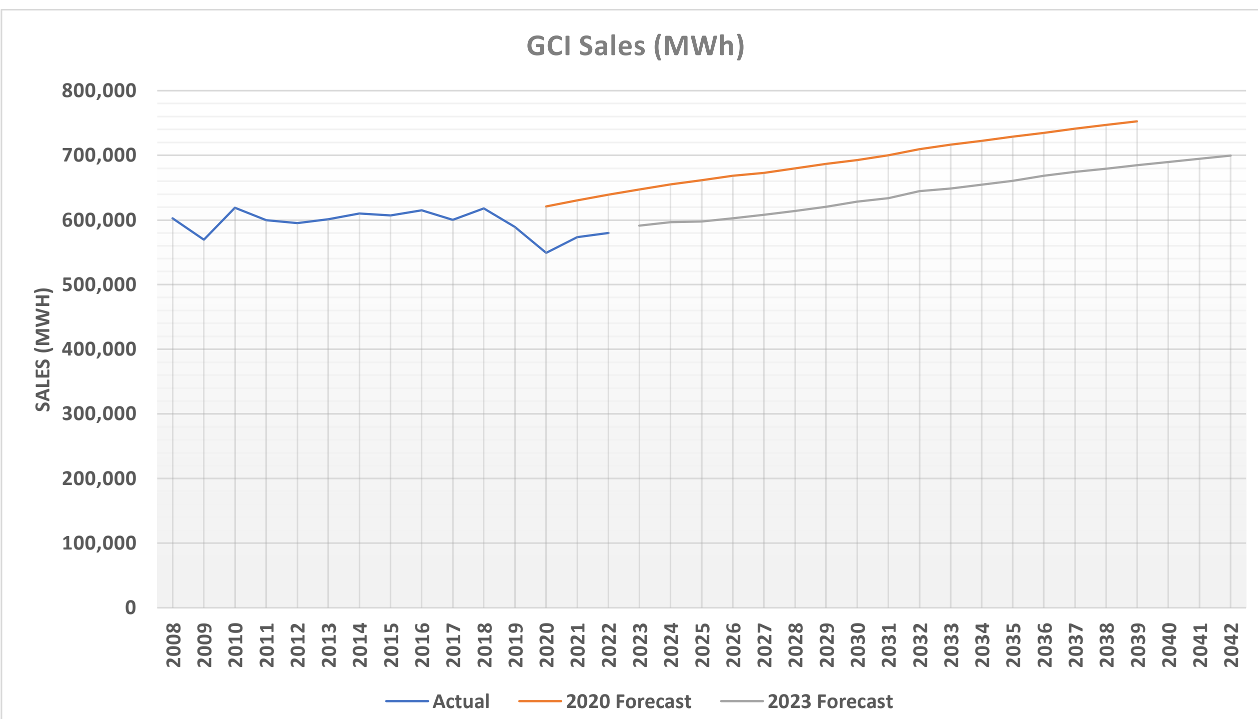
2020 Forecast Residential Use Per Consumer Comparison



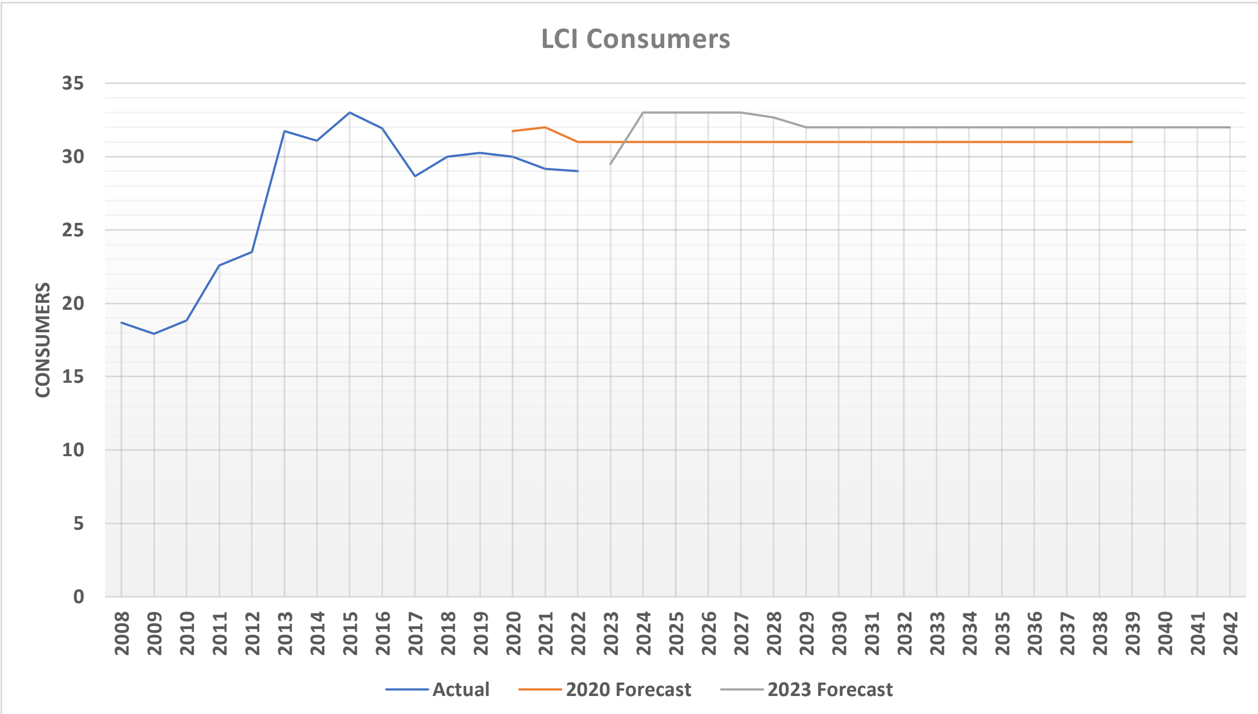
2020 Forecast GCI Consumer Comparison



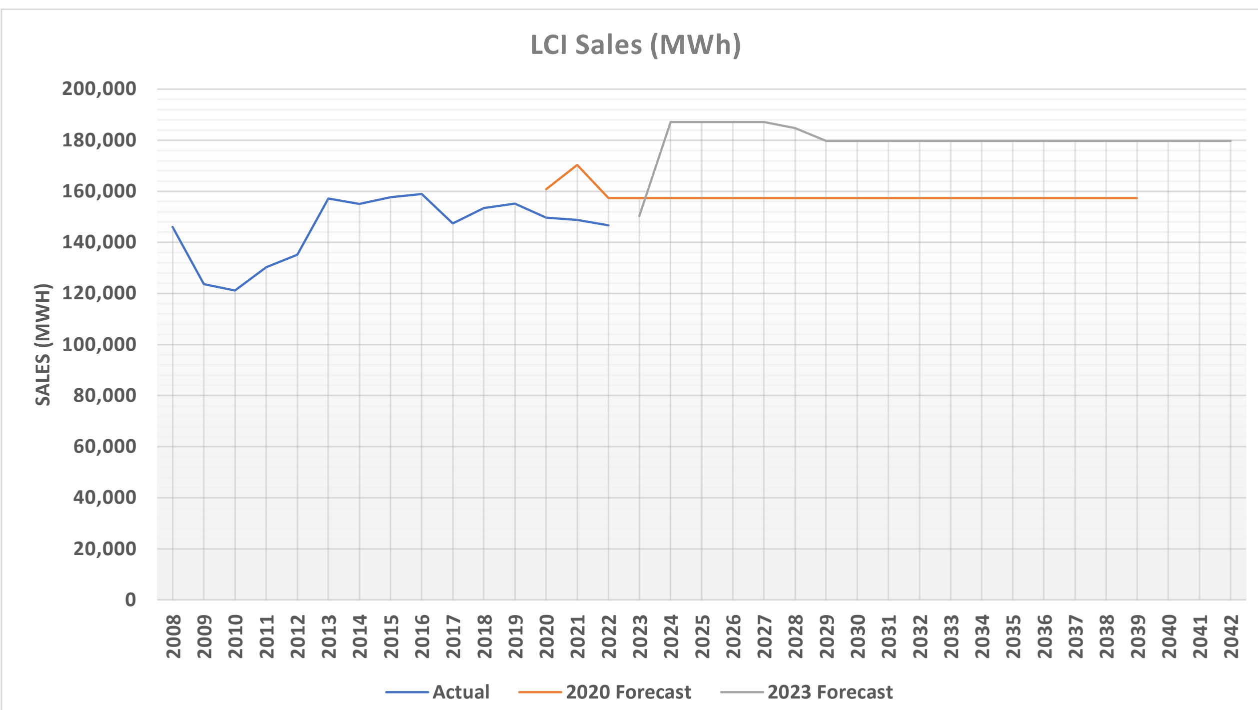
2020 Forecast GCI Sales Comparison



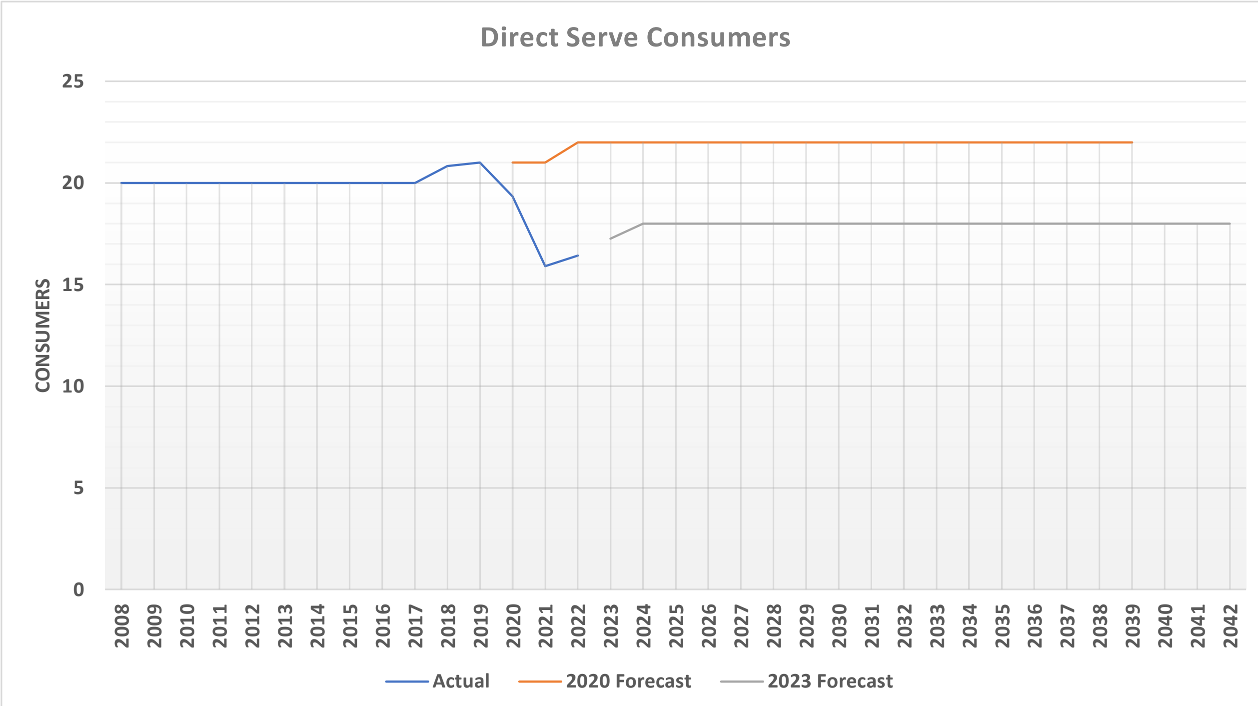
2020 Forecast LCI Consumer Comparison



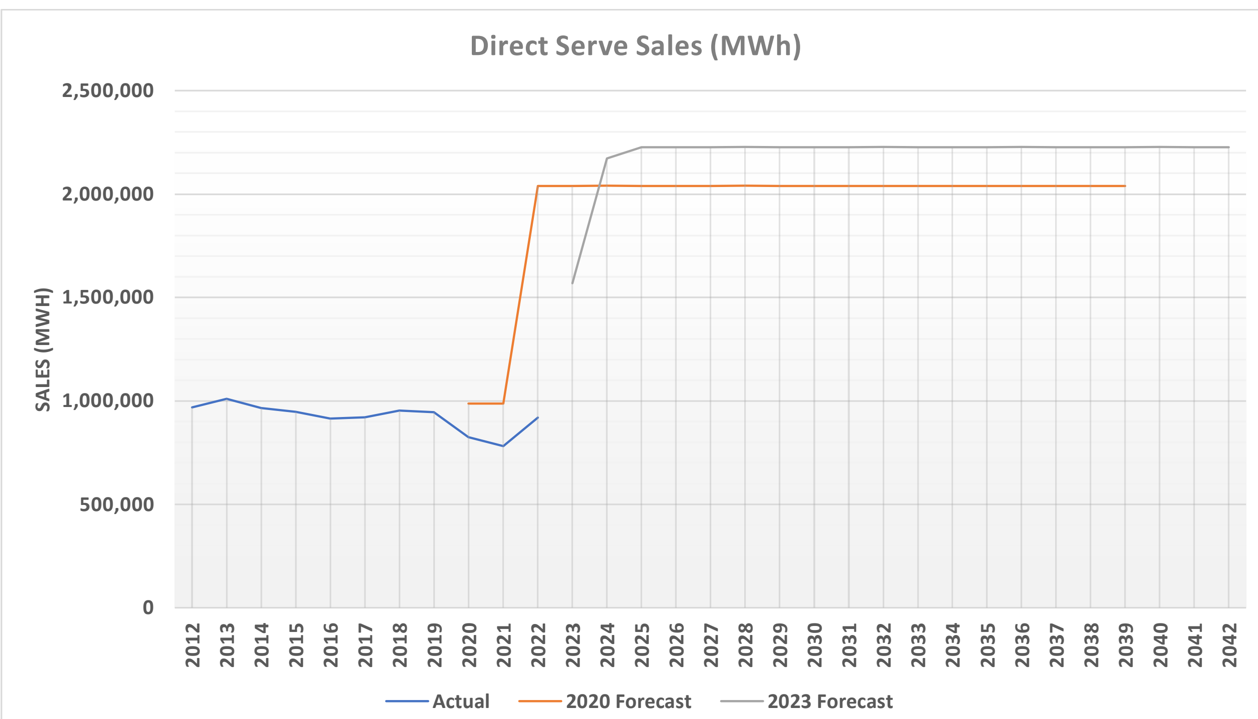
2020 Forecast LCI Sales Comparison



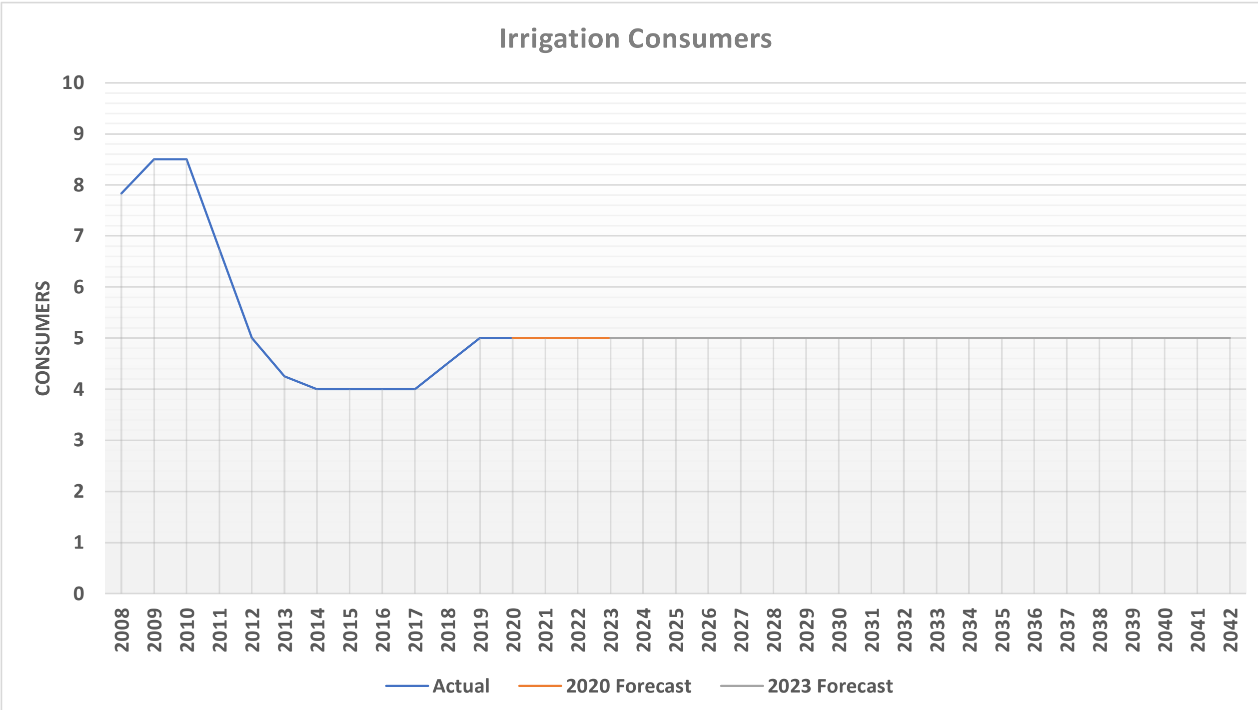
2020 Forecast Direct Serve Consumer Comparison



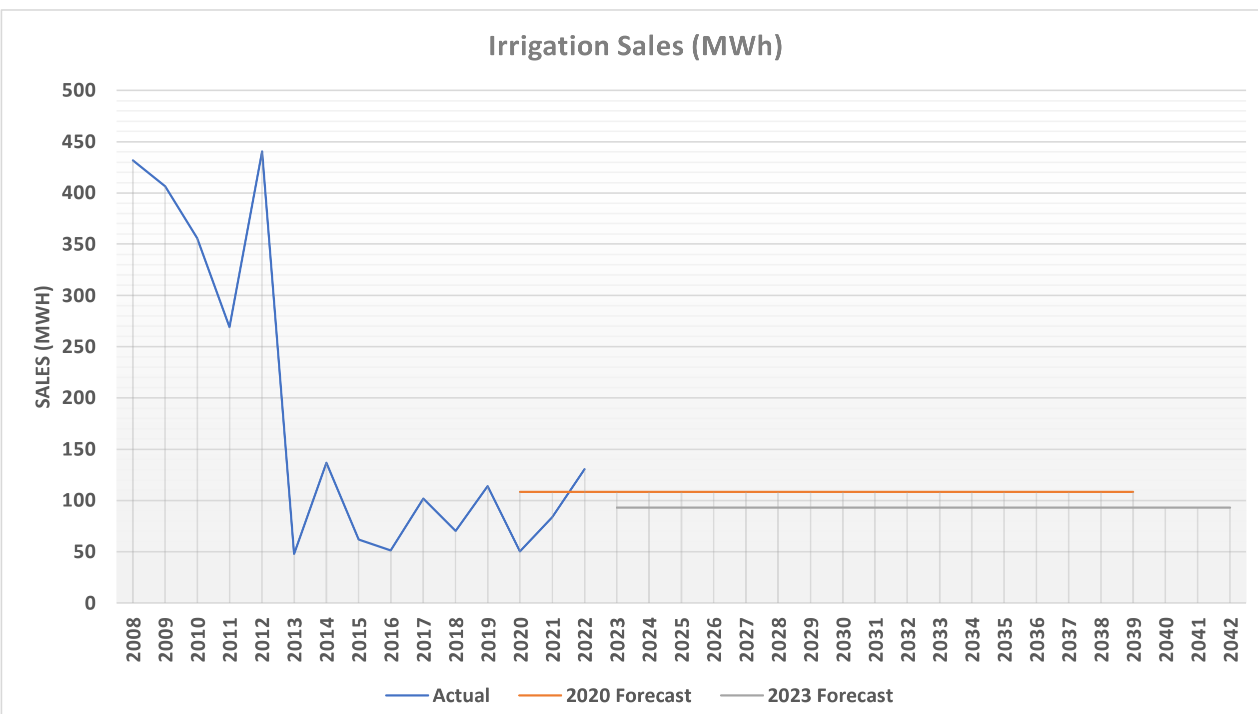
2020 Forecast Direct Serve Sales Comparison



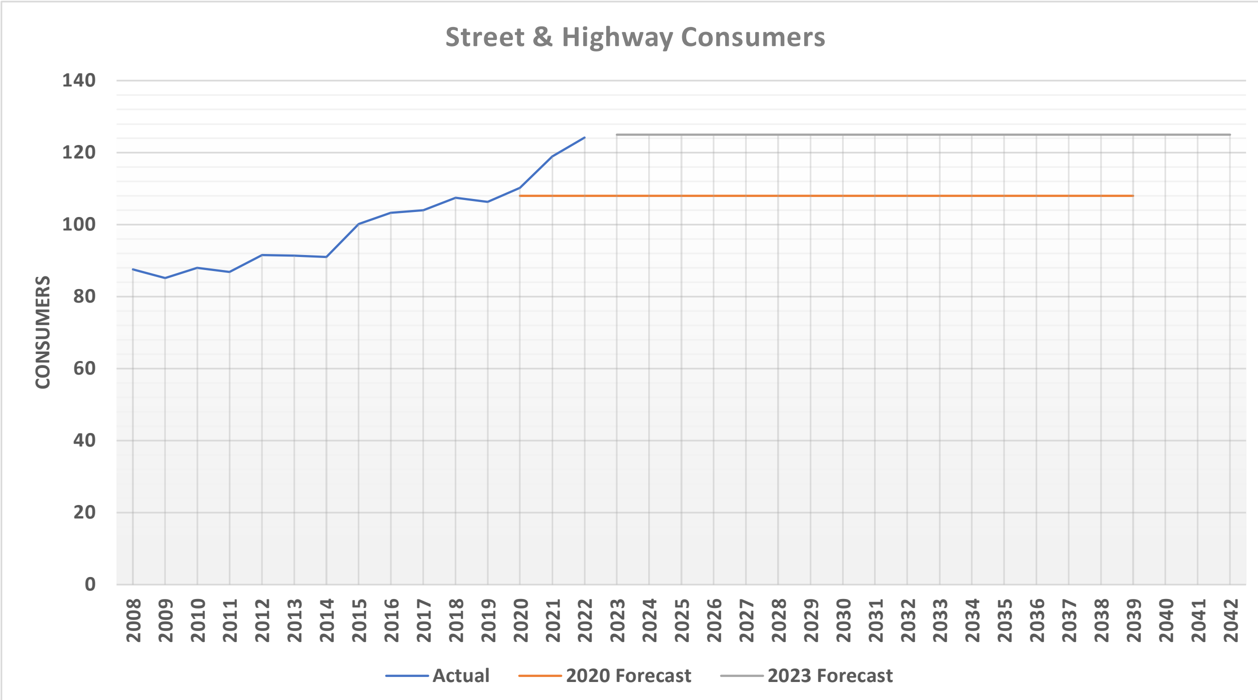
2020 Forecast Irrigation Consumer Comparison



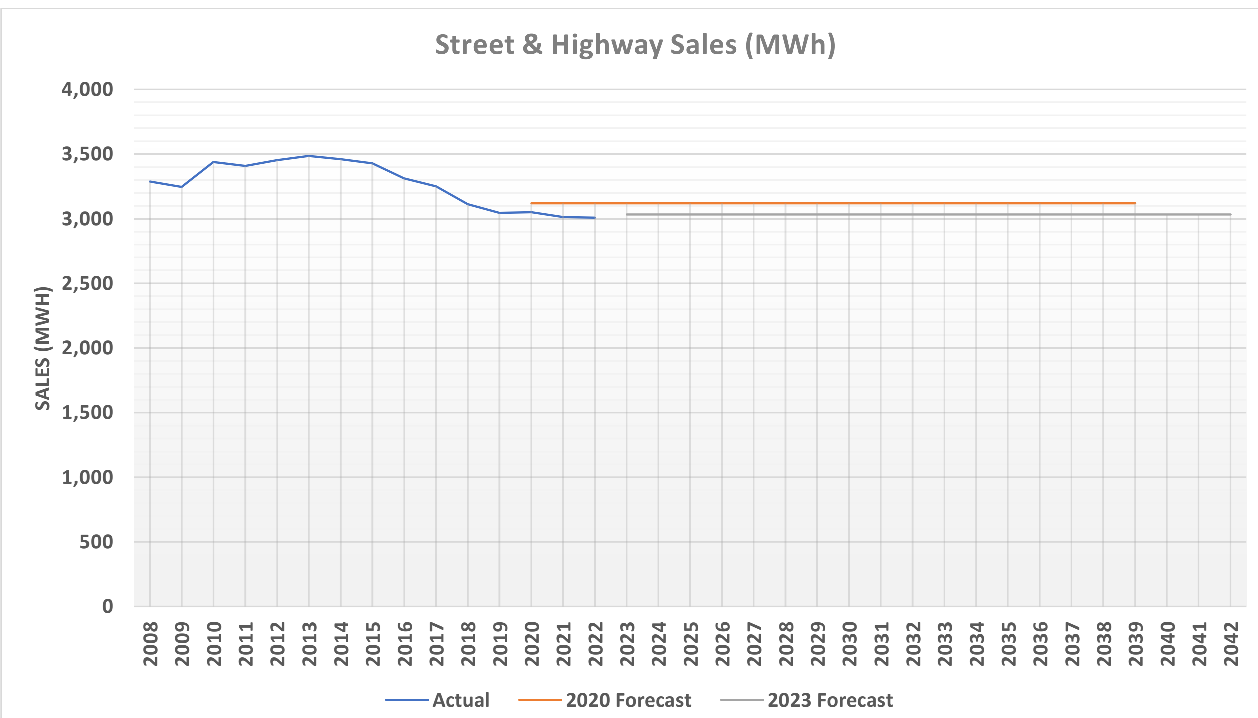
2020 Forecast Irrigation Sales Comparison



2020 Forecast Street & Highway Consumer Comparison



2020 Forecast Street & Highway Sales Comparison



10 APPENDIX

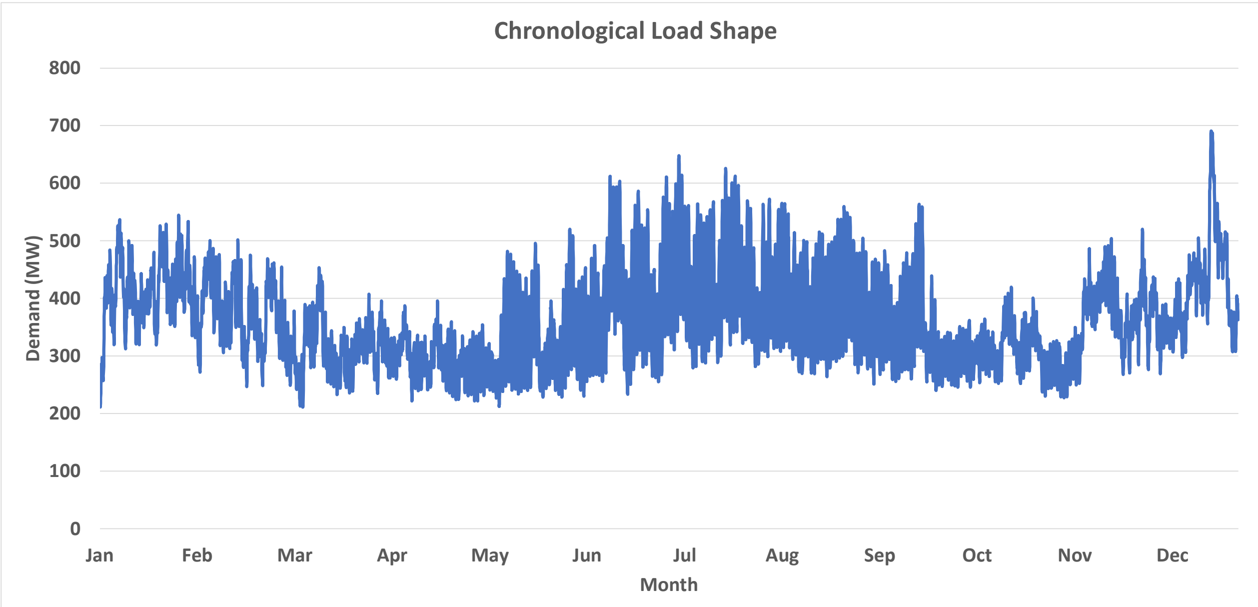
The following table provides the details on the consumers, sales, and use per consumer for each class for the Big Rivers Native system. The prior five years and the forecasted year values are provided in the table. Both historical and forecasted growth rates for each class are also provided.

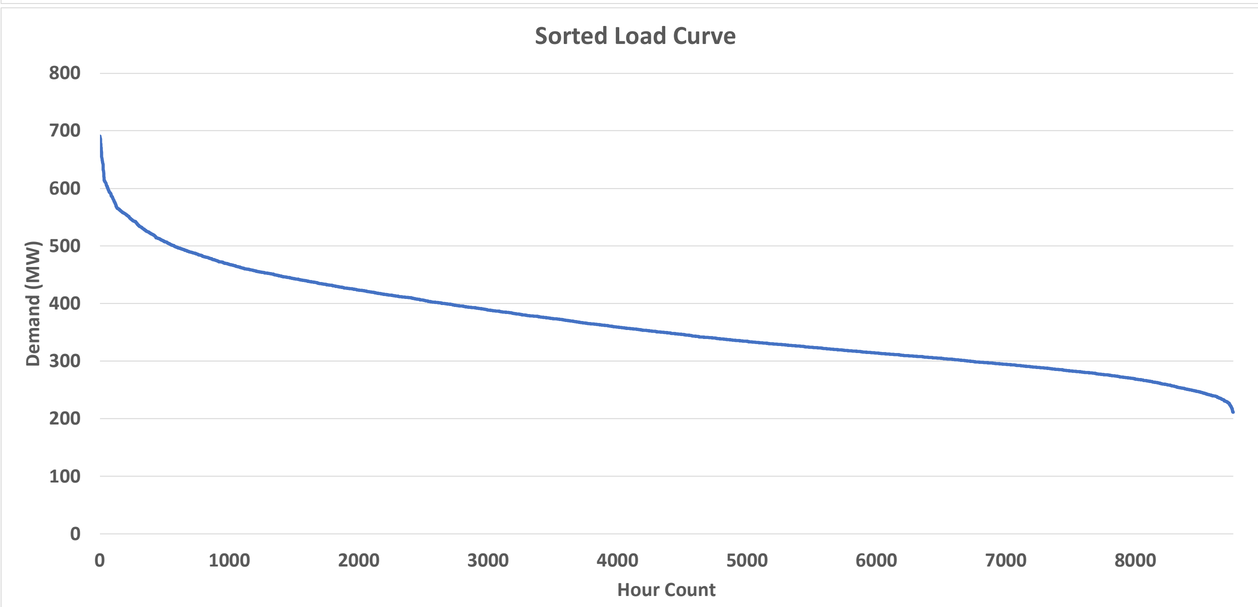
BIG RIVERS TOTAL FORECAST										
RESIDENTIAL	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
CONSUMERS	99,724	99,871	100,257	100,954	101,506	102,118	102,864	103,563	104,147	104,633
SALES-MWH	1,491,338	1,410,779	1,359,904	1,395,391	1,430,495	1,438,426	1,446,158	1,445,944	1,450,553	1,454,971
USE PER CONSUMER-kWH	14,955	14,126	13,564	13,822	14,093	14,086	14,059	13,962	13,928	13,905
GENERAL C&I	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
CONSUMERS	17,482	17,749	18,262	18,502	18,815	19,096	19,124	19,302	19,505	19,702
SALES-MWH	618,143	589,282	548,908	573,487	579,464	591,349	596,736	597,500	602,749	607,821
USE PER CONSUMER-kWH	35,358	33,201	30,057	30,995	30,798	30,967	31,203	30,955	30,903	30,851
LARGE C&I	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
CONSUMERS	30	30	30	29	29	30	33	33	33	33
SALES-MWH	153,431	155,205	149,601	148,832	146,626	150,305	187,146	187,146	187,146	187,146
USE PER CONSUMER-kWH	5,114,366	5,130,733	4,986,683	5,102,807	5,056,063	5,095,086	5,671,098	5,671,098	5,671,098	5,671,098
IRRIGATION	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
CONSUMERS	5	5	5	5	5	5	5	5	5	5
SALES-MWH	70	114	50	84	130	93	93	93	93	93
USE PER CONSUMER-kWH	15,618	22,742	10,043	16,704	26,082	18,625	18,625	18,625	18,625	18,625
STREET & HIGHWAY	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
CONSUMERS	107	106	110	119	124	125	125	125	125	125
SALES-MWH	3,111	3,045	3,050	3,012	3,007	3,034	3,034	3,034	3,034	3,034
USE PER CONSUMER-kWH	28,965	28,640	27,662	25,332	24,202	24,272	24,272	24,272	24,272	24,272
RURAL TOTAL	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
CONSUMERS	117,348	117,761	118,664	119,609	120,479	121,373	122,151	123,028	123,814	124,498
SALES-MWH	2,266,093	2,158,425	2,061,512	2,120,806	2,159,723	2,183,207	2,233,167	2,233,718	2,243,576	2,253,065
USE PER CONSUMER-kWH	19,311	18,329	17,373	17,731	17,926	17,988	18,282	18,156	18,120	18,097
OWNUSE-MWH	3,211	3,087	2,814	3,666	4,103	4,051	4,073	4,098	4,121	4,142
PURCHASES-MWH	2,366,988	2,261,069	2,164,868	2,219,380	2,269,586	2,291,062	2,343,506	2,344,105	2,354,461	2,364,427
DISTRIBUTION LOSSES-MWH	97,684	99,557	100,542	94,909	105,760	103,804	106,266	106,290	106,764	107,220
LOSSES (%)	4.1%	4.4%	4.6%	4.3%	4.7%	4.5%	4.5%	4.5%	4.5%	4.5%
DIRECT SERVE	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
CONSUMERS	21	21	19	16	16	17	18	18	18	18
SALES-MWH (SMELTERS AND DOMTAR REMOVED)	823,823	815,322	701,697	648,808	745,683	1,396,521	1,999,963	1,997,196	1,997,196	1,997,196
USE PER CONSUMER-kWH	39,543,509	38,824,859	36,294,688	40,762,820	45,422,312	80,957,713	111,109,034	110,955,311	110,955,311	110,955,311
AUX SALES-MWH	0	4,434	16,944	18,367	6,184	0	0	0	0	0
DOMTAR TAKE-MWH	240,369	273,974	240,564	242,657	229,274	227,932	227,932	227,932	227,932	227,932
DOMTAR UP TO TARIFF-MWH	129,999	130,718	122,998	132,751	173,674	172,657	172,657	227,932	227,932	227,932
SYSTEM TOTAL WITH DIRECT SERVE	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
CONSUMERS	117,369	117,782	118,684	119,625	120,496	121,391	122,169	123,046	123,832	124,516
SALES-MWH	3,219,916	3,104,465	2,886,207	2,902,364	3,079,080	3,752,384	4,405,787	4,458,845	4,468,703	4,478,193
USE PER CONSUMER-kWH	27,434	26,358	24,318	24,262	25,553	30,912	36,063	36,237	36,087	35,965
OWNUSE-MWH	3,211	3,087	2,814	3,666	4,103	4,051	4,073	4,098	4,121	4,142
TOTAL ENERGY REQUIREMENTS-MWH (NO TRANS. LOSSES)	3,320,811	3,211,544	3,006,507	3,019,306	3,195,127	3,860,240	4,516,125	4,569,232	4,579,589	4,589,554
DISTRIBUTION LOSSES-MWH	97,684	99,557	100,542	94,909	105,760	103,804	106,266	106,290	106,764	107,220
DISTRIBUTION LOSS (%)	2.9%	3.1%	3.3%	3.1%	3.3%	2.7%	2.4%	2.3%	2.3%	2.3%
TRANSMISSION LOSSES-MWH	86,858	82,848	77,120	71,125	74,851	92,323	108,209	109,482	109,730	109,969
TRANSMISSION LOSS (%)	2.6%	2.5%	2.5%	2.3%	2.3%	2.3%	2.3%	2.3%	2.3%	2.3%
TOTAL ENERGY REQUIREMENTS-MWH	**3,407,668**	**3,294,392**	**3,083,627**	**3,090,431**	**3,269,978**	**3,952,563**	**4,624,335**	**4,678,714**	**4,689,319**	**4,699,523**
ANNUAL PEAK	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
RURAL CP - kW	556,742	490,895	460,173	492,854	590,652	473,447	481,988	482,030	483,992	485,932
DIRECT SERVE CP - kW	80,530	102,931	90,992	81,513	64,682	241,127	318,288	318,288	318,288	318,288
AUX CP - kW	0	0	1,756	3,046	246	0	0	0	0	0
DOMTAR TAKE - kW	17,993	16,308	19,451	19,051	51,937	40,816	40,816	40,816	40,816	40,816
DOMTAR UP TO TARIFF - kW	15,000	15,000	15,000	15,000	35,000	20,000	20,000	40,816	40,816	40,816
TOTAL CP - kW	652,272	608,826	567,921	592,413	690,580	734,575	820,276	841,133	843,095	845,035
TRANSMISSION LOSSES - kW	16,382	15,995	14,562	13,822	16,185	17,601	19,654	20,154	20,201	20,248
TRANSMISSION LOSS (%)	2.6%	2.5%	2.5%	2.3%	2.3%	2.3%	2.3%	2.3%	2.3%	2.3%
TOTAL CP - kW (WITH TRANSMISSION LOSSES)	**668,654**	**624,821**	**582,483**	**606,235**	**706,765**	**752,176**	**839,930**	**861,287**	**863,296**	**865,283**
SUM OF COOP RURAL NCP - kW	561,382	517,109	497,373	522,923	604,578	520,744	530,273	530,229	532,427	534,316
SUM OF COOP DIRECT SERVE SUM OF INDIVIDUAL NCP - kW	892,945	940,172	889,584	897,274	992,296	742,991	778,571	826,013	826,013	826,013

BIG RIVERS TOTAL FORECAST										
RESIDENTIAL	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
CONSUMERS	105,087	105,504	105,888	106,248	106,580	106,891	107,185	107,467	107,737	108,000
SALES-MWH	1,459,775	1,465,364	1,471,171	1,474,949	1,483,909	1,486,097	1,489,378	1,492,870	1,498,803	1,502,402
USE PER CONSUMER-kWH	13,891	13,889	13,894	13,882	13,923	13,903	13,895	13,891	13,912	13,911
GENERAL C&I	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
CONSUMERS	19,896	20,089	20,278	20,467	20,653	20,839	21,024	21,209	21,394	21,579
SALES-MWH	613,805	620,295	627,982	633,667	644,527	648,826	654,474	660,644	668,727	674,242
USE PER CONSUMER-kWH	30,850	30,878	30,968	30,961	31,207	31,135	31,130	31,150	31,258	31,246
LARGE C&I	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
CONSUMERS	33	32	32	32	32	32	32	32	32	32
SALES-MWH	184,693	179,788	179,788	179,788	179,788	179,788	179,788	179,788	179,788	179,788
USE PER CONSUMER-kWH	5,653,881	5,618,370	5,618,370	5,618,370	5,618,370	5,618,370	5,618,370	5,618,370	5,618,370	5,618,370
IRRIGATION	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
CONSUMERS	5	5	5	5	5	5	5	5	5	5
SALES-MWH	93	93	93	93	93	93	93	93	93	93
USE PER CONSUMER-kWH	18,625	18,625	18,625	18,625	18,625	18,625	18,625	18,625	18,625	18,625
STREET & HIGHWAY	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
CONSUMERS	125	125	125	125	125	125	125	125	125	125
SALES-MWH	3,034	3,034	3,034	3,034	3,034	3,034	3,034	3,034	3,034	3,034
USE PER CONSUMER-kWH	24,272	24,272	24,272	24,272	24,272	24,272	24,272	24,272	24,272	24,272
RURAL TOTAL	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
CONSUMERS	125,146	125,755	126,328	126,876	127,395	127,892	128,371	128,838	129,293	129,740
SALES-MWH	2,261,401	2,268,574	2,282,068	2,291,531	2,311,351	2,317,837	2,326,767	2,336,429	2,350,446	2,359,558
USE PER CONSUMER-kWH	18,070	18,040	18,065	18,061	18,143	18,123	18,125	18,135	18,179	18,187
OWNUSE-MWH	4,161	4,179	4,195	4,211	4,225	4,238	4,250	4,262	4,273	4,284
PURCHASES-MWH	2,373,176	2,380,698	2,394,861	2,404,797	2,425,591	2,432,406	2,441,782	2,451,925	2,466,634	2,476,201
DISTRIBUTION LOSSES-MWH	107,614	107,945	108,598	109,056	110,016	110,330	110,764	111,234	111,915	112,359
LOSSES (%)	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%
DIRECT SERVE	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
CONSUMERS	18	18	18	18	18	18	18	18	18	18
SALES-MWH (SMELTERS AND DOMTAR REMOVED)	1,999,963	1,997,196	1,997,196	1,997,196	1,999,963	1,997,196	1,997,196	1,997,196	1,999,963	1,997,196
USE PER CONSUMER-kWH	111,109,034	110,955,311	110,955,311	110,955,311	111,109,034	110,955,311	110,955,311	110,955,311	111,109,034	110,955,311
AUX SALES-MWH	0	0	0	0	0	0	0	0	0	0
DOMTAR TAKE-MWH	227,932	227,932	227,932	227,932	227,932	227,932	227,932	227,932	227,932	227,932
DOMTAR UP TO TARIFF-MWH	227,932	227,932	227,932	227,932	227,932	227,932	227,932	227,932	227,932	227,932
SYSTEM TOTAL WITH DIRECT SERVE	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
CONSUMERS	125,164	125,773	126,346	126,894	127,413	127,910	128,389	128,856	129,311	129,758
SALES-MWH	4,489,295	4,493,701	4,507,195	4,516,658	4,539,245	4,542,965	4,551,894	4,561,557	4,578,340	4,584,685
USE PER CONSUMER-kWH	35,867	35,729	35,673	35,594	35,626	35,517	35,454	35,401	35,406	35,333
OWNUSE-MWH	4,161	4,179	4,195	4,211	4,225	4,238	4,250	4,262	4,273	4,284
TOTAL ENERGY REQUIREMENTS-MWH (NO TRANS. LOSSES)	4,601,070	4,605,825	4,619,988	4,629,924	4,653,485	4,657,533	4,666,909	4,677,052	4,694,528	4,701,328
DISTRIBUTION LOSSES-MWH	107,614	107,945	108,598	109,056	110,016	110,330	110,764	111,234	111,915	112,359
DISTRIBUTION LOSS (%)	2.3%	2.3%	2.4%	2.4%	2.4%	2.4%	2.4%	2.4%	2.4%	2.4%
TRANSMISSION LOSSES-MWH	110,245	110,359	110,698	110,936	111,501	111,598	111,822	112,065	112,484	112,647
TRANSMISSION LOSS (%)	2.3%	2.3%	2.3%	2.3%	2.3%	2.3%	2.3%	2.3%	2.3%	2.3%
TOTAL ENERGY REQUIREMENTS-MWH	**4,711,315**	**4,716,184**	**4,730,686**	**4,740,860**	**4,764,986**	**4,769,131**	**4,778,731**	**4,789,118**	**4,807,012**	**4,813,975**
ANNUAL PEAK	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
RURAL CP - kW	488,179	489,348	492,199	494,185	498,436	499,759	501,606	503,602	506,528	508,354
DIRECT SERVE CP - kW	318,288	318,288	318,288	318,288	318,288	318,288	318,288	318,288	318,288	318,288
AUX CP - kW	0	0	0	0	0	0	0	0	0	0
DOMTAR TAKE - kW	40,816	40,816	40,816	40,816	40,816	40,816	40,816	40,816	40,816	40,816
DOMTAR UP TO TARIFF - kW	40,816	40,816	40,816	40,816	40,816	40,816	40,816	40,816	40,816	40,816
TOTAL CP - kW	847,282	848,452	851,303	853,289	857,539	858,862	860,709	862,706	865,632	867,457
TRANSMISSION LOSSES - kW	20,301	20,329	20,398	20,445	20,547	20,579	20,623	20,671	20,741	20,785
TRANSMISSION LOSS (%)	2.3%	2.3%	2.3%	2.3%	2.3%	2.3%	2.3%	2.3%	2.3%	2.3%
TOTAL CP - kW (WITH TRANSMISSION LOSSES)	**867,584**	**868,781**	**871,701**	**873,734**	**878,087**	**879,441**	**881,332**	**883,377**	**886,373**	**888,242**
SUM OF COOP RURAL NCP - kW	536,545	537,649	540,557	542,584	547,013	548,417	550,407	552,584	555,809	557,945
SUM OF COOP DIRECT SERVE SUM OF INDIVIDUAL NCP - kW	826,013	826,013	826,013	826,013	826,013	826,013	826,013	826,013	826,013	826,013

BIG RIVERS TOTAL FORECAST						Last 10 Yrs	Last 5 Yrs	Next 5 Yrs	Next 10 Yrs	Next 20 Yrs
RESIDENTIAL	2038	2039	2040	2041	2042	2012 - 2022	2017 - 2022	2022 - 2027	2022 - 2032	2022 - 2042
CONSUMERS	108,251	108,493	108,734	108,984	109,252	0.4%	0.4%	0.6%	0.5%	0.4%
SALES-MWH	1,505,605	1,508,589	1,511,367	1,514,309	1,517,731	-0.2%	1.2%	0.3%	0.4%	0.3%
USE PER CONSUMER-kWH	13,909	13,905	13,900	13,895	13,892	-0.6%	0.8%	-0.3%	-0.1%	-0.1%
GENERAL C&I	2038	2039	2040	2041	2042	2012 - 2022	2017 - 2022	2022 - 2027	2022 - 2032	2022 - 2042
CONSUMERS	21,764	21,951	22,138	22,326	22,517	2.0%	1.7%	0.9%	0.9%	0.9%
SALES-MWH	679,545	684,683	689,438	694,269	699,737	-0.3%	-0.7%	1.0%	1.1%	0.9%
USE PER CONSUMER-kWH	31,223	31,192	31,143	31,097	31,076	-2.2%	-2.4%	0.0%	0.1%	0.0%
LARGE C&I	2038	2039	2040	2041	2042	2012 - 2022	2017 - 2022	2022 - 2027	2022 - 2032	2022 - 2042
CONSUMERS	32	32	32	32	32	2.1%	0.2%	2.6%	1.0%	0.5%
SALES-MWH	179,788	179,788	179,788	179,788	179,788	0.8%	-0.1%	5.0%	2.1%	1.0%
USE PER CONSUMER-kWH	5,618,370	5,618,370	5,618,370	5,618,370	5,618,370	-1.3%	-0.3%	2.3%	1.1%	0.5%
IRRIGATION	2038	2039	2040	2041	2042	2012 - 2022	2017 - 2022	2022 - 2027	2022 - 2032	2022 - 2042
CONSUMERS	5	5	5	5	5	0.0%	4.6%	0.0%	0.0%	0.0%
SALES-MWH	93	93	93	93	93	-11.5%	5.1%	-6.5%	-3.3%	-1.7%
USE PER CONSUMER-kWH	18,625	18,625	18,625	18,625	18,625	-11.5%	0.5%	-6.5%	-3.3%	-1.7%
STREET & HIGHWAY	2038	2039	2040	2041	2042	2012 - 2022	2017 - 2022	2022 - 2027	2022 - 2032	2022 - 2042
CONSUMERS	125	125	125	125	125	3.1%	3.6%	0.1%	0.1%	0.0%
SALES-MWH	3,034	3,034	3,034	3,034	3,034	-1.4%	-1.5%	0.2%	0.1%	0.0%
USE PER CONSUMER-kWH	24,272	24,272	24,272	24,272	24,272	-4.3%	-5.0%	0.1%	0.0%	0.0%
RURAL TOTAL	2038	2039	2040	2041	2042	2012 - 2022	2017 - 2022	2022 - 2027	2022 - 2032	2022 - 2042
CONSUMERS	130,177	130,606	131,034	131,473	131,931	0.6%	0.6%	0.7%	0.6%	0.5%
SALES-MWH	2,368,066	2,376,186	2,383,720	2,391,492	2,400,382	-0.2%	0.6%	0.8%	0.7%	0.5%
USE PER CONSUMER-kWH	18,191	18,194	18,192	18,190	18,194	-0.8%	0.0%	0.2%	0.1%	0.1%
OWNUSE-MWH	4,295	4,305	4,315	4,326	4,337	15.3%	6.9%	0.2%	0.3%	0.3%
PURCHASES-MWH	2,485,134	2,493,662	2,501,574	2,509,737	2,519,073	-0.2%	0.5%	0.8%	0.7%	0.5%
DISTRIBUTION LOSSES-MWH	112,773	113,170	113,539	113,919	114,353	-1.3%	-0.4%	0.3%	0.4%	0.4%
LOSSES (%)	4.5%	4.5%	4.5%	4.5%	4.5%	-1.1%	-0.9%	-0.5%	-0.3%	-0.1%
DIRECT SERVE	2038	2039	2040	2041	2042	2012 - 2022	2017 - 2022	2022 - 2027	2022 - 2032	2022 - 2042
CONSUMERS	18	18	18	18	18	-2.0%	-3.9%	1.9%	0.9%	0.5%
SALES-MWH (SMELTERS AND DOMTAR REMOVED)	1,997,196	1,997,196	1,999,963	1,997,196	1,997,196	-1.1%	-1.2%	21.8%	10.4%	5.0%
USE PER CONSUMER-kWH	110,955,311	110,955,311	111,109,034	110,955,311	110,955,311	0.9%	2.8%	19.6%	9.4%	4.6%
AUX SALES-MWH	0	0	0	0	0	-	-	-100.0%	-100.0%	-100.0%
DOMTAR TAKE-MWH	227,932	227,932	227,932	227,932	227,932	-4.0%	3.0%	-0.1%	-0.1%	0.0%
DOMTAR UP TO TARIFF-MWH	227,932	227,932	227,932	227,932	227,932	2.2%	6.0%	5.6%	2.8%	1.4%
SYSTEM TOTAL WITH DIRECT SERVE	2038	2039	2040	2041	2042	2012 - 2022	2017 - 2022	2022 - 2027	2022 - 2032	2022 - 2042
CONSUMERS	130,195	130,624	131,052	131,491	131,949	0.6%	0.6%	0.7%	0.6%	0.5%
SALES-MWH	4,593,193	4,601,313	4,611,614	4,616,620	4,625,510	-0.3%	0.4%	7.8%	4.0%	2.1%
USE PER CONSUMER-kWH	35,279	35,226	35,189	35,110	35,055	-0.9%	-0.2%	7.1%	3.4%	1.6%
OWNUSE-MWH	4,295	4,305	4,315	4,326	4,337	15.3%	6.9%	0.2%	0.3%	0.3%
TOTAL ENERGY REQUIREMENTS-MWH (NO TRANS. LOSSES)	4,710,261	4,718,789	4,729,468	4,734,864	4,744,200	-0.3%	0.4%	7.5%	3.8%	2.0%
DISTRIBUTION LOSSES-MWH	112,773	113,170	113,539	113,919	114,353	-1.3%	-0.4%	0.3%	0.4%	0.4%
DISTRIBUTION LOSS (%)	2.4%	2.4%	2.4%	2.4%	2.4%	-1.0%	-0.8%	-6.7%	-3.3%	-1.6%
TRANSMISSION LOSSES-MWH	112,861	113,065	113,321	113,451	113,674	7.6%	-0.8%	8.0%	4.1%	2.1%
TRANSMISSION LOSS (%)	2.3%	2.3%	2.3%	2.3%	2.3%	7.8%	-1.2%	0.4%	0.2%	0.1%
TOTAL ENERGY REQUIREMENTS-MWH	**4,823,122**	**4,831,854**	**4,842,789**	**4,848,315**	**4,857,874**	**-0.2%**	**0.4%**	**7.5%**	**3.8%**	**2.0%**
ANNUAL PEAK	2038	2039	2040	2041	2042	2012 - 2022	2017 - 2022	2022 - 2027	2022 - 2032	2022 - 2042
RURAL CP - kW	510,032	511,611	513,047	514,533	516,266	0.9%	3.2%	-3.8%	-1.7%	-0.7%
DIRECT SERVE CP - kW	318,288	318,288	318,288	318,288	318,288	-3.6%	-8.2%	37.5%	17.3%	8.3%
AUX CP - kW	0	0	0	0	0	-	-	-100.0%	-100.0%	-100.0%
DOMTAR TAKE - kW	40,816	40,816	40,816	40,816	40,816	9.7%	16.4%	-4.7%	-2.4%	-1.2%
DOMTAR UP TO TARIFF - kW	40,816	40,816	40,816	40,816	40,816	5.8%	18.5%	3.1%	1.5%	0.8%
TOTAL CP - kW	869,135	870,714	872,150	873,637	875,369	0.5%	2.2%	4.1%	2.2%	1.2%
TRANSMISSION LOSSES - kW	20,825	20,863	20,897	20,933	20,974	8.4%	0.8%	4.6%	2.4%	1.3%
TRANSMISSION LOSS (%)	2.3%	2.3%	2.3%	2.3%	2.3%	7.8%	-1.2%	0.4%	0.2%	0.1%
TOTAL CP - kW (WITH TRANSMISSION LOSSES)	**889,961**	**891,577**	**893,048**	**894,570**	**896,344**	**0.7%**	**2.2%**	**4.1%**	**2.2%**	**1.2%**
SUM OF COOP RURAL NCP - kW	559,942	561,876	563,690	565,570	567,733	3.1%	2.4%	-2.4%	-1.0%	-0.3%
SUM OF COOP DIRECT SERVE SUM OF INDIVIDUAL NCP - kW	826,013	826,013	826,013	826,013	826,013	-0.3%	6.1%	-3.6%	-1.8%	-0.9%

The following figures display the 2022 annual load shape and descending load curve for the Big Rivers Native system excluding transmission losses. 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 Sales	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
2023	January	158,973	51,401	12,350	1	271	222,997	10,627	525	234,148	91,277	325,425	7,627	333,052	474,429	180,360	654,789	15,346	670,136
2023	February	135,725	44,646	11,573	1	212	192,157	9,154	501	201,812	90,356	292,168	7,001	299,169	452,584	188,380	640,965	15,358	656,323
2023	March	115,083	42,334	12,831	1	257	170,507	8,110	328	178,945	101,401	280,346	6,717	287,063	386,485	193,311	579,796	13,892	593,689
2023	April	89,262	39,213	12,002	3	251	140,731	6,690	274	147,696	109,663	257,359	6,166	263,525	300,364	206,804	507,169	12,152	519,321
2023	May	97,011	45,920	12,556	3	271	155,760	7,398	235	163,394	119,632	283,026	6,782	289,808	374,228	218,580	592,809	14,204	607,013
2023	June	120,027	55,411	12,443	19	257	188,158	8,932	273	197,362	128,259	325,621	7,802	333,423	453,843	229,367	683,210	16,370	699,580
2023	July	140,416	59,156	13,253	19	253	213,098	10,119	302	223,519	130,155	353,675	8,474	362,149	473,447	261,127	734,575	17,601	752,176
2023	August	136,148	56,801	13,826	19	240	207,034	9,831	303	217,168	147,398	364,566	8,735	373,301	478,861	250,573	729,434	17,478	746,912
2023	September	107,368	48,914	13,167	19	244	169,711	8,057	280	178,047	146,651	324,699	7,780	332,479	433,453	261,465	694,918	16,651	711,569
2023	October	90,381	45,898	12,292	3	258	148,831	7,071	256	156,158	162,804	318,962	7,643	326,604	337,969	281,885	619,854	14,852	634,706
2023	November	106,217	48,362	12,160	1	270	167,011	7,948	329	175,288	167,828	343,116	8,221	351,337	371,275	293,396	664,671	15,926	680,597
2023	December	141,815	53,293	11,851	1	251	207,211	9,869	446	217,525	173,752	391,277	9,375	400,652	432,573	301,952	734,525	17,600	752,124
2024	January	159,575	51,986	15,727	1	271	227,561	10,852	527	238,940	180,620	419,560	10,053	429,613	484,213	313,128	797,342	19,105	816,447
2024	February	136,378	45,123	14,950	1	212	196,664	9,376	504	206,544	167,926	374,470	8,973	383,443	447,172	310,697	757,869	18,159	776,028
2024	March	115,842	42,753	16,208	1	257	175,061	8,334	330	183,725	178,267	361,992	8,674	370,666	396,789	307,341	704,130	16,871	721,001
2024	April	89,969	39,564	15,379	3	251	145,166	6,909	276	152,351	177,523	329,873	7,904	337,777	309,320	311,941	621,260	14,886	636,146
2024	May	97,708	46,305	15,933	3	271	160,220	7,619	236	168,075	184,019	352,093	8,436	360,530	384,546	314,479	699,025	16,749	715,774
2024	June	120,612	55,841	15,820	19	257	192,549	9,148	274	201,971	183,641	385,612	9,240	394,852	464,591	316,547	781,138	18,717	799,855
2024	July	140,926	59,582	16,016	19	253	216,796	10,301	304	227,401	182,064	409,465	9,811	419,276	481,988	338,288	820,276	19,654	839,930
2024	August	136,693	57,246	16,590	19	240	210,788	10,016	304	221,108	193,069	414,177	9,924	424,101	487,784	318,364	806,148	19,316	825,464
2024	September	108,055	49,326	15,930	19	244	173,575	8,246	281	182,103	183,317	365,419	8,756	374,175	442,997	320,538	763,535	18,295	781,830
2024	October	91,069	46,319	15,055	3	258	152,704	7,261	257	160,222	182,562	342,784	8,213	350,997	346,108	311,410	657,518	15,755	673,272
2024	November	106,891	48,842	14,924	1	270	170,927	8,140	331	179,398	178,581	357,979	8,577	366,557	380,082	313,552	693,635	16,620	710,255
2024	December	142,440	53,850	14,615	1	251	211,156	10,063	449	221,667	181,032	402,700	9,649	412,349	440,863	312,738	753,601	18,057	771,658
2025	January	159,313	51,952	15,727	1	271	227,264	10,837	531	238,632	184,257	422,889	10,133	433,021	483,438	333,944	817,382	19,585	836,967
2025	February	136,286	45,105	14,950	1	212	196,554	9,371	507	206,431	168,333	374,765	8,980	383,744	462,577	334,622	797,200	19,101	816,301
2025	March	115,956	42,754	16,208	1	257	175,176	8,340	332	183,848	182,466	366,314	8,777	375,091	396,641	328,156	724,798	17,367	742,164
2025	April	90,166	39,574	15,379	3	251	145,373	6,919	277	152,569	181,816	334,385	8,012	342,397	309,662	332,757	642,419	15,393	657,812
2025	May	97,855	46,346	15,933	3	271	160,408	7,628	238	168,273	189,079	357,352	8,562	365,915	384,897	335,295	720,192	17,256	737,448
2025	June	120,536	55,928	15,820	19	257	192,560	9,149	276	201,985	189,670	391,655	9,384	401,040	464,687	337,363	802,050	19,218	821,268
2025	July	140,679	59,707	16,016	19	253	216,675	10,295	305	227,275	185,987	413,262	9,902	423,164	482,030	359,104	841,133	20,154	861,287
2025	August	136,499	57,362	16,590	19	240	210,710	10,012	306	221,028	200,171	421,200	10,092	431,292	487,869	339,180	827,049	19,817	846,866
2025	September	108,139	49,424	15,930	19	244	173,756	8,255	283	182,294	188,392	370,686	8,882	379,568	443,150	341,354	784,504	18,797	803,301
2025	October	91,245	46,412	15,055	3	258	152,973	7,274	259	160,506	187,052	347,558	8,328	355,885	346,409	332,226	678,635	16,261	694,895
2025	November	106,976	48,954	14,924	1	270	171,125	8,149	333	179,608	183,014	362,621	8,689	371,310	380,296	334,368	714,664	17,124	731,788
2025	December	142,294	53,982	14,615	1	251	211,143	10,062	451	221,656	184,889	406,545	9,741	416,286	440,592	333,554	774,147	18,549	792,696
2026	January	159,670	52,434	15,727	1	271	228,103	10,878	534	239,514	184,257	423,771	10,154	433,925	485,070	333,944	819,014	19,624	838,638
2026	February	136,697	45,519	14,950	1	212	197,379	9,411	510	207,300	168,333	375,633	9,000	384,634	464,227	334,622	798,849	19,141	817,990
2026	March	116,474	43,143	16,208	1	257	176,084	8,383	334	184,801	182,466	367,267	8,800	376,067	398,291	328,156	726,447	17,406	743,853
2026	April	90,664	39,926	15,379	3	251	146,223	6,960	279	153,462	181,816	335,278	8,033	343,311	311,395	332,757	644,151	15,434	659,585
2026	May	98,333	46,750	15,933	3	271	161,290	7,670	239	169,199	189,079	358,278	8,585	366,863	386,936	335,295	722,231	17,305	739,536
2026	June	120,886	56,402	15,820	19	257	193,384	9,188	277	202,850	189,670	392,520	9,405	401,925	466,726	337,363	804,089	19,267	823,356
2026	July	140,933	60,214	16,016	19	253	217,436	10,332	307	228,075	185,987	414,061	9,921	423,983	483,992	359,104	843,095	20,201	863,296
2026	August	136,776	57,853	16,590	19	240	211,478	10,049	308	221,835	200,171	422,006	10,112	432,118	489,884	339,180	829,064	19,865	848,929
2026	September	108,561	49,851	15,930	19	244	174,604	8,296	285	183,185	188,392	371,577	8,903	380,480	445,030	341,354	786,384	18,842	805,226
2026	October	91,678	46,815	15,055	3	258	153,809	7,314	260	161,383	187,052	348,436	8,349	356,784	348,024	332,226	680,250	16,299	696,549
2026	November	107,348	49,385	14,924	1	270	171,928	8,188	335	180,451	183,014	363,465	8,709	372,173	381,850	334,368	716,218	17,161	733,379
2026	December	142,534	54,457	14,615	1	251	211,858	10,096	454	222,408	184,889	407,297	9,759	417,056	441,827	333,554	775,381	18,579	793,959
2027	January	159,917	52,893	15,727	1	271	228,809	10,911	537	240,257	184,257	424,514	10,172	434,686	486,409	333,944	820,353	19,656	840,010
2027	February	137,023	45,915	14,950	1	212	198,101	9,445	513	208,059	168,333	376,392	9,019	385,411	465,628	334,622	800,250	19,175	819,425
2027	March	116,922	43,517	16,208	1	257	176,906	8,423	336	185,664	182,466	368,130	8,821	376,951	399,745	328,156	727,901	17,441	745,342
2027	April	91,112	40,266	15,379	3	251	147,012	6,998	281	154,290	181,816	336,106	8,053	344,160	313,011	332,757	645,767	15,473	661,240
2027	May	98,776	47,142	15,933	3	271	162,125	7,710	240	170,075	189,079	359,154	8,606	367,760	388,877	335,295	724,172	17,352	741,524
2027	June	121,229	56,861	15,820	19	257	194,186	9,227	279	203,692	189,670	393,362	9,425	402,788	468,701	337,363	806,064	19,314	825,378
2027	July	141,209	60,705	16,016	19	253	218,203	10,369	309	228,880	185,987	414,867	9,940	424,807	485,932	359,104	845,035	20,248	865,283
2027	August	137,083	58,328	16,590	19	240	212,261	10,086	309	222,656	200,171	422,828	10,131	432,959	491,903	339,180	831,083	19,913	850,996
2027	September	108,994	50,264	15,930	19	244	175,452	8,336	286	184,074	188,392	372,466	8,925	381,391	446,928	341,354	788,282	18,888	807,170
2027	October	92,118	47,208	15,055	3	258	154,641	7,354	261	162,257	187,052	349,309	8,370	357,679	349,653	332,226	681,879	16,338	698,217
2027	November	107,747	49,803	14,924	1	270	172,745	8,227	336	181,309	183,014	364,322	8,729	373,052	383,437	334,368	717,806	17,199	735,005
2027	December	142,841	54,917	14,615	1	251	212,625	10,133	456	223,214	184,889	408,103	9,778	417,882	443,176	333,554	776,730	18,611	795,341

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

JPEC Residential Use Per Consumer Model				
Sample: 2007 - 2022 Total Observations: 192				
Variable	Coefficient	Std. Error	t-Statistic	Prob.
January	6.50012	0.053849	120.7103	0
February	6.424839	0.046082	139.4207	0
March	6.432226	0.03445	186.7111	0
April	6.321211	0.028267	223.6233	0
May	6.441712	0.029541	218.0578	0
June	6.549976	0.039385	166.3081	0
July	6.613713	0.045236	146.2039	0
August	6.611691	0.042095	157.0667	0
September	6.526753	0.031866	204.8161	0
October	6.345541	0.029723	213.4862	0
November	6.360766	0.03734	170.3494	0
December	6.495581	0.045505	142.7432	0
Log(Residential Price/Alternate Fuel Price)	-0.093701	0.009515	-9.848174	0
Cooling Degree Days*(AC Saturation)*(1/AC Efficiency)	0.014648	0.001001	14.63427	0
Heating Degree Days*Electric Heat Saturation*(1/Heating Efficiency)	0.01476	0.001164	12.68421	0
Weighted Statistics				
Adjusted R-squared: 0.935468				

JPEC General C&I Consumer Model				
Sample: 2007 - 2022 Total Observations: 192				
Variable	Coefficient	Std. Error	t-Statistic	Prob.
GRP	0.782666	0.098542	7.94247	0
Total Retail Sales	3.746979	0.23796	15.74626	0
January 1999 - July 2015	-989.4468	28.5973	-34.5993	0
Weighted Statistics				
Adjusted R-squared: 0.936031				

JPEC General C&I Use Per Consumer Model

Sample: 1999 - 2022
Total Observations: 288

Variable	Coefficient	Std. Error	t-Statistic	Prob.
January	8.70329	0.272652	31.92087	0
February	8.629245	0.271437	31.79095	0
March	8.653618	0.267624	32.33501	0
April	8.666321	0.262633	32.9978	0
May	8.733576	0.263235	33.17791	0
June	8.728799	0.261557	33.37239	0
July	8.754806	0.262977	33.29112	0
August	8.76183	0.262092	33.43037	0
September	8.753171	0.260023	33.66312	0
October	8.729997	0.267028	32.69317	0
November	8.681836	0.26909	32.2637	0
December	8.685957	0.271616	31.97883	0
Log(C&I Electricity Price)	-0.173507	0.050016	-3.469004	0.0006
Cooling Degree Days	0.000634	0.0000907	6.995956	0
Heating Degree Days	0.000227	0.0000482	4.702313	0
Log(Total Employment/C&I Consumers)	0.184802	0.036738	5.030221	0
January 1999 - July 2015	0.076907	0.017999	4.272847	0
2019 Forward	-0.145457	0.013339	-10.90443	0

Weighted Statistics

Adjusted R-squared: 0.876752

JPEC Load Factor Model

Sample: 2007 - 2022
Total Observations: 192

Variable	Coefficient	Std. Error	t-Statistic	Prob.
January	0.659135	0.038221	17.24524	0
February	0.694448	0.03032	22.90415	0
March	0.676344	0.028803	23.48166	0
April Cold Peaking	0.705439	0.020673	34.12325	0
April Hot Peaking	0.654156	0.021337	30.65783	0
May	0.592177	0.017158	34.51349	0
June	0.60758	0.023881	25.44169	0
July	0.602278	0.025044	24.04883	0
August	0.587836	0.024952	23.55824	0
September	0.602414	0.022121	27.23264	0
October Cold Peaking	0.738494	0.029593	24.95536	0
October Hot Peaking	0.624062	0.024917	25.04524	0
November	0.688301	0.028675	24.00356	0
December	0.691394	0.033179	20.83827	0
Cooling Degree Days on Peak Day*(AC Saturation)*(1/AC Efficiency)	-0.089863	0.01648	-5.452801	0
Heating Degree Days on Peak Day*Electric Heating Saturation*(1/Heating Efficiency)	-0.09496	0.018234	-5.20796	0
Cooling Degree During Remainder of Month*(AC Saturation)*(1/AC Efficiency)	0.005366	0.000701	7.652608	0
Heating Degree During Remainder of Month*Electric Heating Saturation*(1/Heating Efficiency)	0.005294	0.000881	6.011511	0

Weighted Statistics

Adjusted R-squared: 0.615507

The following tables provide the econometric models for Kenergy Corporation.

Kenergy Residential Use Per Consumer Model

Sample: 2007 - 2022
Total Observations: 192

Variable	Coefficient	Std. Error	t-Statistic	Prob.
January	6.673584	0.04215	158.3306	0
February	6.640706	0.042985	154.4881	0
March	6.656935	0.039388	169.0105	0
April	6.573364	0.040008	164.3021	0
May	6.642724	0.033776	196.6695	0
June	6.719563	0.04065	165.3023	0
July	6.816312	0.041692	163.4917	0
August	6.823566	0.040221	169.6513	0
September	6.739677	0.039465	170.7762	0
October	6.562754	0.037525	174.889	0
November	6.51234	0.035711	182.3614	0
December	6.625338	0.042229	156.8901	0
Log(Residential Price/Alternate Fuel Price)	-0.058399	0.012305	-4.745989	0
Cooling Degree Days*(AC Saturation)*(1/AC Efficiency)	0.011387	0.000772	14.75387	0
Heating Degree Days*Electric Heat Saturation*(1/Heating Efficiency)	0.011171	0.000817	13.67731	0

Weighted Statistics

Adjusted R-squared:0.910082

Kenergy General C&I Consumer Model

Sample: 2007 - 2022
Total Observations: 192

Variable	Coefficient	Std. Error	t-Statistic	Prob.
GRP	0.734062	0.230635	3.182792	0.0017
Total Retail Sales	2.803564	0.585334	4.789682	0
Total Employment	46.98086	14.96738	3.138883	0.002
October 2019 Forward	1098.972	148.7559	7.387753	0

Weighted Statistics

Adjusted R-squared: 0.774798

Kenergy General C&I Use Per Consumer Model

Sample: 1999 - 2022
Total Observations: 288

Variable	Coefficient	Std. Error	t-Statistic	Prob.
January	11.03645	0.207304	53.23799	0
February	10.93705	0.204755	53.41537	0
March	11.00622	0.203932	53.97002	0
April	11.00094	0.20395	53.93943	0
May	11.17826	0.20233	55.2476	0
June	11.31377	0.20111	56.25665	0
July	11.29531	0.202361	55.81773	0
August	11.25122	0.202944	55.44013	0
September	11.22539	0.20222	55.51071	0
October	11.20665	0.202942	55.22087	0
November	11.19524	0.202515	55.2809	0
December	11.19523	0.206601	54.18779	0
Log(C&I Electricity Price)	-0.064042	0.034125	-1.876652	0.0616
Cooling Degree Days	0.000881	0.0000901	9.769975	0
Heating Degree Days	0.000501	0.0000589	8.500675	0
Log(Total Employment/C&I Consumers)	0.725979	0.032022	22.67147	0
October 2019 Forward	-0.068991	0.021149	-3.262197	0.0012

Weighted Statistics

Adjusted R-squared: 0.887782

Kenergy Load Factor Model

Sample: 2007 - 2022
Total Observations: 192

Variable	Coefficient	Std. Error	t-Statistic	Prob.
January	0.718176	0.029719	24.16522	0
February	0.72945	0.026261	27.77668	0
March	0.69766	0.026209	26.61952	0
April Cold Peaking	0.712995	0.017761	40.14352	0
April Hot Peaking	0.68294	0.020216	33.78176	0
May	0.597144	0.015007	39.79006	0
June	0.592762	0.017443	33.98304	0
July	0.594202	0.017177	34.59384	0
August	0.582306	0.016989	34.27491	0
September	0.592213	0.016945	34.94977	0
October Cold Peaking	0.767759	0.023177	33.12577	0
October Hot Peaking	0.631916	0.022456	28.14008	0
November	0.718783	0.023541	30.53281	0
December	0.732803	0.028761	25.47863	0
Cooling Degree Days on Peak Day*(AC Saturation)*(1/AC Efficiency)	-0.082995	0.014745	-5.628784	0
Heating Degree Days on Peak Day*Electric Heating Saturation*(1/Heating Efficiency)	-0.093226	0.013556	-6.877317	0
Cooling Degree During Remainder of Month*(AC Saturation)*(1/AC Efficiency)	0.005343	0.000666	8.018808	0
Heating Degree During Remainder of Month*Electric Heating Saturation*(1/Heating Efficiency)	0.003671	0.000617	5.94997	0

Weighted Statistics

Adjusted R-squared: 0.591129

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

MCRECC Residential Use Per Consumer Model

Sample: 2007 - 2022
Total Observations: 192

Variable	Coefficient	Std. Error	t-Statistic	Prob.
January	6.461398	0.031277	206.5872	0
February	6.415865	0.029951	214.2127	0
March	6.436066	0.022697	283.5684	0
April	6.329947	0.017815	355.3205	0
May	6.38794	0.017506	364.8938	0
June	6.458584	0.022991	280.9206	0
July	6.508964	0.024912	261.2788	0
August	6.476187	0.025746	251.5415	0
September	6.398572	0.021098	303.2857	0
October	6.340907	0.017898	354.2897	0
November	6.404882	0.022625	283.0942	0
December	6.479919	0.028882	224.3548	0
Log(Residential Price/Alternate Fuel Price)	-0.037817	0.005331	-7.093359	0
Cooling Degree Days*(AC Saturation)*(1/AC Efficiency)	0.012707	0.000564	22.54483	0
Heating Degree Days*Electric Heat Saturation*(1/Heating Efficiency)	0.011247	0.000466	24.11515	0

Weighted Statistics

Adjusted R-squared: 0.976605

MCRECC General C&I Consumer Model

Sample: 2007 - 2022
Total Observations: 192

Variable	Coefficient	Std. Error	t-Statistic	Prob.
GRP	0.258294	0.028435	9.083512	0
Total Employment	119.2644	1.617385	73.73899	0

Weighted Statistics

Adjusted R-squared: 0.274853

MCRECC General C&I Use Per Consumer Model

Sample: 1999 - 2022
Total Observations: 288

Variable	Coefficient	Std. Error	t-Statistic	Prob.
January	9.964495	0.358661	27.78245	0
February	9.955098	0.357753	27.82671	0
March	9.989172	0.355435	28.10404	0
April	10.00987	0.359455	27.84734	0
May	10.10943	0.357824	28.2525	0
June	10.12273	0.35724	28.33592	0
July	10.13845	0.358164	28.30671	0
August	10.15559	0.358897	28.29669	0
September	10.12805	0.356995	28.37026	0
October	10.14746	0.357573	28.37866	0
November	10.0758	0.358343	28.11776	0
December	10.01551	0.359667	27.84665	0
Log(C&I Electricity Price)	-0.266032	0.096135	-2.767257	0.006
Cooling Degree Days	0.000601	0.0000745	8.060065	0
Heating Degree Days	0.00032	0.0000455	7.036529	0
Log(Total Employment/C&I Consumers)	0.535753	0.094235	5.685278	0
2013 Forward	-0.13121	0.022573	-5.812777	0
2015 Forward	0.047711	0.019045	2.50518	0.0128

Weighted Statistics

Adjusted R-squared: 0.7947

MCRECC Load Factor Model

Sample: 2007 - 2022
Total Observations: 192

Variable	Coefficient	Std. Error	t-Statistic	Prob.
January	0.68625	0.037243	18.42603	0
February	0.698022	0.032236	21.65336	0
March	0.669116	0.025031	26.73158	0
April Cold Peaking	0.650418	0.02154	30.19621	0
April Hot Peaking	0.7152	0.021627	33.06905	0
May	0.626818	0.01979	31.67407	0
June	0.595771	0.029619	20.11459	0
July	0.600986	0.034557	17.39111	0
August	0.584584	0.033233	17.59062	0
September	0.602629	0.024881	24.22038	0
October Cold Peaking	0.695728	0.023127	30.0832	0
October Hot Peaking	0.660994	0.021538	30.6897	0
November	0.6757	0.023813	28.37488	0
December	0.689357	0.03088	22.32351	0
Cooling Degree Days on Peak Day*(AC Saturation)*(1/AC Efficiency)	-0.11587	0.016171	-7.165212	0
Heating Degree Days on Peak Day*Electric Heating Saturation*(1/Heating Efficiency)	-0.108129	0.010787	-10.02427	0
Cooling Degree During Remainder of Month*(AC Saturation)*(1/AC Efficiency)	0.006445	0.001014	6.358579	0
Heating Degree During Remainder of Month*Electric Heating Saturation*(1/Heating Efficiency)	0.004786	0.000575	8.323475	0

Weighted Statistics

Adjusted R-squared: 0.572842

Appendix B

Demand-Side Management Potential Study

Demand-Side Management
Potential Study

Big Rivers Electric Corporation

Henderson, Kentucky

Prepared By:

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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, Terry Wright, Ron Repsher, and Marlene Parsley.

…

Expertise and analysis on this project were provided by Joshua Hoyt (Project Manager), and Katherine Steward (Economist).

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.

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 Owensboro, 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, demand response, 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 when 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 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 member 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:

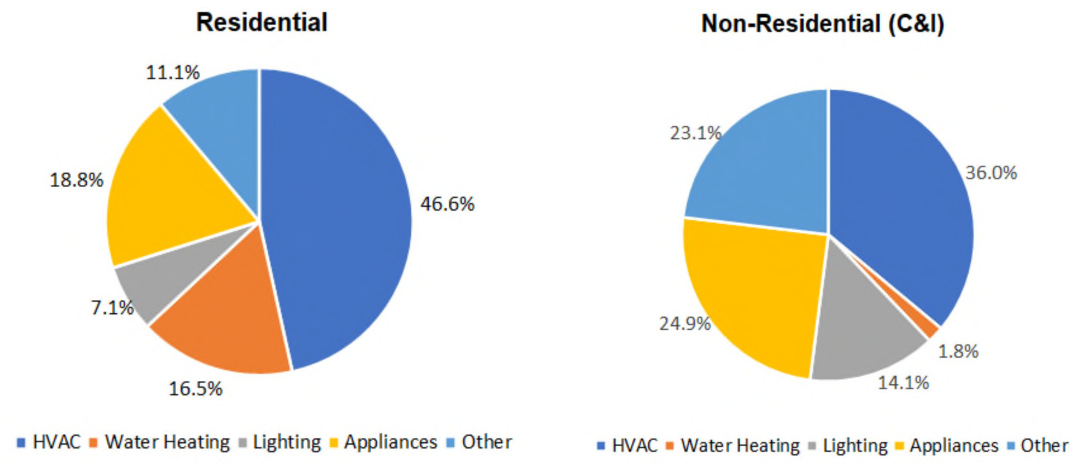
- Develop residential and non-residential segment end-use models of energy use.
- Identify potential demand response / energy efficiency measures.
- Evaluate this measure list with a qualitative screening tool.
- Perform a quantitative economic analysis on the cost-effectiveness of these measures.
- 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 (2023). 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 member type (residential and non-residential) and process type (lighting, heating, cooling, appliance, etc.). A total of 273 individual measures were identified with 86 measures identified for the residential segment and 187 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, member acceptance, etc. A total of 180 individual measures were segmented into 65 residential measures and 115 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 net present value of potential benefits of a measure to the present value of costs, yielding a "benefit-cost ratio." A benefit-cost ratio greater than one (1.0) indicates that a measure has a positive economic impact 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 of 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 showing the impacts over a ten-year study window (2024-2033) 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 members.

Table ES-1
Energy Efficiency Potential (Cumulative Annual) Energy Savings (MWh) 2024-2033

DSM Potential (Annual Cumulative) Energy (MWh)		
Potential	**Residential**	**Non-Res (C&I)**
Technical	296,037	216,489
Economic	213,006	147,314
Achievable	108,886	121,046
Program ($1m)	23,110	61,508

Note: Cumulative Annual Impact

Table ES-2
Energy Efficiency Potential (Cumulative Annual) Demand Savings (MW) 2024-2033

DSM Potential (Annual Cumulative) Demand (MW)		
Potential	**Residential**	**Non-Res**
Technical	49	48
Economic	29	32
Achievable	15	26
Program ($1m)	3	13

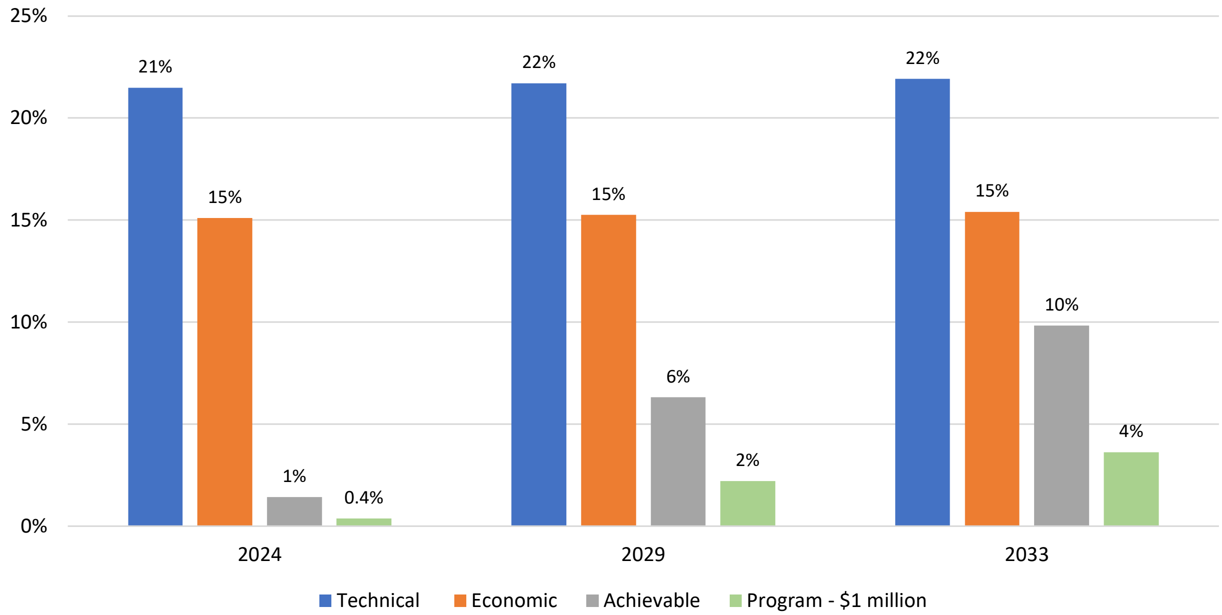
Note: Cumulative Annual Impact

As shown in figure ES-2, maximum technical potential represents approximately 22 percent of 2033 retail MWh energy sales for Big Rivers. Economic potential represents 15 percent in 2033 while achievable potential is 10 percent. These findings are consistent with previous studies which have looked at energy efficiency potential.[1]

A hypothetical program budget scenario was also developed as part of this study for the program potential. This $1 million annual demand-side budget scenario projects energy savings of 4.0 percent by 2033 or roughly 0.4 percent per year. The TRC benefit-cost ratio that results from this program spending is 3.1. This compares with a program TRC of 1.9 in the 2020 study, and reflects higher avoided cost values. Overall, 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. A program scenario based on a $1 million annual budget was evaluated as part of the program potential.

There are challenges to the implementation of demand-side programs by Big Rivers. As market values change, 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 use energy.

In the end, the cost-effective DSM 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

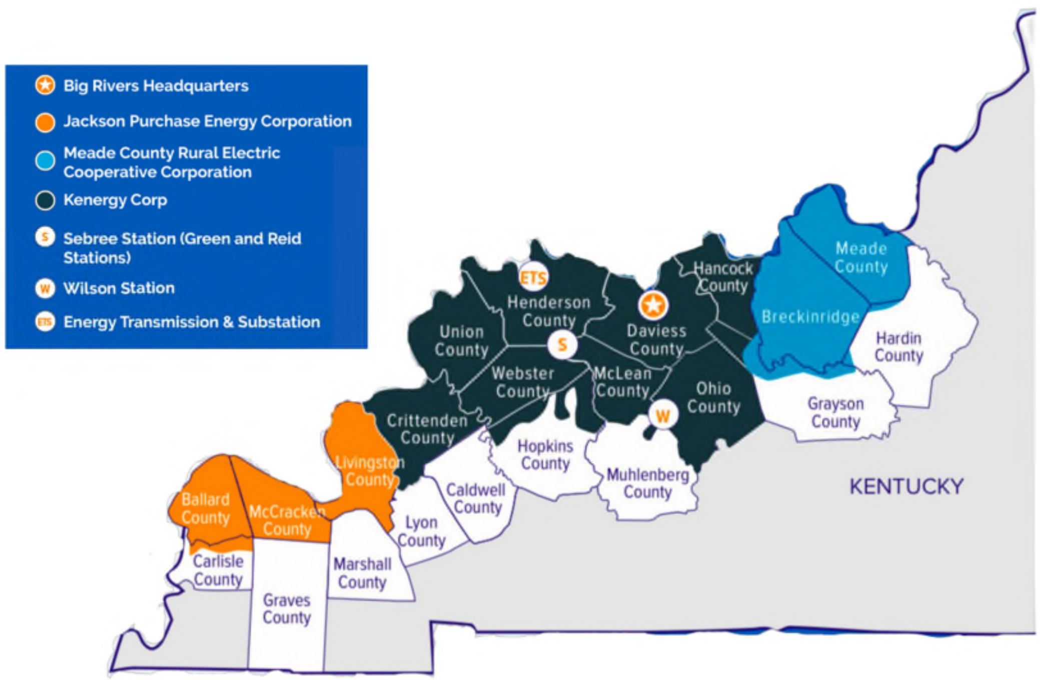
STUDY APPROACH

1.0 Study Approach

1.1 Background

Big Rivers Electric Corporation (Big Rivers) is an electric generation and transmission cooperative located in Owensboro, 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 121,000 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



Clearspring Energy Advisors, LLC

Clearspring Energy was formed in 2004 and has been providing consulting services to utilities, primarily electric cooperatives, for 19 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 staff with the most involvement are Joshua Hoyt and Katherine Steward. Brief biographies of both are presented below.

Joshua Hoyt

Mr. Hoyt is a Principal and co-founder of Clearspring Energy Advisors with over 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 applied 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.

Katherine Steward

Ms. Steward is an Economist with Clearspring Energy Advisors with four years of experience working with electric and gas utilities. Prior to joining Clearspring, Ms. Steward served as a data analyst at a consulting firm serving cooperative utilities where she assisted on the evaluation of energy efficiency studies. She also has extensive experience analyzing large AMI and survey datasets. Ms. Steward has a bachelor's degree in economics and master's degree in applied economics, both from the University of Wisconsin-Madison.

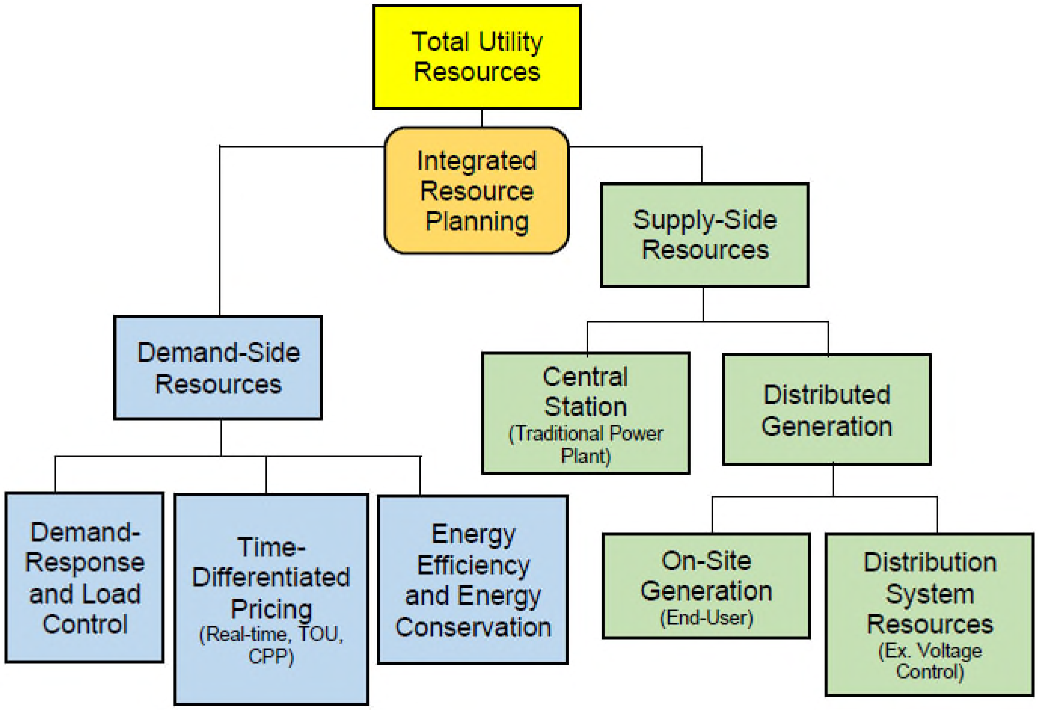
1.2 Study Objectives

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 over a period covering 2024-2033. 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 member 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 member classes is the 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 2023 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 member to be evaluated. Numerous studies and tools exist to compile a comprehensive list and the experience of energy agencies, 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 better technology that could replace it?

An example in this analysis 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 might provide value to Big Rivers and its Member Owners. 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 members 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(s) 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 (PCT)
- Utility Cost (UCT)
- 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.[4] 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. The use of recently published technical resource manuals ensure more up to date costs of measures are utilized in calculations, however specific adjustments for current inflationary conditions were not made.

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:

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[3] Understanding Cost-Effectiveness of Energy Efficiency Programs, November 2008
The current study utilizes more recent Technical Resource Manuals with updated costs and savings and updated avoided costs from BREC, however no specific adjustments have been made to those cost to reflect recent inflationary pressures.

- Impact of avoided carbon taxes or surplus credits for cap and trade. The lack of any clearly defined programs makes this problematic.
- 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.[5]
- 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 because 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 (if any). 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 member 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 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:

[5] 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 saved by demand-side measures. It disregards non-engineering constraints such as cost-effectiveness and the willingness of end-users to adopt 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" obstacles 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 Cost Test under aggressive implementation parameters. For this analysis, it assumes Big Rivers pays the full incremental cost of implementing the energy efficient measure.

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 an annual budget scenario of $1 million in 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's 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 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 makes 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 Existing State and Federal Programs

As part of the codes and standards review, a review of Kentucky and federal programs was conducted and presented here. Many of the programs are informational in nature, although there are some tax incentives programs (such as for electric vehicles) that could impact adoption of a specific program if developed later on. Many of the programs have stringent criteria making it difficult to assess their impact in a potential study, however, should specific programs be developed by Big Rivers in the future these state and federal programs should be assessed for inclusion.

Name	Territory	Category	Type	Created	Updated
Modified Accelerated Cost-Recovery System (MACRS)	US	Financial Incentive	Corporate Depreciation	3/15/2002	7/12/2023
Business Energy Investment Tax Credit (ITC)	US	Financial Incentive	Corporate Tax Credit	3/15/2002	6/29/2023
Building Energy Code	KY	Regulatory Policy	Building Energy Code	7/27/2006	6/18/2023
Residential Energy Conservation Subsidy Exclusion (Corporate)	US	Financial Incentive	Corporate Tax Exemption	3/5/2002	5/19/2023
Energy-Efficient New Homes Tax Credit for Home Builders	US	Financial Incentive	Corporate Tax Credit	1/10/2006	3/29/2023
Alternative Fuel Vehicle Refueling Property Tax Credit (Corporate)	US	Financial Incentive	Corporate Tax Credit	8/18/2022	1/26/2023
Low Income Home Energy Assistance Program (LIHEAP)	US	Financial Incentive	Grant Program	3/16/2015	11/18/2022
Residential Energy Efficiency Tax Credit	US	Financial Incentive	Personal Tax Credit	1/10/2006	11/8/2022
U.S. Department of Energy - Loan Guarantee Program	US	Financial Incentive	Loan Program	9/12/2008	9/8/2022
Plug-In Electric Drive Vehicle Tax Credit	US	Financial Incentive	Personal Tax Credit	8/18/2021	8/29/2022
Previously-Owned Clean Vehicle Tax Credit	US	Financial Incentive	Personal Tax Credit	8/26/2022	8/26/2022
Qualified Commercial Clean Vehicle Tax Credit	US	Financial Incentive	Corporate Tax Credit	8/18/2022	8/18/2022
Alternative Fuel Vehicle Refueling Property Tax Credit (Personal)	US	Financial Incentive	Personal Tax Credit	8/18/2022	8/18/2022
Energy-Efficient Commercial Buildings Tax Deduction	US	Financial Incentive	Corporate Tax Deduction	1/10/2006	8/16/2022
Together We Save - Kentucky's Touchstone Energy Cooperatives	KY	Financial Incentive	Rebate Program	9/25/2006	7/27/2022
Residential Energy Conservation Subsidy Exclusion (Personal)	US	Financial Incentive	Personal Tax Exemption	3/5/2002	7/20/2022
Weatherization Assistance Program (WAP)	US	Financial Incentive	Grant Program	3/31/2015	7/18/2022
Energy-Efficient Appliance Manufacturing Tax Credit	US	Financial Incentive	Industry Recruitment/Support	1/10/2006	7/14/2021
Federal Appliance Standards	US	Regulatory Policy	Appliance/Equipment Efficiency Standards	6/30/2006	7/7/2021
Net Metering	KY	Regulatory Policy	Net Metering	5/4/2004	6/18/2021
On-Farm Energy Efficiency Grant Program	KY	Financial Incentive	Grant Program	1/15/2010	4/2/2021
Energy-Efficient Mortgages	US	Financial Incentive	Loan Program	3/21/2002	8/5/2020
Sales Tax Exemption for Manufacturing Facilities	KY	Financial Incentive	Sales Tax Incentive	10/10/2007	7/31/2020
Fannie Mae Green Financing – Loan Program	US	Financial Incentive	Loan Program	5/28/2015	5/8/2020
Office of Indian Energy Policy and Programs - Funding Opportunitie	US	Financial Incentive	Grant Program	5/1/2003	2/26/2020
Energy Goals and Standards for Federal Government	US	Regulatory Policy	Energy Standards for Public Buildings	6/19/2006	8/21/2018
Interconnection Standards for Small Generators	US	Regulatory Policy	Interconnection	10/30/2007	7/27/2016
Interconnection Standards	KY	Regulatory Policy	Interconnection	1/14/2009	11/30/2015

1.8 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 (2022).
- Big Rivers electric load forecast (2023).
- 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. https://www.epa.gov/energy/guide-conducting-energy-efficiency-potential-studies
- https://appliance-standards.org/national

Data Sources for Measure Costs and Savings Estimates

- Illinois Technical Resource Manual (2021)
- Pennsylvania Technical Resource Manual (2021)
- Iowa Technical Resource Manual (2020)
- Michigan Technical Resource Manual (2017)
- "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.
- https://programs.dsireusa.org/system/program/ky

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' 2022 residential member 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 2023 Big Rivers electric load forecast study using 2023 as a base year and evaluating the measures over the 2024-2033 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 foundation on which to evaluate total potential energy efficiency savings.

Figure 2.1
Residential End-Use %

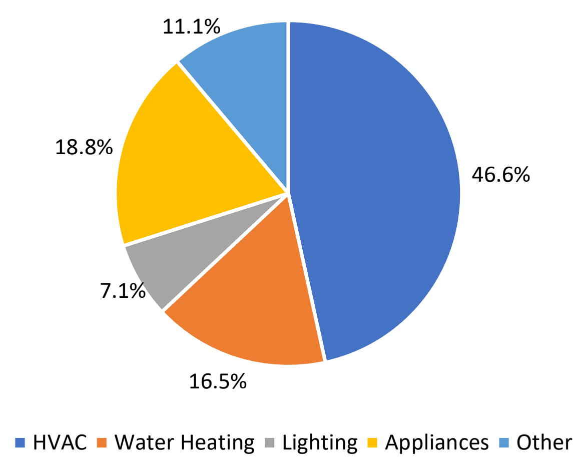


Table 2.1
Residential End-Use % (2023)

End-Use	kWh Per Household /1	Big Rivers Survey % /2	Member Count /3	Total Energy (MWh)	Percent of Total %
Space heating	*6,744*	50.1%	51,161	345,029	24.0%
Air handlers (heat)	114	89.5%	91,398	10,419	0.7%
Air conditioning	*2,716*	91.6%	93,540	254,054	17.6%
Air handlers (cool)	136	91.6%	93,540	12,721	0.9%
Ceiling fans	358	91.0%	92,927	33,268	2.3%
Dehumidifiers	768	19.3%	19,709	15,136	1.1%
Water heating	3,476	66.8%	68,215	237,114	16.5%
Clothes washers	73	97.1%	99,156	7,238	0.5%
Clothes dryers	875	94.1%	96,093	84,081	5.8%
Lighting	*1,000*	100.0%	102,118	102,118	7.1%
Refrigerators	579	99.4%	101,505	58,771	4.1%
Second refrig.	487	*25.3%*	25,836	12,582	0.9%
Separate freezers	513	68.9%	70,359	36,094	2.5%
Cooking	291	67.7%	69,134	20,118	1.4%
Microwaves	110	98.3%	100,382	11,042	0.8%
Dishwashers	116	80.4%	82,103	9,524	0.7%
Most-used TVs	260	98.0%	100,075	26,020	1.8%
Second TVs	141	*32.5%*	33,188	4,680	0.3%
Pool pumps	1,329	18.3%	18,688	24,836	1.7%
Hot tub pumps	*325*	5.7%	5,821	1,892	0.1%
Hot tub heaters	*1,000*	5.7%	5,821	5,821	0.4%
Other	*1,250*	100.0%	102,118	127,647	8.9%
TOTAL			**102,118**	1,440,205	100.0%

Notes: */1 From EIA, Residential Energy Consumption Survey*
/2 Appliance penetration data from 2022 Big Rivers survey
/3 2023 estimate from 2023 Big Rivers load forecast

2.2.2 Non-Residential End-Use Model

Non-residential members 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 nationwide 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 %

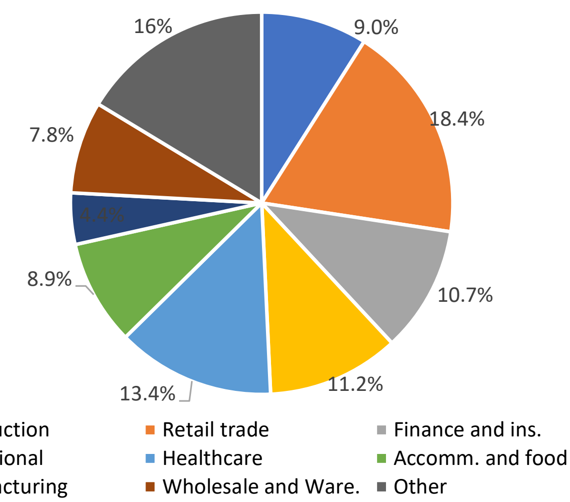


Table 2.2
Non-Residential Breakdown By Industry Type

Code	NAICS Industry	CBP Share %	Retail Accounts
11	Agriculture, forestry, fishing, hunting	0.1%	25
21	Mining, quarrying, oil, gas extraction	0.4%	72
22	Utilities	0.4%	74
23	Construction	9.0%	1,720
31-33	Manufacturing	4.4%	832
42	Wholesale trade	4.3%	829
44-45	Retail trade	18.4%	3,522
48-49	Transp. and warehousing	3.5%	663
51	Information	1.4%	273
52	Finance and insurance	6.8%	1,291
53	Real estate, rental, leasing	3.9%	748
54	Prof./scient./tech. services	6.7%	1,278
55	Management of companies and ente	0.3%	66
56	Admin. and support	4.2%	794
61	Educational services	0.9%	165
62	Health care and social assist.	13.4%	2,560
71	Arts, entertainment, and recreation	1.1%	209
72	Accommodation, food services	8.9%	1,699
81	Other services (excl. public admin.)	12.1%	2,305
	TOTAL	100.0%	**19,126**

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

Direct Non-Process

- Facility HVAC
- Facility Lighting
- Other Facility Support
- On-Site Transportation
- Conventional Electric Generation
- Other Non-Process

Other

- 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 in the Big Rivers 2023 Electric Load Forecast Study 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 36 percent of total end-use energy and appliances with 25 percent of energy consumption.

Figure 2.3
Non-Residential End-Use %

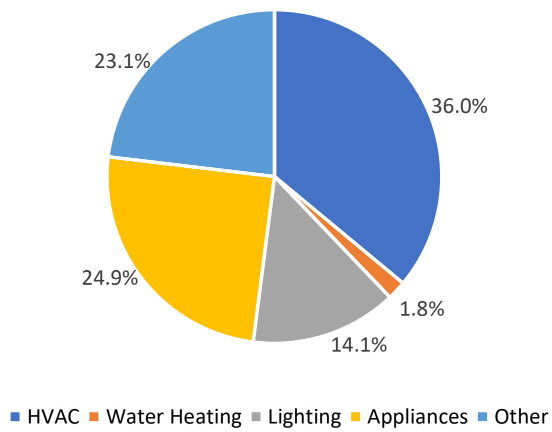


Table 2.3
Non-Residential End-Use Shares

Code	NAICS Industry	Space Heating	Space Cooling	Vent.	Water Heating	Lighting	Cooking	Refrig.	Office Equip.	Comp.	Other	Total
11	Agriculture, forestry, fishing, hunting	10%	10%	26%	1%	16%	1%	3%	1%	10%	21%	100%
21	Mining, quarrying, oil, gas extraction	3%	4%	2%	2%	6%	10%	8%	0%	0%	65%	100%
22	Utilities	10%	10%	26%	1%	16%	1%	3%	1%	10%	21%	100%
23	Construction	10%	10%	26%	1%	16%	1%	3%	1%	10%	21%	100%
31-33	Manufacturing	3%	4%	2%	2%	6%	10%	8%	0%	0%	65%	100%
42	Wholesale trade	12%	15%	7%	1%	20%	3%	14%	1%	3%	24%	100%
44-45	Retail trade	9%	8%	15%	1%	15%	5%	30%	1%	2%	15%	100%
48-49	Transp. and warehousing	12%	15%	7%	1%	20%	3%	14%	1%	3%	24%	100%
51	Information	10%	10%	26%	1%	16%	1%	3%	1%	10%	21%	100%
52	Finance and insurance	10%	10%	26%	1%	16%	1%	3%	1%	10%	21%	100%
53	Real estate, rental, leasing	10%	10%	26%	1%	16%	1%	3%	1%	10%	21%	100%
54	Prof./scient./tech. services	10%	10%	26%	1%	16%	1%	3%	1%	10%	21%	100%
55	Management of companies and enterpri	10%	10%	26%	1%	16%	1%	3%	1%	10%	21%	100%
56	Admin. and support	10%	10%	26%	1%	16%	1%	3%	1%	10%	21%	100%
61	Educational services	10%	10%	26%	1%	16%	1%	3%	1%	10%	21%	100%
62	Health care and social assist.	5%	11%	28%	2%	14%	4%	3%	1%	7%	25%	100%
71	Arts, entertainment, and recreation	8%	7%	15%	7%	10%	7%	30%	0%	1%	14%	100%
72	Accommodation, food services	8%	7%	15%	7%	10%	7%	30%	0%	1%	14%	100%
81	Other services (excl. public admin.)	5%	12%	7%	0%	11%	2%	2%	0%	30%	30%	100%
	TOTAL	8%	10%	18%	2%	14%	4%	12%	1%	9%	23%	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 technology would be found there. The lists of the various measures form the TRMs was then consolidated into a master list for the residential and non-residential segments.

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

2.3.2 Final Measure List Results

A total of 273 individual measures were identified including 86 measures for the residential segment and 187 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 (%)

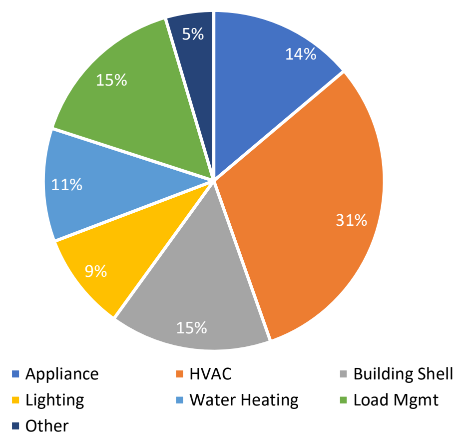
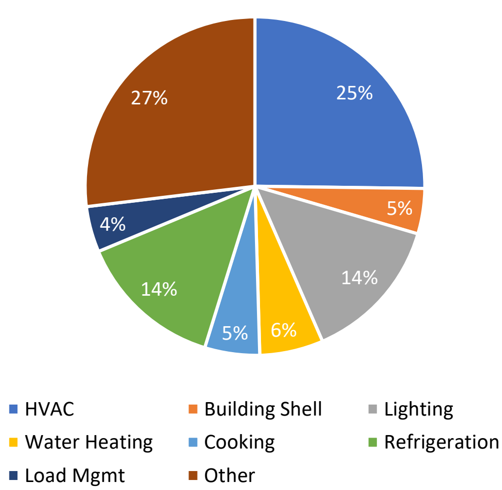


Figure 2.5
Non-Residential Measure End-Use Categories (%)



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. In general, a “No” answer increased the likelihood that a measure would be dropped. Typical questions include:

- *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 member acceptance*: Are members likely to accept the proposed measure and is it easily integrated into their appliance portfolio?

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.
- The draft screening results were provided to Big Rivers for review and comment.

Following that review, a total of 180 individual measures were identified: 65 measures for the residential segment and 115 for the non-residential segment. 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 180 measures and sub-measures identified in the qualitative phase were evaluated using the quantitative screening tool in an iterative process.[6] 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:

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

- 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.[7]
- 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.
- 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 5.5% 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 4.5% and transmission losses of 2.34% were applied to energy and demand as identified in the 2023 Big Rivers load forecast.
- Administration costs of 15% of incentive spending was applied to the overall program cost.[8]

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 critically important to emphasize that each of these are fundamentally estimates and contain inherent uncertainty.

[7] The incremental costs associated with most of the measures were taken from the various Technical Resource Manuals used. While efforts were taken to use TRMs that were published more recently, no additional inflationary effects were applied to the deemed measure costs.

[8] 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.

Figure 2.6
Type of Energy Efficiency Potential

Not Technically Feasible	Technical Potential		
Not Technically Feasible	Not Cost Effective	Economic Potential	
Not Technically Feasible	Not Cost Effective	Market Barriers	Achievable 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)

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 2022 Big Rivers residential appliance survey was used to determine the percentage of a specific appliance stock that was 5 years old or less.[9] 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 5 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

[9] 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.

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 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 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)

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 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 factor was set at 78 percent based on passing measures, 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 was reduced to 31 percent based on passing measures while water heating end-uses were reduced over fifty percent. Cooking was reduced by 26 percent for cooking measures failed the TRC test. Office equipment was set to 100 percent based on server optimization measures after computers and monitors were deemed to be a transformed market in the qualitative stage. Eighty-three percent of the lighting measures passed the TRC, as did 83 percent of refrigeration. The Other category (which includes the process uses from manufacturing) was set at 63 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 x Adoption Factor = End-Use Program Potential (MWh)

For the purposes of this study, one program budget scenario was developed. This scenario was 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 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 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. An adoption factor based on the percentage of survey respondents who indicated they did not intend to adopt energy efficient measures and a budget factor were then used to scale the total cost up or down to match the program-level budget.[10]

[10] The 2022 BREC Residential and most recent CBECS surveys were used to develop the adoption factor.

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. Only summer peak savings are shown as this analysis was conducted prior to MISO seasonal forecasts being available. The residential program scenario achieved a TRC of 2.4.

3.2 Technical Potential

Technical potential represents an estimate of maximum energy efficiency potential. A total of 65 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	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Energy (MWh)	HVAC	161,776	163,343	164,650	165,739	166,755	167,690	168,550	169,355	170,099	170,796
	Water Heating	75,075	75,822	76,446	76,965	77,450	77,896	78,306	78,690	79,044	79,377
	Appliance	33,357	33,787	34,147	34,447	34,726	34,984	35,220	35,442	35,646	35,838
	Lighting	1,346	1,507	1,641	1,753	1,857	1,953	2,042	2,124	2,201	2,272
	Other	7,438	7,493	7,539	7,577	7,613	7,645	7,676	7,704	7,730	7,754
	Total	278,993	281,952	284,423	286,481	288,401	290,168	291,793	293,314	294,720	296,037
	Category	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
Demand (MW)	HVAC	35.1	35.5	35.7	36.0	36.2	36.4	36.6	36.7	36.9	37.0
	Water Heating	3.8	3.8	3.8	3.8	3.9	3.9	3.9	3.9	4.0	4.0
	Appliance	4.9	5.0	5.1	5.1	5.2	5.2	5.3	5.3	5.3	5.4
	Lighting	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
	Other	1.8	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9
	Total	45.8	46.3	46.7	47.0	47.3	47.6	47.8	48.1	48.3	48.5

Note: MISO Summer Peak

Note: Cumulative Annual Impact

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

End-Use	Category	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Space heating	HVAC	79,509	80,289	80,940	81,482	81,988	82,453	82,881	83,282	83,652	83,999
Air handlers (heat)	HVAC	701	706	711	715	719	722	725	728	731	734
Air conditioning	HVAC	58,803	59,411	59,920	60,343	60,738	61,102	61,436	61,749	62,038	62,309
Air handlers (cool)	HVAC	856	862	868	873	878	882	886	889	893	896
Ceiling fans	HVAC	18,412	18,551	18,667	18,764	18,854	18,937	19,013	19,085	19,151	19,213
Dehumidifiers	HVAC	3,496	3,522	3,544	3,562	3,579	3,594	3,608	3,622	3,634	3,646
Water heating	Water Heating	75,075	75,822	76,446	76,965	77,450	77,896	78,306	78,690	79,044	79,377
Clothes washers	Appliance	782	793	802	810	817	824	830	835	840	845
Clothes dryers	Appliance	17,359	17,578	17,761	17,913	18,055	18,185	18,305	18,418	18,522	18,619
Lighting	Lighting	1,346	1,507	1,641	1,753	1,857	1,953	2,042	2,124	2,201	2,272
Refrigerators	Appliance	3,440	3,480	3,514	3,542	3,568	3,592	3,614	3,635	3,654	3,672
Second refrig.	Appliance	7,364	7,450	7,522	7,582	7,638	7,690	7,737	7,781	7,822	7,861
Separate freezers	Appliance	2,113	2,137	2,158	2,175	2,191	2,206	2,220	2,232	2,244	2,255
Cooking	Appliance	888	894	900	905	909	914	917	921	924	927
Microwaves	Appliance	487	491	494	497	499	501	503	505	507	509
Dishwashers	Appliance	660	668	674	680	685	689	694	698	701	705
Most-used TVs	Appliance	224	250	273	291	309	325	339	353	366	378
Second TVs	Appliance	40	45	49	52	56	58	61	63	66	68
Pool pumps	Other	1,168	1,177	1,184	1,190	1,195	1,200	1,205	1,209	1,213	1,217
Hot tub pumps	Other	89	90	90	91	91	91	92	92	92	93
Hot tub heaters	Other	274	276	277	279	280	281	282	283	284	285
Other	Other	5,907	5,951	5,988	6,018	6,046	6,072	6,097	6,119	6,140	6,159
	Total	278,993	281,952	284,423	286,481	288,401	290,168	291,793	293,314	294,720	296,037

Note: Cumulative Annual Impact

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

End-Use	Category	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
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	23.5	23.8	24.0	24.1	24.3	24.4	24.6	24.7	24.8	24.9
Air handlers (cool)	HVAC	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Ceiling fans	HVAC	9.2	9.3	9.3	9.4	9.4	9.5	9.5	9.5	9.6	9.6
Dehumidifiers	HVAC	2.1	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2
Water heating	Water Hea	3.8	3.8	3.8	3.8	3.9	3.9	3.9	3.9	4.0	4.0
Clothes washers	Appliance	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Clothes dryers	Appliance	1.7	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.9	1.9
Lighting	Lighting	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Refrigerators	Appliance	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Second refrig.	Appliance	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.6	1.6	1.6
Separate freezers	Appliance	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.5
Cooking	Appliance	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Microwaves	Appliance	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Dishwashers	Appliance	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Most-used TVs	Appliance	0.1	0.1	0.1	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	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
	Total	45.8	46.3	46.7	47.0	47.3	47.6	47.8	48.1	48.3	48.5

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 65 measures presented in the technical potential analysis, 34 measures yielded a benefit-cost greater than 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	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Energy (MWh)	HVAC	108,786	109,866	110,768	111,519	112,220	112,864	113,458	114,013	114,526	115,006
	Water Heating	74,324	75,064	75,681	76,195	76,675	77,117	77,523	77,903	78,254	78,583
	Appliance	13,699	13,861	13,997	14,109	14,214	14,311	14,400	14,483	14,560	14,632
	Lighting	1,050	1,175	1,280	1,367	1,449	1,524	1,592	1,657	1,716	1,772
	Other	2,889	2,910	2,928	2,943	2,957	2,970	2,981	2,992	3,003	3,012
	Total	200,749	202,877	204,654	206,134	207,515	208,785	209,954	211,048	212,059	213,006
	Category	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
Demand (MW)	HVAC	20.0	20.2	20.4	20.5	20.7	20.8	20.9	21.0	21.1	21.2
	Water Heating	3.7	3.8	3.8	3.8	3.8	3.9	3.9	3.9	3.9	3.9
	Appliance	2.7	2.7	2.7	2.7	2.8	2.8	2.8	2.8	2.8	2.8
	Lighting	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2
	Other	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
	Total	27.2	27.5	27.8	28.0	28.1	28.3	28.5	28.6	28.8	28.9

Note: MISO Summer Peak

Note: Cumulative Annual Impact

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

End-Use	Category	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Space heating	HVAC	59,632	60,216	60,705	61,111	61,491	61,840	62,161	62,461	62,739	62,999
Air handlers (heat)	HVAC	701	706	711	715	719	722	725	728	731	734
Air conditioning	HVAC	44,102	44,559	44,940	45,257	45,554	45,826	46,077	46,312	46,529	46,732
Air handlers (cool)	HVAC	856	862	868	873	878	882	886	889	893	896
Ceiling fans	HVAC	0	0	0	0	0	0	0	0	0	0
Dehumidifiers	HVAC	3,496	3,522	3,544	3,562	3,579	3,594	3,608	3,622	3,634	3,646
Water heating	Water Heating	74,324	75,064	75,681	76,195	76,675	77,117	77,523	77,903	78,254	78,583
Clothes washers	Appliance	782	793	802	810	817	824	830	835	840	845
Clothes dryers	Appliance	0	0	0	0	0	0	0	0	0	0
Lighting	Lighting	1,050	1,175	1,280	1,367	1,449	1,524	1,592	1,657	1,716	1,772
Refrigerators	Appliance	3,440	3,480	3,514	3,542	3,568	3,592	3,614	3,635	3,654	3,672
Second refrig.	Appliance	7,364	7,450	7,522	7,582	7,638	7,690	7,737	7,781	7,822	7,861
Separate freezers	Appliance	2,113	2,137	2,158	2,175	2,191	2,206	2,220	2,232	2,244	2,255
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	2,889	2,910	2,928	2,943	2,957	2,970	2,981	2,992	3,003	3,012
	Total	200,749	202,877	204,654	206,134	207,515	208,785	209,954	211,048	212,059	213,006

Note: Cumulative Annual Impact

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

End-Use	Category	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
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	17.6	17.8	18.0	18.1	18.2	18.3	18.4	18.5	18.6	18.7
Air handlers (cool)	HVAC	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
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	2.1	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2
Water heating	Water Heating	3.7	3.8	3.8	3.8	3.8	3.9	3.9	3.9	3.9	3.9
Clothes washers	Appliance	0.1	0.1	0.1	0.1	0.1	0.1	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	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2
Refrigerators	Appliance	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Second refrig.	Appliance	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.6	1.6	1.6
Separate freezers	Appliance	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.5
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	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
	Total	27.2	27.5	27.8	28.0	28.1	28.3	28.5	28.6	28.8	28.9

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 34 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	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Energy (MWh)	HVAC	5,522	10,985	16,306	21,506	26,666	31,781	36,611	41,410	46,175	50,915
	Water Heating	4,525	9,011	13,401	17,707	21,987	26,236	30,457	34,657	38,835	42,995
	Appliance	1,322	2,635	3,923	5,191	6,451	7,705	8,951	10,191	10,563	10,930
	Lighting	251	495	719	926	1,128	1,323	1,513	1,574	1,631	1,684
	Other	244	487	726	963	1,199	1,433	1,667	1,900	2,132	2,364
	Total	11,865	23,613	35,075	46,293	57,431	68,478	79,198	89,733	99,335	108,886

	Category	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Demand (MW)	HVAC	1.1	2.1	3.2	4.2	5.2	6.2	7.1	8.1	9.0	10.0
	Water Heating	0.2	0.5	0.7	0.9	1.1	1.3	1.5	1.7	1.9	2.1
	Appliance	0.3	0.5	0.8	1.0	1.3	1.5	1.7	2.0	2.1	2.1
	Lighting	0.0	0.0	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2
	Other	0.1	0.1	0.2	0.2	0.3	0.4	0.4	0.5	0.5	0.6
	Total	1.6	3.3	4.9	6.4	8.0	9.5	11.0	12.4	13.7	15.0

Note: MISO Summer Peak

Note: Cumulative Annual Impact

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

End-Use	Category	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Space heating	HVAC	2,842	5,653	8,387	11,057	13,704	16,328	18,929	21,514	24,081	26,634
Air handlers (heat)	HVAC	116	231	346	459	573	686	689	692	694	697
Air conditioning	HVAC	2,121	4,219	6,256	8,242	10,212	12,163	14,096	16,017	17,923	19,819
Air handlers (cool)	HVAC	141	282	422	561	700	838	841	845	848	851
Ceiling fans	HVAC	0	0	0	0	0	0	0	0	0	0
Dehumidifiers	HVAC	301	600	895	1,187	1,478	1,767	2,055	2,342	2,629	2,914
Water heating	Water Heating	4,525	9,011	13,401	17,707	21,987	26,236	30,457	34,657	38,835	42,995
Clothes washers	Appliance	63	126	187	246	305	364	422	480	537	594
Clothes dryers	Appliance	0	0	0	0	0	0	0	0	0	0
Lighting	Lighting	251	495	719	926	1,128	1,323	1,513	1,574	1,631	1,684
Refrigerators	Appliance	193	384	570	751	930	1,108	1,285	1,460	1,634	1,807
Second refrig.	Appliance	951	1,896	2,828	3,749	4,666	5,578	6,487	7,392	7,431	7,467
Separate freezers	Appliance	115	229	338	445	550	654	757	859	961	1,061
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	244	487	726	963	1,199	1,433	1,667	1,900	2,132	2,364
	Total	11,865	23,613	35,075	46,293	57,431	68,478	79,198	89,733	99,335	108,886

Note: Cumulative Annual Impact

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

End-Use	Category	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
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	0.8	1.7	2.5	3.3	4.1	4.9	5.6	6.4	7.2	7.9
Air handlers (cool)	HVAC	0.0	0.1	0.1	0.2	0.2	0.3	0.3	0.3	0.3	0.3
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	0.4	0.5	0.7	0.9	1.1	1.3	1.4	1.6	1.8
Water heating	Water Heating	0.2	0.5	0.7	0.9	1.1	1.3	1.5	1.7	1.9	2.1
Clothes washers	Appliance	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	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	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2
Refrigerators	Appliance	0.0	0.1	0.1	0.2	0.2	0.2	0.3	0.3	0.3	0.4
Second refrig.	Appliance	0.2	0.4	0.6	0.7	0.9	1.1	1.3	1.5	1.5	1.5
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	0.1	0.2	0.2	0.3	0.4	0.4	0.5	0.5	0.6
	Total	1.6	3.3	4.9	6.4	8.0	9.5	11.0	12.4	13.7	15.0

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. A program scenario was developed based on an annual energy efficiency budget of $1 million. The incentive levels for each of the measures was 35 percent of incremental cost to be consistent with the previous filings. Of the measures that passed the TRC economic screening test, 34 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 twenty measures. Lighting, HVAC, and water heat-related measures dominate the field. The residential program scenario achieved a TRC of 2.4.

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

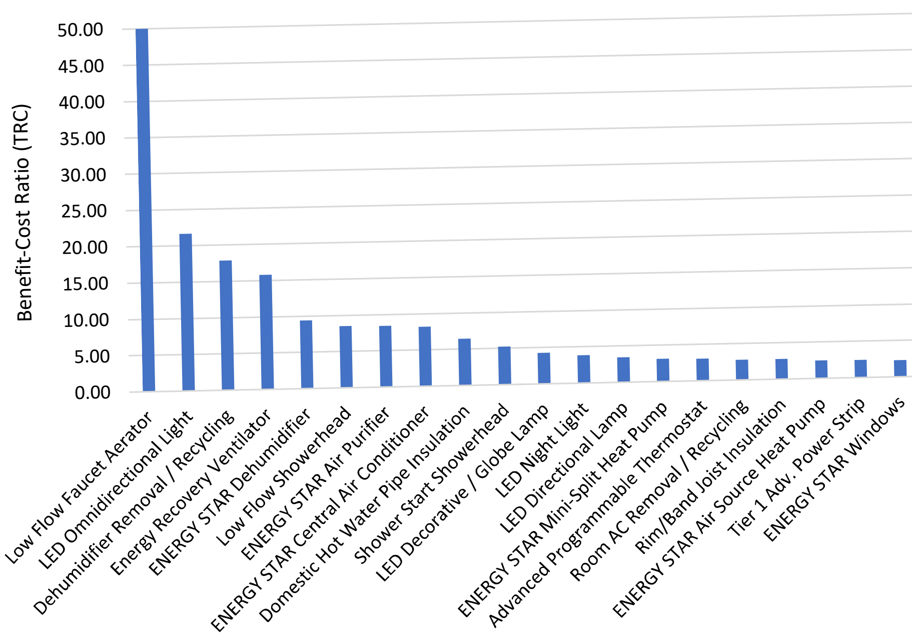


Table 3.10
Residential Program Potential By Major End-Use Category ($1 Million Scenario)

	Category	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Energy (MWh)	HVAC	1,050	2,099	3,149	4,198	5,248	6,298	7,347	8,397	9,446	10,496
	Water Heating	891	1,781	2,672	3,562	4,453	5,344	6,234	7,125	8,016	8,906
	Appliance	269	539	808	1,077	1,347	1,616	1,886	2,155	2,424	2,694
	Lighting	51	103	154	206	257	309	360	411	463	514
	Other	50	100	150	200	250	300	350	400	450	500
	Total	2,311	4,622	6,933	9,244	11,555	13,866	16,177	18,488	20,799	23,110
	Category	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
Demand (MW)	HVAC	0.2	0.4	0.6	0.8	1.0	1.2	1.4	1.6	1.9	2.1
	Water Heating	0.0	0.1	0.1	0.2	0.2	0.3	0.3	0.4	0.4	0.4
	Appliance	0.1	0.1	0.2	0.2	0.3	0.3	0.4	0.4	0.5	0.5
	Lighting	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
	Other	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1
	Total	0.3	0.6	1.0	1.3	1.6	1.9	2.2	2.6	2.9	3.2

Note: MISO Summer Peak

Note: Cumulative Annual Impact

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

End-Use	Category	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Space heating	HVAC	536	1,071	1,607	2,142	2,678	3,213	3,749	4,284	4,820	5,355
Air handlers (heat)	HVAC	25	50	74	99	124	149	174	199	223	248
Air conditioning	HVAC	397	794	1,192	1,589	1,986	2,383	2,781	3,178	3,575	3,972
Air handlers (cool)	HVAC	30	61	91	121	152	182	212	243	273	303
Ceiling fans	HVAC	0	0	0	0	0	0	0	0	0	0
Dehumidifiers	HVAC	62	123	185	247	309	370	432	494	555	617
Water heating	Water Heating	891	1,781	2,672	3,562	4,453	5,344	6,234	7,125	8,016	8,906
Clothes washers	Appliance	12	25	37	49	61	74	86	98	110	123
Clothes dryers	Appliance	0	0	0	0	0	0	0	0	0	0
Lighting	Lighting	51	103	154	206	257	309	360	411	463	514
Refrigerators	Appliance	37	73	110	147	184	220	257	294	330	367
Second refrig.	Appliance	200	399	599	798	998	1,197	1,397	1,597	1,796	1,996
Separate freezers	Appliance	21	42	62	83	104	125	146	167	187	208
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	50	100	150	200	250	300	350	400	450	500
	Total	2,311	4,622	6,933	9,244	11,555	13,866	16,177	18,488	20,799	23,110

Note: Cumulative Annual Impact

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

End-Use	Category	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
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	0.3	0.5	0.6	0.8	1.0	1.1	1.3	1.4	1.6
Air handlers (cool)	HVAC	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1
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	0.0	0.1	0.1	0.2	0.2	0.2	0.3	0.3	0.3	0.4
Water heating	Water Hea	0.0	0.1	0.1	0.2	0.2	0.3	0.3	0.4	0.4	0.4
Clothes washers	Appliance	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
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	0.1
Refrigerators	Appliance	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1
Second refrig.	Appliance	0.0	0.1	0.1	0.2	0.2	0.2	0.3	0.3	0.4	0.4
Separate freezers	Appliance	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
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	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1
	Total	0.3	0.6	1.0	1.3	1.6	1.9	2.2	2.6	2.9	3.2

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. Only summer peak savings are shown as this analysis was conducted prior to MISO seasonal forecasts being available. The non-residential program scenario achieved a TRC of 3.6.

4.2 Technical Potential

Technical potential represents an estimate of maximum energy efficiency potential. A total of the 115 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	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Energy (MWh)	HVAC	72,837	72,914	73,493	74,043	74,411	74,572	75,395	76,009	77,187	77,645
	Water Heating	6,546	6,552	6,599	6,643	6,673	6,685	6,752	6,801	6,896	6,933
	Lighting	39,932	39,981	40,349	40,698	40,932	41,034	41,557	41,947	42,695	42,986
	Appliance	50,287	50,352	50,838	51,300	51,609	51,744	52,435	52,951	53,940	54,325
	Other	32,604	32,636	32,876	33,104	33,257	33,324	33,665	33,920	34,409	34,599
	Total	202,207	202,434	204,155	205,789	206,882	207,358	209,804	211,628	215,126	216,489
	Category	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
Demand (MW)	HVAC	16.6	16.7	16.8	16.9	17.0	17.0	17.2	17.4	17.6	17.7
	Water Heating	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
	Lighting	8.0	8.0	8.1	8.1	8.2	8.2	8.3	8.4	8.5	8.6
	Appliance	16.6	16.6	16.7	16.9	16.9	17.0	17.2	17.3	17.6	17.7
	Other	3.3	3.3	3.3	3.3	3.3	3.3	3.4	3.4	3.4	3.5
	Total	45.1	45.2	45.5	45.9	46.1	46.2	46.7	47.1	47.9	48.2

Note: MISO Summer Peak
Note: Cumulative Annual Impact

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

End-Use	Category	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Space Heating	HVAC	20,731	20,753	20,918	21,074	21,179	21,225	21,459	21,634	21,969	22,100
Space Cooling	HVAC	28,567	28,597	28,824	29,040	29,184	29,247	29,570	29,811	30,272	30,452
Ventilation	HVAC	23,540	23,564	23,752	23,929	24,048	24,100	24,366	24,565	24,945	25,094
Water Heating	Water Heating	6,546	6,552	6,599	6,643	6,673	6,685	6,752	6,801	6,896	6,933
Lighting	Lighting	39,932	39,981	40,349	40,698	40,932	41,034	41,557	41,947	42,695	42,986
Cooking	Appliance	8,467	8,475	8,536	8,593	8,632	8,648	8,735	8,799	8,922	8,970
Refrigeration	Appliance	38,495	38,531	38,809	39,073	39,250	39,327	39,722	40,016	40,581	40,801
Office Equipment	Appliance	3,326	3,345	3,493	3,634	3,728	3,769	3,979	4,136	4,436	4,553
Other (incl. Process)	Other	32,604	32,636	32,876	33,104	33,257	33,324	33,665	33,920	34,409	34,599
	Total	202,207	202,434	204,155	205,789	206,882	207,358	209,804	211,628	215,126	216,489

Note: Cumulative Annual Impact

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

End-Use	Category	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
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	14.3	14.3	14.4	14.5	14.6	14.6	14.8	14.9	15.1	15.2
Ventilation	HVAC	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.5	2.5	2.5
Water Heating	Water Hea	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Lighting	Lighting	8.0	8.0	8.1	8.1	8.2	8.2	8.3	8.4	8.5	8.6
Cooking	Appliance	0.8	0.8	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
Refrigeration	Appliance	15.4	15.4	15.5	15.6	15.7	15.7	15.9	16.0	16.2	16.3
Office Equipment	Appliance	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.5
Other (incl. Process)	Other	3.3	3.3	3.3	3.3	3.3	3.3	3.4	3.4	3.4	3.5
	Total	45.1	45.2	45.5	45.9	46.1	46.2	46.7	47.1	47.9	48.2

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 115 non-residential measures that were presented in the technical potential screening, 66 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	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Energy (MWh)	HVAC	38,822	38,863	39,171	39,465	39,661	39,746	40,185	40,512	41,140	41,385
	Water Heating	3,208	3,211	3,233	3,255	3,270	3,276	3,308	3,333	3,379	3,397
	Lighting	33,144	33,184	33,490	33,780	33,974	34,058	34,492	34,816	35,437	35,679
	Appliance	41,542	41,598	42,021	42,423	42,692	42,810	43,412	43,860	44,721	45,057
	Other	20,540	20,560	20,712	20,856	20,952	20,994	21,209	21,370	21,678	21,798
	Total	137,255	137,416	138,628	139,779	140,548	140,884	142,606	143,891	146,355	147,314

	Category	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Demand (MW)	HVAC	6.8	6.8	6.8	6.9	6.9	6.9	7.0	7.1	7.2	7.2
	Water Heating	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
	Lighting	6.6	6.6	6.7	6.8	6.8	6.8	6.9	7.0	7.1	7.1
	Appliance	13.7	13.8	13.9	14.0	14.0	14.1	14.2	14.4	14.6	14.7
	Other	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.2	2.2
	Total	29.5	29.6	29.8	30.0	30.2	30.3	30.6	30.9	31.4	31.5

Note: MISO Summer Peak

Note: Cumulative Annual Impact

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

End-Use	Category	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Space Heating	HVAC	6,427	6,433	6,485	6,533	6,566	6,580	6,652	6,706	6,810	6,851
Space Cooling	HVAC	8,856	8,865	8,935	9,002	9,047	9,067	9,167	9,241	9,384	9,440
Ventilation	HVAC	23,540	23,564	23,752	23,929	24,048	24,100	24,366	24,565	24,945	25,094
Water Heating	Water Heating	3,208	3,211	3,233	3,255	3,270	3,276	3,308	3,333	3,379	3,397
Lighting	Lighting	33,144	33,184	33,490	33,780	33,974	34,058	34,492	34,816	35,437	35,679
Cooking	Appliance	6,265	6,271	6,316	6,359	6,387	6,400	6,464	6,511	6,602	6,638
Refrigeration	Appliance	31,951	31,981	32,212	32,431	32,577	32,641	32,969	33,214	33,683	33,865
Office Equipment	Appliance	3,326	3,345	3,493	3,634	3,728	3,769	3,979	4,136	4,436	4,553
Other (incl. Process)	Other	20,540	20,560	20,712	20,856	20,952	20,994	21,209	21,370	21,678	21,798
	Total	137,255	137,416	138,628	139,779	140,548	140,884	142,606	143,891	146,355	147,314

Note: Cumulative Annual Impact

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

End-Use	Category	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
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	4.4	4.4	4.5	4.5	4.5	4.5	4.6	4.6	4.7	4.7
Ventilation	HVAC	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.5	2.5	2.5
Water Heating	Water Heating	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Lighting	Lighting	6.6	6.6	6.7	6.8	6.8	6.8	6.9	7.0	7.1	7.1
Cooking	Appliance	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.7	0.7	0.7
Refrigeration	Appliance	12.8	12.8	12.9	13.0	13.0	13.1	13.2	13.3	13.5	13.5
Office Equipment	Appliance	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.5
Other (incl. Process)	Other	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.2	2.2
	Total	29.5	29.6	29.8	30.0	30.2	30.3	30.6	30.9	31.4	31.5

Note: Cumulative Annual Impact

4.4 Achievable Potential

Of the 66 measures that passed the TRC screening test, 65 measures yielded a benefit-cost greater than one from the participant perspective under the aggressive incremental cost assumption. 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	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Energy (MWh)	HVAC	4,852	7,355	10,112	12,854	15,504	18,049	20,930	23,704	26,765	29,460
	Water Heating	397	621	864	1,105	1,340	1,566	1,818	2,062	2,327	2,565
	Lighting	4,790	7,255	9,972	12,675	15,286	17,793	20,633	23,367	26,384	29,041
	Appliance	6,844	10,465	14,436	18,386	21,705	24,881	28,517	32,008	35,890	39,272
	Other	3,210	5,267	7,449	9,623	11,753	13,830	16,073	18,263	20,594	20,708
	Total	20,093	30,963	42,832	54,643	65,588	76,120	87,970	99,404	111,959	121,046

	Category	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Demand (MW)	HVAC	0.8	1.3	1.8	2.2	2.7	3.2	3.7	4.1	4.7	5.1
	Water Heating	0.0	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.3
	Lighting	1.0	1.5	2.0	2.5	3.1	3.6	4.1	4.7	5.3	5.8
	Appliance	2.0	3.1	4.4	5.6	6.8	7.9	9.1	10.3	11.6	12.8
	Other	0.3	0.5	0.7	1.0	1.2	1.4	1.6	1.8	2.1	2.1
	Total	4.2	6.5	9.0	11.5	13.9	16.1	18.7	21.2	23.9	26.1

Note: MISO Summer Peak
Note: Cumulative Annual Impact

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

End-Use	Category	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Space Heating	HVAC	803	1,218	1,674	2,128	2,567	2,988	3,465	3,924	4,431	4,877
Space Cooling	HVAC	1,107	1,678	2,307	2,932	3,537	4,117	4,774	5,407	6,105	6,720
Ventilation	HVAC	2,942	4,460	6,131	7,794	9,401	10,944	12,691	14,373	16,229	17,863
Water Heating	Water Heating	397	621	864	1,105	1,340	1,566	1,818	2,062	2,327	2,565
Lighting	Lighting	4,790	7,255	9,972	12,675	15,286	17,793	20,633	23,367	26,384	29,041
Cooking	Appliance	814	1,287	1,797	2,304	2,798	3,277	3,805	4,317	4,871	5,372
Refrigeration	Appliance	4,382	7,008	9,824	12,629	15,366	18,023	20,932	23,761	26,804	29,575
Office Equipment	Appliance	1,648	2,170	2,815	3,452	3,541	3,580	3,780	3,929	4,215	4,326
Other (incl. Process)	Other	3,210	5,267	7,449	9,623	11,753	13,830	16,073	18,263	20,594	20,708
	Total	20,093	30,963	42,832	54,643	65,588	76,120	87,970	99,404	111,959	121,046

Note: Cumulative Annual Impact

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

End-Use	Category	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
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	0.6	0.8	1.2	1.5	1.8	2.1	2.4	2.7	3.1	3.4
Ventilation	HVAC	0.3	0.4	0.6	0.8	0.9	1.1	1.3	1.4	1.6	1.8
Water Heating	Water Heating	0.0	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.3
Lighting	Lighting	1.0	1.5	2.0	2.5	3.1	3.6	4.1	4.7	5.3	5.8
Cooking	Appliance	0.1	0.1	0.2	0.2	0.3	0.3	0.4	0.4	0.5	0.5
Refrigeration	Appliance	1.8	2.8	3.9	5.1	6.1	7.2	8.4	9.5	10.7	11.8
Office Equipment	Appliance	0.2	0.2	0.3	0.3	0.4	0.4	0.4	0.4	0.4	0.4
Other (incl. Process)	Other	0.3	0.5	0.7	1.0	1.2	1.4	1.6	1.8	2.1	2.1
	Total	4.2	6.5	9.0	11.5	13.9	16.1	18.7	21.2	23.9	26.1

Note: Cumulative Annual Impact

4.5 Program Potential

As mentioned in section 3.5, a program scenario was developed based on a $1 million annual budget (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, 65 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 as determined by TRC. A broad mix of measure-types make up the list. The non-residential program scenario achieved a TRC of 3.6.

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

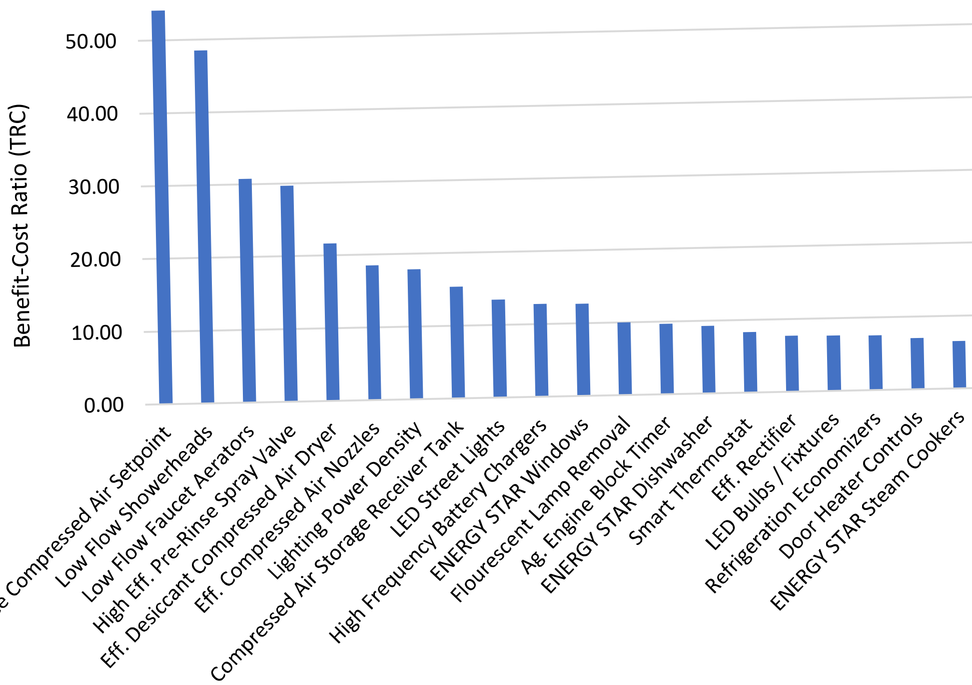


Table 4.10
Non-Residential Program Potential By Major End-Use Category ($1 Million Scenario)

	Category	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Energy (MWh)	HVAC	1,359	2,717	4,076	5,435	6,793	8,152	9,510	10,869	12,228	13,586
	Water Heating	120	240	360	480	600	721	841	961	1,081	1,201
	Lighting	1,367	2,733	4,100	5,466	6,833	8,199	9,566	10,932	12,299	13,665
	Appliance	2,192	4,385	6,577	8,770	10,962	13,154	15,347	17,539	19,732	21,924
	Other	1,113	2,226	3,339	4,453	5,566	6,679	7,792	8,905	10,018	11,132
	Total	6,151	12,302	18,452	24,603	30,754	36,905	43,056	49,207	55,357	61,508
	Category	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
Demand (MW)	HVAC	0.2	0.5	0.7	0.9	1.2	1.4	1.7	1.9	2.1	2.4
	Water Heating	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1
	Lighting	0.3	0.5	0.8	1.1	1.4	1.6	1.9	2.2	2.5	2.7
	Appliance	0.6	1.3	1.9	2.6	3.2	3.9	4.5	5.1	5.8	6.4
	Other	0.1	0.2	0.3	0.4	0.6	0.7	0.8	0.9	1.0	1.1
	Total	1.3	2.6	3.8	5.1	6.4	7.7	8.9	10.2	11.5	12.8

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	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Space Heating	HVAC	225	450	675	900	1,125	1,349	1,574	1,799	2,024	2,249
Space Cooling	HVAC	310	620	930	1,240	1,550	1,859	2,169	2,479	2,789	3,099
Ventilation	HVAC	824	1,648	2,471	3,295	4,119	4,943	5,767	6,590	7,414	8,238
Water Heating	Water Heating	120	240	360	480	600	721	841	961	1,081	1,201
Lighting	Lighting	1,367	2,733	4,100	5,466	6,833	8,199	9,566	10,932	12,299	13,665
Cooking	Appliance	254	508	763	1,017	1,271	1,525	1,780	2,034	2,288	2,542
Refrigeration	Appliance	1,415	2,830	4,245	5,660	7,075	8,490	9,905	11,320	12,735	14,150
Office Equipment	Appliance	523	1,046	1,570	2,093	2,616	3,139	3,662	4,186	4,709	5,232
Other (incl. Process)	Other	1,113	2,226	3,339	4,453	5,566	6,679	7,792	8,905	10,018	11,132
	Total	6,151	12,302	18,452	24,603	30,754	36,905	43,056	49,207	55,357	61,508

Note: Cumulative Annual Impact

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

End-Use	Category	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
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	0.2	0.3	0.5	0.6	0.8	0.9	1.1	1.2	1.4	1.5
Ventilation	HVAC	0.1	0.2	0.2	0.3	0.4	0.5	0.6	0.7	0.7	0.8
Water Heating	Water Hea	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1
Lighting	Lighting	0.3	0.5	0.8	1.1	1.4	1.6	1.9	2.2	2.5	2.7
Cooking	Appliance	0.0	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.3
Refrigeration	Appliance	0.6	1.1	1.7	2.3	2.8	3.4	4.0	4.5	5.1	5.7
Office Equipment	Appliance	0.1	0.1	0.2	0.2	0.3	0.3	0.4	0.4	0.5	0.5
Other (incl. Process)	Other	0.1	0.2	0.3	0.4	0.6	0.7	0.8	0.9	1.0	1.1
	Total	1.3	2.6	3.8	5.1	6.4	7.7	8.9	10.2	11.5	12.8

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. A study by the Brattle Group revealed about 50% of investor-owned utilities nationwide offer optional time-differentiated rates for residential customers.[11] At the time of the study, less than 2% residential customers have elected to use them. 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. The report 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.

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 members' bills by shifting usage to lower cost periods or avoidance of high-cost periods.
- Reductions in power consumption during high cost periods 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.

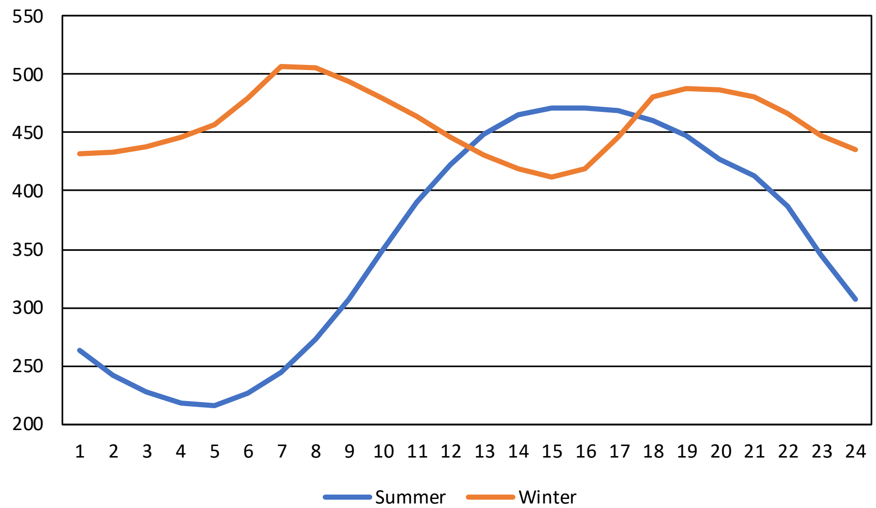
[11] Brattle Group, 2019

- 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 occurring on very hot or cold days or shifting power consuming activities to inconvenient times of day.
- Increased member exposure to volatile wholesale power prices.
- Higher bills for those members 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. MISO offers participation in Demand Response (DR) for members with the capability to reduce load when the market requires additional resources. Load shifting and load control also offer opportunities for Big Rivers and its Members to reduce cost by changing load shape and reducing forecast peaks.

Figure 5.1
Big Rivers Average Peak Day Load Shape 2015-2022 (MW)



The implementation of MISO's seasonal capacity market is complicating benefit-cost calculations and at the time of this study it was unknown how it would impact costs. 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 member 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. 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 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.[12]
- 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.
- 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.

5.3 Load Management and Control

This section presents potential options common to utilities 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

[12] Utility Dive 2019, Iowa Power Study 1993, Brattle Group 2019

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

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, three 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, the second evaluated two control groups (50% control), while the third looked at a single group. The control window was assumed to be an afternoon summer peak window of six hours. Table 5.1 presents the results. Two of the three options 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%)	1.6	0.7	2.2
Air Conditioner Cycling (50%)	3.3	1.5	2.2
Air Conditioner Control	6.5	2.9	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. None of the options passed all three perspective analyses as shown in the table below.

Table 5.2
Electric Storage Water Heater Cycling Program Benefit-Cost Ratios

Program	TRC	Utility	Participant
Water Heater Cycling (25%)	0.3	0.1	2.2
Water Heater Cycling (50%)	0.5	0.2	2.2
Water Heater Control	0.99	0.4	2.2

5.3.4 Peak-Time Rebate (Residential)

Peak-time rebates (PTR) are an interesting option for load management in that they rely on voluntary behavioral 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	121.9	2.3	49.6
Non-Residential PTR	121.9	2.7	49.4

5.3.5 Direct Load Control

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 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.[13] The differential between the market price and system average market rate was split between the end-user and Big Rivers as an incentive in the utility-owned model while a cash rebate of 75% of the capital cost was required to make the project work under the member-owned scenario. A separate generic residential load control option was also modeled that did not include the assumption of back-up generation.

Table 5.4
Direct Load Control (DLC) Program Benefit-Cost Ratios

Program	TRC	Utility	Participant
DLC (Residential)	5.5	3.4	1.6
DLC (Non-Res, Member Ownership)	2.1	1.2	1.2
DLC (Non-Res, Utility Ownership)	2.1	1.8	1.5

5.3.6 Electric Vehicle Charging

As the plug-in electric vehicle car market expands there will need to be adjustments made to avoid an increasing peak load from charging. Two measures were evaluated, both moving charging to off-peak periods in return for an incentive. This includes a residential Level 2 charger and fleet charging controls for operations like school or municipal buses, and delivery vehicles. Table 5.5

[13] DLC without backup generation was not modeled due to the inherent issues with interrupting economic production in non-residential commercial customers.

presents the results and shows that these types of programs could result in cost-effective reductions.

Table 5.5
Electric Vehicle Charging Program Benefit-Cost Ratios

Program	TRC	Utility	Participant
Residential Level 2	1.2	1.1	1.3
Non-Residential Fleet	2366	3.4	600

5.3.7 Battery Storage

Battery storage systems take energy produced at off-peak periods, either via lower market prices or from renewable generation such as wind and solar and stores that energy in batteries to be discharged later during peak periods. While retail systems exist, the economics of such systems do not yet meet the threshold for viability in the models. Table 5.6 presents the results and shows that this type of program could result in cost-effective reductions.

Table 5.6
Battery Storage Program Benefit-Cost Ratios

Program	TRC	Utility	Participant
Residential Battery	0.4	1.0	2.8
Non-Residential Battery	0.9	2.4	5.9

5.4 Dynamic Pricing and Rate Options

Time-differentiated rates allow utilities to charge members 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.

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 members 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 potential obstacles to implementing this for Big Rivers is the fact that the differential between on and off-peak 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 analysis relies on the assumption that AMI is deployed. Currently, Kenergy is at 100 percent implementation, with Meade County expected to be at 100 percent by the end of 2023. 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 is required for meaningful peak kW reduction.[14] Table 5.7 presents the results of the time-of-use pricing program options.

Table 5.7
Time-of-Use Program Benefit-Cost Ratios

Program	TRC	Utility	Participant
Residential TOU	18.7	30.8	13.7
Residential CPP	41.1	67.9	68.6
Non-Residential TOU	10.5	53.1	30.4
Non-Residential CPP	37.8	191.7	199.3

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.

[14] "An Emerging Push…", Utility Dive, 2019.

A review of EV programs around the country shows that there is a split between the “punitive” pricing TOU and simply using 5:1 (peak-to-off-peak) ratio TOUs that apply to all customers.[15] This analysis uses the differential between on-peak and off-peak price from the power cost forecasts.Table 5.8 presents the results based on the differential in the on-peak and off-peak avoided cost forward curves to incentivize end-users to charge outside of the peak window.

Table 5.8
Electric Vehicle Time-of-Use Program Benefit-Cost Ratios

Program	TRC	Utility	Participant
Plug-In EV TOU	0.1	1.0	0.1

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 cost changes.

[15] 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. The 5:1 ratio could result in class cross-subsidization.

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								
Air Purifiers								DC, MD, NJ, NV, WA
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, DC, HI, MA, ME, NJ, NV, OR, 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								MA, NV, RI, WA
External Power Supplies	EPACT 2005	2014	2016	DOE		2021		CA
Faucets	EPACT 1992	1992	1994	Congress				CA, CO, DC, HI, MA, MD, ME, NJ, NV, NY, RI, VT, WA
Furnace Fans	EPACT 2005	2014	2019	DOE	2020	2022	2025	
Furnaces	NAECA 1987	2007	2015	DOE		2016		
Game Consoles				N/A				
Gas Fireplaces				N/A				NV, RI
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, DC, MA, MD, ME, NJ, NV, OR, RI, VT, WA
Refrigerators and Freezers	NAECA 1987	2011	2014	DOE	2017	2019	2022	
Residential Ventilating Fans								CO, DC, MA, MD, NJ, NV, OR, RI, VT, WA
Room Air Conditioners	NAECA 1987	2011	2014	DOE	2017	2019	2022	
Set-top Boxes				N/A				
Showerheads	EPACT 1992	1992	1994	Congress				CA, CO, DC, HI, MA, MD, ME, NJ, NV, NY, RI, VT, WA
Televisions	NAECA 1987			N/A				CA, CT, OR
Toilets	EPACT 1992	1992	1992	Congress				CA, CO, DC, GA, MA, MD, ME, NJ, NV, NY, RI, TX, WA
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, DC, MA, MD, NJ, NV, OR, RI, VT, WA

Product Covered	Initial Legislation	Last Standard Published	Compliance Date	Issued By	Proposed Standards Due	New Final Standard Due	Potential Compliance Date	States With Standard
Commercial Fryers								CO, DC, MA, NJ, NV, OR, RI, VT, WA
Commercial Ovens								MA, NJ, NV, RI, WA
Commercial Refrigeration Equipment	EPACT 2005	2014	2017	DOE		2020	2023	
Commercial Steam Cookers								CO, DC, MA, MD, NJ, NV, OR, RI, 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, MA, MD, ME, NH, NJ, NV, OR, RI, VT, WA
Packaged Terminal AC and HP	EPACT 1992	2015	2017	DOE	2021	2023	2026	
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				
Urinals	EPACT 1992	1992	1994	Congress				CA, CO, DC, MA, MD, ME, NJ, NV, NY, RI, TX, VT, WA
Walk-In Coolers and Freezers	EISA 2007	2014	2017	DOE		2020	2023	
Water Coolers								CA, CO, CT, DC, MA, MD, ME, NH, NJ, NV, OR, RI, VT, WA
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, DC, MA, ME, NJ, 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, DC, HI, MA, NJ, NV, OR, 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 Corporation

	Class	Category	Measure				Qualitative
1	Residential	Appliance	ENERGY STAR and CEE Tier 2 Refrigerator	IL	2021	E	Pass
2	Residential	Appliance	ENERGY STAR Clothes Dryer	IL	2021	E	Pass
3	Residential	Appliance	ENERGY STAR Clothes Washers	IL	2021	E&G	Pass
4	Residential	Appliance	ENERGY STAR Dehumidifier	IL	2021	E	Pass
5	Residential	Appliance	ENERGY STAR Dishwasher	IL	2021	E&G	Pass
6	Residential	Appliance	ENERGY STAR Freezer	IL	2021	E	Pass
7	Residential	Appliance	ENERGY STAR Water Coolers	IL	2021	E	Pass
8	Residential	Appliance	Fuel Switching: Electric Clothes Dryer to Gas Clothes Dryer	PA	2021	E	Fail
9	Residential	Appliance	Ozone Laundry	IL	2021	G	Fail
10	Residential	Appliance	Refrigerator and Freezer Recycling	IL	2021	E	Pass
11	Residential	HVAC	Advanced Thermostats	IL	2021	E&G	Pass
12	Residential	HVAC	Air Handler Filter Whistles	PA	2021	E	Pass
13	Residential	HVAC	Air Source Heat Pump	IL	2021	E&G	Pass
14	Residential	HVAC	Boiler Pipe Insulation	IL	2021	G	Fail
15	Residential	HVAC	Boiler Reset Controls	IL	2021	G	Fail
16	Residential	HVAC	Central Air Conditioner Tune-Up	IA	2020	E	Pass
17	Residential	HVAC	Central Air Conditioning	IL	2021	E	Pass
18	Residential	HVAC	Central Air Source Heat Pump Tune-Up	IA	2020	E	Pass
19	Residential	HVAC	Duct Insulation and Sealing	IL	2021	E&G	Pass
20	Residential	HVAC	Ductless Heat Pumps	IL	2021	E&G	Pass
21	Residential	Appliance	ENERGY STAR Air Purifier/Cleaner	IL	2021	E	Pass
22	Residential	HVAC	ENERGY STAR and CEE Tier 2 Room Air Conditioner	IL	2021	E	Pass
23	Residential	HVAC	ENERGY STAR Ceiling Fan	IL	2021	E	Pass
24	Residential	HVAC	Furnace Blower Motor	IL	2021	E&G	Pass
25	Residential	HVAC	Gas High Efficiency Boiler	IL	2021	G	Fail
26	Residential	HVAC	Gas High Efficiency Combination Boiler	IL	2021	G	Fail
27	Residential	HVAC	Gas High Efficiency Furnace	IL	2021	G	Fail
28	Residential	HVAC	Geothermal Source Heat Pump Tune-Up	IA	2020	E	Pass
29	Residential	HVAC	Ground Source Heat Pump	IL	2021	E&G	Pass
30	Residential	HVAC	GSHP Desuperheaters	PA	2021	E	Pass
31	Residential	HVAC	High Efficiency Bathroom Exhaust Fan	IL	2021	E	Pass
32	Residential	HVAC	HVAC Tune-up	IL	2021	E	Pass
33	Residential	HVAC	Programmable Thermostats	IL	2021	E&G	Fail
34	Residential	HVAC	Residential Energy Recovery Ventilator	IL	2021	E&G	Pass
35	Residential	HVAC	Residential Furnace Tune-Up	IL	2021	E&G	Pass
36	Residential	HVAC	Room Air Conditioner Recycling	IL	2021	E	Pass
37	Residential	HVAC	Whole House Fan	IA	2020	E	Pass
38	Residential	Lighting	Connected LED Lamps	IL	2021	E	Pass
39	Residential	Lighting	Holiday String Lighting	IL	2021	E	Pass
40	Residential	Lighting	LED Exit Signs	IL	2021	E	Fail
41	Residential	Lighting	LED Fixtures	IL	2021	E	Pass
42	Residential	Lighting	LED Nightlights	IL	2021	E	Pass
43	Residential	Lighting	LED Screw Based Omnidirectional Bulbs	IL	2021	E	Pass
44	Residential	Lighting	LED Specialty Lamps	IL	2021	E	Pass
45	Residential	Load Mgmt	Air Conditioner Cycling - 100%			E	Pass
46	Residential	Load Mgmt	Air Conditioner Cycling - 25%			E	Pass
47	Residential	Load Mgmt	Air Conditioner Cycling - 50%			E	Pass
48	Residential	Load Mgmt	Battery Storage			E	Pass
49	Residential	Load Mgmt	Direct Load Control and Behavior-Based Demand Response Programs	PA	2021	E&G	Pass
50	Residential	Load Mgmt	Level 2 Electric Vehicle Charger	IL	2021	E	Pass
51	Residential	Load Mgmt	Peak Time Rebate Program			E	Pass
52	Residential	Load Mgmt	Water Heater Cycling - 100%			E	Pass
53	Residential	Load Mgmt	Water Heater Cycling - 25%			E	Pass
54	Residential	Load Mgmt	Water Heater Cycling - 50%			E	Pass
55	Residential	Other	Advanced Power Strip - Tier 1	IL	2021	E	Pass
56	Residential	Other	Advanced Power Strips - Tier 2 Residential AV	IL	2021	E	Pass
57	Residential	Other	ENERGY STAR Manufactured Homes	PA	2021	E&G	Fail
58	Residential	Other	ENERGY STAR Office Equipment	PA	2021	E	Fail
59	Residential	Other	Fuel Switching: Electric Heat to Gas/Propane/Oil/Heat	PA	2021	E	Fail
60	Residential	Other	Gas Fireplace	IA	2020	G	Fail
61	Residential	Other	High Efficiency Pool Pumps	IL	2021	E	Fail
62	Residential	Other	Home Energy Reports	PA	2021	E&G	Fail
63	Residential	Other	Pool Covers	IL	2021	E&G	Fail
64	Residential	Other	Residential New Construction	PA	2021	E&G	Pass
65	Residential	Building Shell	Air Sealing	IL	2021	E&G	Pass
66	Residential	Building Shell	Basement Sidewall Insulation	IL	2021	E&G	Pass
67	Residential	Building Shell	Ceiling/Attic Insulation	IL	2021	E&G	Pass
68	Residential	Building Shell	Floor and Rim Joist Insulation	PA	2021	E&G	Pass
69	Residential	Building Shell	Floor Insulation Above Crawlspace	IL	2021	E&G	Pass
70	Residential	Building Shell	Insulated Doors	IA	2020	E&G	Pass
71	Residential	Building Shell	Low-E Storm Window	IL	2021	E&G	Pass
72	Residential	Building Shell	Rim/Brand Joist Insulation	IL	2021	E&G	Pass
73	Residential	Building Shell	Triple Pane and Thin Triple Windows	IL	2021	E&G	Pass
74	Residential	Building Shell	Wall Insulation	IL	2021	E&G	Pass
75	Residential	Water Heating	Domestic Hot Water Pipe Insulation	IL	2021	E&G	Pass
76	Residential	Water Heating	Drain Water Heat Recovery	IL	2021	E&G	Fail
77	Residential	Water Heating	Fuel Switching: Electric Resistence to Fossil Fuel Water Heater	PA	2021	E	Fail
78	Residential	Water Heating	Gas Water Heater	IL	2021	G	Fail
79	Residential	Water Heating	Heat Pump Water Heater	IL	2021	E	Pass
80	Residential	Water Heating	Low Flow Faucet Aerators	IL	2021	E&G	Pass
81	Residential	Water Heating	Low Flow Showerheads	IL	2021	E&G	Pass
82	Residential	Water Heating	Shower Timer	IL	2021	E&G	Fail
83	Residential	Water Heating	Solar Water Heaters	PA	2021	E	Fail
84	Residential	Water Heating	Thermostatic Restrictor Shower Valve	IL	2021	E&G	Pass
85	Residential	Water Heating	Water Heater Temperature Setback	IL	2021	E&G	Pass
86	Residential	Water Heating	Water Heater Wrap	IL	2021	E	Pass

Qualitative Screening Results - Non-Residential
Big Rivers Electric Corporation

	Class	Category	Measure			Qualitative
1	Non-Residential	Building Shell	Commercial Weather Stripping	IL	2021 E&G	Pass
2	Non-Residential	Building Shell	Efficient Windows	IA	2020 E&G	Pass
3	Non-Residential	Building Shell	High Speed Rollup Doors	IL	2021 E	Fail
4	Non-Residential	Building Shell	Industrial Air Curtain	IL	2021 E&G	Fail
5	Non-Residential	Building Shell	Infrared Film for Greenhouse	IL	2021 G	Fail
6	Non-Residential	Building Shell	Insulated Doors	IA	2020 E&G	Pass
7	Non-Residential	Building Shell	Roof Insulation for C&I Facilities	IL	2021 E	Pass
8	Non-Residential	Building Shell	Spring-Loaded Garage Door Hinge	IL	2021 G	Fail
9	Non-Residential	Building Shell	Wall Insulation	IA	2020 E&G	Pass
10	Non-Residential	Cooking	Combination Oven	IL	2021 E&G	Pass
11	Non-Residential	Cooking	Commercial Steam Cooker	IL	2021 E&G	Pass
12	Non-Residential	Cooking	Conveyor Oven	IL	2021 G	Fail
13	Non-Residential	Cooking	Efficient Dipper Wells	IL	2021 E	Fail
14	Non-Residential	Cooking	ENERGY STAR Convection Oven	IL	2021 G	Fail
15	Non-Residential	Cooking	ENERGY STAR Electric Convection Oven	IL	2021 E	Pass
16	Non-Residential	Cooking	ENERGY STAR Fryer	IL	2021 E&G	Pass
17	Non-Residential	Cooking	ENERGY STAR Griddle	IL	2021 E&G	Fail
18	Non-Residential	Cooking	ENERGY STAR Hot Food Holding Cabinets	IL	2021 E	Pass
19	Non-Residential	Cooking	High Efficiency Pre-Rinse Spray Valve	IL	2021 E&G	Pass
20	Non-Residential	Cooking	Infrared Charbroiler	IL	2021 G	Fail
21	Non-Residential	Cooking	Infrared Salamander Broiler	IL	2021 G	Fail
22	Non-Residential	Cooking	Infrared Upright Broiler	IL	2021 G	Fail
23	Non-Residential	Cooking	Pasta Cooker	IL	2021 G	Fail
24	Non-Residential	Cooking	Rack Oven - Double Oven	IL	2021 G	Fail
25	Non-Residential	Cooking	Rotisserie Oven	IL	2021 G	Fail
26	Non-Residential	HVAC	Absorbent Air Cleaning	IL	2021 E&G	Pass
27	Non-Residential	HVAC	Advanced Rooftop Controls	IL	2021 E&G	Pass
28	Non-Residential	HVAC	Air and Water Source Heat Pump Systems	IL	2021 E	Pass
29	Non-Residential	HVAC	Air Conditioner Tune-up	IL	2021 E	Pass
30	Non-Residential	HVAC	Air Deflectors for Unit Ventilators	IL	2021 G	Fail
31	Non-Residential	HVAC	Boiler Chemical Descaling	IL	2021 G	Fail
32	Non-Residential	HVAC	Boiler Lockout/Reset Controls	IL	2021 G	Fail
33	Non-Residential	HVAC	Commercial Gas Heat Pump	IL	2021 E&G	Fail
34	Non-Residential	HVAC	Commercial Ground Source and Ground Water Source Heat Pump	IL	2021 E&G	Pass
35	Non-Residential	HVAC	Condensing Unit Heaters	IL	2021 G	Fail
36	Non-Residential	HVAC	Covers and Gap Sealers for Room Air Conditioners	IL	2021 E&G	Pass
37	Non-Residential	HVAC	Demand Controlled Ventilation	IL	2021 E&G	Pass
38	Non-Residential	HVAC	Destratification Fan	IL	2021 E&G	Pass
39	Non-Residential	HVAC	Duct Insulation	IA	2020 E&G	Pass
40	Non-Residential	HVAC	Duct Repair and Sealing	IA	2020 E&G	Pass
41	Non-Residential	HVAC	Ductless Mini-Split Heat Pumps	PA	2021 E	Pass
42	Non-Residential	HVAC	Economizer Repair and Optimization	IL	2021 E&G	Fail
43	Non-Residential	HVAC	Electric Chiller	IL	2021 E	Pass
44	Non-Residential	HVAC	Electric Chillers with Integrated Variable Speed Drives	IL	2021 E	Pass
45	Non-Residential	HVAC	Energy Recovery Ventilator	IL	2021 E&G	Pass
46	Non-Residential	HVAC	ENERGY STAR and CEE Tier 2 Room Air Conditioner	IL	2021 E	Pass
47	Non-Residential	HVAC	Fan Thermostat Controller	IL	2021 E	Pass
48	Non-Residential	HVAC	Fuel Switching: Small Commercial Electric Heat to Natural Gas/Propane/Oil	PA	2021 G	Fail
49	Non-Residential	HVAC	Gas High Efficiency Single Package Vertical Air Conditioner	IL	2021 G	Fail
50	Non-Residential	HVAC	Greenhouse Boiler Tune-Up	IL	2021 G	Fail
51	Non-Residential	HVAC	Greenhouse Thermal Curtains	IL	2021 G	Fail
52	Non-Residential	HVAC	Guest Room Energy Management	IL	2021 E	Pass
53	Non-Residential	Water Heating	Heat Pump Water Heaters	PA	2021 E	Pass
54	Non-Residential	HVAC	High Efficiency Boiler	IL	2021 G	Fail
55	Non-Residential	HVAC	High Efficiency Furnace	IL	2021 G	Fail
56	Non-Residential	HVAC	High Speed Fans	IL	2021 E	Pass
57	Non-Residential	HVAC	High Temperature Heating and Ventilation Direct Fired Heater	IL	2021 G	Fail
58	Non-Residential	HVAC	High Turndown Burner for Space Heating Boilers	IL	2021 G	Fail
59	Non-Residential	HVAC	High Volume Low Speed Fans	IL	2021 E	Pass
60	Non-Residential	HVAC	Hydronic Heater Radiator Replacement	IL	2021 G	Fail
61	Non-Residential	HVAC	Infrared Heaters	IL	2021 G	Fail
62	Non-Residential	HVAC	Kitchen Demand Ventilation Controls	IL	2021 E&G	Fail
63	Non-Residential	HVAC	Linkageless Boiler Controls for Space Heating	IL	2021 G (E onl	Fail
64	Non-Residential	HVAC	Multi-Family Space Heating Steam Boiler Averaging Controls	IL	2021 G	Fail
65	Non-Residential	HVAC	Notched V Belts for HVAC Systems	IL	2021 E	Fail
66	Non-Residential	HVAC	Oxygen Trim Controls for Space Heating Boilers	IL	2021 G	Fail
67	Non-Residential	HVAC	Package Terminal Air Conditioner and Package Terminal Heat Pump	IL	2021 E	Pass
68	Non-Residential	HVAC	Packaged RTU Sealing	IL	2021 E&G	Pass
69	Non-Residential	HVAC	Process Boiler Tune-up	IL	2021 G	Fail
70	Non-Residential	HVAC	Process Heating Boiler	IL	2021 G	Fail

Qualitative Screening Results - Non-Residential
Big Rivers Electric Corporation

	Class	Category	Measure			Qualitative
71	Non-Residential	HVAC	Room Air Conditioner Recycling	IA	2020 E	Pass
72	Non-Residential	HVAC	Server Room Temperature Set Back	IL	2021 E	Pass
73	Non-Residential	HVAC	Shut Off Damper for Space Heating Boilers or Furnaces	IL	2021 G	Fail
74	Non-Residential	HVAC	Single-Package and Split System Unitary Air Conditioners	IL	2021 E	Pass
75	Non-Residential	HVAC	Small Business Furnace Tune-Up	IL	2021 G	Fail
76	Non-Residential	HVAC	Small Commercial Thermostats	IL	2021 E&G	Pass
77	Non-Residential	HVAC	Space Heating Boiler Tune-up	IL	2021 G	Fail
78	Non-Residential	HVAC	Stack Economizer for Boilers Serving HVAC Loads	IL	2021 G	Fail
79	Non-Residential	HVAC	Stack Economizer for Boilers Serving Process Loads	IL	2021 G	Fail
80	Non-Residential	HVAC	Steam Trap Replacement or Repair	IL	2021 E&G	Fail
81	Non-Residential	HVAC	Unitary HVAC Condensing Furnace	IL	2021 E&G	Fail
82	Non-Residential	HVAC	Variable Speed Drive for Condenser Fans	IL	2021 E	Pass
83	Non-Residential	HVAC	Variable Speed Drives for HVAC Pumps and Cooling Tower Fans	IL	2021 E	Pass
84	Non-Residential	HVAC	Variable Speed Drives for HVAC Pumps and Return Fans	IL	2021 E	Pass
85	Non-Residential	HVAC	Variable Speed Drives for Process Fans	IL	2021 E	Pass
86	Non-Residential	Lighting	Commercial LED Exit Signs	IL	2021 E&G	Pass
87	Non-Residential	Lighting	Commercial LED Grow Lights	IL	2021 E&G	Pass
88	Non-Residential	Lighting	Exterior Photocell Repair	IL	2021 E	Pass
89	Non-Residential	Lighting	Flourescent delamping	IL	2021 E&G	Pass
90	Non-Residential	Lighting	High Performance and Reduced Wattage T8 Fixtures and Lamps	IL	2021 E&G	Pass
91	Non-Residential	Lighting	LED Bulbs and Fixtures	IL	2021 E&G	Pass
92	Non-Residential	Lighting	LED Open Sign	IL	2021 E&G	Pass
93	Non-Residential	Lighting	LED Streetlighting	IL	2021 E	Pass
94	Non-Residential	Lighting	LED Traffic and Pedestrian Signals	IL	2021 E	Pass
95	Non-Residential	Lighting	Lighting Controls	IL	2021 E&G	Pass
96	Non-Residential	Lighting	Lighting Power Density	IL	2021 E&G	Pass
97	Non-Residential	Lighting	Miscellaneous Commercial/Industrial Lighting	IL	2021 E&G	Pass
98	Non-Residential	Lighting	Multi-Level Lighting Switch	IL	2021 E&G	Pass
99	Non-Residential	Lighting	Occupancy Controlled Bi-Level Lighting Fixtures	IL	2021 E&G	Pass
100	Non-Residential	Lighting	Solar Light Tubes	IL	2021 E&G	Pass
101	Non-Residential	Lighting	T5 Fixtures ad Lamps	IL	2021 E&G	Pass
102	Non-Residential	Load Mgmt	Battery Storage		E	Pass
103	Non-Residential	Load Mgmt	Electric Fleet Charging		E	Pass
104	Non-Residential	Load Mgmt	Facility Load Control		E	Pass
105	Non-Residential	Load Mgmt	Load Curtailment for Commercial and Industrial Programs	PA	2021 E	Pass
106	Non-Residential	Load Mgmt	Peak Time Rebate Program		E	Pass
107	Non-Residential	Other	Advanced Power Strip - Tier 1 Commercial	IL	2021 E	Pass
108	Non-Residential	Other	Automatic Milker Takeoffs	PA	2021 E	Fail
109	Non-Residential	Other	Building Operator Certification	IL	2021 E&G	Pass
110	Non-Residential	Other	Combined Heat and Power	IL	2021 G	Fail
111	Non-Residential	Other	Commercial Clothes Dryer Moisture Sensor	IL	2021 G	Fail
112	Non-Residential	Other	Compressed Air Heat Recovery	IL	2021 G	Fail
113	Non-Residential	Other	Compressed Air Low Pressure Drop Filters	IL	2021 E	Pass
114	Non-Residential	Other	Compressed Air No-Loss Condensate Drains	IL	2021 E	Pass
115	Non-Residential	Other	Compressed Air Storage Receiver Tank	IL	2021 E	Pass
116	Non-Residential	Other	Computer Power Management Software	IL	2021 E	Pass
117	Non-Residential	Other	Dairy Refrigeration Heat Recovery	IL	2021 E&G	Fail
118	Non-Residential	Other	Desiccant Dryer Dew Point Demand Controls	IL	2021 E	Pass
119	Non-Residential	Other	Efficient Compressed Air Nozzles	IL	2021 E	Pass
120	Non-Residential	Other	Efficient Desiccant Compressed Air Dryer	IL	2021 E	Pass
121	Non-Residential	Other	Efficient Refrigerated Compressed Air Dryer	IL	2021 E	Pass
122	Non-Residential	Other	Efficient Thermal Oxidizers	IL	2021 G	Fail
123	Non-Residential	Other	Energy Efficient Gear Lubricants	IL	2021 E	Fail
124	Non-Residential	Other	Energy Efficient Hydraulic Oils	IL	2021 E	Fail
125	Non-Residential	Other	Energy Efficient Rectifier	IL	2021 E	Pass
126	Non-Residential	Other	ENERGY STAR Computers	IL	2021 E	Fail
127	Non-Residential	Other	ENERGY STAR Dishwasher	IL	2021 E&G	Pass
128	Non-Residential	Other	ENERGY STAR Office Equipment	PA	2021 E	Pass
129	Non-Residential	Other	ENERGY STAR Servers	PA	2021 E	Pass
130	Non-Residential	Other	ENERGY STAR Uninterruptible Power Supply	IL	2021 E	Pass
131	Non-Residential	Other	Engine Block Timer for Agricultural Equipment	IL	2021 E	Pass
132	Non-Residential	Other	High Efficiency Grain Dryer	IL	2021 E&G	Pass
133	Non-Residential	Other	High Efficiency Pumps	PA	2021 E	Pass
134	Non-Residential	Other	High Efficiency Transformer	IL	2021 E	Fail
135	Non-Residential	Other	High Frequency Battery Chargers	IL	2021 E	Pass
136	Non-Residential	Other	High Speed Clothes Washer	IL	2021 E	Fail
137	Non-Residential	Other	Irrigaton Pump VFD	IL	2021 E	Pass
138	Non-Residential	Other	Lithium Ion Forklift Batteries	IL	2021 E	Pass
139	Non-Residential	Other	Livestock Waterer	IL	2021 E	Pass
140	Non-Residential	Other	Low Pressure Sprinkler Nozzles	IL	2021 E	Pass

Qualitative Screening Results - Non-Residential
Big Rivers Electric Corporation

	Class	Category	Measure			Qualitative
141	Non-Residential	Other	Modulating Commercial Gas Glothes Dryer	IL	2021 G	Fail
142	Non-Residential	Other	Premium Efficiency Motors	PA	2021 E	Pass
143	Non-Residential	Other	Pump Optimization	IL	2021 E	Pass
144	Non-Residential	Other	Reduce Compressed Air Setpoint	IL	2021 E	Pass
145	Non-Residential	Other	Server Virtualization	PA	2021 E	Pass
146	Non-Residential	Other	Smart Irrigation Controls	IL	2021 E	Pass
147	Non-Residential	Other	Smart Sockets	IL	2021 E	Fail
148	Non-Residential	Other	Swine Heat Pads	IL	2021 E	Pass
149	Non-Residential	Other	Tunnel Washers	IL	2021 E&G	Pass
150	Non-Residential	Other	VSD Air Compressor	IL	2021 E	Pass
151	Non-Residential	Other	Warm-Mix Asphalt Chemical Additives	IL	2021 G	Fail
152	Non-Residential	Refrigeration	Add Doors to Open Refrigerated Display Cases	IL	2021 E&G	Pass
153	Non-Residential	Refrigeration	Automatic Door Closer for Walk-In Coolers and Freezers	IL	2021 E	Pass
154	Non-Residential	Refrigeration	Beverage and Snack Machine Controls	IL	2021 E	Pass
155	Non-Residential	Refrigeration	Commercial Solid and Glass Door Refrigerators & Freezers	IL	2021 E	Pass
156	Non-Residential	Refrigeration	Door Heater Controls for Cooler or Freezer	IL	2021 E	Pass
157	Non-Residential	Refrigeration	Efficient Motor Controls for Walk-in and Display Case Coolers/Freezers	IA	2020 E	Pass
158	Non-Residential	Refrigeration	Efficient Motors for Walk-in and Display Case Coolers/Freezers	IA	2020 E	Pass
159	Non-Residential	Refrigeration	Electronically Commutated Motors for Walk-in and Reach-in Freezers	IL	2021 E	Pass
160	Non-Residential	Refrigeration	ENERGY STAR Refrigerated Beverage Vending Machine	IL	2021 E	Pass
161	Non-Residential	Refrigeration	ENERGY STAR Refrigeration/Freezer Cases	PA	2021 E	Pass
162	Non-Residential	Refrigeration	Ice Maker	IL	2021 E	Pass
163	Non-Residential	Refrigeration	LED Refrigerator Case Light Occupancy Sensor	IA	2020 E	Pass
164	Non-Residential	Refrigeration	Milk Pre-Coolers	IL	2021 E	Fail
165	Non-Residential	Refrigeration	Night Covers for Open Refrigerated Display Cases	IL	2021 E	Pass
166	Non-Residential	Refrigeration	Refrigerated Display Cases with Door Replacing Open Cases	PA	2021 E	Pass
167	Non-Residential	Refrigeration	Refrigeration Economizers	IL	2021 E	Pass
168	Non-Residential	Refrigeration	Scroll Compressor for Dairy Refrigeration	IL	2021 E	Fail
169	Non-Residential	Refrigeration	Scroll Refrigeration Compressor	IA	2020 E	Fail
170	Non-Residential	Refrigeration	Strip Curtain for Walk-in Coolers and Freezers	IL	2021 E	Pass
171	Non-Residential	Refrigeration	VSD Milk Pump with Plate Cooler Heat Exchanger	IL	2021 E	Fail
172	Non-Residential	Water Heating	Commercial Pool Covers	IL	2021 E&G	Fail
173	Non-Residential	Water Heating	Controls for Central Domestic Hot Water	IL	2021 G	Fail
174	Non-Residential	Water Heating	DHW Boiler Tune-up	IL	2021 G	Fail
175	Non-Residential	Water Heating	ENERGY STAR Dairy Water Heater	IL	2021 E&G	Pass
176	Non-Residential	Water Heating	Floating Head Pressure Control	IL	2021 E	Pass
177	Non-Residential	Water Heating	Fuel Switching: Electric Resistance Water Heaters to Gas/Propane	PA	2021 G	Fail
178	Non-Residential	Water Heating	Gas Hot Water Heater	IA	2020 G	Fail
179	Non-Residential	Water Heating	Heat Recovery Grease Trap Filter	IL	2021 E&G	Pass
180	Non-Residential	Water Heating	Low Flow Faucet Aerators	IL	2021 E&G	Pass
181	Non-Residential	Water Heating	Low Flow Showerheads	IL	2021 E&G	Pass
182	Non-Residential	Water Heating	Multifamily Central Domestic Hot Water Plants	IL	2021 G	Fail
183	Non-Residential	Water Heating	Ozone Laundry	IL	2021 G	Fail
184	Non-Residential	Water Heating	Pipe Insulation		E	Fail
185	Non-Residential	Water Heating	Tank Insulation		E	Fail
186	Non-Residential	Water Heating	Tankless Water Heater	IL	2021 G	Fail
187	Non-Residential	Water Heating	Water Heater	IL	2021 E&G	Pass

APPENDIX C

MULTI-PERSPECTIVE MODEL RESULTS

Big Rivers Electric Corporation

Residential DSM Evaluation Summary

May 2023

						Benefit/Cost Ratios									
Category	Measure	Measure Code	Annual kWh	Summer Peak kW	Winter Peak kW	Participant (PCT)	Program (UCT)	Total Resource Cost (TRC)	Rate Impact Measure (RIM)	Program Cost (Life) $/kWh	G&T IRR	Simple Payback (yrs)	TRC Cost	TRC Ben	Life
Water Heat	Low Flow Faucet Aerator	LF Faucet	205	0.07	0.07	78.21	125.65	50.58	0.65	$0.001	1438%	0.1	$0.001	$0.074	10
Lighting	LED Omnidirectional Light	LED Omni	64	0.01	0.05	42.46	53.74	21.63	0.51	$0.001	760%	0.1	$0.003	$0.061	8
Appliance	Dehumidifier Removal / Recycling	Dehumd. Recycle	812	0.25	0.00	31.21	44.35	17.85	0.58	$0.001	438%	0.2	$0.000	$0.000	12
HVAC	Energy Recovery Ventilator	ERV	726	0.02	0.42	34.42	39.18	15.77	0.46	$0.001	338%	0.2	$0.003	$0.049	15
Appliance	ENERGY STAR Dehumidifier	Dehumidifier	131	0.03	0.00	17.82	23.30	9.38	0.54	$0.003	234%	0.4	$0.000	$0.000	12
Water Heat	Low Flow Showerhead	LF Showerhead	104	0.01	0.01	17.24	21.11	8.50	0.50	$0.003	252%	0.3	$0.007	$0.057	10
Appliance	ENERGY STAR Air Purifier	Air Purifier	133	0.02	0.02	16.87	20.92	8.42	0.51	$0.003	272%	0.3	$0.007	$0.059	9
HVAC	ENERGY STAR Central Air Conditioner	Central AC	529	0.43	0.00	9.17	20.36	8.20	0.93	$0.005	143%	1.0	$0.011	$0.093	18
Water Heat	Domestic Hot Water Pipe Insulation	WH Pipe Ins.	142	0.02	0.02	12.88	15.96	6.42	0.51	$0.003	138%	0.6	$0.008	$0.054	15
Water Heat	Shower Start Showerhead	Showerstart	394	0.02	0.02	11.32	13.10	5.27	0.48	$0.004	159%	0.5	$0.010	$0.055	10
Lighting	LED Decorative / Globe Lamp	LED Decor.	55	0.01	0.01	8.88	10.58	4.26	0.50	$0.006	548%	0.1	$0.015	$0.065	2
Lighting	LED Night Light	LED Nightlight	30	0.00	0.00	8.87	9.51	3.83	0.45	$0.006	140%	0.5	$0.014	$0.053	8
Lighting	LED Directional Lamp	LED Spec.	44	0.01	0.01	7.25	8.56	3.45	0.50	$0.008	439%	0.2	$0.019	$0.065	2
HVAC	ENERGY STAR Mini-Split Heat Pump	Mini-Split AC	661	0.33	0.25	4.57	7.75	3.12	0.74	$0.010	66%	1.8	$0.025	$0.078	15
HVAC	Advanced Programmable Thermostat	Adv. Thermostat	470	0.17	0.20	5.00	7.56	3.04	0.65	$0.010	83%	1.3	$0.024	$0.074	11
HVAC	Room AC Removal / Recycling	Room AC Recyc.	324	0.26	0.00	3.71	6.96	2.80	0.83	$0.015	187%	0.7	$0.038	$0.106	4
Shell	Rim/Band Joist Insulation	Joist Insulation	355	0.10	0.12	4.91	6.88	2.77	0.61	$0.009	50%	2.0	$0.021	$0.058	20
HVAC	ENERGY STAR Air Source Heat Pump	ASHP	1046	0.37	0.41	4.18	6.21	2.50	0.65	$0.011	52%	2.0	$0.027	$0.068	16
Appliance	Tier 1 Adv. Power Strip	Smart Strip T1	57	0.01	0.01	5.12	6.03	2.43	0.51	$0.010	99%	0.8	$0.025	$0.061	7
Shell	ENERGY STAR Windows	Windows	201	0.15	0.00	2.94	5.68	2.29	0.88	$0.015	40%	3.5	$0.037	$0.085	20
Water Heat	Heat Pump Water Heater <55 Gal	HPWH<55	3095	0.15	0.29	5.11	6.27	2.26	0.47	$0.008	57%	1.6	$0.022	$0.050	15
Lighting	LED Flood Light	LED Flood	47	0.01	0.01	4.49	5.30	2.13	0.52	$0.010	48%	1.8	$0.026	$0.054	15
Water Heat	Water Heater Temperature Setback	WH Temp Setback	82	0.01	0.01	4.58	5.22	2.10	0.50	$0.012	256%	0.3	$0.031	$0.064	2
Appliance	Refrigerator Removal / Recycling	Refrig. Removal	940	0.12	0.12	4.42	5.19	2.09	0.51	$0.012	97%	0.9	$0.030	$0.063	6
Water Heat	Heat Pump Water Heater >55 Gal	HPWH>55	3095	0.15	0.29	4.75	5.60	2.09	0.47	$0.009	51%	1.7	$0.024	$0.050	15
Appliance	ENERGY STAR Water Cooler	Water Cooler	58	0.01	0.01	4.28	4.97	2.00	0.51	$0.012	61%	1.4	$0.029	$0.058	10
Appliance	Freezer Removal / Recycling	Freezer Removal	882	0.10	0.10	4.17	4.85	1.95	0.51	$0.013	90%	0.9	$0.032	$0.063	6
Water Heat	Water Heater Wrap	WH Tank Wrap	100	0.01	0.01	3.49	3.96	1.59	0.51	$0.016	85%	0.9	$0.040	$0.063	5
Appliance	Tier 2 Adv. Power Strip	Smart Strip T2	97	0.02	0.02	3.07	3.69	1.48	0.55	$0.018	59%	1.5	$0.044	$0.066	7
Appliance	ENERGY STAR Freezer	Freezer	47	0.01	0.01	3.09	3.61	1.45	0.53	$0.014	27%	3.5	$0.034	$0.049	22
Shell	Low-E Storm Window	Low E Storm	675	0.45	0.04	1.95	3.34	1.34	0.84	$0.024	25%	5.7	$0.060	$0.081	20
HVAC	Air Handler Filter Whistles	Filter Whistle	19	0.00	0.00	2.67	3.06	1.23	0.53	$0.022	63%	1.3	$0.054	$0.066	5
HVAC	Furnace Blower Motor	Furn. Blower Motor	924	0.26	0.26	2.29	2.85	1.15	0.59	$0.025	50%	1.8	$0.063	$0.073	6
Appliance	ENERGY STAR Clothes Washer	Clothes Washer	118	0.02	0.02	2.46	2.73	1.10	0.52	$0.021	26%	3.4	$0.051	$0.056	14
Appliance	ENERGY STAR Refrigerator	Refrigerator	43	0.01	0.01	2.22	2.47	1.00	0.53	$0.022	21%	4.4	$0.055	$0.054	17
HVAC	Duct Sealing	Duct Sealing	953	0.40	0.22	1.58	2.11	0.85	0.69	$0.032	16%	7.4	$0.079	$0.067	20
Shell	Wall Insulation	Wall Insulation	1570	0.17	0.71	1.88	1.91	0.77	0.50	$0.025	14%	6.0	$0.063	$0.048	20
HVAC	HVAC Tune Up	HVAC Tune Up	888	0.07	0.52	1.87	1.83	0.74	0.49	$0.034	45%	1.2	$0.084	$0.062	3
HVAC	High Eff. Bathroom Exhaust Fan	Bath Exh. Fan	30	0.00	0.00	1.62	1.62	0.65	0.51	$0.031	12%	7.0	$0.078	$0.051	19
Shell	Air Sealing	Air Sealing	760	0.19	0.27	1.36	1.48	0.60	0.59	$0.038	10%	9.0	$0.095	$0.057	20
Lighting	Occupancy Sensors	Occ. Sensors	29	0.00	0.00	1.67	1.46	0.59	0.45	$0.035	14%	4.1	$0.087	$0.051	10
Water Heat	Thermostatic Restriction Valve	Therm. Restr.	50	0.00	0.00	1.49	1.40	0.56	0.49	$0.040	13%	4.7	$0.100	$0.056	10
Shell	Sidewall Insulation	Sidewall Insulation	332	0.07	0.09	1.26	1.29	0.52	0.57	$0.043	9%	10.0	$0.106	$0.055	20
Appliance	ENERGY STAR Clothes Dryer	Clothes Dryer	213	0.03	0.03	1.22	1.14	0.46	0.52	$0.048	7%	9.0	$0.119	$0.054	16
HVAC	ENERGY STAR Ground Source Heat Pump	GSHP	3321	1.12	1.86	1.06	1.12	0.45	0.64	$0.050	7%	14.6	$0.124	$0.056	25
HVAC	ENERGY STAR Room AC	Room AC	13	0.01	0.00	0.77	0.94	0.38	0.90	$0.106	5%	14.9	$0.263	$0.100	12
HVAC	ENERGY STAR Ceiling Fan	Ceiling Fan	21	0.01	0.00	0.87	0.93	0.38	0.73	$0.089	4%	10.4	$0.221	$0.083	10
Shell	Attic Insulation	Attic Insulation	1260	0.18	0.54	0.98	0.82	0.33	0.52	$0.062	3%	14.5	$0.154	$0.050	20
HVAC	Ground Source Heat Pump Desuperheaters	GSHP Desuper.	447	0.04	0.04	0.87	0.64	0.26	0.49	$0.081	0%	14.3	$0.201	$0.052	15
Appliance	ENERGY STAR Dishwasher	Dishwasher	31	0.00	0.00	0.85	0.61	0.24	0.49	$0.090	-3%	11.7	$0.225	$0.055	11
Shell	Floor Insulation Above Crawlspace	Floor Insulation	429	0.06	0.18	0.76	0.54	0.22	0.52	$0.094	-1%	22.0	$0.233	$0.050	20
HVAC	Whole House Fan	House Fan	343	0.00	0.00	0.85	0.53	0.21	0.42	$0.070	0%	20.6	$0.175	$0.037	25
Lighting	LED Holiday String Lighting	Holiday String	6	0.00	0.03	0.68	0.37	0.15	0.45	$0.145	-16%	11.9	$0.361	$0.054	7
Shell	Insulated Doors	Insulated Door	118	0.01	0.06	0.52	0.20	0.08	0.48	$0.205	-6%	60.0	$0.509	$0.042	25
Lighting	LED Fixture Replacement	LED Fixture	31	0.01	0.01	0.48	0.17	0.07	0.52	$0.400	-65%	9.4	$0.994	$0.067	2
Lighting	LED Connected Lamps	LED Lamps	3	0.00	0.00	0.47	0.16	0.06	0.52	$0.393	-33%	28.1	$0.976	$0.063	6

Big Rivers Electric Corporation

Non-Residential DSM Evaluation Summary

May 2023

						Benefit/Cost Ratios										
Category	Measure	Measure Code	Annual kWh	Summer Peak kW	Winter Peak kW	Participant (PCT)	Program (UCT)	Total Resource Cost (TRC)	Rate Impact Measure (RIM)	Program Cost (Life) $/kWh	G&T IRR	Simple Payback (yrs)	TRC Cost	TRC Ben	Life
Other	Reduce Compressed Air Setpoint	Red. CA Setpoint	164	0.03	0.03	99.84	134.32	54.06	0.54	$0.000	2880%	0.0	$0.001	$0.066	5
Water Heat	Low Flow Showerheads	LF Shower	1,013	0.10	0.10	94.05	120.54	48.52	0.52	$0.000	1412%	0.1	$0.001	$0.057	10
Water Heat	Low Flow Faucet Aerators	Faucet Aerators	347	0.11	0.11	48.56	76.38	30.74	0.63	$0.001	879%	0.1	$0.002	$0.071	10
Cooking	High Eff. Pre-Rinse Spray Valve	Spray Valves	5680	0.00	0.00	64.25	73.81	29.71	0.46	$0.001	1581%	0.0	$0.002	$0.056	5
Other	Eff. Desiccant Compressed Air Dryer	Desiccant CA Dryer	4,423	0.69	0.69	39.49	53.73	21.63	0.55	$0.001	451%	0.2	$0.003	$0.057	15
Other	Eff. Compressed Air Nozzles	Air Nozzles	1,240	0.19	0.19	33.85	45.99	18.51	0.55	$0.001	387%	0.2	$0.003	$0.057	15
Lighting	Lighting Power Density	Light Dens. Red.	3,284	0.77	0.77	30.11	44.36	17.86	0.59	$0.001	369%	0.3	$0.003	$0.062	15
Other	Compressed Air Storage Receiver Tank	CA Storage Tank	12,627	5.69	5.69	21.79	38.14	15.35	0.70	$0.002	437%	0.3	$0.005	$0.079	10
Lighting	LED Street Lights	LED Street	701	0.00	0.00	30.22	33.38	13.43	0.44	$0.001	244%	0.3	$0.003	$0.042	20
Other	High Frequency Battery Chargers	HF Battery Charger	7,061	0.12	0.12	27.53	31.70	12.76	0.46	$0.002	275%	0.3	$0.004	$0.048	15
Shell	ENERGY STAR Windows	Window Repl.	363	0.06	0.06	23.02	31.44	12.66	0.55	$0.002	221%	0.4	$0.004	$0.052	20
Lighting	Flourescent Lamp Removal	Flour. Delamp	173	0.04	0.04	16.96	24.84	10.00	0.59	$0.002	209%	0.5	$0.006	$0.062	15
Other	Ag. Engine Block Timer	Block Timer	571	0.00	0.00	21.34	24.04	9.68	0.45	$0.002	845%	0.1	$0.006	$0.058	3
Other	ENERGY STAR Dishwasher	Dish Washer	3,955	0.25	0.25	19.12	23.07	9.29	0.48	$0.002	276%	0.3	$0.006	$0.055	10
HVAC	Smart Thermostat	Smart Therm	2062	0.45	0.60	14.52	20.59	8.29	0.57	$0.003	223.6%	0.4	$0.008	$0.064	11
Other	Eff. Rectifier	EE Rectifier	5,151	0.82	0.82	14.26	19.18	7.72	0.54	$0.003	164%	0.5	$0.007	$0.057	15
Lighting	LED Bulbs / Fixtures	LED Bulbs	77	0.02	0.02	13.66	18.83	7.58	0.55	$0.004	992%	0.1	$0.009	$0.072	2
Refrigeration	Refrigeration Economizers	Refrig. Economizer	6175	5.04	5.04	8.27	18.66	7.51	0.90	$0.005	150%	0.9	$0.013	$0.097	15
Refrigeration	Door Heater Controls	Door Heater Controls	1179	0.06	0.06	14.78	17.49	7.04	0.47	$0.003	211%	0.4	$0.008	$0.054	10
Cooking	ENERGY STAR Steam Cookers	Steam Cooker	13649	2.55	2.55	12.02	16.18	6.51	0.54	$0.001	104%	0.9	$0.004	$0.024	50
Other	ENERGY STAR Office Equipment	ES Office Equip.	124	0.02	0.02	12.58	16.11	6.48	0.51	$0.004	431%	0.2	$0.010	$0.065	4
HVAC	HVAC Pipe Insulation	HVAC Pipe Ins.	129	0.04	0.04	10.02	15.55	6.26	0.62	$0.004	108.6%	0.9	$0.010	$0.061	20
HVAC	Ductless Heat Pump	Ductless Mini-Split	3513	0.56	2.02	11.17	4.45	6.00	0.49	$0.013	62.7%	0.7	$0.009	$0.057	15
HVAC	Server Room Temperature Setback	Server Setback	752	0.09	0.00	10.88	13.60	5.47	0.50	$0.005	364.3%	0.2	$0.012	$0.064	4
Other	No-Loss Condensate Drains	CA Cond. Drains	1,970	0.30	0.30	9.31	12.19	4.91	0.52	$0.005	146%	0.6	$0.012	$0.061	10
HVAC	HVAC VFDs	HVAC VFD	1122	0.16	0.16	8.99	11.74	4.72	0.52	$0.005	102.2%	0.9	$0.012	$0.056	15
Other	Advanced Power Strips	Adv. Power Strip	109	0.00	0.00	9.26	10.26	4.13	0.44	$0.005	168%	0.4	$0.013	$0.054	7
HVAC	High Eff. Air Source Heat Pump	ASHP	21397	4.30	11.51	6.94	8.48	3.82	0.54	$0.007	83.1%	1.1	$0.016	$0.059	15
Refrigeration	ENERGY STAR Ice Machine	Ice Machine	1575	0.35	0.35	6.88	9.45	3.80	0.55	$0.007	136%	0.7	$0.018	$0.067	8
Lighting	LED Traffic / Pedestrian Signals	LED Traffic	299	0.03	0.03	6.98	8.64	3.48	0.49	$0.007	105%	0.8	$0.017	$0.058	10
Lighting	LED Grow Lights	LED Grow	1,677	0.32	0.32	6.23	8.29	3.34	0.53	$0.007	109%	0.8	$0.018	$0.061	9.5
Lighting	LED Exit Sign	LED Exit	340	0.04	0.04	6.70	8.24	3.32	0.49	$0.008	180%	0.5	$0.019	$0.063	5
Water Heat	Heat Pump Water Heater	HP Water Heat	433	0.06	0.06	6.21	7.82	3.15	0.50	$0.008	95%	0.9	$0.019	$0.060	10
Water Heat	Hot Water Pipe Wrap	WH Pipe Wrap	14	0.01	0.01	3.96	7.80	3.14	0.78	$0.011	66%	2.1	$0.028	$0.089	15
Shell	Weather Stripping	Weather Stripping	487	0.00	0.16	7.11	7.77	3.13	0.44	$0.007	96%	0.8	$0.016	$0.051	10
Refrigeration	ENERGY STAR Solid / Glass Doors	Refrig. Glass Door	112	0.01	0.01	6.31	7.74	3.11	0.49	$0.007	82%	1.1	$0.018	$0.056	12
HVAC	High Eff. Chiller for AC	AC Chiller	10753	7.94	0.00	3.66	7.53	3.03	0.82	$0.011	48.3%	3.0	$0.027	$0.081	23
Other	Low Pressure Drop Filters	CA Drop Filters	4,693	0.73	0.73	5.56	7.10	2.86	0.51	$0.009	87%	1.0	$0.021	$0.061	10
Refrigeration	Refrigerator Automatic Door Closers	Refrig. Closers	2399	0.62	0.62	4.75	6.60	2.66	0.55	$0.011	96%	1.0	$0.026	$0.070	8
HVAC	Guest Room Energy Management	HVAC Sensors	682	0.21	0.21	4.39	6.46	2.60	0.59	$0.010	56.5%	1.9	$0.025	$0.066	15
HVAC	Seal / Repair Ductwork	Duct Seal	387	0.13	0.14	4.19	6.27	2.53	0.60	$0.011	54.9%	1.9	$0.027	$0.067	15
Lighting	LED Open Sign	LED Open	191	0.04	0.04	4.55	6.06	2.44	0.53	$0.010	54%	1.8	$0.024	$0.060	15
Refrigeration	Refrigeration Occupancy Sensors	Refrig. Occ. Sensor	291	0.04	0.04	4.81	6.05	2.43	0.50	$0.010	89%	1.0	$0.026	$0.063	8
Other	Pump Optimization	Pump Opt.	7,564	0.69	0.69	5.07	5.92	2.38	0.47	$0.011	205%	0.4	$0.026	$0.063	3
HVAC	Window AC	Window AC	70	0.25	0.00	1.24	5.47	2.20	1.70	$0.051	68.1%	5.5	$0.127	$0.279	9
Other	Variable Frequency Drives	VFD	9,067	3.20	3.20	3.61	5.43	2.19	0.60	$0.013	48%	2.3	$0.031	$0.069	15
Refrigeration	ENERGY STAR Refrigerator / Freezer Cases	ES Refrig Cases	453	0.05	0.05	4.25	5.10	2.05	0.48	$0.011	54%	1.6	$0.028	$0.057	12
HVAC	Energy Recovery Ventilator	ERV	22358	41.23	0.00	1.66	5.09	2.05	1.20	$0.032	42.6%	5.7	$0.078	$0.160	15
Other	ENERGY STAR Servers	ES Servers	3,631	0.41	0.41	3.93	4.63	1.86	0.47	$0.014	122%	0.7	$0.034	$0.064	4
Other	High Efficiency Pumps	HE Pumps	398	0.07	0.07	3.49	4.36	1.75	0.50	$0.013	44%	2.1	$0.033	$0.058	13.3
Refrigeration	Eff. Motors for Coolers / Freezers	Motors	652	0.07	0.07	3.65	4.32	1.74	0.47	$0.013	39%	2.3	$0.031	$0.054	15
HVAC	HVAC Split / Unitary Systems	HVAC SplitSys	759	0.59	0.00	2.19	1.49	1.70	0.57	$0.063	19.7%	4.1	$0.056	$0.095	15
HVAC	Rooftop Unit Sealing	RTU Sealing	577	0.43	0.00	2.15	0.52	1.50	0.32	$0.197	2.7%	1.6	$0.068	$0.102	5
Refrigeration	Refrigerated Display Cases with Door	Refrig Display	2022	1.15	1.15	2.22	3.68	1.48	0.65	$0.023	38%	3.4	$0.058	$0.085	12
Lighting	T5 Lamps	T5 Fixtures/Lamps	190	0.05	0.05	2.80	3.65	1.47	0.51	$0.018	39%	2.6	$0.044	$0.065	12
HVAC	Demand Controlled Ventilation	DCV	4165	0.00	2.00	3.43	3.52	1.42	0.41	$0.014	43.8%	1.7	$0.036	$0.051	10
Cooking	ENERGY STAR Fryer	ES Fryer	3274	0.00	0.23	3.17	3.51	1.41	0.44	$0.015	38%	2.2	$0.038	$0.054	12
Lighting	LED Lighting Controls	LED Controls	74	0.06	0.06	1.84	3.29	1.32	0.70	$0.030	39%	3.6	$0.075	$0.099	10
Other	Eff. Refrigerated Compressed Air Dryer	CA Dryer	237	0.05	0.05	2.52	3.20	1.29	0.50	$0.020	32%	3.1	$0.049	$0.063	13
HVAC	PTAC / PTHP Systems	PTAC	6621	4.89	0.00	1.80	2.68	1.26	0.65	$0.037	43.0%	3.1	$0.079	$0.100	8
Other	Server Virtualization	Virtual Server	4,341	0.50	0.50	2.73	3.07	1.24	0.44	$0.021	76%	1.0	$0.052	$0.064	4
Cooking	Convection Oven	Conv. Oven	837	0.16	0.16	2.51	3.06	1.23	0.48	$0.020	32%	2.9	$0.050	$0.061	12
Other	Livestock Waterer	Livestock Waterer	1,593	0.00	0.00	2.60	2.56	1.03	0.39	$0.020	31%	2.4	$0.049	$0.051	10
Refrigeration	Strip Curtains for Walk-In Freezers / Coolers	Strip Curtains	859	0.10	0.10	2.32	2.55	1.03	0.43	$0.025	60%	1.2	$0.062	$0.064	4

Big Rivers Electric Corporation

Non-Residential DSM Evaluation Summary

May 2023

Category	Measure	Measure Code	Annual kWh	Summer Peak kW	Winter Peak kW	Benefit/Cost Ratios: Participant (PCT)	Program (UCT)	Total Resource Cost (TRC)	Rate Impact Measure (RIM)	Program Cost (Life) $/kWh	G&T IRR	Simple Payback (yrs)	TRC Cost	TRC Ben	Life
Other	Computer Power Management Software	CPM Software	93	0.01	0.01	2.30	2.54	1.02	0.43	$0.025	50%	1.5	$0.062	$0.064	5
Other	ENERGY STAR Uninterruptible Power Supply	UPS	65	0.01	0.01	2.05	2.52	1.01	0.48	$0.024	22%	4.4	$0.060	$0.061	15
Other	VSD Air Compressor	Air Comp.	3,290	1.48	1.48	1.70	2.43	0.98	0.56	$0.032	23%	5.0	$0.079	$0.077	13
Refrigeration	Efficient Motor Controls	Motor Controls	293	0.03	0.03	2.19	2.40	0.97	0.43	$0.022	22%	4.1	$0.056	$0.054	15
Other	Low Pressure Sprinkler Nozzles	Sprinkler Nozzles	4	0.00	0.00	1.77	2.38	0.96	0.53	$0.035	46%	2.1	$0.086	$0.082	5
HVAC	Destratification Fan	Destrat. Fan	123906	0.00	42.59	2.39	2.33	0.94	0.38	$0.022	27.5%	2.6	$0.054	$0.051	10
Cooking	Combination Oven	Comb. Oven	7538	0.00	0.00	2.30	2.23	0.90	0.38	$0.022	23%	3.2	$0.055	$0.050	12
Refrigeration	Open Cooler Night Curtains	Night Curtains	1048	0.00	0.00	2.24	2.19	0.88	0.38	$0.026	41%	1.6	$0.064	$0.056	5
HVAC	Insulate Ductwork	Duct Ins.	3	0.00	0.00	2.06	2.17	0.88	0.41	$0.022	16.7%	5.3	$0.055	$0.048	20
Lighting	Exterior Photocell Repair	Photocell Repair	402	0.09	0.09	1.89	2.16	0.87	0.45	$0.033	81%	0.8	$0.082	$0.071	2
HVAC	High Eff. Fans	Fans	372	0.12	0.12	1.57	1.92	0.77	0.48	$0.039	26.6%	3.3	$0.096	$0.074	7
HVAC	AC Removal / Recycling	AC Recycle	86	0.26	0.00	0.75	1.91	0.77	0.96	$0.125	49.1%	4.5	$0.311	$0.239	3
HVAC	AC Tune-Up	AC Tune-Up	865	0.64	0.00	1.28	1.88	0.76	0.57	$0.054	47.4%	2.0	$0.135	$0.102	3
Other	Lithium Ion Forklift Batteries	Forklift Battery	17,092	0.00	0.00	1.90	1.77	0.71	0.36	$0.027	15%	4.8	$0.066	$0.047	15
HVAC	Absorbant Air Cleaning	Absorbant Air	23342	23.67	37.88	0.98	1.71	0.69	0.66	$0.059	12.2%	14.4	$0.148	$0.101	20
Water Heat	ENERGY STAR Dairy Water Heater	Dairy WH	1,784	0.26	0.26	1.76	1.61	0.65	0.46	$0.029	13%	5.3	$0.073	$0.047	15
HVAC	Advanced Rooftop Unit Controls	Adv RTU Control	2383	0.36	1.27	1.42	1.46	0.59	0.40	$0.041	12.6%	5.9	$0.101	$0.059	12
Other	Building Operator Certification	Bldg. Op. Cert.	1,370	0.15	0.15	1.46	1.45	0.58	0.39	$0.038	12%	6.0	$0.095	$0.056	13
Lighting	Occupancy Sensors	Occ. Sensors	288	0.01	0.01	1.54	1.41	0.57	0.36	$0.037	13%	4.5	$0.093	$0.053	10
Other	Vending Machine Controls	Vending Controls	432	0.00	0.00	1.57	1.41	0.57	0.35	$0.040	19%	2.4	$0.100	$0.056	5
Lighting	Bi-Level Lighting Fixtures	Contr. Bi-Level	254	0.02	0.02	1.38	1.28	0.51	0.36	$0.043	11%	5.2	$0.108	$0.055	10
Refrigeration	Machine Controls	Machine Controls	370	0.00	0.00	1.27	1.06	0.43	0.32	$0.053	8%	3.2	$0.132	$0.056	5
Lighting	Solar Light Tubes	Solar Tubes	417	0.14	0.14	0.97	1.00	0.40	0.39	$0.072	5%	8.7	$0.180	$0.072	10
Other	Tunnel Washers	Tunnel Washers	5,324	0.00	0.00	1.17	0.94	0.38	0.31	$0.050	5%	9.1	$0.125	$0.047	15
Cooking	ENERGY STAR Hot Food Holding Cabinets	ES Cabinet	545	0.07	0.07	1.05	0.93	0.38	0.34	$0.062	4%	8.9	$0.153	$0.057	12
Other	Desiccant Dryer Dew Point Controls	Des. Dryer Contr.	3,359	1.51	1.51	0.86	0.88	0.35	0.39	$0.096	1%	5.8	$0.238	$0.084	5
Other	Swine Heat Pads	Swine Pads	128	0.00	0.00	0.97	0.72	0.29	0.28	$0.079	-5%	4.8	$0.196	$0.057	5
Other	Smart Irrigation Controls	Smart Irrigation	193	0.00	0.00	0.94	0.68	0.27	0.27	$0.070	0%	12.6	$0.173	$0.047	15
HVAC	Economizer	Economizer	1073	0.25	0.25	0.78	0.63	0.25	0.30	$0.112	-9.2%	6.8	$0.279	$0.070	5
Refrigeration	Refrigerated Display Case Doors	Refrig. Solid Door	1340	0.08	0.08	0.79	0.54	0.22	0.26	$0.094	-2%	17.0	$0.233	$0.051	15
Water Heat	Heat Recovery Grease Trap Filter	Grease Trap Heat	104	0.01	0.01	0.75	0.51	0.21	0.52	$0.104	-3%	18.8	$0.258	$0.053	15
HVAC	Ground Source Heat Pump	GSHP	23941	7.58	15.44	0.56	0.39	0.14	0.24	$0.141	-2.1%	48.7	$0.401	$0.055	25
Refrigeration	ENERGY STAR Beverage Vending Machine	ES Vending	90	0.00	0.00	0.61	0.30	0.12	0.18	$0.160	-9%	27.0	$0.397	$0.048	14
HVAC	AC Covers / Gap Sealers	AC Gap Seal	21	0.00	0.02	0.56	0.24	0.10	0.16	$0.233	-30.7%	14.0	$0.578	$0.056	5
Shell	Roof Insulation	Roof Insulation	135	0.01	0.08	0.53	0.22	0.09	0.15	$0.209	-8%	50.4	$0.519	$0.046	20
Other	High Efficiency Grain Dryer	HE Grain Dryer	4,115	0.00	0.00	0.54	0.22	0.09	0.15	$0.196	-8%	47.2	$0.486	$0.042	20
Shell	Wall Insulation	Wall Insulation	635	0.04	0.38	0.50	0.18	0.07	0.13	$0.254	-9%	61.2	$0.630	$0.046	20
Lighting	Multi-Level Lighting Switch	Multi-Level Switch	27	0.01	0.01	0.46	0.16	0.07	0.13	$0.403	-21%	48.6	$1.001	$0.066	10
Shell	Insulated Doors	Insulated Doors	18	0.00	0.01	0.43	0.09	0.04	0.08	$0.440	-11%	132.8	$1.093	$0.041	25

Appendix C

CONFIDENTIAL Detailed Transmission System Map

In the Matter of:

ELECTRONIC 2023 INTEGRATED RESOURCE PLAN OF BIG RIVERS ELECTRIC CORPORATION	)))	Case No. 2023-00310

CONFIDENTIAL

Appendix C
Big Rivers Transmission System Map
FILED: September 29, 2023

INFORMATION SUBMITTED WITH
MOTION FOR CONFIDENTIAL TREATMENT

Appendix D

MISO 2023-2024 Loss of Load Expectation Study Report

Planning Year 2023-2024 Loss of Load Expectation Study Report

MISO – Resource Adequacy

Highlights

- MISO's seasonal construct, accepted by FERC in September 2022, introduces seasonal requirements to the Planning Resource Auction (PRA) to account for the unique risk profile of each season.

- MISO made several modeling improvements to the LOLE study to support the new seasonal construct.

- MISO's annual Loss of Load Expectation (LOLE) study sets the system-wide Planning Reserve Margin and the zonal Local Reliability Requirements for each season of the upcoming Planning Year.

Update (5/1/2023): outyear Planning Reserve Margin (PRM) and Local Reliability Requirement (LRR) results added to study report

Contents

Executive Summary

Midcontinent Independent System Operator (MISO) conducts an annual Loss of Load Expectation (LOLE) study to determine a Planning Reserve Margin Unforced Capacity (PRM UCAP), zonal per-unit Local Reliability Requirements (LRR), Zonal Import Ability (ZIA), Zonal Export Ability (ZEA), Capacity Import Limits (CIL) and Capacity Export Limits (CEL) for each season (Summer, Fall, Winter, & Spring) of the upcoming Planning Year. The results of the study and its deliverables supply inputs to the MISO Planning Resource Auction (PRA).

The Planning Year 2023-2024 (PY 2023-2024) LOLE Study:

- Establishes PRM UCAP for each season to be applied to the Load Serving Entity (LSE) seasonal coincident peaks for the Planning Year starting June 2023 and ending May 2024:
  - Summer 2023 PRM UCAP of 7.4%
  - Fall 2023 PRM UCAP of 14.9%
  - Winter 2023-2024 PRM UCAP of 25.5%
  - Spring 2024 PRM UCAP of 24.5%
- Uses the Strategic Energy Risk Valuation Model (SERVM) software for Loss of Load analysis to provide results applicable across the MISO market footprint.
- Provides zonal ZIA, ZEA, CIL and CEL for each Local Resource Zone (LRZ) (Figure ES-1). These values may be adjusted in March 2023 based on changes to MISO units with firm capacity commitments to non-MISO load, and equipment rating changes since the LOLE analysis. The Simultaneous Feasibility Test (SFT) process can further adjust CIL and CEL to ensure the resources cleared in the auction are simultaneously reliable.
- Determines a minimum planning reserve margin for each season of the studied Planning Year that would result in the MISO system experiencing a less than one-day loss of load event every 10 years, as per the MISO Tariff.[1] The MISO analysis shows that the system would achieve this reliability level for the summer 2023 season when the amount of installed capacity available (considering external support) is 1.159 times that of the MISO system summer 2023 coincident peak.
- Sets forth initial zonal-based (Table 1-1) PRA deliverables in the LOLE charter.

The stakeholder review process played an integral role in this study. The MISO staff would like to thank the Loss of Load Expectation Working Group (LOLEWG) for its assistance and input. There were several process improvements made to the LOLE study this year including updated transfer limits due to improved redispatch and four major LOLE modeling enhancements: seasonal outage rates, wind and solar hourly profiles, probabilistic modeling of non-firm support, and correlated cold weather outages.

[1] A one-day loss of load in 10 years (0.1 day/year) is not necessarily equal to 24 hours loss of load in 10 years (2.4 hours/year).

PRA and LOLE Metrics	LRZ 1	LRZ 2	LRZ 3	LRZ 4	LRZ 5	LRZ 6	LRZ 7	LRZ 8	LRZ 9	LRZ 10
Summer 2023 PRM UCAP	7.4%	7.4%	7.4%	7.4%	7.4%	7.4%	7.4%	7.4%	7.4%	7.4%
LRR UCAP per-unit of LRZ Peak Demand	1.139	1.120	1.299	1.212	1.333	1.172	1.171	1.473	1.157	1.538
Capacity Import Limit (CIL) (MW)	5,301	3,477	6,108	7,884	3,576	8,492	5,087	4,139	5,268	3,064
Capacity Export Limit (CEL) (MW)	3,959	2,550	4,310	No Limit Found[2]	No Limit Found	2,703	3,953	5,503	1,574	1,794
Zonal Import Ability (ZIA) (MW)	5,299	3,477	6,043	6,992	3,576	8,092	5,087	4,091	4,456	3,064
Zonal Export Ability (ZEA) (MW)	3,961	2,550	4,375	No Limit Found	No Limit Found	3,109	3,953	5,551	2,386	1,794

Table ES-1: Initial Planning Resource Auction Deliverables — Summer 2023

PRA and LOLE Metrics	LRZ 1	LRZ 2	LRZ 3	LRZ 4	LRZ 5	LRZ 6	LRZ 7	LRZ 8	LRZ 9	LRZ 10
Fall 2023 PRM UCAP	14.9%	14.9%	14.9%	14.9%	14.9%	14.9%	14.9%	14.9%	14.9%	14.9%
LRR UCAP per-unit of LRZ Peak Demand	1.274	1.218	1.408	1.254	1.452	1.247	1.345	1.490	1.278	1.619
Capacity Import Limit (CIL) (MW)	6,528	4,411	14,375[2]	5,173	5,380	6,070	4,285	4,705	6,045	2,425
Capacity Export Limit (CEL) (MW)	3,804	3,577	4,354	4,878	1,992	1,701	3,990	5,080	1,526	2,878
Zonal Import Ability (ZIA) (MW)	6,526	4,411	14,310[2]	4,281	5,380	5,670	4,285	4,657	5,233	2,425
Zonal Export Ability (ZEA) (MW)	3,806	3,577	4,419	5,770	1,992	2,101	3,990	5,128	2,338	2,878

Table ES-2: Initial Planning Resource Auction Deliverables — Fall 2023

[2] "No Limit Found" reflects no valid constraint identified.

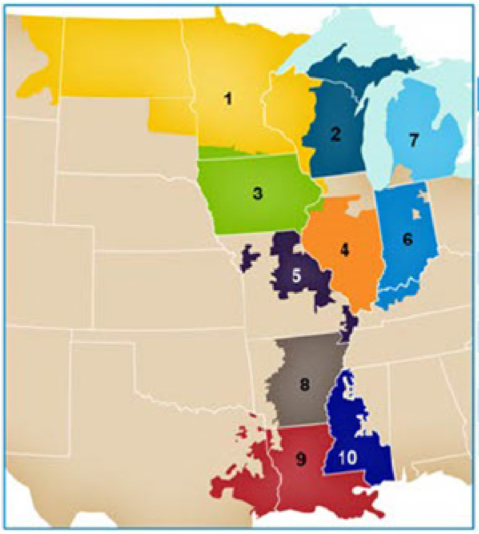
PRA and LOLE Metrics	LRZ 1	LRZ 2	LRZ 3	LRZ 4	LRZ 5	LRZ 6	LRZ 7	LRZ 8	LRZ 9	LRZ 10
Winter 23-24 PRM UCAP	25.5%	25.5%	25.5%	25.5%	25.5%	25.5%	25.5%	25.5%	25.5%	25.5%
LRR UCAP per-unit of LRZ Peak Demand	1.403	1.422	1.850	1.365	1.474	1.301	1.573	1.503	1.323	1.777
Capacity Import Limit (CIL) (MW)	4,937	4,905	11,039[2]	3,928	3,811	8,818	6,340	4,729	6,080	2,396
Capacity Export Limit (CEL) (MW)	3,501	4,198	7,002	3,445	6,348	1,242	4,350	5,351	877	1,980
Zonal Import Ability (ZIA) (MW)	4,935	4,905	10,974[2]	3,036	3,811	8,418	6,340	4,681	5,268	2,396
Zonal Export Ability (ZEA) (MW)	3,503	4,198	7,067	4,337	6,348	1,642	4,350	5,399	1,689	1,980

Table ES-3: Initial Planning Resource Auction Deliverables — Winter 2023-2024

PRA and LOLE Metrics	LRZ 1	LRZ 2	LRZ 3	LRZ 4	LRZ 5	LRZ 6	LRZ 7	LRZ 8	LRZ 9	LRZ 10
Spring 2024 PRM UCAP	24.5%	24.5%	24.5%	24.5%	24.5%	24.5%	24.5%	24.5%	24.5%	24.5%
LRR UCAP per-unit of LRZ Peak Demand	1.375	1.267	1.623	1.454	1.610	1.320	1.329	1.627	1.315	1.747
Capacity Import Limit (CIL) (MW)	6,185	4,454	7,675	5,906	3,881	8,162	5,559	4,606	6,250	2,144
Capacity Export Limit (CEL) (MW)	4,321	3,679	6,173	3,745	3,724	2,344	4,413	5,472	2,240	2,720
Zonal Import Ability (ZIA) (MW)	6,183	4,454	7,610	5,014	3,881	7,762	5,559	4,558	5,438	2,144
Zonal Export Ability (ZEA) (MW)	4,323	3,679	6,238	4,637	3,724	2,744	4,413	5,520	3,052	2,720

Table ES-4: Initial Planning Resource Auction Deliverables — Spring 2024

LRZ3 Fall and Winter ZIA and CIL were updated after the final results were presented at the October LOLEWG. Both studies resulted in No Limit found and the equation was updated to include Tier 2, the October 3rd 2022 LOLEWG presentation has also been updated accordingly.



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, HMPL, IPL, NIPS, SIGE
7	CONS, DECO
8	EAI
9	CLEC, EES, LAFA, LAGN, LEPA
10	EMBA, SME

Figure ES-1: Local Resource Zones (LRZ)

1. LOLE Study Process Overview

1 LOLE Study Process Overview

In compliance with Module E-1 of the MISO Tariff, MISO performed its annual LOLE study to determine, for each season of Planning Year 2023-2024, the system unforced capacity (UCAP) Planning Reserve Margin (PRM) and the per-unit Local Reliability Requirements (LRR) of Local Resource Zone (LRZ) Peak Demand.

In addition to the LOLE analysis, MISO performed seasonal transfer analyses to determine seasonal Zonal Import Ability (ZIA), Zonal Export Ability (ZEA), Capacity Import Limits (CIL) and Capacity Export Limits (CEL). CIL, CEL, and ZIA are used, in conjunction with the LOLE analysis results, in the Planning Resource Auction (PRA). ZEA is informational and not used in the PRA.

The PY 2023-2024 per-unit seasonal LRR UCAP multiplied by the updated LRZ seasonal Peak Demand forecasts submitted for the 2023-2024 PRA determines each LRZ's seasonal LRR. Once the seasonal LRR is determined, the ZIA values and non-pseudo tied exports are subtracted from the seasonal LRR to determine each LRZ's seasonal Local Clearing Requirement (LCR) consistent with Section 68A.6 of Module E-1[3]. An example calculation pursuant to Section 68A.6 of the current effective Module E-1 shows how these values are reached (Table 1-1).

Local Resource Zone (LRZ) EXAMPLE	Example LRZ	Formula Key
Installed Capacity (ICAP)	17,442	[A]
Unforced Capacity (UCAP)	16,326	[B]
Adjustment to UCAP (1d in 10yr)	50	[C]
Local Reliability Requirement (LRR) (UCAP)	16,376	[D]=[B]+[C]
LRZ Peak Demand	14,270	[E]
LRR UCAP per-unit of LRZ Peak Demand	114.8%	[F]=[D]/[E]
Zonal Import Ability (ZIA)	3,469	[G]
Zonal Export Ability (ZEA)	2,317	[H]
Proposed PRA (UCAP) EXAMPLE	**Example LRZ**	**Formula Key**
Forecasted LRZ Peak Demand	14,270	[I]
Forecasted LRZ Coincident Peak Demand	13,939	[J]
Non-Pseudo Tied Exports UCAP	150	[K]
Local Reliability Requirement (LRR) UCAP	16,376	[L]=[F]x[I]
Local Clearing Requirement (LCR)	12,757	[M]=[L]-[G]-[K]
Planning Reserve Margin (PRM)	7.4%	[N]
Zone's System Wide PRMR	14,970	[O]=[1.074]x[J]
PRMR	14,970	[P]=Higher of [M] or [O]

Table 1-1: Example LRZ Calculation

[3] https://www.misoenergy.org/legal/tariff
Effective Date: November 1, 2018

The actual effective PRM Requirement (PRMR) for each season of Planning Year 2023-2024 will be determined after the updated LRZ Seasonal Peak Demand forecasts are submitted by November 1, 2022, for the 2023-2024 PRA. The ZIA, ZEA, CIL and CEL values are subject to updates in March 2023 based on changes to exports of MISO resources to non-MISO load, changes to pseudo tied commitments, and updates to facility ratings following the completion of the LOLE study.

Finally, the simultaneous feasibility test (SFT) is performed as part of the PRA where cleared generation is tested to ensure transmission reliability and if constraints arise, they are mitigated by adjusting CIL and CEL values as needed.

1.1 Study Improvements

The Planning Year 2023-2024 LOLE study incorporated a number of study improvements as a result of the approved seasonal construct. These improvements include seasonal outage rates, correlated cold weather outages, probabilistic distribution of non-firm support, and hourly wind and solar profiles.

Historically, the LOLE model utilized a 5-year average EFORd, based on historic GADS data, which was constant throughout the simulated year for all resources. This year, seasonal EFORd was calculated using the same GADS data but outages were classified by season to produce four unique seasonal EFORd values for each resource. This change better captures the seasonal availability of resources observed in operations.

Additional outages are added to the model during times of extreme cold temperatures to better capture the magnitude of correlated outages observed. The magnitude of forced outages added increases as temperatures decrease based on the relationship between outages and temperature determined from historic GADS and weather data. Each LRZ has a unique outage/temperature curve based on actual performance. The incremental cold weather outages are not assigned to a particular resource but instead represent the aggregate impact on the system for coal and gas resources.

For the last several years MISO has accounted for non-firm support in the LOLE process by simply reducing the PRM by a fixed amount on a 1-for-1 MW basis. This year's study incorporated seasonal distributions of non-firm support directly in the model which are based on historic Net Scheduled Interchange (NSI) data. As the model steps through time chronologically, SERVM will randomly draw import values from this distribution to be used to serve load.

In previous LOLE studies, wind resources were modeled as perfect units with a constant output equal to their monthly ELCC values while solar resources were modeled as perfect units with constant output equal to their capacity credit. For Planning Year 2023-2024, wind and solar resources were modeled as variable energy resources with 30 unique hourly profiles corresponding to the 30 unique weather years within SERVM.

2. Transfer Analysis

2 Transfer Analysis

2.1 Calculation Methodology and Process Description

Transfer analyses determined CIL and CEL values for LRZs in each season for Planning Year 2023-2024. Annual adjustments are made for Border External Resources (BERs) and Coordinating Owner Resources (COs) to determine the ZIA and ZEA in each season. Further adjustments are made for exports to non-MISO Loads to arrive at the CIL and CEL values. The objective of transfer analysis is to determine constraints caused by the transfer of capacity between zones and the associated transfer capability. Multiple factors impacted the analysis when compared to previous studies, including:

- 3.7 GW of Retirements / Suspensions
- New Intermittent Resources
- Base Model Dispatch in MISO and Seams

2.1.1 Generation Pools

To determine an LRZ's import or export limit, a transfer is modeled by ramping generation up in a source subsystem and ramping generation down in a sink subsystem. The source and sink definitions depend on the limit being tested. The LRZ studied for import limits is the sink subsystem and the adjacent MISO LBA's are the source subsystem. The LRZ studied for export limits is the source subsystem and the rest of MISO is the sink subsystem. These are the same in all seasons for the upcoming Planning Year.

Transfers can cause potential issues, which are addressed through the study assumptions. First, an abundantly large source pool spreads the impact of the transfer widely which can cause differences in studied zones transfer capabilities and constraints identified. Second, ramping up generation from remote areas could cause electrically distant constraints for any given LRZ, which should not determine a zone's limit. For example, export constraints due to dispatch of LRZ 1 generation in the northwest portion of the footprint should not limit the import capability of LRZ 10, which covers the MISO portion of Mississippi.

To address these potential issues, the transfer studies limit the source pool for the import studies to the Tier 1 and Tier 2 adjacent LBA's to the study zone. Since the generation that is ramped up in export studies are contained in the study LRZ, these issues only apply to import studies. Generation within the zone studied for an export limit is ramped up and constraints are expected to be near or in the study zone.

2.1.2 Redispatch

Limited redispatch is applied after performing transfer analyses to mitigate constraints. Redispatch ensures constraints are not caused by the base dispatch and aligns with potential actions that can be implemented for the constraint in MISO operations. Redispatch scenarios can be designed to address multiple constraints as required and may be used for constraints that are electrically close to each other or to further optimize transfer limits for several constraints requiring only minor redispatch. The redispatch assumptions include:

- The use of no more than 10 conventional fuel plants or intermittent resources
- Redispatch limit at 2,000 MW total (1,000 MW up and 1,000 MW down)
- No adjustments to nuclear units
- No adjustments to the portions of pseudo-tied units committed to non-MISO load

2.1.3 Generation Limited Transfer for CIL/CEL and ZIA/ZEA

When conducting transfer analysis to determine import or export limits, the source subsystem might run out of generation to dispatch before identifying a valid constraint caused by a transmission limit. MISO developed a Generation Limited Transfer (GLT) process to identify transmission constraints in these situations, when possible, for both imports and exports.

After running the First Contingency Incremental Transfer Capability (FCITC) analysis to determine limits for each LRZ, MISO will determine whether a zone is experiencing a GLT (e.g. whether the first constraint would only occur after all the generation is dispatched at its maximum amount). If the LRZ experiences a GLT, MISO will adjust the base model depending on whether it is an import or export analysis and re-run the transfer analysis.

For an export study, when a transmission constraint has not been identified after dispatching all generation within the exporting system (LRZ under study) MISO will decrease load and generation dispatch in the study zone. The adjustment creates additional capacity to export from the zone. After the adjustments are complete, MISO will rerun the transfer analysis. If a GLT reappears, MISO will make further adjustments to the load and generation of the study zone.

For an import study, when a transmission constraint has not been identified after dispatching all generation within the source subsystem, MISO will decrease load and generation in the source subsystem. This increases the export capacity of the adjacent LBA's for the study zone. After the adjustments are complete, MISO will run the transfer analysis again. If a GLT reappears, MISO will make further adjustments to the model's load and generation in the source subsystem.

FCITC could indicate the transmission system can support larger thermal transfers than would be available based on installed generation for some zones. However, large variations in load and generation for any zone may lead to unreliable limits and constraints. Therefore, MISO limits load scaling for both import and export studies to 50 percent of the zone's load. In a GLT, redispatch, or GLT plus redispatch scenario, the FCITC of the most limiting constraint might exceed Zonal Export/Import Capability. If the GLT does not produce a limit for a zone(s), due to a valid constraint not being identified, or due to other considerations as listed in the prior paragraph, MISO shall report that LRZ as having no limit and ensure that the limit will not bind in the first iteration of the Simultaneous Feasibility Test (SFT).

2.1.4 Voltage Limited Transfer for CIL/CEL and ZIA/ZEA

Zonal imports may be limited by voltage constraints due to a decrease in the generation in the study zone. Voltage constraints might occur at lower transfer levels than thermal limits determined by linear FCITC. As such, LOLE studies may evaluate Power-Voltage curves for LRZs with known voltage-based transfer limitations identified through existing MISO or Transmission Owner studies. Such evaluation may also occur if an LRZ's import reaches a level where the majority of the zone's load would be served using imports from resources outside of the zone. MISO will coordinate with stakeholders as it encounters these scenarios. For Planning Year 2023-2024, all seasons only Zones 1, 4 and 7 import analysis included voltage screening and study. Only LRZ4 Summer identified a voltage limit with lower transfer capability than the thermal limit.

2.2 Powerflow Models and Assumptions

2.2.1 Tools Used

MISO used the Siemens PTI Power System Simulator for Engineering (PSS/E) and Transmission Adequacy and Reliability Assessment (TARA) for analysis tools.

2.2.2 Inputs Required

Thermal transfer analysis requires powerflow models and related input files. MISO used contingency files from MTEP[4] reliability assessment studies. Single-element contingencies in MISO/seam areas were also evaluated.

MISO developed a subsystem file to monitor its footprint and seam areas which was used for all seasons. LRZ definitions were developed as sources and sinks in the study. See Appendix B for tables containing adjacent area definitions (Tiers 1 and 2) used for this study. The monitored file includes all facilities under MISO functional control and single elements in the seam areas of 100 kV and above.

2.2.3 Powerflow Modeling

The MTEP22 models were built using MISO's Model on Demand (MOD) model data repository, with the following base assumptions (Table 2-1).

Scenario	Effective Date	Projects Applied	External Modeling	Load and Generation Profile	Wind %	Solar %
Summer 2023	July 15th	MTEP Appendix A and Target A	2021 Series 2023 Summer ERAG MMWG	Summer Peak	Capacity Credit ~15.5%	50%
Fall 2023	October 15th	MTEP Appendix A and Target A	2021 Series 2023 Summer ERAG MMWG	Fall Peak	32%	28.5%
Winter 2023-2024	January 15th	MTEP Appendix A and Target A	2021 Series 2023 Summer ERAG MMWG	Winter Peak	67%	0%
Spring 2024	April 15th	MTEP Appendix A and Target A	2021 Series 2023 Summer ERAG MMWG	Spring Peak	28.5%	32%

Table 2-1: Model Assumptions

MISO excluded several types of units from the transfer analysis dispatch—these units' base dispatch remained fixed.

- Nuclear dispatch does not change for any transfer
- Wind and solar resources can be ramped down, but not up
- Pseudo-tied resources were modeled at their expected commitments to non-MISO load, although portions of these units committed to MISO could participate in transfer analyses

System conditions such as load, dispatch, topology, and interchange have an impact on transfer capability. The model was reviewed as part of the base model build for MTEP22 analyses, with study files made available on MISO

[4] Refer to the Transmission Planning BPM (BPM-20) for more information regarding MTEP input files. https://www.misoenergy.org/legal/business-practice-manuals/

ShareFile. MISO worked closely with transmission owners and stakeholders in order to model the transmission system accurately, as well as to validate constraints and redispatch. Like other planning studies, transmission outage schedules were not included in the analysis. This is driven partly by limited availability of outage information as well as current transmission planning standards. Although no outage schedules were evaluated, single element contingencies were evaluated. This includes BES lines, transformers, and generators.

Contingency coverage covers most of category P1 and some of category P2 outlined in Table 1 of TPL-001: (https://www.nerc.com/pa/Stand/Reliability%20Standards/TPL-001-5.pdf).

2.2.4 General Assumptions

MISO uses TARA to process the powerflow model and associated input files to determine the import and export limits of each LRZ in each season by determining the transfer capability. Transfer capability measures the ability of interconnected power systems to reliably transfer power from one area to another under specified system conditions. The incremental amount of power that can be transferred is determined through FCITC analysis. FCITC analysis and base power transfers provide the information required to calculate the First Contingency Total Transfer Capability (FCTTC), which indicates the total amount of transferrable power before a constraint is identified. FCTTC is the base power transfer plus the incremental transfer capability (Equation 3-1). All published limits are based on the zone's FCTTC and may be adjusted for capacity exports.

$$First\ Contingency\ Total\ Transfer\ Capability\ (FCTTC) = FCITC + Base\ Power\ Transfer$$

Equation 2-1: Total Transfer Capability

FCITC constraints are identified under base case situations in each season or under P1 contingencies provided through the MTEP process. Linear FCITC analysis identifies the limiting constraints using a minimum transfer Distribution Factor (DF) cutoff of 3 percent, meaning the transfer must increase the loading on the overloaded element, under system intact or contingency conditions, by 3 percent or more.

A pro-rata dispatch is used, which ensures all available generators will reach their maximum dispatch level at the same time. The pro-rata dispatch is based on the MW reserve available for each unit and the cumulative MW reserve available in the subsystem. The MW reserve is found by subtracting a unit's base model generation dispatch from its maximum dispatch, which reflects the available capacity of the unit.

Table 2-2 and Equation 2-2 show an example of how one unit's dispatch is set, given all machine data for the source subsystem.

Machine	Base Model Unit Dispatch (MW)	Minimum Unit Dispatch (MW)	Maximum Unit Dispatch (MW)	Reserve MW (Unit Dispatch Max – Unit Dispatch Min)
1	20	20	100	80
2	50	10	150	100
3	20	20	100	80
4	450	0	500	50
5	500	100	500	0
			Total Reserve	310

Table 2-2: Example Subsystem

$$\textit{Machine 1 Incremental Post Transfer Dispatch} = \frac{\textit{Machine 1 Reserve MW}}{\textit{Source Subsystem Reserve MW}} \times \textit{Transfer Level MW}$$

$$\textit{Machine 1 Incremental Post Transfer Dispatch} = \frac{80}{310} \times 100 = 25.8$$

$$\textit{Machine 1 Incremental Post Transfer Dispatch} = 25.8$$

Equation 2-2: Machine 1 Dispatch Calculation for 100 MW Transfer

2.3 Results for CIL/CEL and ZIA/ZEA

Study constraints and associated ZIA, ZEA, CIL, and CEL for each LRZ for each season were presented and reviewed through the LOLEWG with final results for Planning Year 2023-2024 presented at the October 3rd, 2022 meeting. Table 2-3 below shows the Planning Year 2023-2024 CIL and ZIA with corresponding constraint, GLT, and redispatch (RDS) information.

All zones had an identified ZIA this year. If there is no valid constraint identified the following equation will be used where the FCITC will be replaced by the Tier 1 & 2 capacity.

$$\textit{ZIA} = \textit{FCITC} + \textit{AI} - \textit{Border External Resources and Coordinating Owners}$$

Equation 2-3: Zonal Import Ability (ZIA) Calculation

LRZ1	Monitored Element	Contingency	GLT	RDS	ZIA	CIL
Summer 2023	North Appleton - Werner W 345kV	North Appleton - Morgan 345kV	15%	494MWx2	5299	5301
Fall 2023	North Appleton - Werner W 345kV	North Appleton - Morgan 345kV	None	636MWx2	6526	6528
Winter 2023/24	Council Bluffs - Sarpy County 345kV	Arbor Hill - Raccoon Trail 345kV	None	681MWx2	4935	4937
Spring 2024	North Appleton - Werner W 345kV	North Appleton - Morgan 345kV	None	328MWx2	6183	6185
LRZ2	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2023	Elk Mound - Wheaton 161kV	King - Eau Claire 345kV	10%	1000MWx2	3477	3477
Fall 2023	Arpin - Sigel 138kV	Rocky Run - Arpin 345kV	None	1000MWx2	4411	4411
Winter 2023/24	Arpin - Sigel 138kV	Rocky Run - Arpin 345kV	None	1000MWx2	4905	4905
Spring 2024	Arpin - Sigel 138kV	Rocky Run - Arpin 345kV	None	603MWx2	4454	4454
LRZ3	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2023	S3458 3 - S3456 3 345kV	S3455 - S3740 345kV	10%	113MWx2	6043	6108
Fall 2023	No Limit Found		None	None	14,310	14,375
Winter 2023/24	No Limit Found		None	None	10,974	11,039
Spring 2024	Prairie Island - North Rochester 345kV	North Rochester - Hampton Corner 345kV	None	345MWx2	7610	7675
LRZ4	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2023	Bus 636410 Sub P Iowa City 161kV	Hills 345/161kV Transformer	None	None	6992	7884
Fall 2023	Marblehead 161/138kV Transformer	Herlman - Maywood 345kV	None	1000MWx2	4281	5173
Winter 2023/24	Marblehead 161/138kV Transformer	Herlman - Maywood 345kV	None	1000MWx2	3036	3928
Spring 2024	Marblehead 161/138kV Transformer	Herlman - Maywood 345kV	None	935MWx2	5014	5906
LRZ5	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2023	Pike - Cryene 161kV	Maywood - Spencer Creek 345kV	10%	81MWx2	3576	3576
Fall 2023	Mississippi Tap - Sioux 138kV	Loss of Sioux Generation	15%	708MWx2	5380	5380
Winter 2023/24	Overton 345/161kV Transformer	Mc Credie - Overton 345kV	None	1000MWx2	3811	3811
Spring 2024	Calif - Apache Tap 161kV	Mc Credie - Montgomery 345kV	None	244MWx2	3881	3881
LRZ6	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2023	Cayuga Sub - Cayuga 345kV	Kansas - Sugar Creek 345kV	20%	619MWx2	8092	8492
Fall 2023	Jord - West Frankfort 138kV	Mount Vernon - West Frankfort 345kV	None	1000MWx2	5670	6070
Winter 2023/24	Cayuga Sub - Cayuga 345kV	Kansas - Sugar Creek 345kV	None	923MWx2	8418	8818
Spring 2024	Cayuga Sub - Cayuga 345kV	Kansas - Sugar Creek 345kV	None	620MWx2	7762	8162
LRZ7	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2023	Argenta - Tompkins 345kV	Argenta - Battle Creek 345kV	15%	1000MWx2	5087	5087
Fall 2023	Benton Harbor - Segreto 345kV	Cook - Segreto 345kV	None	1000MWx2	4285	4285
Winter 2023/24	Stillwell 345kV/138kV Transformer	Dumont - Stillwell 345kV	None	1000MWx2	6340	6340
Spring 2024	Benton Harbor - Segreto 345kV	Cook - Segreto 345kV	None	1000MWx2	5559	5559
LRZ8	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2023	Lyon - Jonestown 115kV	Crossroads - Moonlake 230kV	None	180MWx2	4091	4139
Fall 2023	Moon Lake - Ritchie 230kV	Clarksdale - Crossroads 230/115kV Transformer	None	372MWx2	4657	4705
Winter 2023/24	Mount Olive - Vienna 115kV	Mount Olive - El Dorado 500kV	None	1000MWx2	4681	4729
Spring 2024	Mount Olive - Vienna 115kV	Mount Olive - El Dorado 500kV	None	181MWx2	4558	4606

LRZ9	Monitored Element	Contingency	GLT	RDS	ZIA	CIL
Summer 2023	Bogalusa - Barkers Corner 230kV	McKnight - Franklin 500kV	None	1000MWx2	4456	5268
Fall 2023	Braswell - Franklin 500kV	Franklin - Grand Gulf 500kV	None	325MWx2	5233	6045
Winter 2023/24	Camden - Smackover 115kV	McNeil - Camden 115kV	None	963MWx2	5268	6080
Spring 2024	Boogalusa 500/230kV Transformer	McKnight - Franklin 500kV	None	1000MWx2	5438	6250
LRZ10	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2023	Braswell - Northside 230kV	Braswell - Lakeover 500kV	None	38MWx2	3064	3064
Fall 2023	Braswell - Northside 230kV	Braswell - Lakeover 500kV	None	33MWx2	2425	2425
Winter 2023/24	Adams Creek - Angie 230kV	Slidel - Logtown 230kV	None	134MWx2	2396	2396
Spring 2024	Hernando - Coldwater 115kV	Moonlake - Ritchie 230kV	None	31MWx2	2144	2144

Table 2-3: Planning Year 2023–2024 Import Limits

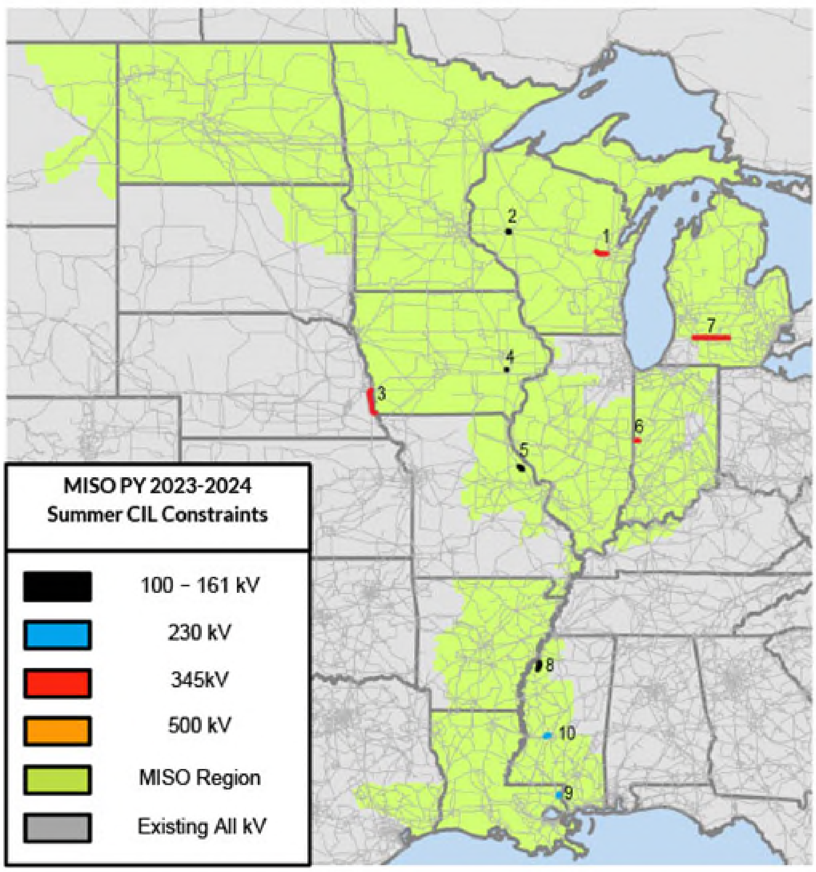


Figure 2-1: Planning Year 2023-2024 Summer Capacity Import Constraints Map

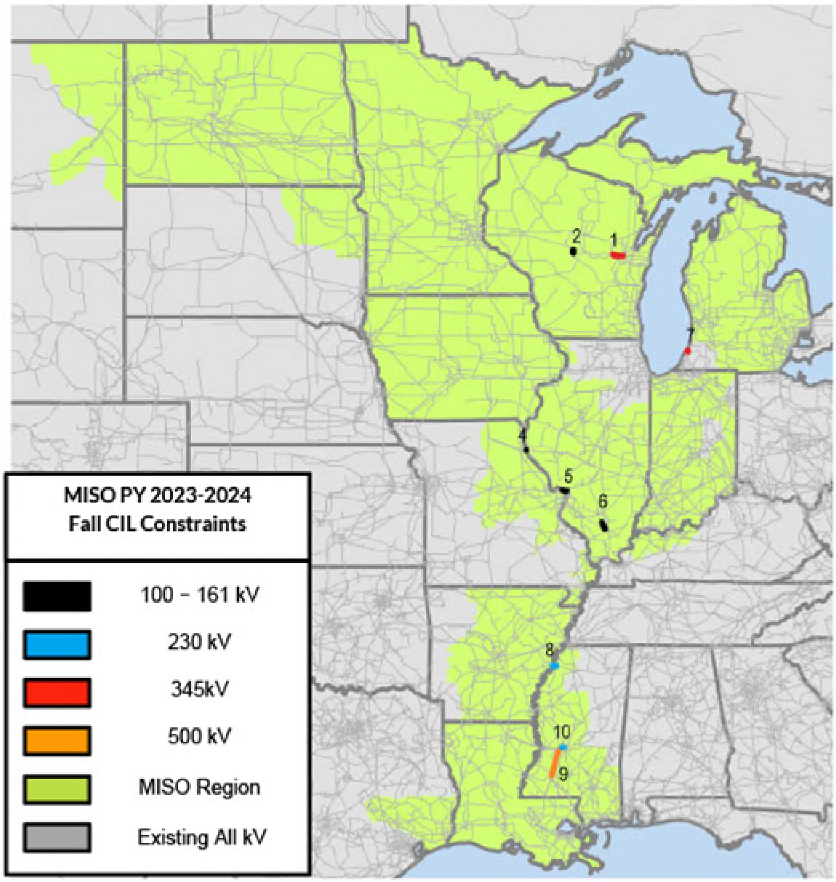


Figure 2-2: Planning Year 2023-2024 Fall Capacity Import Constraints Map

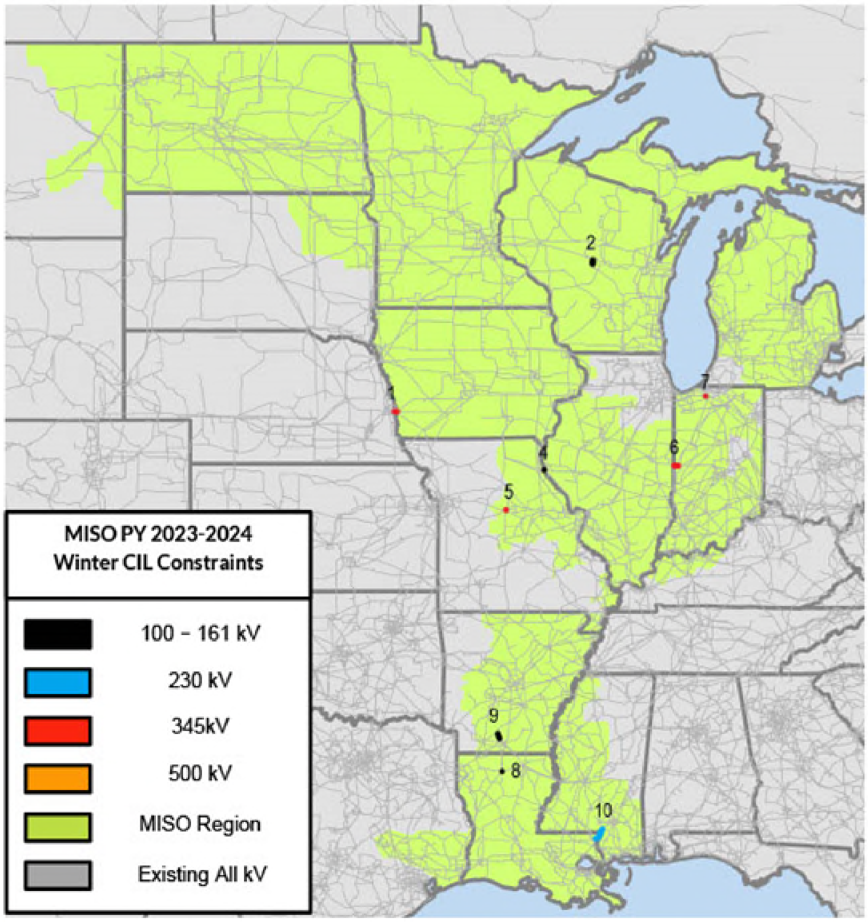


Figure 2-3: Planning Year 2023-2024 Winter Capacity Import Constraints Map

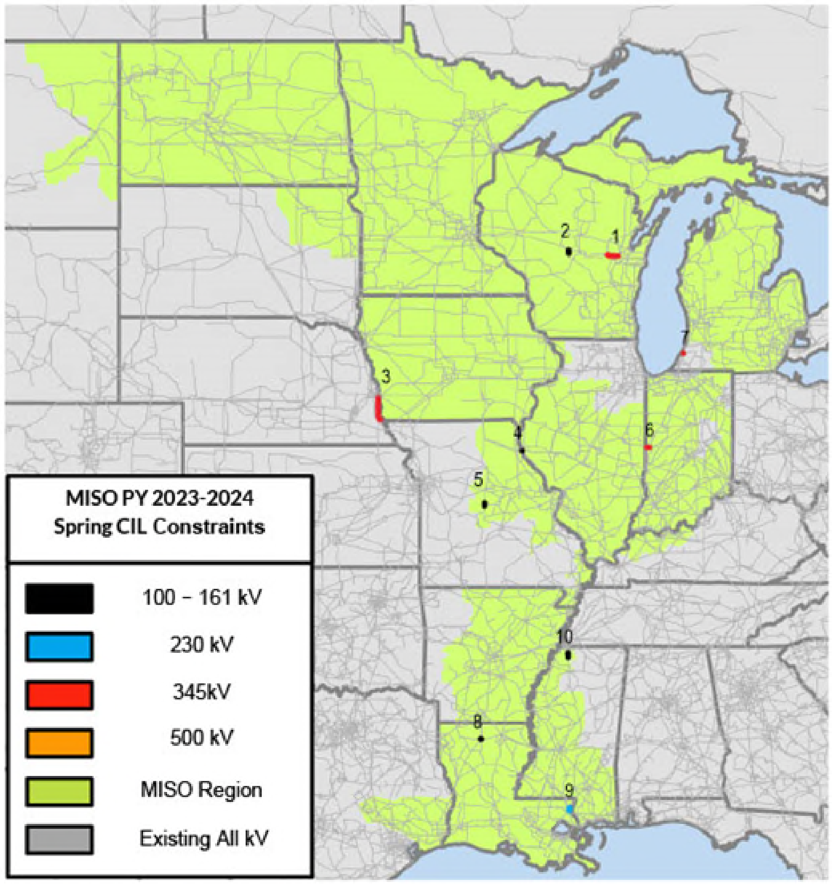


Figure 2-4: Planning Year 2023-2024 Spring Capacity Import Constraints Map

Capacity Exports Limits are found by increasing generation in the study zone and decreasing generation in the rest of the MISO footprint to create a transfer. Table 2-4 below shows the Planning Year 2023-2024 CEL and ZEA with corresponding constraint, GLT, and redispatch information.

LRZ1	Monitored Element	Contingency	GLT	RDS	ZEA	CEL
Summer 2023	Granville - Butler 138kV	Granville - Arcadian 345kV	15%	None	3961	3959
Fall 2023	Arpin - Sigel 138kV	Rocky Run - Arpin 345kV	None	18MWx2	3806	3804
Winter 2023/24	Arpin - Sigel 138kV	Rocky Run - Arpin 345kV	None	29MWx2	3503	3501
Spring 2024	Rocky Run - Werner 345kV	Highway 22 - Gardner Park 345kV	None	21MWx2	4323	4321
LRZ2	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2023	Wempletown 345/138kV Transformer	Cherry Valley - Wempleton 345kV	20%	None	2550	2550
Fall 2023	Elm Road - Racine 345kV	Base Case	None	None	3577	3577
Winter 2023/24	Pleasant Prairie - Zion EC 345kV	Pleasant Prairie - Zion 345kV	15%	None	4198	4198
Spring 2024	Elm Road - Racine 345kV	Base Case	None	None	3679	3679
LRZ3	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2023	Mercer - Sandburg 161kV	Sandburg - Oak Grove 345kV	45%	None	4375	4310
Fall 2023	Prar Creek - Marion 115	Prar Creek - Bertram 115kV	None	147MWx2	4419	4354
Winter 2023/24	Sandburg 161/138kV Transformer	Sandburg - Oak Grove 345kV	None	109MWx2	7067	7002
Spring 2024	Sandburg 161/138kV Transformer	Sandburg - Oak Grove 345kV	40%	None	6238	6173
LRZ4	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2023	No CEL Found	No CEL Found	50%	None	9999	9999
Fall 2023	No CEL Found	No CEL Found	50%	None	9999	9999
Winter 2023/24	No CEL Found	No CEL Found	50%	None	9999	9999
Spring 2024	No CEL Found	No CEL Found	50%	None	9999	9999
LRZ5	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2023	No CEL Found	No CEL Found	45%	None	9999	9999
Fall 2023	Jord - West Frankfort 138kV	Mount Vernon - West Frankfort 345kV	None	None	1992	1992
Winter 2023/24	Miles Avenue - Moro 138kV	Roxford - Moro 345kV	35%	121MWx2	6348	6348
Spring 2024	Mass 345/161 kV Transformer	Joppa - Mass 345kV	None	None	3724	3724
LRZ6	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2023	Franscisco - Duff 345kV	AB Brown - Reid 345kV	15%	206MWx2	3109	2703
Fall 2023	Newtonville - Coleman 161kV	Duff - Coleman 345kV	None	493MWx2	2101	1701
Winter 2023/24	Newtonville- Grandview 138kV	Cutley - Dubois 138kV	None	42MWx2	1642	1242
Spring 2024	Newtonville - Coleman 161kV	AB Brown - Reid 345kV	None	65MWx2	2744	2344
LRZ7	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2023	Monroe - Lulu 345kV	Monroe - Lallendorf 345kV	25%	None	3953	3953
Fall 2023	Monroe - Lulu 345kV	Monroe - Lallendorf 345kV	None	None	3990	3990
Winter 2023/24	Monroe - Lulu 345kV	Monroe - Lallendorf 345kV	None	None	4350	4350
Spring 2024	Monroe - Lulu 345kV	Monroe - Lallendorf 345kV	None	None	4413	4413
LRZ8	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2023	Cash - Jonesboro 161kV	Ises - Powerlane Road 500kV	50%	218MWx2	5551	5503
Fall 2023	Arklahoma - HS EHV 115kV 2	Arklahoma - HS EHV 115kV 2	None	177MWx2	5128	5080
Winter 2023/24	Cash - Jonesboro 161kV	Ises - Powerlane Road 500kV	25%	134MWx2	5399	5351
Spring 2024	Cash - Jonesboro 161kV	Ises - Powerlane Road 500kV	None	177MWx2	5520	5472

LRZ9	Monitored Element	Contingency	GLT	RDS	ZEA	CEL
Summer 2023	Adams Creek - Angie 230kV	Slidel - Log Town 230kV	None	None	2386	1574
Fall 2023	Wrightsville - Keo 500kV	White Bluff - Keo 500kV	None	None	2338	1526
Winter 2023/24	Adams Creek - Angie 230kV	Slidel - Log Town 230kV	None	None	1689	877
Spring 2024	Adams Creek - Angie 230kV	Slidel - Log Town 230kV	None	None	3052	2240
LRZ10	Monitored Element	Contingency	GLT	RDS	ZEA	CEL
Summer 2023	Andrus 230/115kV Transformer	Andrus - Indianola	None	510MWx2	1794	1794
Fall 2023	Clarksdale - Lyon 115kV	Crossroads - Moon Lake 230kV	None	284MWx2	2878	2878
Winter 2023/24	Batesville - Tallahachie 161kV	Choctaw - Clay 500kV	None	690MWx2	1980	1980
Spring 2024	Clarksdale - Lyon 115kV	Crossroads - Moon Lake 230kV	None	535MWx2	2720	2720

Table 2-4: Planning Year 2023–2024 Export Limits

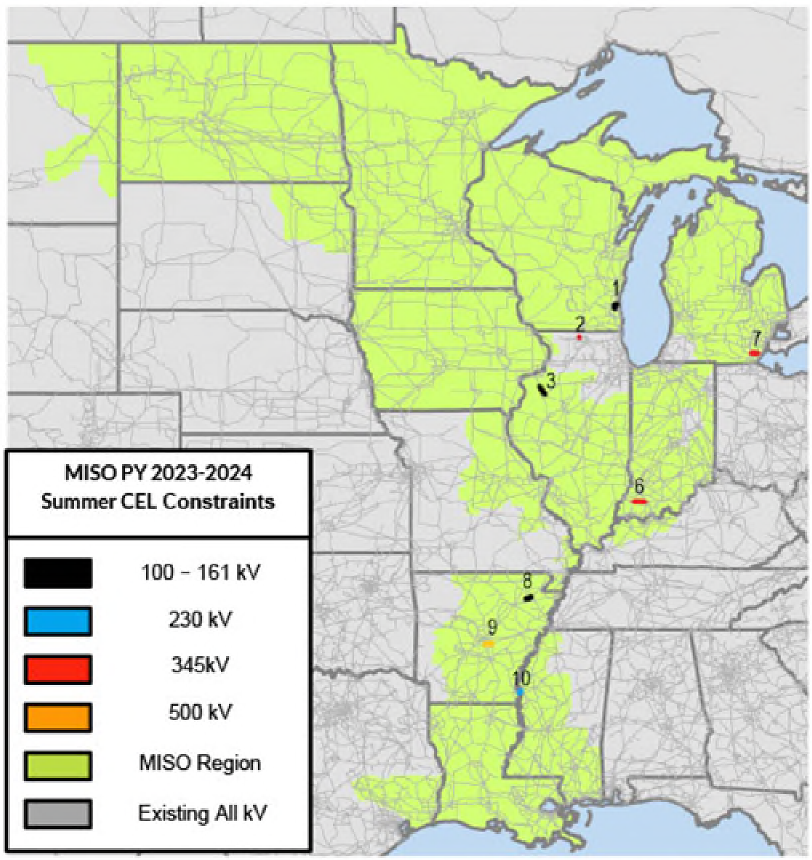


Figure 2-5: Planning Year 2023-2024 Summer Export Constraint Map

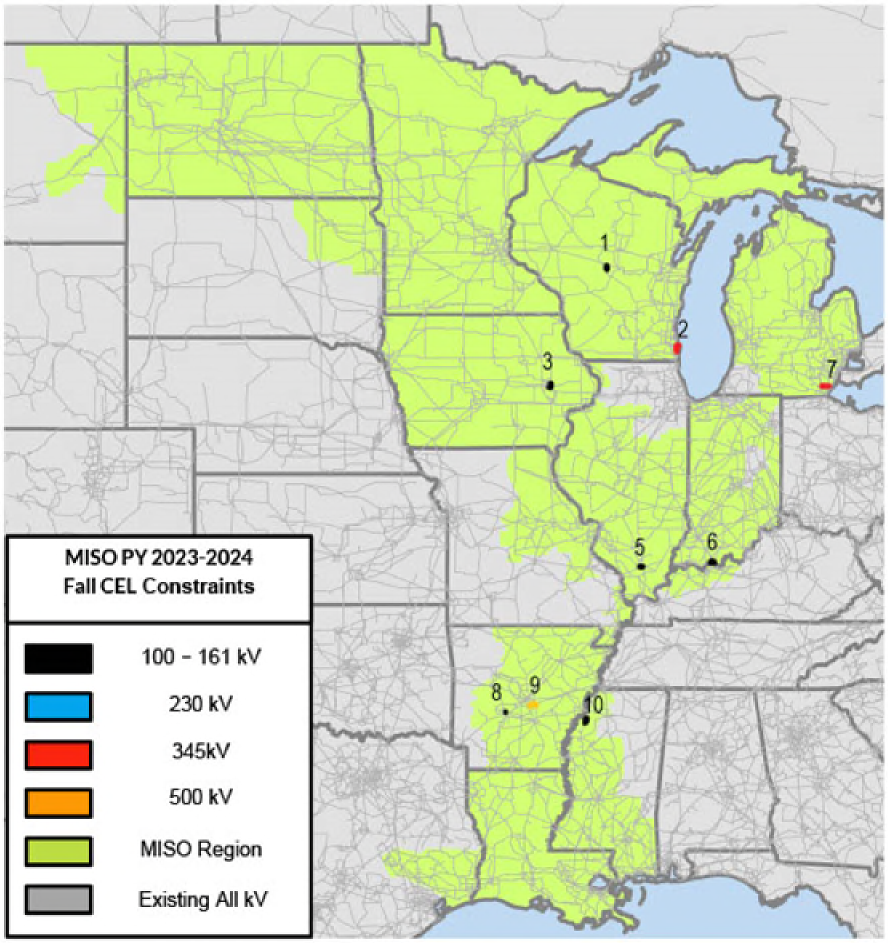


Figure 2-6: Planning Year 2023-2024 Fall Export Constraint Map

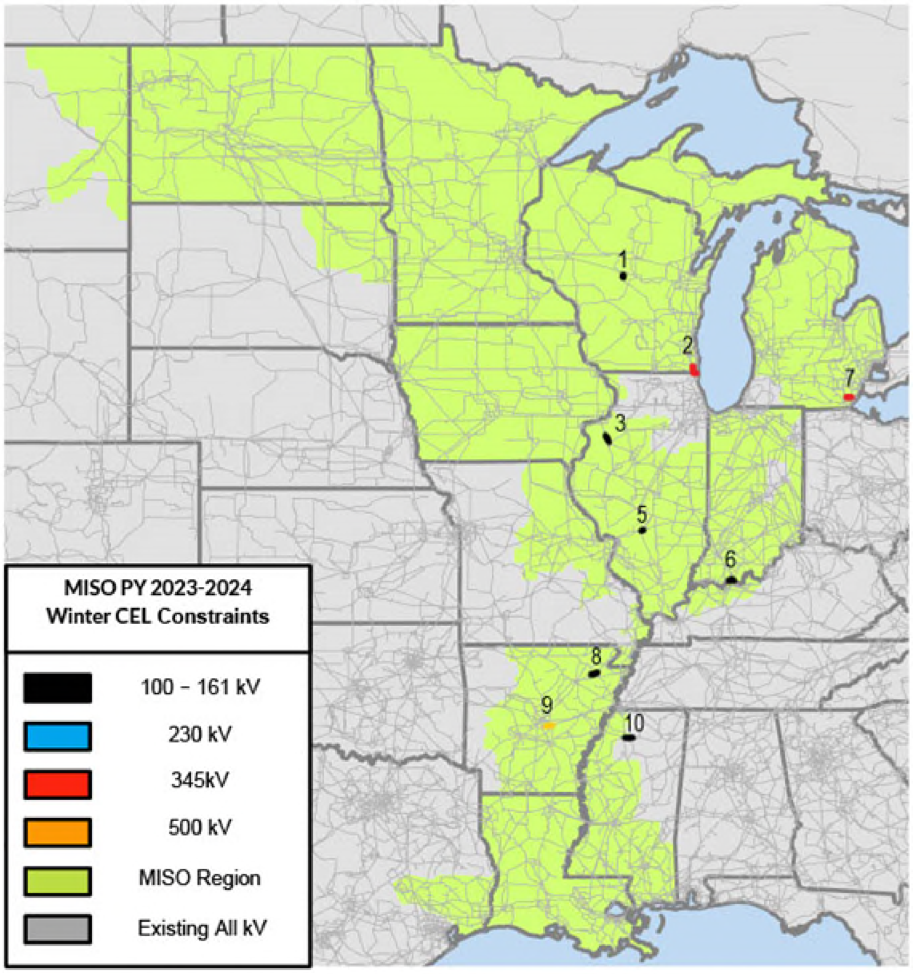


Figure 2-7: Planning Year 2023-2024 Winter Export Constraint Map

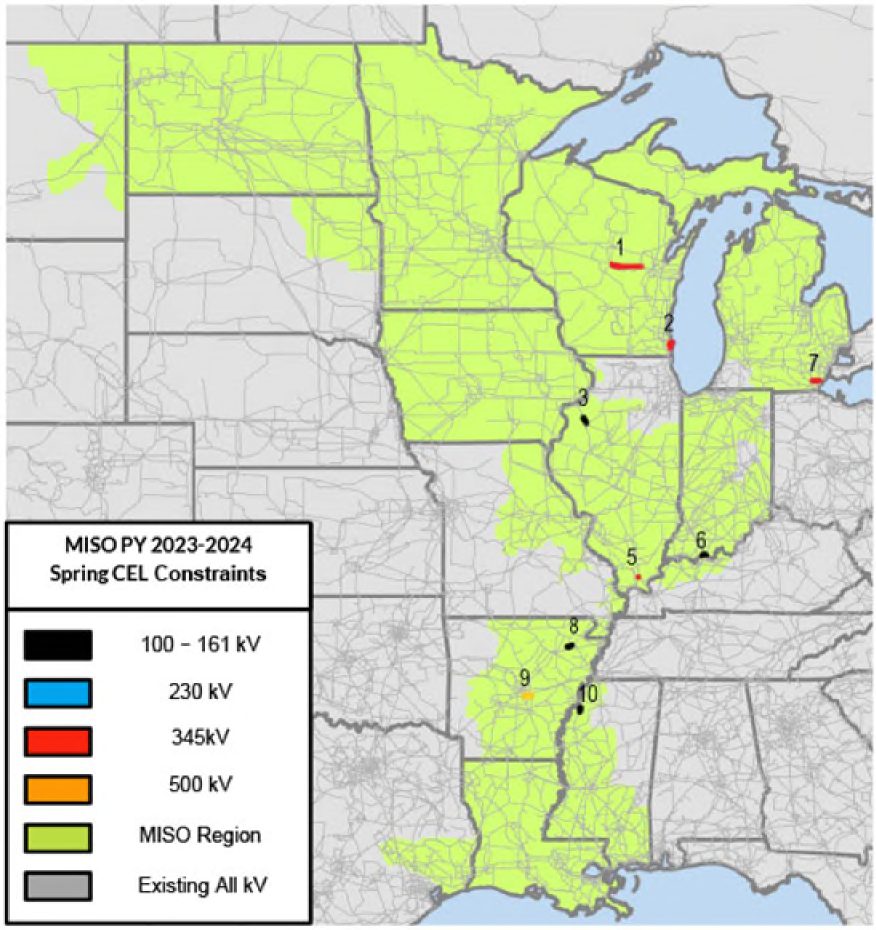


Figure 2-8: Planning Year 2023-2024 Spring Export Constraint Map

2.3.1 Outyear Analysis

In 2018, MISO and its stakeholders redesigned the outyear LOLE transfer analysis process through the LOLEWG and Resource Adequacy Subcommittee (RASC). The outyear analysis is now performed after the prompt Planning Year analyses are complete. The outyear results are informational only. The zones identified for outyear analysis are determined by BPM-011 criteria. The results will be documented outside of the LOLE report and recorded in RASC meeting materials in Q2 of 2023 and memorialized at a later date as an addendum to the LOLE report in 2023.

3. Loss of Load Expectation Analysis

3 Loss of Load Expectation Analysis

3.1 LOLE Modeling Input Data and Assumptions

MISO uses a program managed by Astrapé Consulting called Strategic Energy & 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 LOLE for the MISO system and each 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 LOLE study. Many scenarios are built in order to determine how certain variables impact the results. The base case models determine the seasonal MISO PRM Installed Capacity (ICAP), PRM UCAP, and the LRRs for each LRZ for future Planning Years one, four and six.

3.2 MISO Generation

3.2.1 Thermal Units

The Planning Year 2023-2024 LOLE study used the 2022-2023 PRA converted capacity as a starting point for which 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 GIA with an anticipated in-service date for PY 2023-2024—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 2017 to December 2021) and modeled as four seasonal values for each unit. Some units did not have five years of historical data in MISO's Generator Availability Data System (PowerGADS)—however, if they had at least 3 consecutive months of seasonal data, unit-specific information was used to calculate their seasonal forced outage rates and maintenance factors. Units with fewer than 3 consecutive months of seasonal unit-specific data were assigned the corresponding MISO seasonal class average forced outage rate and seasonal planned maintenance factor based on their fuel type. The overall MISO ICAP-weighted seasonal class average forced outage rate and seasonal planned maintenance factor are applied in lieu of class averages for classes with fewer than 30 units. When the units are populated into the LOLE model, the weighted outage rate in SERVM may be different from the calculated MISO-wide weighted average because the MISO-wide weighted average excludes units with insufficient operating history. Therefore, the weighted outage rate is recalculated to include units that were assigned class average outage rates to gauge how SERVM views the MISO-wide weighted average. This value is for information only and is not assigned to any units.

Each nuclear unit has a fixed maintenance schedule, which was pulled from publicly available information and was modeled for each of the study years.

The historical class average outage rates as well as the MISO system-wide weighted average forced outage rate are provided in Table 3-1 to show the year-over-year trends, as well as in Table 3-2 on a seasonal basis.

Pooled EFORd GADS Years	2017-2021 (%)	2016-2020 (%)	2015-2019 (%)	2014-2018 (%)	2013-2017 (%)	2012-2016 (%)
LOLE Study Planning Year	PY 2023-2024 LOLE Study – Summer 2023	PY 2022-2023 LOLE Study	PY 2021-2022 LOLE Study	PY 2020-2021 LOLE Study	PY 2019-2020 LOLE Study	PY 2018-2019 LOLE Study
Combined Cycle	5.54	5.85	5.52	5.70	5.370	4.62
Combustion Turbine (0-20 MW)	23.40	35.20	36.38	40.39	23.18	29.02
Combustion Turbine (20-50 MW)	6.30	13.65	14.20	15.29	15.76	13.48
Combustion Turbine (50+ MW)	4.07	4.36	4.76	4.65	5.18	6.19
Diesel Engines	12.79	7.25	10.05	23.53	10.26	10.42
Fluidized Bed Combustion	*	*	*	*	*	*
Hydro (0-30 MW)	*	*	*	*	*	*
Hydro (30+ MW)	*	*	*	*	*	*
Nuclear	*	*	*	*	*	*
Pumped Storage	*	*	*	*	*	*
Steam - Coal (0-100 MW)	*	*	*	5.33	4.60	5.14
Steam - Coal (100-200 MW)	*	*	*	*	*	*
Steam - Coal (200-400 MW)	*	*	10.47	10.16	9.82	9.77
Steam - Coal (400-600 MW)	*	*	*	*	*	*
Steam - Coal (600-800 MW)	*	*	*	*	8.22	7.90
Steam - Coal (800-1000 MW)	*	*	*	*	*	*

Steam - Gas	11.26	11.84	12.91	12.54	11.56	11.94
Steam - Oil	*	*	*	*	*	*
Steam - Waste Heat	*	*	*	*	*	*
Steam - Wood	*	*	*	*	*	*
MISO Weighted System-wide	8.23	9.04	9.36	9.24	9.28	9.16
MISO Weighted as seen in SERVM	7.64	8.95	9.17	9.22	9.18	-

**MISO system-wide weighted forced outage rate used in place of class data for those with less than 30 units reporting 12 or more months of data*

Table 3-1: Historical Class Average Forced Outage Rates

Pooled EFORd GADS Years	2017-2021 (%)	2017-2021 (%)	2017-2021 (%)	2017-2021 (%)
LOLE Study Planning Year 2023-2024	**Summer 2023**	**Fall 2023**	**Winter 2023-2024**	**Spring 2024**
Combined Cycle	5.54	8.32	4.70	6.19
Combustion Turbine (0-20 MW)	23.40	53.44	42.92	58.75
Combustion Turbine (20-50 MW)	6.30	16.79	56.52	25.23
Combustion Turbine (50+ MW)	4.07	6.60	9.68	4.81
Diesel Engines	12.79	9.32	14.84	8.07
Fluidized Bed Combustion	*	*	*	*
Hydro (0-30 MW)	*	*	*	*
Hydro (30+ MW)	*	*	*	*

Nuclear	*	*	*	*
Pumped Storage	*	*	*	*
Steam - Coal (0-100 MW)	*	*	*	*
Steam - Coal (100-200 MW)	*	*	*	*
Steam - Coal (200-400 MW)	*	*	*	*
Steam - Coal (400-600 MW)	*	*	*	*
Steam - Coal (600-800 MW)	*	*	*	*
Steam - Coal (800-1000 MW)	*	*	*	*
Steam - Gas	12.48	13.66	8.28	11.26
Steam - Oil	*	*	*	*
Steam - Waste Heat	*	*	*	*
Steam - Wood	*	*	*	*
MISO Weighted System-wide	8.23	9.48	12.47	11.42

**MISO system-wide weighted forced outage rate used in place of class data for those with less than 30 units reporting 12 or more months of data*

Table 3-2: Planning Year 2023-2024 Seasonal Class Average Forced Outage Rates

3.2.2 Behind-the-Meter Generation

Behind-the-Meter Generation data came from the Module E Capacity Tracking (MECT) tool. Behind-the-Meter Generation backed by thermal resources were explicitly modeled just as any other thermal generator with a monthly capacity and forced outage rate. Performance data was pulled from PowerGADS. Behind-the-Meter Generation backed by wind or solar resources had their hourly generation tied to the hourly wind and solar profiles in the model.

3.2.3 Attachment Y

MISO obtained information on generating units with approved suspensions or retirements (as of June 1, 2022) through MISO's Attachment Y process. Any unit with approved retirement or suspension in Planning Year 2023-2024 was excluded from the year-one analysis during the months the unit has been approved to be out-of-service for. This same methodology is used for the four- and six-year analyses.

3.2.4 Future Generation

Future thermal generation and upgrades were added to the LOLE model based on unit information in the MISO Generator Interconnection Queue. The LOLE model included units with a signed generator interconnection agreement (as of June 1, 2022). These new units were assigned seasonal class average forced outage rates and planned maintenance factors based on their particular unit class. Units upgraded during the study period reflect the megawatt increase for each month, beginning the month the upgrade was finished. The LOLE analysis also included future wind and solar generation, tied to the same hourly wind and solar profiles used for existing wind and solar resources in the model.

3.2.5 Intermittent Resources

Intermittent resources such as run-of-river hydro, biomass, wind and solar were explicitly modeled as demand-side resources. Run-of-river hydro and biomass provide MISO with a minimum of 3 years and up to 15 years of historical output data during seasonal peak hours, defined as hours ending 15, 16, & 17 EST for summer, fall, and spring, and hours ending 8, 9, 19, & 20 for winter. This data is averaged at the seasonal level and modeled in the LOLE analysis as UCAP for all months within a given season. Each individual unit is modeled and put in the corresponding LRZ.

As a process improvement to the LOLE model for this year's study, in collaboration with the SERVM vendor Astrapé, hourly wind and solar profiles were developed and introduced into the model to better simulate the variance in renewable generation on an hourly basis.

Using historical hourly wind data from 246 front-of-meter wind resources from 2013 to 2021, normalized hourly capacity profiles were developed and aggregated at the LRZ level to represent wind in the model. As a result of the LOLE analysis being based on 30 weather years (1992 – 2021), synthetic shapes were created for the 1992 – 2013 period based on historical wind performance and temperatures. Once the weather and wind performance matching has been performed, the data is analyzed as a function of load to ensure the variability around the load profiles is reasonable.

Solar profiles were developed using historical solar irradiance data from the NREL National Solar Radiation Database (NSRDB) from 1998 – 2021.

For more details, refer to the supporting documentation Astrapé provided for stakeholders at the LOLEWG detailing the development of the wind and solar profiles: MISO Seasonal Inputs for the 2022 LOLE Study

3.2.6 Demand Response

Demand response data came from the MECT tool. These resources were explicitly modeled as dispatch-limited resources. Each demand response program was modeled individually with a monthly capacity, limited to the number of times each program can be called upon, and limited by duration.

3.3 MISO Load Data

The Planning Year 2023-2024 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 30 years of hourly historical weather data to create 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. The results of this process are shown as the MISO System Peak Demand (Table 4-1) and LRZ Peak Demands (Table 5-1, Table 5-2, Table 5-3, & Table5-4).

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.

3.3.1 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. The first step of this process requires the collection of five years of historical real-time load modifying resource (LMR) performance and load data, as well as the collection of 30 years of historical weather data. Both the LMR and load data are taken from the MISO market for each LBA, while the historical weather data is collected from the National Oceanic and Atmospheric Administration (NOAA) for each LRZ. After collecting the data, the hourly gross load for each LRZ is calculated using the five years of historical data.

The second step of the process is to normalize the five years of load data to consistent economics. With the load growth due to economics removed from 5 years of historical LRZ load, the third step of the process utilizes neural network software to establish functional relationships between the five years of historical weather and load data. In the fourth step of the process the neural network relationships are applied to the 30 years of historical weather data in order to predict/create 30 years' worth of load shapes for each LRZ.

In the fifth step of the load training process, MISO undertakes extreme temperature verification on the 30 years of load shapes to ensure that the hourly load data is accurate at extremely hot or cold temperatures. This is required since there are fewer data points available at the temperature extremes when determining the neural network functional relationships. This lack of data at the extremes can result in inaccurate predictions when creating load shapes, which will need to be corrected before moving forward.

The sixth and final step of the load training process is to average the monthly peak loads of the predicted load shapes and adjust them to match each LR's Module E 50/50 monthly zonal peak load forecasts for each study year. In order to calculate this adjustment, the ratio of the first year's non-coincident peak forecast to the zonal coincident peak forecast is applied to future year's non-coincident peak forecast.

By adopting this new 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.

3.3.2 Economic Load Uncertainty

To account for economic load uncertainty in the Planning Year 2023-2024 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 (CBO), the actual GDP growth was taken from the Bureau of Economic Analysis (BEA), and the electric use was taken from the U.S. Energy Information Administration (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 is 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 Table 3-3.

	LFE Levels				
	-2.0%	-1.0%	0.0%	1.0%	2.0%
Standard Deviation in LFE	Probability assigned to each LFE				
0.90%	4.8%	24.1%	42.1%	24.1%	4.8%

Table 3-3: Economic Uncertainty

As a result of stakeholder feedback MISO is exploring possible alternative methods for determining economic uncertainty to be used in the LOLE process.

3.4 External System

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 LRRs. Due to the locational Tariff filing, 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 Planning Year 2022-2023 Planning Resource Auction (PRA).

The LOLE analysis incorporates firm exports to neighboring regions where information was available. For units with capacity sold off-system, their monthly capacities were reduced by the megawatt amount exported. These values came from PJM's Reliability Pricing Model (RPM) as well as information on exports to other external areas taken from the Independent Market Monitor (IMM) exclusion list.

Firm exports from MISO to external areas were modeled the same as previous years. Capacity ineligible as MISO capacity due to transactions with external areas is removed from the model. Table 3-4 shows the amount of firm imports and exports in this year's study.

Contracts	Summer ICAP (MW)	Summer UCAP (MW)	Fall ICAP (MW)	Fall UCAP (MW)	Winter ICAP (MW)	Winter UCAP (MW)	Spring ICAP (MW)	Spring UCAP (MW)
Imports (MW)	1,731	1,673	1,734	1,672	1,874	1,819	1,803	1,755
Exports (MW)	2,543	2,287	2,543	2,287	2,543	2,287	2,543	2,287
Net	-812	-614	-809	-615	-669	-468	-740	-532

Table 3-4: Planning Year 2023-2024 Firm Imports and Exports

Non-firm imports in the Planning Year 2023-2024 LOLE study were modeled as a probabilistic distribution of capacity value. These distributions were developed using historic seasonal NSI data which accounted for imports into MISO during emergency pricing hours. Firm imports cleared in the PRA for each planning year were subtracted from the NSI data to isolate the non-firm values. An additional region was included in SERVM which contained 12,000 MW of perfect generation connected to the MISO system. A distribution of the regions export capability was modeled up to the upper and lower bounds. As SERVM steps through the hourly simulation, random draws on the export limits of the external region were used to represent the amount of capacity MISO could import to meet peak demand. The probability distribution of non-firm external imports used in the LOLE model has been provided in Table 3-5.

	Summer	Fall	Winter	Spring
p5	1,456	649	-	1,777
p10	2,663	1,259	205	2,144
p25	3,674	2,199	1,142	2,768
p50	4,708	3,393	3,143	4,031
p75	5,608	4,537	4,941	5,265
p90	6,465	5,453	7,249	6,271
p95	6,807	6,217	8,452	7,055

Table 3-5: Non-Firm External Import Distribution During Emergency Pricing Hours

3.5 Loss of Load Expectation Analysis and Metric Calculations

Upon completion of the annual LOLE study model refresh, MISO performed probabilistic analyses to determine the seasonal PRM ICAP and PRM UCAP for the Planning Year 2023-2024 as well as the seasonal Local Reliability Requirement for each of the 10 LRZs. These metrics were derived through probabilistic modeling of the system, first solving to the industry standard annual LOLE risk target of 1 day in 10 years, or 0.1 day per year, and then solving to the seasonal LOLE targets.

3.5.1 Seasonal LOLE Distribution

To determine the seasonal LOLE distribution that will be used to calculate the PRM and LRRs, MISO followed the process described in Section 68A.2.1 of Module E-1 of the MISO Tariff. This process involves first solving the LOLE model to an annual value of 0.1 and then checking the seasonal distribution of the annual LOLE of 0.1. If a season had an LOLE value of at least 0.01, then it met the minimum seasonal criteria and would be set to that LOLE. If a season had less than 0.01 LOLE, additional analysis was performed until the minimum seasonal criteria of 0.01 LOLE was met.

Example: Assume the model is solved to an annual LOLE of 0.1 with 0.05 occurring in both summer and winter while spring and fall had LOLE values of 0 from this simulation. In this case the summer and winter seasons would not need additional analysis since both had at least 0.01 LOLE naturally when the model was solved to an annual value of 0.1. Since spring and fall had 0 LOLE they would be assigned the LOLE minimum seasonal criteria of 0.01 and additional LOLE simulations would be performed until the minimum seasonal criteria was met.

The seasonal LOLE distribution determined in the Planning Year 2023-2024 LOLE study are shown in Table 3-6.

Region	Summer	Fall	Winter	Spring
MISO-wide	0.1	0.01	0.01	0.01
1	0.08	0.01	0.02	0.01
2	0.1	0.01	0.01	0.01
3	0.07	0.01	0.03	0.01
4	0.04	0.01	0.04	0.01
5	0.04	0.01	0.05	0.01
6	0.05	0.01	0.04	0.01
7	0.07	0.03	0.01	0.01
8	0.01	0.01	0.08	0.01
9	0.06	0.01	0.02	0.01
10	0.05	0.04	0.01	0.01

Table 3-6: Planning Year 2023-2024 Seasonal LOLE Distribution

3.7.1 MISO-Wide LOLE Analysis and PRM Calculation

MISO will determine the appropriate PRM for each season of the applicable Planning Year based upon probabilistic analysis of reliably serving expected demand. The probabilistic analysis will utilize a Loss of Load Expectation (LOLE) study which assumes that there are no internal transmission limitations.

To determine the PRM, the LOLE model will initially be run with no adjustments to the capacity. If the LOLE is less than 0.1 day per year, a negative unit with zero forced outage rate will be added until the LOLE reaches 0.1 day per year. This is comparable 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 will be added to the model until the LOLE reaches 0.1 day per year.

MISO's annual LOLE study will calculate the seasonal PRMs based on the LOLE targets identified in the previous section. The minimum seasonal PRM requirement will be determined using the LOLE analysis by either adding a zero EFORd, negative output unit or adding proxy units until a minimum LOLE of 0.01 day per season is reached.

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

PRM ICAP % = (Installed Capacity + Firm External Support ICAP + ICAP Adjustment to meet LOLE target – MISO Coincident Peak Demand)/MISO Coincident Peak Demand

PRM UCAP % = (Unforced Capacity + Firm External Support UCAP + UCAP Adjustment to meet LOLE target – MISO Coincident Peak Demand)/MISO Coincident Peak Demand

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

3.7.2 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 analysis, unforced capacity is either added or removed in each LRZ such that an LOLE of 0.1 day per year is achieved when solving for the annual target and a minimum LOLE at least 0.01 day per season when solving for a seasonal target. 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 Planning Year 2023-2024 seasonal LRRs were determined using the LOLE analysis by first either adding or removing capacity until the annual 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 will be added to the model until the LOLE reaches 0.1 day per year.

After solving each LRZ for to the annual LOLE target of 0.1 day per year, MISO will calculate each seasonal LRR such that the summation of seasonal LOLE across the year in each zone is 1 day in 10 years, or 0.1 day per year. An LOLE target of 0.01 will be used to calculate the LRR in seasons with less than 0.01 LOLE risk. The seasonal Local Reliability Requirement will be determined using the LOLE analysis by either adding a zero EFORd, negative output unit or adding proxy units until a minimum LOLE of 0.01 day per season is reached.

For Planning Year 2023-2024, only LRZ-1 had sufficient capacity internal to the LRZ to achieve any of the seasonal LOLE targets as an island. In the nine zones without sufficient capacity as an island, proxy units of typical size (160 MW) and class average seasonal EFORd were added to the LRZ. When needed, a fraction of the final proxy unit was added to achieve the exact seasonal LOLE target for the LRZ.

LRR UCAP % = (Unforced Capacity + UCAP Adjustment to meet LOLE target – Zonal Coincident Peak Demand)/Zonal Coincident Peak Demand

4. MISO System Planning Reserve Margin Results

4 MISO System Planning Reserve Margin Results

4.1 Planning Year 2023-2024 MISO Planning Reserve Margin Results

For Planning Year 2023-2024, the ratio of MISO capacity to forecasted MISO system peak demand yielded a planning ICAP reserve margin of 15.9 percent and a planning UCAP reserve margin of 7.4 percent for the summer season. Numerous values and calculations went into determining the MISO system PRM ICAP and PRM UCAP (Table 4-1).

MISO Planning Reserve Margin (PRM)	2023/2024 PY Summer	2023/2024 PY Fall	2023/2024 PY Winter	2023/2024 PY Spring	Formula Key
MISO System Peak Demand (MW)	123,711	111,012	103,455	99,113	[A]
Installed Capacity (ICAP) (MW)	144,268	144,992	150,673	145,366	[B]
Unforced Capacity (UCAP) (MW)	133,764	132,911	134,503	130,753	[C]
Firm External Support (ICAP) (MW)	1,731	1,734	1,874	1,803	[D]
Firm External Support (UCAP) (MW)	1,707	1,714	1,857	1,778	[E]
Adjustment to ICAP {1d in 10yr} (MW)	-2,650	-7,100	-6,500	-9,150	[F]
Adjustment to UCAP {1d in 10yr} (MW)	-2,650	-7,100	-6,500	-9,150	[G]
ICAP PRM Requirement (PRMR) (MW)	143,349	139,626	146,047	138,019	[H]=[B]+[D]+[F]
UCAP PRM Requirement (PRMR) (MW)	132,821	127,525	129,860	123,381	[I]=[C]+[E]+[G]
MISO PRM ICAP	**15.9%**	**25.8%**	**41.2%**	**39.3%**	[J]=([H]-[A])/[A]
MISO PRM UCAP	**7.4%**	**14.9%**	**25.5%**	**24.5%**	[K]=([I]-[A])/[A]

Table 4-1: Planning Year 2023-2024 MISO System Planning Reserve Margins

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One MISO Voice Style Guide

4.2 Comparison of PRM Targets Across 10 Years

Figure 4-1 compares the PRM UCAP values over the last 10 Planning Years. The last endpoint of the green line shows the Planning Year 2023-2024 Summer PRM value.

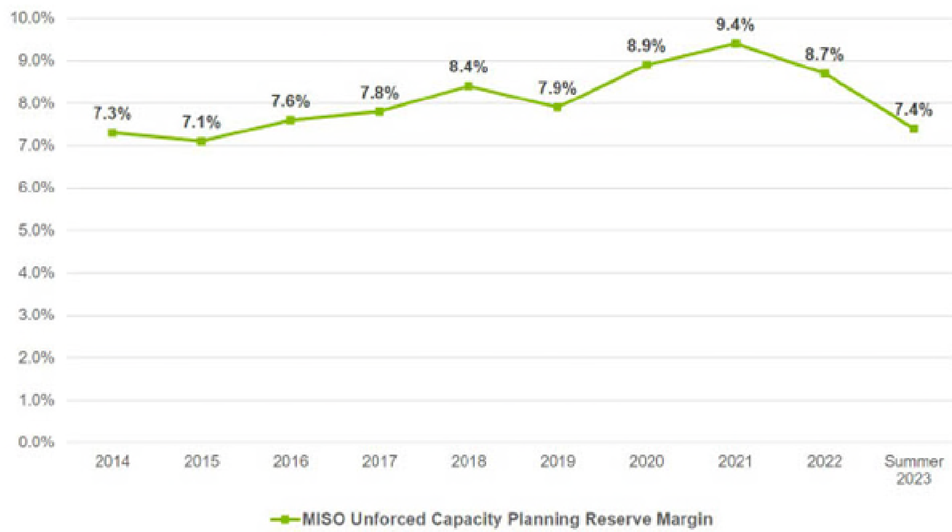

Figure 4-1: Comparison of PRM Targets Across 10 Years

4.3 Future Years 2023 through 2032 Planning Reserve Margins

Beyond the Planning Year 2023-2024 LOLE study analysis, an LOLE analysis will be performed for the four-year-out Planning Year of 2026-2027, as well as for the six-year-out Planning Year of 2028-2029. All other future Planning Years in scope will be derived from interpolation and extrapolation of the three modeled Planning Years.

5. Local Resource Zone Analysis – LRR Results

5 Local Resource Zone Analysis – LRR Results

5.1 Planning Year 2023-2024 Local Resource Zone Analysis

MISO calculated the per-unit LRR of LRZ Seasonal Peak Demand for Planning Year 2023-2024 on a seasonal basis (Table 5-1, Table 5-2, Table 5-3, and Table 5-4). The UCAP values in the seasonal LRR tables reflect the assumed seasonal UCAP within each LRZ, including Border External Resources and Coordinating Owners. The adjustments 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 Seasonal Peak Demand to determine the per-unit LRR UCAP. The Planning Year 2023-2024 per-unit LRR UCAP values will be multiplied by the updated seasonal peak demand forecasts submitted for the 2023-2024 PRA to determine each LRZ's LRR. The zonal LRR LOLE targets have been provided for peak demand timestamps for all 30 weather years modeled in SERVM is shown in Table 5-5. These peak demand timestamps are the result of the SERVM load training process and are not necessarily the actual peaks for each year.

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
PY 2023-2024 Local Reliability Requirements – Summer 2023											
Installed Capacity (ICAP) (MW)	21,839	13,026	11,651	8,734	7,917	17,585	21,512	11,290	24,264	6,449	[A]
Unforced Capacity (UCAP) (MW)	20,843	12,145	11,225	7,986	7,410	15,973	20,476	10,866	21,097	5,743	[B]
Adjustment to UCAP {1d in 10yr} (MW)	-255	2,062	1,583	3,242	2,859	4,844	3,952	403	2,897	1,209	[C]
LRR (UCAP) (MW)	20,588	14,207	12,808	11,228	10,269	20,817	24,428	11,269	23,994	6,952	[D]=[B]+[C]
Peak Demand (MW)	18,077	12,686	9,859	9,263	7,704	17,760	20,855	7,652	20,739	4,521	[E]
LRR UCAP per-unit of LRZ Peak Demand	**113.9%**	**112.0%**	**129.9%**	**121.2%**	**133.3%**	**117.2%**	**117.1%**	**147.3%**	**115.7%**	**153.8%**	[F]=[D]/[E]

Table 5-1: Planning Year 2023-2024 LRZ Local Reliability Requirements for Summer 2023

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
PY 2023-2024 Local Reliability Requirements – Fall 2023											
Installed Capacity (ICAP) (MW)	21,895	13,096	12,134	8,748	8,068	17,659	21,574	11,149	24,245	6,424	[A]
Unforced Capacity (UCAP) (MW)	20,460	12,097	11,545	7,787	7,201	16,014	20,269	10,190	21,787	5,561	[B]
Adjustment to UCAP {1d in 10yr} (MW)	-1,230	1,289	1,046	3,138	2,625	4,170	3,848	28	2,821	1,177	[C]
LRR (UCAP) (MW)	19,230	13,386	12,591	10,925	9,825	20,184	24,117	10,218	24,607	6,738	[D]=[B]+[C]
Peak Demand (MW)	15,093	10,991	8,942	8,713	6,767	16,180	17,933	6,858	19,258	4,162	[E]
LRR UCAP per-unit of LRZ Peak Demand	**127.4%**	**121.8%**	**140.8%**	**125.4%**	**145.2%**	**124.7%**	**134.5%**	**149.0%**	**127.8%**	**161.9%**	[F]=[D]/[E]

Table 5-2: Planning Year 2023-2024 LRZ Local Reliability Requirements for Fall 2023

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
PY 2023-2024 Local Reliability Requirements – Winter 2023-2024											
Installed Capacity (ICAP) (MW)	22,449	13,578	14,291	9,028	8,528	18,244	21,710	11,298	24,921	6,626	[A]
Unforced Capacity (UCAP) (MW)	20,931	12,041	13,353	7,125	7,032	16,480	20,151	9,901	21,775	5,714	[B]
Adjustment to UCAP {1d in 10yr} (MW)	-255	1,536	1,491	3,054	2,692	4,562	1,789	379	2,728	1,138	[C]
LRR (UCAP) (MW)	20,676	13,577	14,844	10,179	9,724	21,042	21,940	10,280	24,503	6,852	[D]=[B]+[C]
Peak Demand (MW)	14,738	9,549	8,025	7,456	6,599	16,173	13,945	6,839	18,523	3,856	[E]
LRR UCAP per-unit of LRZ Peak Demand	140.3%	142.2%	185.0%	136.5%	147.4%	130.1%	157.3%	150.3%	132.3%	177.7%	[F]=[D]/[E]

Table 5-3: Planning Year 2023-2024 LRZ Local Reliability Requirements for Winter 2023-2024

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
PY 2023-2024 Local Reliability Requirements – Spring 2024											
Installed Capacity (ICAP) (MW)	21,224	13,196	12,339	8,776	8,281	18,041	21,224	11,228	24,631	6,427	[A]
Unforced Capacity (UCAP) (MW)	19,769	11,963	11,601	7,265	7,342	16,150	19,638	9,700	21,470	5,856	[B]
Adjustment to UCAP {1d in 10yr} (MW)	-1,330	626	1,147	2,907	2,371	3,615	1,836	152	2,601	726	[C]
LRR (UCAP) (MW)	18,439	12,590	12,748	10,172	9,713	19,765	21,475	9,852	24,071	6,582	[D]=[B]+[C]
Peak Demand (MW)	13,407	9,938	7,856	6,998	6,034	14,977	16,157	6,055	18,310	3,768	[E]
LRR UCAP per-unit of LRZ Peak Demand	137.5%	126.7%	162.3%	145.4%	161.0%	132.0%	132.9%	162.7%	131.5%	174.7%	[F]=[D]/[E]

Table 5-4: Planning Year 2023-2024 LRZ Local Reliability Requirements for Spring 2024

Weather Year Time of Peak Demand (ESTHE)	MISO	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
1992	7/9/92 16:00	8/9/92 17:00	8/10/92 18:00	7/8/92 17:00	7/2/92 15:00	7/2/92 17:00	1/16/92 8:00	7/2/92 16:00	7/16/92 17:00	7/11/92 18:00	7/12/92 17:00
1993	7/27/93 17:00	8/11/93 17:00	8/27/93 14:00	8/22/93 19:00	7/17/93 17:00	7/27/93 16:00	7/25/93 16:00	7/9/93 15:00	7/31/93 17:00	8/14/93 16:00	7/31/93 18:00
1994	7/6/94 15:00	6/14/94 17:00	6/15/94 17:00	7/19/94 17:00	7/5/94 17:00	7/19/94 18:00	1/19/94 6:00	6/18/94 17:00	6/29/94 18:00	8/14/94 17:00	7/5/94 17:00
1995	7/13/95 17:00	7/13/95 18:00	7/13/95 16:00	7/14/95 17:00	7/14/95 17:00	7/13/95 16:00	7/13/95 17:00	7/13/95 17:00	8/17/95 14:00	7/27/95 17:00	7/12/95 15:00
1996	6/29/96 17:00	8/6/96 17:00	6/29/96 17:00	7/18/96 17:00	7/18/96 18:00	7/18/96 17:00	7/19/96 17:00	8/7/96 15:00	7/20/96 15:00	2/5/96 7:00	7/3/96 18:00
1997	7/26/97 16:00	7/16/97 16:00	7/16/97 17:00	7/25/97 18:00	7/18/97 16:00	7/26/97 17:00	7/26/97 16:00	7/16/97 16:00	7/25/97 18:00	8/16/97 16:00	7/25/97 18:00
1998	7/20/98 16:00	7/13/98 16:00	6/25/98 18:00	7/20/98 18:00	7/20/98 18:00	7/19/98 16:00	7/19/98 17:00	6/25/98 18:00	7/6/98 17:00	8/28/98 18:00	8/27/98 15:00
1999	7/30/99 14:00	7/25/99 15:00	7/13/95 16:00	7/30/99 18:00	7/18/99 22:00	7/30/99 17:00	7/26/97 16:00	7/30/99 14:00	7/25/99 17:00	8/14/99 18:00	8/20/99 18:00
2000	8/31/00 16:00	6/8/00 19:00	9/1/00 17:00	8/31/00 16:00	9/1/00 15:00	8/17/00 16:00	9/1/00 15:00	9/1/00 14:00	7/19/00 17:00	8/30/00 16:00	8/30/00 17:00
2001	8/8/01 16:00	8/7/01 16:00	8/9/01 16:00	7/31/01 16:00	7/23/01 17:00	7/23/01 17:00	8/7/01 17:00	8/8/01 16:00	7/11/01 16:00	7/10/01 16:00	7/20/01 17:00
2002	7/3/02 16:00	7/6/02 18:00	8/1/02 15:00	7/20/02 18:00	7/5/02 17:00	8/1/02 16:00	8/3/02 16:00	7/3/02 16:00	7/9/02 17:00	8/2/02 19:00	10/4/02 15:00
2003	8/21/03 16:00	8/24/03 17:00	8/21/03 16:00	7/26/03 18:00	8/21/03 16:00	8/21/03 18:00	8/27/03 17:00	8/21/03 17:00	7/18/03 14:00	8/10/03 16:00	7/17/03 17:00
2004	7/22/04 16:00	6/7/04 17:00	7/22/04 16:00	7/20/04 17:00	7/13/04 17:00	7/13/04 16:00	1/31/04 9:00	7/22/04 16:00	7/14/04 17:00	7/24/04 17:00	7/25/04 15:00
2005	7/24/05 17:00	7/17/05 17:00	7/24/05 16:00	7/25/05 17:00	7/24/05 16:00	7/24/05 18:00	7/25/05 17:00	7/24/05 18:00	8/21/05 18:00	7/25/05 16:00	8/21/05 15:00
2006	7/31/06 17:00	7/31/06 17:00	8/1/06 17:00	7/19/06 18:00	7/31/06 18:00	7/31/06 16:00	7/31/06 16:00	7/31/06 16:00	7/31/93 17:00	8/15/06 18:00	7/16/06 15:00
2007	8/1/07 17:00	7/26/07 15:00	8/2/07 15:00	7/17/07 17:00	8/15/07 18:00	8/15/07 18:00	8/29/07 17:00	7/31/07 18:00	8/17/95 14:00	8/14/07 15:00	8/14/07 15:00

2008	7/16/08 17:00	7/11/08 18:00	7/17/08 17:00	8/3/08 17:00	7/20/08 17:00	7/20/08 16:00	8/23/08 16:00	8/24/08 12:00	8/17/95 14:00	7/20/08 17:00	7/27/08 16:00
2009	6/25/09 16:00	6/22/09 19:00	7/28/09 16:00	7/24/09 18:00	8/9/09 16:00	8/9/09 16:00	1/16/09 8:00	6/25/09 16:00	6/22/09 16:00	7/2/09 16:00	7/2/09 18:00
2010	8/10/10 17:00	8/8/10 18:00	8/20/10 14:00	7/17/10 19:00	7/15/10 15:00	8/3/10 16:00	8/2/91 18:00	9/1/10 17:00	8/17/95 14:00	8/1/10 17:00	8/2/10 17:00
2011	7/20/11 18:00	6/7/11 19:00	7/13/95 16:00	7/20/11 16:00	9/1/11 16:00	8/31/11 16:00	7/26/97 16:00	7/20/11 19:00	7/31/93 17:00	7/2/11 17:00	7/10/11 18:00
2012	7/6/12 17:00	7/6/12 18:00	7/13/95 16:00	7/7/12 16:00	7/7/12 17:00	7/25/12 18:00	7/26/97 16:00	7/6/12 17:00	7/30/12 17:00	6/26/12 16:00	7/3/12 15:00
2013	7/19/13 16:00	7/18/13 19:00	8/27/13 16:00	8/30/13 16:00	9/11/13 16:00	8/31/13 17:00	8/31/13 15:00	7/19/13 14:00	6/27/13 18:00	8/7/13 16:00	8/8/13 17:00
2014	7/22/14 16:00	7/22/14 17:00	7/22/14 16:00	7/22/14 16:00	9/5/14 16:00	7/26/14 15:00	2/7/14 9:00	7/22/14 17:00	7/27/14 17:00	8/23/14 16:00	7/26/14 17:00
2015	7/29/15 16:00	8/14/15 15:00	8/14/15 17:00	7/13/15 15:00	9/3/15 16:00	7/13/15 16:00	7/18/15 17:00	8/2/15 16:00	8/7/15 18:00	8/10/15 16:00	7/30/15 16:00
2016	7/20/16 15:00	7/21/16 17:00	8/10/16 17:00	7/22/16 16:00	9/22/16 16:00	7/23/16 17:00	6/11/16 14:00	8/10/16 14:00	7/20/16 13:00	9/1/16 16:00	7/20/16 15:00
2017	7/20/17 16:00	7/6/17 17:00	6/12/17 14:00	7/21/17 17:00	9/26/17 15:00	7/12/17 15:00	9/26/17 16:00	6/12/17 14:00	7/21/17 15:00	8/19/17 15:00	7/20/17 15:00
2018	6/29/18 15:00	6/29/18 15:00	6/29/18 15:00	5/28/18 14:00	9/5/18 15:00	8/6/18 16:00	9/5/18 16:00	9/5/18 15:00	1/17/18 6:00	1/17/18 6:00	9/19/18 16:00
2019	7/19/19 14:00	7/19/19 18:00	7/19/19 16:00	7/19/19 14:00	9/12/19 16:00	10/1/19 15:00	9/13/19 16:00	7/19/19 13:00	8/13/19 14:00	10/4/19 15:00	10/2/19 16:00
2020	7/9/20 15:00	7/2/20 17:00	8/27/20 14:00	7/8/20 14:00	7/8/20 15:00	7/11/20 15:00	8/25/20 15:00	7/9/20 15:00	7/12/20 15:00	7/11/20 15:00	9/4/20 16:00
2021	8/24/21 15:00	7/27/21 16:00	8/10/21 15:00	7/28/21 16:00	8/27/21 15:00	8/25/21 16:00	8/24/21 16:00	8/24/21 15:00	8/10/21 14:00	8/23/21 16:00	7/29/21 14:00

Table 5-5: Historical Peak Days/Hours by Local Resource Zone

6. Appendix A: Comparison of Planning Year 2022 to 2034

6 Appendix A: Comparison of Planning Year 2022 to 2023

Multiple study sensitivity analyses were performed to compute changes in the PRM target on an UCAP basis, from Planning Year 2022-2023 to Planning Year 2023-2024. These sensitivities included one-off incremental changes of input parameters to quantify how each change affected the PRM result independently. Note the impact of the incremental PRM changes from Planning Year 2022-2023 to Planning Year 2023-2024 in the waterfall chart of Figure A-1. Summer was determined to be the season most comparable to the annual PRM from last year's study. The following subsections provide more details around each of the sensitivities.

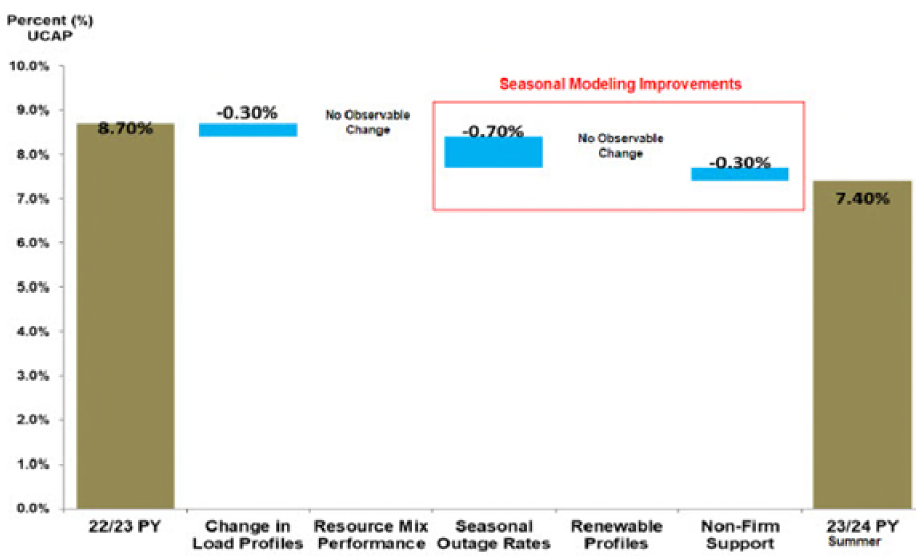

Figure A-1: Waterfall Chart of PY 2022-2023 Annual PRM UCAP to PY 2023-2024 Summer PRM UCAP

6.1 A.1 Waterfall Chart Details

6.1.1 A.1.1 Load

The MISO Coincident Peak Demand increased from the 2021-2022 planning year, which was driven by the updated actual load forecasts submitted by the LSEs. Overall, the magnitude of changes in the load profiles and economic uncertainty resulted in a slight decrease in the PRM.

6.1.2 A.1.2 Units

Changes from 2022-2023 planning year values are due to changes in Generation Verification Test Capacity (GVTC), seasonal EFORd or equivalent forced outage rate demand, new units, retirements, suspensions, and changes in the resource mix. The MISO fleet weighted average forced outage rate decreased from an annual 9.04 percent to a summer value of 8.23 percent from the previous study to this study. A general decrease in unit outage rates lead to a decrease in summer reserve margin. Non-firm support was included in the model which resulted in a slight decrease to the summer PRM.

7. Appendix B: Capacity Import Limit Tier 1 & 2 Source Subsystem Definitions

7 Appendix B: Capacity Import Limit Tier 1 & 2 Source Subsystem Definitions

MISO Local Resource Zone 1

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #
XEL / 600	ITCM / 627	WEC / 295
MP / 608	ALTE / 694	MIUP / 296
SMMPA / 613	WPS / 696	AMMO / 356
GRE / 615	MGE / 697	AMIL / 357
OTP / 620		MPW / 633
MDU / 661		MEC / 635
BEPC-MISO / 663		
DPC / 680		

MISO Local Resource Zone 2

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #
WEC / 295	METC / 218	NIPS / 217
MIUP / 296	XEL / 600	ITCT / 219
ALTE / 694	MP / 608	SMMPA / 613
WPS / 696	DPC / 680	GRE / 615
MGE / 697		OTP / 620
UPPC / 698		ITCM / 627

MISO Local Resource Zone 3

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #	
ITCM / 627	AMMO / 356	DEI / 208	GRE / 615
MPW / 633	AMIL / 357	NIPS / 217	OTP / 620
MEC / 635	XEL / 600	CWLP / 360	ALTE / 694
	SMMPA / 613	SIPC/ 361	WPS / 696
	DPC / 680	GLHB / 362	MGE / 697
		MP / 608	

MISO Local Resource Zone 4

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #	
ITCM / 627	AMMO / 356	DEI / 208	GRE / 615
MPW / 633	AMIL / 357	NIPS / 217	OTP / 620
MEC / 635	XEL / 600	CWLP / 360	ALTE / 694
	SMMPA / 613	SIPC/ 361	WPS / 696
	DPC / 680	GLHB / 362	MGE / 697
		MP / 608	

MISO Local Resource Zone 5

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #	
CWLD / 333	AMIL / 357	DEI / 208	XEL / 600
AMMO / 356	GLHB / 362	NIPS / 217	SMMPA / 613
	ITCM / 627	CWLP / 360	MPW / 633
	MEC / 635	SIPC / 361	DPC / 680

MISO Local Resource Zone 6

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #
HE / 207	METC / 218	ITCT / 219
DEI / 208	AMIL / 357	MIUP / 296
SIGE / 210	SIPC / 361	AMMO / 356
IPL / 216		CWLP / 360
NIPS / 217		GLHB / 362
BREC / 314		ITCM / 627
HMPL / 315		MEC / 635

MISO Local Resource Zone 7

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #
HE / 207	METC / 218	ITCT / 219
DEI / 208	AMIL / 357	MIUP / 296
SIGE / 210	SIPC / 361	AMMO / 356
IPL / 216		CWLP / 360
NIPS / 217		GLHB / 362
BREC / 314		ITCM / 627
HMPL / 315		MEC / 635

MISO Local Resource Zone 8

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #
HE / 207	METC / 218	ITCT / 219
DEI / 208	AMIL / 357	MIUP / 296
SIGE / 210	SIPC / 361	AMMO / 356
IPL / 216		CWLP / 360
NIPS / 217		GLHB / 362
BREC / 314		ITCM / 627
HMPL / 315		MEC / 635

MISO Local Resource Zone 9

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #
LAGN / 332	EES-EMI / 326	Cooperative Energy / 349
EES / 351	EES-EAI / 327	
CLEC / 502		
LAFA / 503		
LEPA / 504		

MISO Local Resource Zone 10

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #
EES-EMI / 326	EES-EAI / 327	LAGN / 332
Cooperative Energy / 349	EES / 351	CLEC / 502
		LAFA / 503

8. Appendix C: Compliance Conformance Table

8 Appendix C: Compliance Conformance Table

Requirements under: Standard BAL-502-RF-03	Response
R1 The Planning Coordinator shall perform and document a Resource Adequacy analysis annually. The Resource Adequacy analysis shall:	The Planning Year 2023-2024 LOLE Study Report is the annual Resource Adequacy Analysis for the peak season of June 2023 through May 2024 and beyond. Analysis of Planning Year 2023-2024 is in Sections 4.1 and 5.1. Analysis of Future Years 2024-2033 is in Section 10.
R1.1 Calculate a planning reserve margin that will result in the sum of the probabilities for loss of Load for the integrated peak hour for all days of each planning year[1] analyzed (per R1.2) being equal to 0.1. (This is comparable to a "one day in 10 year" criterion).	Section 3.5 of this report outlines the utilization of LOLE in the reserve margin determination. "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."
R1.1.1 The utilization of Direct Control Load Management or curtailment of Interruptible Demand shall not contribute to the loss of Load probability.	Section 3.3 of this report. "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."
R1.1.2 The planning reserve margin developed from R1.1 shall be expressed as a percentage of the median forecast peak Net Internal Demand (planning reserve margin).	Section 4.1 of this report. "...the ratio of MISO capacity to forecasted MISO system peak demand yielded a planning ICAP reserve margin..."
R1.2 Be performed or verified separately for each of the following planning years.	Covered in the segmented R1.2 responses below.
R1.2.1 Perform an analysis for Year One.	In Sections 4.1 and 5.1, a full analysis was performed for Planning Year 2023-2024.
R1.2.2 Perform an analysis or verification at a minimum for one year in the 2 through 5 year period and at a minimum one year in the 6 though 10 year period.	Sections 4.3 and 5.1 show a full analysis was performed for future planning years 2025 and 2027.
R1.2.2.1 If the analysis is verified, the verification must be supported by current or past studies for the same planning year.	Analysis was performed.
R1.3 Include the following subject matter and documentation of its use:	Covered in the segmented R1.3 responses below.

R1.3.1 Load forecast characteristics: • Median (50:50) forecast peak load • Load forecast uncertainty (reflects variability in the Load forecast due to weather and regional economic forecasts). • Load diversity. • Seasonal Load variations. • Daily demand modeling assumptions (firm, interruptible). • Contractual arrangements concerning curtailable/Interruptible Demand.	Median forecasted load – In Section 3.3 of this report: "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." Load Forecast Uncertainty – A detailed explanation of the weather and economic uncertainties are given in Sections 3.3 and 3.3.2. Load Diversity/Seasonal Load Variations — In Section 3.3 of this report: "The Planning Year 2023-2024 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 30 years of hourly historical weather data to create 30 different load shapes for each LRZ in order to capture both load diversity and seasonal variations." Demand Modeling Assumptions/Curtailable and Interruptible Demand — All Load Modifying Resources must first meet registration requirements through Module E. As stated in Section 3.2.6: "Each demand response program was modeled individually with a monthly capacity and was limited to the number of times each program can be called upon as well as limited by duration."
R1.3.2 Resource characteristics: • Historic resource performance and any projected changes • Seasonal resource ratings • Modeling assumptions of firm capacity purchases from and sales to entities outside the Planning Coordinator area. • Resource planned outage schedules, deratings, and retirements. • Modeling assumptions of intermittent and energy limited resource such as wind and cogeneration. • Criteria for including planned resource additions in the analysis.	Section 3.2 details how historic performance data and seasonal ratings are gathered, and includes discussion of future units and the modeling assumptions for intermittent capacity resources. A more detailed explanation of firm capacity purchases and sales is in Section 3.4.
R1.3.3 Transmission limitations that prevent the delivery of generation reserves	Annual MTEP deliverability analysis identifies transmission limitations preventing delivery of generation reserves. Additionally, Section 2 of this report details the transfer analysis to capture transmission constraints limiting capacity transfers.
R1.3.3.1 Criteria for including planned Transmission Facility additions in the analysis	Inclusion of the planned transmission addition assumptions is detailed in Section 2.2.3.

R1.3.4 Assistance from other interconnected systems including multi-area assessment considering Transmission limitations into the study area.	Section 3.4 provides the analysis on the treatment of external support assistance and limitations.
R1.4 Consider the following resource availability characteristics and document how and why they were included in the analysis or why they were not included: • Availability and deliverability of fuel. • Common mode outages that affect resource availability. • Environmental or regulatory restrictions of resource availability. • Any other demand (Load) response programs not included in R1.3.1. • Sensitivity to resource outage rates. • Impacts of extreme weather/drought conditions that affect unit availability. • Modeling assumptions for emergency operation procedures used to make reserves available. • Market resources not committed to serving Load (uncommitted resources) within the Planning Coordinator area.	Fuel availability, environmental restrictions, common mode outage and extreme weather conditions are all part of the historical availability performance data that goes into the unit's EFORd statistic. The use of the EFORd values is covered in Section 3.2.1. The use of demand response programs is mentioned in Section 3.2.6. The effects of resource outage characteristics on the reserve margin are outlined in Section 3.7.1 by examining the difference between PRM ICAP and PRM UCAP values.
R1.5 Consider Transmission maintenance outage schedules and document how and why they were included in the Resource Adequacy analysis or why they were not included	Transmission maintenance schedules were not included in the analysis of the transmission system due to the limited availability of reliable long-term maintenance schedules and minimal impact to the results of the analysis. However, Section 2 treats worst-case theoretical outages by Perform First Contingency Total Transfer Capability (FCTTC) analysis for each LRZ, by modeling NERC Category P0 (system intact) and Category P1 (N-1) contingencies.
R1.6 Document that capacity resources are appropriately accounted for in its Resource Adequacy analysis	MISO internal resources are among the quantities documented in the tables provided in Sections 4 and 5.
R1.7 Document that all Load in the Planning Coordinator area is accounted for in its Resource Adequacy analysis	MISO load is among the quantities documented in the tables provided in Sections 4 and 5.
R2 The Planning Coordinator shall annually document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis.	In Sections 4 and 5, the peak load and estimated amount of resources for Planning Years 2023-2024, 2026-2027, and 2028-2029 are shown. This includes the detail for each transmission constrained sub-area.

R2.1 This documentation shall cover each of the years in year one through ten.	Section 10.3 and Tables 10-3, 10-4, 10-5, and 10-6 show the three calculated study years, in-between years estimated by interpolation, and future outyears estimated by extrapolation. Estimated transmission limitations may be determined through a review of the PY 2023-2024 LOLE study transfer analysis shown in Section 2 of this report, along with the results from previous LOLE studies.
R2.2 This documentation shall include the Planning Reserve margin calculated per requirement R1.1 for each of the three years in the analysis.	Covered in Sections 10.1 and 10.2.
R2.3 The documentation as specified per requirement R2.1 and R2.2 shall be publicly posted no later than 30 calendar days prior to the beginning of Year One.	The 2023-2024 LOLE Study Report documentation is posted on November 1 prior to the planning year.
R3 The Planning Coordinator shall identify any gaps between the needed amount of planning reserves defined in Requirement R1, Part 1.1 and the projected planning reserves documented in Requirement R2.	In Sections 4 and 5, the difference between the needed amount and the projected planning reserves for Planning Years 2023-2024, 2026-2027, and 2028-2029 are shown in the adjustments to ICAP and UCAP in Table 4-1, Table 10-1, and Table 10-2.

9. Appendix D: Acronyms List Table

9 Appendix D: Acronyms List Table

CEL	Capacity Export Limit
CIL	Capacity Import Limit
CPNode	Commercial Pricing Node
DF	Distribution Factor
EFORd	Equivalent Forced Outage Rate demand
ELCC	Effective Load Carrying Capability
ERZ	External Resource Zone
EUE	Expected Unserved Energy
FERC	Federal Energy Regulatory Commission
FCITC	First Contingency Incremental Transfer Capability
FCTTC	First Contingency Total Transfer Capability
GADS	Generator Availability Data System
GLT	Generation Limited Transfer
GVTC	Generation Verification Test Capacity
ICAP	Installed Capacity
LBA	Local Balancing Authority
LCR	Local Clearing Requirement
LFE	Load Forecast Error
LFU	Load Forecast Uncertainty
LOLE	Loss of Load Expectation
LOLEWG	Loss of Load Expectation Working Group
LRR	Local Reliability Requirement
LRZ	Local Resource Zones
LSE	Load Serving Entity
MARS	Multi-Area Reliability Simulation
MECT	Module E Capacity Tracking
MISO	Midcontinent Independent System Operator
MOD	Model on Demand
MTEP	MISO Transmission Expansion Plan
MW	Megawatt
MWh	Megawatt hours
NERC	North American Electric Reliability Corp.

PRA	Planning Resource Auction
PRM	Planning Reserve Margin
PRM ICAP	PRM Installed Capacity
PRM UCAP	PRM Unforced Capacity
PRMR	Planning Reserve Margin Requirement
PSS E	Power System Simulator for Engineering
RCF	Reciprocal Coordinating Flowgate
RDS	Redispatch
RPM	Reliability Pricing Model
SERVM	Strategic Energy & Risk Valuation Model
SPS	Special Protection Scheme
TARA	Transmission Adequacy and Reliability Assessment
UCAP	Unforced Capacity
XEFORd	Equivalent forced outage rate demand with adjustment to exclude events outside management control
ZIA	Zonal Import Ability
ZEA	Zonal Export Ability

10. Appendix E: Outyear PRM and LRR Results

10 Appendix E: Outyear PRM and LRR Results

Beyond the prompt Planning Year 2023-2024, LOLE analyses were performed for the four-year-out Planning Year of 2026-2027, and the six-year-out Planning Year of 2028-2029. Tables 10-1 and 10-2 show the capacity and demand values that went into the MISO system seasonal Planning Reserve Margin for outyears four and six, respectively. Tables 10-3, 10-4, 10-5, and 10-6 show the seasonal outyear PRM projections ten years out based on future capacity and demand assumptions. Tables 10-7, 10-8, 10-9, and 10-10 show the MISO zonal seasonal Local Reliability Requirements for outyear four while Tables 10-11, 10-12, 10-13, and 10-14 show the Local Reliability Requirements for outyear six.

10.1 Planning Year 2026-2027 MISO Planning Reserve Margin Results

For Planning Year 2026-2027, the ratio of MISO capacity to forecasted MISO system peak demand yielded a planning ICAP reserve margin of 17.9 percent and a planning UCAP reserve margin of 8.8 percent for the summer season. Numerous values and calculations went into determining the four-year-out MISO system seasonal PRM ICAP and PRM UCAP (Table 10-1).

MISO Planning Reserve Margin (PRM)	2026/2027 PY Summer	2026/2027 PY Fall	2026/2027 PY Winter	2026/2027 PY Spring	Formula Key
MISO System Peak Demand (MW)	125,138	111,950	104,946	99,950	[A]
Installed Capacity (ICAP) (MW)	155,038	152,619	155,210	149,975	[B]
Unforced Capacity (UCAP) (MW)	144,623	139,494	138,423	133,904	[C]
Firm External Support (ICAP) (MW)	1,731	1,734	1,874	1,803	[D]
Firm External Support (UCAP) (MW)	1,707	1,714	1,857	1,778	[E]
Adjustment to ICAP {1d in 10yr} (MW)	-9,200	-11,000	-9,200	-11,850	[F]
Adjustment to UCAP {1d in 10yr} (MW)	-9,200	-11,000	-9,200	-11,850	[G]
ICAP PRM Requirement (PRMR) (MW)	147,569	143,353	147,884	139,928	[H]=[B]+[D]+[F]
UCAP PRM Requirement (PRMR) (MW)	136,130	130,208	131,080	123,832	[I]=[C]+[E]+[G]
MISO PRM ICAP	**17.9%**	**28.1%**	**40.9%**	**40.0%**	[J]=([H]-[A])/[A]
MISO PRM UCAP	**8.8%**	**16.3%**	**24.9%**	**23.9%**	[K]=([I]-[A])/[A]

Table 10-1: Planning Year 2026-2027 MISO System Planning Reserve Margins

10.2 Planning Year 2028-2029 MISO Planning Reserve Margin Results

For Planning Year 2028-2029, the ratio of MISO capacity to forecasted MISO system peak demand yielded a planning ICAP reserve margin of 18.4 percent and a planning UCAP reserve margin of 9.2 percent for the summer season. Numerous values and calculations went into determining the six-year-out MISO system seasonal PRM ICAP and PRM UCAP (Table 10-2).

MISO Planning Reserve Margin (PRM)	2028/2029 PY Summer	2028/2029 PY Fall	2028/2029 PY Winter	2028/2028 PY Spring	Formula Key
MISO System Peak Demand (MW)	125,794	112,548	105,525	100,486	[A]
Installed Capacity (ICAP) (MW)	157,656	155,189	157,826	152,532	[B]
Unforced Capacity (UCAP) (MW)	146,097	141,837	140,816	136,237	[C]
Firm External Support (ICAP) (MW)	1,731	1,734	1,874	1,803	[D]
Firm External Support (UCAP) (MW)	1,707	1,714	1,857	1,778	[E]
Adjustment to ICAP {1d in 10yr} (MW)	-10,400	-14,360	-10,400	-13,165	[F]
Adjustment to UCAP {1d in 10yr} (MW)	-10,400	-14,360	-10,400	-13,165	[G]
ICAP PRM Requirement (PRMR) (MW)	148,987	142,563	149,300	141,170	[H]=[B]+[D]+[F]
UCAP PRM Requirement (PRMR) (MW)	137,404	129,191	132,272	124,850	[I]=[C]+[E]+[G]
MISO PRM ICAP	**18.4%**	**26.7%**	**41.5%**	**40.5%**	[J]=([H]-[A])/[A]
MISO PRM UCAP	**9.2%**	**14.8%**	**25.3%**	**24.2%**	[K]=([I]-[A])/[A]

Table 10-2: Planning Year 2028-2029 MISO System Planning Reserve Margins

10.3 MISO Planning Reserve Margin Outyear Projections

Tables 10-3, 10-4, 10-5, and 10-6 show the outyear seasonal PRM projections. Years one, four, and six were probabilistically modeled. PRM projections in years two, three, and five are the result of interpolation of the years studied and years seven through ten are the resulting extrapolations of the outyear analyses.

Metric	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
PRM ICAP	15.9%	16.6%	17.2%	17.9%	18.2%	18.4%	19.6%	20.1%	20.7%	21.2%
PRM UCAP	7.4%	7.9%	8.3%	8.8%	9.0%	9.2%	10.1%	10.4%	10.8%	11.2%
Demand (GW)	123.7	124.3	124.9	125.5	125.7	125.8	126.9	127.3	127.8	128.2
ICAP (GW)	144.3	150.5	153.0	155.0	155.0	157.7	157.7	157.7	157.7	157.7

Table 10-3: MISO Summer Planning Reserve Margin Outyear Projections

Metric	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
PRM ICAP	25.8%	26.6%	27.3%	28.1%	27.4%	26.7%	27.8%	28.1%	28.3%	28.5%
PRM UCAP	14.9%	15.4%	15.8%	16.3%	15.6%	14.8%	15.4%	15.4%	15.5%	15.5%
Demand (GW)	111.0	111.3	111.7	112.0	112.3	112.5	113.1	113.4	113.8	114.1
ICAP (GW)	144.3	148.8	150.3	152.6	152.6	155.2	155.2	155.2	155.2	155.2

Table 10-4: MISO Fall Planning Reserve Margin Outyear Projections

Metric	23-24	24-25	25-26	26-27	27-28	28-29	29-30	30-31	31-32	32-33
PRM ICAP	41.2%	41.1%	41.0%	40.9%	41.2%	41.5%	41.4%	41.5%	41.5%	41.5%
PRM UCAP	25.5%	25.3%	25.1%	24.9%	25.1%	25.3%	25.0%	25.0%	24.9%	24.8%
Demand (GW)	103.5	104.0	104.4	104.9	105.2	105.5	106.4	106.8	107.2	107.6
ICAP (GW)	150.7	154.0	154.7	155.2	155.2	157.8	157.8	157.8	157.8	157.8

Table 10-5: MISO Winter Planning Reserve Margin Outyear Projections

Metric	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
PRM ICAP	39.3%	39.5%	39.8%	40.0%	40.3%	40.5%	41.0%	41.2%	41.4%	41.7%
PRM UCAP	24.5%	24.3%	24.1%	23.9%	24.1%	24.2%	23.9%	23.8%	23.8%	23.7%
Demand (GW)	99.1	99.4	99.7	100.0	100.3	100.5	101.1	101.4	101.7	101.9
ICAP (GW)	145.4	148.9	149.9	150.0	150.0	152.5	152.5	152.5	152.5	152.5

Table 10-6: MISO Spring Planning Reserve Margin Outyear Projections

10.4 Planning Year 2026-2027 MISO Local Reliability Requirement Results

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
PY 2026-2027 Local Reliability Requirements – Summer 2026											
Installed Capacity (ICAP) (MW)	22,350	15,251	12,350	9,629	9,494	19,595	21,761	12,368	25,425	6,814	[A]
Unforced Capacity (UCAP) (MW)	21,349	14,232	11,903	8,881	8,690	17,946	20,388	11,944	22,182	6,108	[B]
Adjustment to UCAP {1d in 10yr} (MW)	-317	48	2,369	3,060	2,235	3,935	4,012	278	2,230	1,113	[C]
LRR (UCAP) (MW)	21,032	14,280	14,272	11,942	10,925	21,881	24,400	12,222	24,412	7,221	[D]=[B]+[C]
Peak Demand (MW)	18,622	13,121	9,976	9,384	8,121	18,517	21,003	7,880	22,036	4,802	[E]
LRR UCAP per-unit of LRZ Peak Demand	**112.9%**	**108.8%**	**143.1%**	**127.3%**	**134.5%**	**118.2%**	**116.2%**	**155.1%**	**110.8%**	**150.4%**	[F]=[D]/[E]

Table 10-7: Planning Year 2026-2027 LRZ Local Reliability Requirements for Summer 2026

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
PY 2026-2027 Local Reliability Requirements – Fall 2026											
Installed Capacity (ICAP) (MW)	22,303	14,924	12,708	9,267	9,296	19,057	21,756	11,773	24,952	6,584	[A]
Unforced Capacity (UCAP) (MW)	20,862	13,680	12,104	8,306	8,124	17,356	20,120	10,815	22,406	5,721	[B]
Adjustment to UCAP {1d in 10yr} (MW)	-1,150	-608	1,303	2,861	2,032	3,138	3,906	-296	2,172	1,083	[C]
LRR (UCAP) (MW)	19,712	13,072	13,407	11,167	10,156	20,495	24,026	10,519	24,577	6,805	[D]=[B]+[C]
Peak Demand (MW)	18,622	13,121	9,976	9,384	8,121	18,517	21,003	7,880	22,036	4,802	[E]
LRR UCAP per-unit of LRZ Peak Demand	**105.9%**	**99.6%**	**134.4%**	**119.0%**	**125.1%**	**110.7%**	**114.4%**	**133.5%**	**111.5%**	**141.7%**	[F]=[D]/[E]

Table 10-8: Planning Year 2026-2027 LRZ Local Reliability Requirements for Fall 2026

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
PY 2026-2027 Local Reliability Requirements – Winter 2026-2027											
Installed Capacity (ICAP) (MW)	22,576	15,148	14,708	9,272	9,380	19,027	21,721	11,471	25,252	6,654	[A]
Unforced Capacity (UCAP) (MW)	21,048	13,357	13,748	7,369	7,698	17,193	20,149	10,074	22,044	5,742	[B]
Adjustment to UCAP {1d in 10yr} (MW)	-317	45	2,231	2,882	2,105	3,706	1,915	262	2,100	1,048	[C]
LRR (UCAP) (MW)	20,731	13,402	15,980	10,251	9,803	20,899	22,064	10,336	24,145	6,790	[D]=[B]+[C]
Peak Demand (MW)	18,622	13,121	9,976	9,384	8,121	18,517	21,003	7,880	22,036	4,802	[E]
LRR UCAP per-unit of LRZ Peak Demand	**111.3%**	**102.1%**	**160.2%**	**109.2%**	**120.7%**	**112.9%**	**105.0%**	**131.2%**	**109.6%**	**141.4%**	[F]=[D]/[E]

Table 10-9: Planning Year 2026-2027 LRZ Local Reliability Requirements for Winter 2026-2027

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
PY 2026-2027 Local Reliability Requirements – Spring 2027											
Installed Capacity (ICAP) (MW)	21,384	14,796	12,729	9,040	9,196	18,876	21,235	11,457	24,783	6,480	[A]
Unforced Capacity (UCAP) (MW)	19,924	13,355	11,985	7,528	7,922	16,950	18,781	9,929	21,622	5,908	[B]
Adjustment to UCAP {1d in 10yr} (MW)	-1,085	-700	1,023	2,827	1,980	2,719	2,722	53	1,994	647	[C]
LRR (UCAP) (MW)	18,839	12,655	13,008	10,356	9,902	19,669	21,503	9,982	23,616	6,556	[D]=[B]+[C]
Peak Demand (MW)	18,622	13,121	9,976	9,384	8,121	18,517	21,003	7,880	22,036	4,802	[E]
LRR UCAP per-unit of LRZ Peak Demand	**101.2%**	**96.5%**	**130.4%**	**110.4%**	**121.9%**	**106.2%**	**102.4%**	**126.7%**	**107.2%**	**136.5%**	[F]=[D]/[E]

Table 10-10: Planning Year 2026-2027 LRZ Local Reliability Requirements for Spring 2027

10.5 Planning Year 2028-2029 MISO Local Reliability Requirement Results

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
PY 2028-2029 Local Reliability Requirements – Summer 2028											
Installed Capacity (ICAP) (MW)	22,350	16,418	12,350	9,629	9,494	19,595	23,212	12,368	25,425	6,814	[A]
Unforced Capacity (UCAP) (MW)	21,349	15,324	11,903	8,881	8,690	17,946	21,769	11,944	22,182	6,108	[B]
Adjustment to UCAP {1d in 10yr} (MW)	-232	-463	1,981	3,089	2,294	4,020	2,628	39	2,283	1,132	[C]
LRR (UCAP) (MW)	21,117	14,861	13,884	11,970	10,983	21,967	24,398	11,983	24,465	7,240	[D]=[B]+[C]
Peak Demand (MW)	18,177	13,132	10,172	9,485	8,001	18,099	20,705	7,725	21,417	4,716	[E]
LRR UCAP per-unit of LRZ Peak Demand	**116.2%**	**113.2%**	**136.5%**	**126.2%**	**137.3%**	**121.4%**	**117.8%**	**155.1%**	**114.2%**	**153.5%**	[F]=[D]/[E]

Table 10-11: Planning Year 2028-2029 LRZ Local Reliability Requirements for Summer 2028

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
PY 2028-2029 Local Reliability Requirements – Fall 2028											
Installed Capacity (ICAP) (MW)	22,303	16,090	12,708	9,267	9,296	19,057	23,160	11,773	24,952	6,584	[A]
Unforced Capacity (UCAP) (MW)	20,862	14,727	12,104	8,306	8,124	17,356	21,415	10,815	22,406	5,721	[B]
Adjustment to UCAP {1d in 10yr} (MW)	-1,035	-1,100	1,275	2,903	2,078	3,260	2,559	-281	2,223	1,102	[C]
LRR (UCAP) (MW)	19,827	13,627	13,379	11,209	10,202	20,616	23,975	10,534	24,629	6,823	[D]=[B]+[C]
Peak Demand (MW)	18,177	13,132	10,172	9,485	8,001	18,099	20,705	7,725	21,417	4,716	[E]
LRR UCAP per-unit of LRZ Peak Demand	**109.1%**	**103.8%**	**131.5%**	**118.2%**	**127.5%**	**113.9%**	**115.8%**	**136.4%**	**115.0%**	**144.7%**	[F]=[D]/[E]

Table 10-12: Planning Year 2028-2029 LRZ Local Reliability Requirements for Fall 2028

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
PY 2028-2029 Local Reliability Requirements – Winter 2028-2029											
Installed Capacity (ICAP) (MW)	22,576	16,326	14,708	9,272	9,380	19,027	23,159	11,471	25,252	6,654	[A]
Unforced Capacity (UCAP) (MW)	21,048	14,468	13,748	7,369	7,698	17,193	21,430	10,074	22,044	5,742	[B]
Adjustment to UCAP {1d in 10yr} (MW)	-232	-463	1,866	2,909	2,160	3,786	1,301	289	2,150	1,066	[C]
LRR (UCAP) (MW)	20,816	14,005	15,614	10,278	9,858	20,980	22,731	10,363	24,194	6,808	[D]=[B]+[C]
Peak Demand (MW)	18,177	13,132	10,172	9,485	8,001	18,099	20,705	7,725	21,417	4,716	[E]
LRR UCAP per-unit of LRZ Peak Demand	**114.5%**	**106.6%**	**153.5%**	**108.4%**	**123.2%**	**115.9%**	**109.8%**	**134.2%**	**113.0%**	**144.4%**	[F]=[D]/[E]

Table 10-13: Planning Year 2028-2029 LRZ Local Reliability Requirements for Winter 2028-2029

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
PY 2028-2029 Local Reliability Requirements – Spring 2029											
Installed Capacity (ICAP) (MW)	21,384	15,965	12,729	9,040	9,196	18,876	22,622	11,457	24,783	6,480	[A]
Unforced Capacity (UCAP) (MW)	19,924	14,365	11,985	7,528	7,922	16,950	20,104	9,929	21,622	5,908	[B]
Adjustment to UCAP {1d in 10yr} (MW)	-1,030	-1,072	1,471	2,932	1,995	2,970	1,774	50	2,266	652	[C]
LRR (UCAP) (MW)	18,894	13,293	13,456	10,460	9,917	19,920	21,878	9,979	23,887	6,560	[D]=[B]+[C]
Peak Demand (MW)	18,177	13,132	10,172	9,485	8,001	18,099	20,705	7,725	21,417	4,716	[E]
LRR UCAP per-unit of LRZ Peak Demand	**103.9%**	**101.2%**	**132.3%**	**110.3%**	**123.9%**	**110.1%**	**105.7%**	**129.2%**	**111.5%**	**139.1%**	[F]=[D]/[E]

Table 10-14: Planning Year 2028-2029 LRZ Local Reliability Requirements for Spring 2029

11. Appendix F: Outyear CIL/CEL Results

11 Appendix F: Outyear CIL/CEL Results

MISO will not be conducting the outyear CIL/CEL study as part of the PY 2023-2024 LOLE study report. This has been communicated to stakeholders at the February 2023 RASC: https://cdn.misoenergy.org/20230228-0301%20RASC%20Item%2004d%20Out-Year%202027-28%20CIL-CEL%20Study%20Update627986.pdf

The usefulness and value created by the outyear CIL/CEL study is being evaluated by MISO. Any updates or changes to the outyear CIL/CEL study going forward will be communicated through the RASC and/or LOLEWG.

Appendix E

Technical Appendix

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Table E-1

Fuel Cost Inputs for EnCompass Model				
	Wilson Coal	Natural Gas	Green Station	Big Rivers NGCC
Year	Delivered Cost	Henry Hub	Delivered Cost	Delivered Cost
	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu
2023	[redacted]	[redacted]	[redacted]	[redacted]
2024	[redacted]	[redacted]	[redacted]	[redacted]
2025	[redacted]	[redacted]	[redacted]	[redacted]
2026	[redacted]	[redacted]	[redacted]	[redacted]
2027	[redacted]	[redacted]	[redacted]	[redacted]
2028	[redacted]	[redacted]	[redacted]	[redacted]
2029	[redacted]	[redacted]	[redacted]	[redacted]
2030	[redacted]	[redacted]	[redacted]	[redacted]
2031	[redacted]	[redacted]	[redacted]	[redacted]
2032	[redacted]	[redacted]	[redacted]	[redacted]
2033	[redacted]	[redacted]	[redacted]	[redacted]
2034	[redacted]	[redacted]	[redacted]	[redacted]
2035	[redacted]	[redacted]	[redacted]	[redacted]
2036	[redacted]	[redacted]	[redacted]	[redacted]
2037	[redacted]	[redacted]	[redacted]	[redacted]
2038	[redacted]	[redacted]	[redacted]	[redacted]
2039	[redacted]	[redacted]	[redacted]	[redacted]
2040	[redacted]	[redacted]	[redacted]	[redacted]
2041	[redacted]	[redacted]	[redacted]	[redacted]
2042	[redacted]	[redacted]	[redacted]	[redacted]
2043	[redacted]	[redacted]	[redacted]	[redacted]
2044	[redacted]	[redacted]	[redacted]	[redacted]
2045	[redacted]	[redacted]	[redacted]	[redacted]
2046	[redacted]	[redacted]	[redacted]	[redacted]
2047	[redacted]	[redacted]	[redacted]	[redacted]
2048	[redacted]	[redacted]	[redacted]	[redacted]
2049	[redacted]	[redacted]	[redacted]	[redacted]
2050	[redacted]	[redacted]	[redacted]	[redacted]

[redacted]

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Technical Appendix

Table E -2
Production Costs Base Real and Nominal $

* [redacted]	Operating Performance-KPIs	2024	2025	2026	2027	2028
KPIs	Net Capacity (Summer), MW	[redacted]				
	Net Capacity (Winter), MW	[redacted]				
	Net Generation (GWh)	[redacted]				
	Production Cost (Annual Inflation)	[redacted]				
Production Cost (Nominal)	Total Production Cost ($M)	[redacted]				
	Total Production Cost (cents/kWh)	[redacted]				
	Total Variable Cost ($M)	[redacted]				
	Total Variable Cost (cents/kWh)	[redacted]				
	Production Cost (2023$)	[redacted]				
Production Cost (Real)	Total Production Cost ($M)	[redacted]				
	Total Production Cost (cents/kWh)	[redacted]				
	Total Variable Cost ($M)	[redacted]				
	Total Variable Cost (cents/kWh)	[redacted]				
	Cost to Serve Load (Annual Inflation)	[redacted]				
Nominal	Cost to Serve Load (Annual Inflation)	[redacted]				
	Cost to Serve Load (cents/kWh)	[redacted]				
Real 2023$	Total Variable Cost ($M)	[redacted]				
	Total Variable Cost (cents/kWh)	[redacted]				

Cost to serve load Calc	2024	2025	2026	2027	2028
Load Market Cost ($M)	[redacted]				
Market Revenue ($M)	[redacted]				
Net Market ($M)	[redacted]				

* General Escalation Rate

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Technical Appendix

Table E -2
Production Costs Base Real and Nominal $

* [redacted]	Operating Performance-KPIs	2029	2030	2031	2032
KPIs	Net Capacity (Summer), MW	[redacted]			
	Net Capacity (Winter), MW				
	Net Generation (GWh)				
	Production Cost (Annual Inflation)				
Production Cost (Nominal)	Total Production Cost ($M)				
	Total Production Cost (cents/kWh)				
	Total Variable Cost ($M)				
	Total Variable Cost (cents/kWh)				
	Production Cost (2023$)				
Production Cost (Real)	Total Production Cost ($M)				
	Total Production Cost (cents/kWh)				
	Total Variable Cost ($M)				
	Total Variable Cost (cents/kWh)				
	Cost to Serve Load (Annual Inflation)				
Nominal	Cost to Serve Load (Annual Inflation)				
	Cost to Serve Load (cents/kWh)				
Real 2023$	Total Variable Cost ($M)				
	Total Variable Cost (cents/kWh)				

Cost to serve load Calc	2029	2030	2031	2032
Load Market Cost ($M)	[redacted]			
Market Revenue ($M)				
Net Market ($M)				

* General Escalation Rate

Appendix E -
Technical Appendix

Table E -2
Production Costs Base Real and Nominal $

* [redacted]	**Operating Performance-KPIs**	**2033**	**2034**	**2035**	**2036**
KPIs	Net Capacity (Summer), MW	[redacted]	[redacted]	[redacted]	[redacted]
	Net Capacity (Winter), MW	[redacted]	[redacted]	[redacted]	[redacted]
	Net Generation (GWh)	[redacted]	[redacted]	[redacted]	[redacted]
	Production Cost (Annual Inflation)	[redacted]	[redacted]	[redacted]	[redacted]
Production Cost (Nominal)	Total Production Cost ($M)	[redacted]	[redacted]	[redacted]	[redacted]
	Total Production Cost (cents/kWh)	[redacted]	[redacted]	[redacted]	[redacted]
	Total Variable Cost ($M)	[redacted]	[redacted]	[redacted]	[redacted]
	Total Variable Cost (cents/kWh)	[redacted]	[redacted]	[redacted]	[redacted]
	Production Cost (2023$)	[redacted]	[redacted]	[redacted]	[redacted]
Production Cost (Real)	Total Production Cost ($M)	[redacted]	[redacted]	[redacted]	[redacted]
	Total Production Cost (cents/kWh)	[redacted]	[redacted]	[redacted]	[redacted]
	Total Variable Cost ($M)	[redacted]	[redacted]	[redacted]	[redacted]
	Total Variable Cost (cents/kWh)	[redacted]	[redacted]	[redacted]	[redacted]
	Cost to Serve Load (Annual Inflation)	[redacted]	[redacted]	[redacted]	[redacted]
Nominal	Cost to Serve Load (Annual Inflation)	[redacted]	[redacted]	[redacted]	[redacted]
	Cost to Serve Load (cents/kWh)	[redacted]	[redacted]	[redacted]	[redacted]
Real 2023$	Total Variable Cost ($M)	[redacted]	[redacted]	[redacted]	[redacted]
	Total Variable Cost (cents/kWh)	[redacted]	[redacted]	[redacted]	[redacted]

Cost to serve load Calc	2033	2034	2035	2036
Load Market Cost ($M)	[redacted]	[redacted]	[redacted]	[redacted]
Market Revenue ($M)	[redacted]	[redacted]	[redacted]	[redacted]
Net Market ($M)	[redacted]	[redacted]	[redacted]	[redacted]

* General Escalation Rate

Appendix E -
Technical Appendix

Table E -2
Production Costs Base Real and Nominal $

* [redacted]	Operating Performance-KPIs	2037	2038
KPIs	Net Capacity (Summer), MW	[redacted]	[redacted]
	Net Capacity (Winter), MW	[redacted]	[redacted]
	Net Generation (GWh)	[redacted]	[redacted]
	Production Cost (Annual Inflation)	[redacted]	[redacted]
Production Cost (Nominal)	Total Production Cost ($M)	[redacted]	[redacted]
	Total Production Cost (cents/kWh)	[redacted]	[redacted]
	Total Variable Cost ($M)	[redacted]	[redacted]
	Total Variable Cost (cents/kWh)	[redacted]	[redacted]
	Production Cost (2023$)	[redacted]	[redacted]
Production Cost (Real)	Total Production Cost ($M)	[redacted]	[redacted]
	Total Production Cost (cents/kWh)	[redacted]	[redacted]
	Total Variable Cost ($M)	[redacted]	[redacted]
	Total Variable Cost (cents/kWh)	[redacted]	[redacted]
	Cost to Serve Load (Annual Inflation)	[redacted]	[redacted]
Nominal	Cost to Serve Load (Annual Inflation)	[redacted]	[redacted]
	Cost to Serve Load (cents/kWh)	[redacted]	[redacted]
Real 2023$	Total Variable Cost ($M)	[redacted]	[redacted]
	Total Variable Cost (cents/kWh)	[redacted]	[redacted]

Cost to serve load Calc	2037	2038
Load Market Cost ($M)	[redacted]	[redacted]
Market Revenue ($M)	[redacted]	[redacted]
Net Market ($M)	[redacted]	[redacted]

* General Escalation Rate

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Table E -3
Base and Alternative Portfolio Revenue Requirements

* [redacted]	Revenue Requirement ($M)	2024	2025	2026	2027	2028	2029
Base Portfolio (Base)	Annual Inflation	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Real 2023$	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Alt No. 1 (S1)	Annual Inflation	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Real 2023$	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Aggressive Carbon Reduction Portfolio (S2)	Annual Inflation	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Real 2023$	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

* General Escalation Rate

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Table E -3
Base and Alternative Portfolio Revenue Requirem

* [redacted]	Revenue Requirement ($M)	2030	2031	2032	2033	2034	2035
Base Portfolio (Base)	Annual Inflation	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Real 2023$	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Alt No. 1 (S1)	Annual Inflation	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Real 2023$	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Aggressive Carbon Reduction Portfolio (S2)	Annual Inflation	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Real 2023$	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

* General Escalation Rate

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Table E -3
Base and Alternative Portfolio Revenue Requirem

* [redacted]	Revenue Requirement ($M)	2036	2037	2038
Base Portfolio (Base)	Annual Inflation	[redacted]	[redacted]	[redacted]
	Real 2023$	[redacted]	[redacted]	[redacted]
Alt No. 1 (S1)	Annual Inflation	[redacted]	[redacted]	[redacted]
	Real 2023$	[redacted]	[redacted]	[redacted]
Aggressive Carbon Reduction Portfolio (S2)	Annual Inflation	[redacted]	[redacted]	[redacted]
	Real 2023$	[redacted]	[redacted]	[redacted]

* General Escalation Rate

Appendix F

Cross Reference to 807 KAR 5:058

Appendix F
Cross-Reference to 807 KAR 5:058

Citation	Integrated Resource Plan Regulation	2023 IRP Reference *(Where Applicable)*
807 KAR 5:058 Section 1 (1)	General Provisions. This administrative regulation shall apply to electric utilities under commission jurisdiction except a distribution company with less than $10,000,000 annual revenue or a distribution cooperative organized under KRS Chapter 279.	Noted
807 KAR 5:058 Section 1 (2)	Each electric utility shall file triennially with the commission an integrated resource plan. The plan shall include historical and projected demand, resource, and financial data, and other operating performance and system information, and shall discuss the facts, assumptions, and conclusions, upon which the plan is based and the actions it proposes.	Noted
807 KAR 5:058 Section 1 (3)	Each electric utility shall file ten (10) bound copies and one (1) unbound, reproducible copy of its integrated resource plan with the commission	Big Rivers has elected to follow the electronic filing procedures, and will electronically file the IRP with the Commission
807 KAR 5:058 Section 2 (1)	Filing Schedule. Each electric utility shall file its integrated resource plan according to a staggered schedule which provides for the filing of integrated resource plans one (1) every six (6) months beginning nine (9) months from the effective date of this administrative regulation.	Noted
807 KAR 5:058 Section 2 (1) (a)	The integrated resource plans shall be filed at the specified times following the effective date of this administrative regulation:	
	1. Kentucky Utilities Company shall file nine (9) months from the effective date;	
	2. Kentucky Power Company shall file fifteen (15) months from the effective date;	
	3. East Kentucky Power Cooperative, Inc. shall file twenty-one (21) months from the effective date;	
	4. The Union Light, Heat & Power Company shall file twenty-seven (27) months from the effective date;	
	5. Big Rivers Electric Corporation shall file thirty-three (33) months from the effective date; and	Noted
	6. Louisville Gas & Electric Company shall file thirty-nine (39) months from the effective date.	
	The schedule shall provide at such time as all electric utilities have filed integrated resource plans, the sequence shall repeat.	

Appendix F
Cross-Reference to 807 KAR 5:058

Citation	Integrated Resource Plan Regulation	2023 IRP Reference *(Where Applicable)*
807 KAR 5:058 Section 2 (1) (c)	The schedule shall remain in effect until changed by the commission on its own motion or on motion of one (1) or more electric utilities for good cause shown. Good cause may include a change in a utility's financial or resource conditions.	Noted
807 KAR 5:058 Section 2 (1) (d)	If any filing date falls on a weekend or holiday, the plan shall be submitted on the first business day following the scheduled filing date.	Noted
807 KAR 5:058 Section 2 (2)	Immediately upon filing of an integrated resource plan, each utility shall provide notice to intervenors in its last integrated resource plan review proceeding, that its plan has been filed and is available from the utility upon request.	Big Rivers will provide notice as required
807 KAR 5:058 Section 2 (3)	Upon receipt of a utility's integrated resource plan, the commission shall establish a review schedule which may include interrogatories, comments, informal conferences, and staff reports.	Noted
807 KAR 5:058 Section 3	Waiver. A utility may file a motion requesting a waiver of specific provisions of this administrative regulation. Any request shall be made no later than ninety (90) days prior to the date established for filing the integrated resource plan. The commission shall rule on the request within thirty (30) days. The motion shall clearly identify the provision from which the utility seeks a waiver and provide justification for the requested relief which shall include an estimate of costs and benefits of compliance with the specific provision. Notice shall be given in the manner provided in Section 2(2) of this administrative regulation.	Noted
807 KAR 5:058 Section 4 (1)	Format. The integrated resource plan shall be clearly and concisely organized so that it is evident to the commission that the utility has complied with reporting requirements described in subsequent sections.	Noted

Appendix F
Cross-Reference to 807 KAR 5:058

Citation	Integrated Resource Plan Regulation	2023 IRP Reference *(Where Applicable)*
807 KAR 5:058 Section 4 (2)	Each plan filed shall identify the individuals responsible for its preparation, who shall be available to respond to inquiries during the commission's review of the plan.	Section 2.1 Overview, Table 2.1(a)
807 KAR 5:058 Section 5 (1)	Plan Summary. The plan shall contain a summary which discusses the utility's projected load growth and the resources planned to meet that growth. The summary shall include at a minimum: Description of the utility, its customers, service territory, current facilities, and planning objectives	Chapter 2 IRP Summary
807 KAR 5:058 Section 5 (2)	Description of models, methods, data, and key assumptions used to develop the results contained in the plan	Chapter 4 Load Forecast, Chapter 5 Demand-Side Management, Chapter 7 Electric Integration Analysis, and Technical Appendices A Long Term Load Forecast, B Demand-Side Management Potential Study, and Appendix E Technical Appendix
807 KAR 5:058 Section 5 (3)	Summary of forecasts of energy and peak demand, and key economic and demographic assumptions or projections underlying these forecasts	Chapter 4 Load Forecast, Appendix A Long Term Load Forecast Report
807 KAR 5:058 Section 5 (4)	Summary of the utility's planned resource acquisitions including improvements in operating efficiency of existing facilities, demand-side programs, nonutility sources of generation, new power plants, transmission improvements, bulk power purchases and sales, and interconnections with other utilities	Section 10.1 Action Plan Detail

Appendix F
Cross-Reference to 807 KAR 5:058

Citation	Integrated Resource Plan Regulation	2023 IRP Reference *(Where Applicable)*
807 KAR 5:058 Section 5 (5)	Steps to be taken during the next three (3) years to implement the plan	Section 10.1 Action Plan Detail
807 KAR 5:058 Section 5 (6)	Discussion of key issues or uncertainties that could affect successful implementation of the plan.	Chapter 1 Executive Summary, Section 7.4.4 Summary Evaluation
807 KAR 5:058 Section 6	Significant Changes. All integrated resource plans, shall have a summary of significant changes since the plan most recently filed. This summary shall describe, in narrative and tabular form, changes in load forecasts, resource plans, assumptions, or methodologies from the previous plan. Where appropriate, the utility may also use graphic displays to illustrate changes.	Chapter 3 Developments and Changes Since 2020 IRP

Appendix F
Cross-Reference to 807 KAR 5:058

Citation	Integrated Resource Plan Regulation	2023 IRP Reference *(Where Applicable)*
807 KAR 5:058 Section 7 (1) (a - g)	Load Forecasts. The plan shall include historical and forecasted information regarding loads. The information shall be provided for the total system and, where available, disaggregated by the following customer classes:	
	(a) Residential heating;	n/a
	(b) Residential non-heating;	n/a
	(c) Total residential (total of paragraphs (a) and (b) of this subsection);	Appendix A Long Term Load Forecast Residential Class Section
	(d) Commercial;	Appendix A Long Term Load Forecast Commercial and Industrial Class Section
	(e) Industrial;	Appendix A Long Term Load Forecast Commercial and Industrial Class Section
	(f) Sales for resale;	Appendix A Long Term Load Forecast Energy Forecast Results Section
	(g) Utility use and other.	Appendix A Long Term Load Forecast Energy Forecast Results Section
	The utility shall also provide data at any greater level of disaggregation available.	Appendix A Long Term Load Forecast Report

Appendix F
Cross-Reference to 807 KAR 5:058

Citation	Integrated Resource Plan Regulation	2023 IRP Reference *(Where Applicable)*
807 KAR 5:058 Section 7 (2)	The utility shall provide the following historical information for the base year, which shall be the most recent calendar year for which actual energy sales and system peak demand data are available, and the four (4) years preceding the base year:	
807 KAR 5:058 Section 7 (2) (a)	Average annual number of customers by class as defined in subsection (1) of this section;	Appendix A Energy Forecast Results Section
807 KAR 5:058 Section 7 (2) (b)	Recorded and weather-normalized annual energy sales and generation for the system, and sales disaggregated by class as defined in subsection (1) of this section	Appendix A Weather Normalized Values Section
807 KAR 5:058 Section 7 (2) (c)	Recorded and weather-normalized coincident peak demand in summer and winter for the system	Appendix A Weather Normalized Values Section
807 KAR 5:058 Section 7 (2) (d)	Total energy sales and coincident peak demand to retail and wholesale customers for which the utility has firm, contractual commitments	Appendix A Non-Member Energy Sales Section and Non-Coincident Peak Demand Section
807 KAR 5:058 Section 7 (2) (e)	Total energy sales and coincident peak demand to retail and wholesale customers for which service is provided under an interruptible or curtailable contract or tariff or under some other nonfirm basis	Section 5.5 Market Potential - Demand Response
807 KAR 5:058 Section 7 (2) (f)	Annual energy losses for the system	Section 4.4 Energy

Appendix F
Cross-Reference to 807 KAR 5:058

Citation	Integrated Resource Plan Regulation	2023 IRP Reference *(Where Applicable)*
807 KAR 5:058 Section 7 (2) (g)	Identification and description of existing demand-side programs and an estimate of their impact on utility sales and coincident peak demands including utility or government sponsored conservation and load management programs	Chapter 5 Demand Side Management and Appendix B Demand-Side Management Potential Study
807 KAR 5:058 Section 7 (2) (h)	Any other data or exhibits, such as load duration curves or average energy usage per customer, which illustrate historical changes in load or load characteristics.	Appendix A Long Term Load Forecast Report Appendix
807 KAR 5:058 Section 7 (3)	For each of the fifteen (15) years succeeding the base year, the utility shall provide a base load forecast it considers most likely to occur and, to the extent available, alternate forecasts representing lower and upper ranges of expected future growth of the load on its system. Forecasts shall not include load impacts of additional, future demand-side programs or customer generation included as part of planned resource acquisitions estimated separately and reported in Section 8(4) of this administrative regulation. Forecasts shall include the utility's estimates of existing and continuing demand-side programs as described in subsection (5) of this section.	Appendix A Long Term Load Forecast Energy Forecast Results Section, Peak Demand Section, and Alternative System Forecasts and Uncertainty Analysis Section
807 KAR 5:058 Section 7 (4) (a)	Annual energy sales and generation for the system and sales disaggregated by class as defined in subsection (1) of this section	Appendix A Long Term Load Forecast Energy Forecast Results Section
807 KAR 5:058 Section 7 (4) (b)	Summer and winter coincident peak demand for the system	Section 4.3 Non-Coincident Peak and Appendix A Peak Demand Section, Tracking Analysis Section

Appendix F
Cross-Reference to 807 KAR 5:058

Citation	Integrated Resource Plan Regulation	2023 IRP Reference *(Where Applicable)*
807 KAR 5:058 Section 7 (4) (c)	If available for the first two (2) years of the forecast, monthly forecasts of energy sales and generation for the system and disaggregated by class as defined in subsection (1) of this section and system peak demand	Appendix A Long Term Load Forecast Report Monthly Peak Forecast Section and Appendix
807 KAR 5:058 Section 7 (4) (d)	The impact of existing and continuing demand-side programs on both energy sales and system peak demands, including utility and government sponsored conservation and load management programs	Section 5.7 DSM Recommendation
807 KAR 5:058 Section 7 (4) (e)	Any other data or exhibits which illustrate projected changes in load or load characteristics	Appendix A Long Term Load Forecast Tracking Analysis and Appendix

Appendix F
Cross-Reference to 807 KAR 5:058

Citation	Integrated Resource Plan Regulation	2023 IRP Reference (Where Applicable)
807 KAR 5:058 Section 7 (5) (a)	The additional following data shall be provided for the integrated system, when the utility is part of a multistate integrated utility system, and for the selling company, when the utility purchases fifty (50) percent of its energy from another company	Not applicable as Big Rivers is not part of a multistate integrated utility system
	For the base year and the four (4) years preceding the base year:	
	1. Recorded and weather normalized annual energy sales and generation;	
	2. Recorded and weather-normalized coincident peak demand in summer and winter.	
807 KAR 5:058 Section 7 (5) (b)	The additional following data shall be provided for the integrated system, when the utility is part of a multistate integrated utility system, and for the selling company, when the utility purchases fifty (50) percent of its energy from another company:	Not applicable as Big Rivers is not part of a multistate integrated utility system
	For each of the fifteen (15) years succeeding the base year:	
	1. Forecasted annual energy sales and generation;	
	2. Forecasted summer and winter coincident peak demand	
807 KAR 5:058 Section 7 (6)	A utility shall file all updates of load forecasts with the commission when they are adopted by the utility.	Noted

Appendix F
Cross-Reference to 807 KAR 5:058

Citation	Integrated Resource Plan Regulation	2023 IRP Reference *(Where Applicable)*
807 KAR 5:058 Section 7 (7) (a)	The plan shall include a complete description and discussion of all data sets used in producing the forecasts	Appendix A Long Term Load Forecast Report Forecast Methodology Section
807 KAR 5:058 Section 7 (7) (b)	The plan shall include a complete description and discussion of key assumptions and judgments used in producing forecasts and determining their reasonableness	Appendix A Long Term Load Forecast Report Forecast Methodology Section
807 KAR 5:058 Section 7 (7) (c)	The plan shall include a complete description and discussion of the general methodological approach taken to load forecasting (for example, econometric, or structural) and the model design, model specification, and estimation of key model parameters (for example, price elasticities of demand or average energy usage per type of appliance)	Appendix A Long Term Load Forecast Report Forecast Methodology Section
807 KAR 5:058 Section 7 (7) (d)	The plan shall include a complete description and discussion of the utility's treatment and assessment of load forecast uncertainty	Appendix A Long Term Load Forecast Report Alternative System Forecasts Section, Uncertainty Analysis Section, and Tracking Analysis Section

Appendix F
Cross-Reference to 807 KAR 5:058

Citation	Integrated Resource Plan Regulation	2023 IRP Reference *(Where Applicable)*
807 KAR 5:058 Section 7 (7) (e)	The extent to which the utility's load forecasting methods and models explicitly address and incorporate the following factors:	
	1. Changes in prices of electricity and prices of competing fuels;	Appendix A Long Term Load Forecast Report Forecast Methodology Section
	2. Changes in population and economic conditions in the utility's service territory and general region;	Appendix A Long Term Load Forecast Report Forecast Methodology Section and Native Forecast Summary Section
	3. Development and potential market penetration of new appliances, equipment, and technologies that use electricity or competing fuels; and	Section 5.7 DSM Recommendation and Appendix B Demand-Side Management Potential Study
	4. Continuation of existing company and government sponsored conservation and load management or other demand-side programs	Section 5.7 DSM Recommendation and Appendix B Demand-Side Management Potential Study
807 KAR 5:058 Section 7 (7) (f)	Research and development efforts underway or planned to improve performance, efficiency, or capabilities of the utility's load forecasting methods	Section 5.1.1 Member Load Research

Appendix F
Cross-Reference to 807 KAR 5:058

Citation	Integrated Resource Plan Regulation	2023 IRP Reference *(Where Applicable)*
807 KAR 5:058 Section 7 (7) (g)	Description of and schedule for efforts underway or planned to develop end-use load and market data for analyzing demand-side resource options including load research and market research studies, customer appliance saturation studies, and conservation and load management program pilot or demonstration projects.	Section 5.1.1 Member Load Research
	Technical discussions, descriptions, and supporting documentation shall be contained in a technical appendix	Appendix B Demand Side Management Potential Study Appendices
807 KAR 5:058 Section 8 (1)	Resource Assessment and Acquisition Plan. The plan shall include the utility's resource assessment and acquisition plan for providing an adequate and reliable supply of electricity to meet forecasted electricity requirements at the lowest possible cost. The plan shall consider the potential impacts of selected, key uncertainties and shall include assessment of potentially cost-effective resource options available to the utility.	Chapter 7 Electric Integration Analysis, Chapter 10 Action Plan
807 KAR 5:058 Section 8 (2) (a)	The utility shall describe and discuss all options considered for inclusion in the plan including Improvements to and more efficient utilization of existing utility generation, transmission, and distribution facilities	Chapter 7 Electric Integration Analysis, Table 7.1.4(a), Section 8.1

Appendix F
Cross-Reference to 807 KAR 5:058

Citation	Integrated Resource Plan Regulation	2023 IRP Reference *(Where Applicable)*
807 KAR 5:058 Section 8 (2) (b)	The utility shall describe and discuss all options considered for inclusion in the plan including Conservation and load management or other demand-side programs not already in place	Chapter 7 Electric Integration Analysis, Section 7.3.3 DSM Expansion Planning on Portfolios, Chapter 10 Action Plan, Appendix B Demand-Side Management Potential Study
807 KAR 5:058 Section 8 (2) (c)	The utility shall describe and discuss all options considered for inclusion in the plan including: expansion of generating facilities, including assessment of economic opportunities for coordination with other utilities in constructing and operating new units	Chapter 7 Electric Integration Analysis Section 7.1 Power Planning Model (EnCompass), Section 7.2 BREC System Expansion Planning Analysis
807 KAR 5:058 Section 8 (2) (d)	The utility shall describe and discuss all options considered for inclusion in the plan including: assessment of nonutility generation, including generating capacity provided by cogeneration, technologies relying on renewable resources, and other nonutility sources	Chapter 7 Electric Integration Analysis
807 KAR 5:058 Section 8 (3)	The following information regarding the utility's existing and planned resources shall be provided. A utility which operates as part of a multistate integrated system shall submit the following information for its operations within Kentucky and for the multistate utility system of which it is a part. A utility which purchases fifty (50) percent or more of its energy needs from another company shall submit the following information for its operations within Kentucky and for the company from which it purchases its energy needs	Noted

Appendix F
Cross-Reference to 807 KAR 5:058

Citation	Integrated Resource Plan Regulation	2023 IRP Reference *(Where Applicable)*
807 KAR 5:058 Section 8 (3) (a)	A map of existing and planned generating facilities, transmission facilities with a voltage rating of sixty-nine (69) kilovolts or greater, indicating their type and capacity, and locations and capacities of all interconnections with other utilities. The utility shall discuss any known, significant conditions which restrict transfer capabilities with other utilities	Appendix C Detailed Transmission System Map, Figure 2.2.6(a)
807 KAR 5:058 Section 8 (3) (b) (*1-11*)	A list of all existing and planned electric generating facilities which the utility plans to have in service in the base year or during any of the fifteen (15) years of the forecast period, including for each facility:	
	1. Plant name;	Section 2.2, Section 2.3
	2. Unit number(s);	Section 2.2, Section 2.3
	3. Existing or proposed location;	Section 2.2, Section 2.3
	4. Status (existing, planned, under construction, etc.);	Section 2.2, Section 2.3
	5. Actual or projected commercial operation date;	Section 2.2, Section 2.3
	6. Type of facility;	Section 2.2, Section 2.3
	7. Net dependable capability, summer and winter;	Section 2.2, Section 2.3, Section 7.4
	8. Entitlement if jointly owned or unit purchase;	n/a
	9. Primary and secondary fuel types, by unit;	Section 2.3, Section 7.4
	10. Fuel storage capacity;	Section 2.2
	11. Scheduled upgrades, deratings, and retirement dates	Section 2.2

Appendix F
Cross-Reference to 807 KAR 5:058

Citation	Integrated Resource Plan Regulation	2023 IRP Reference *(Where Applicable)*
807 KAR 5:058 Section 8 (3) (b) (*12*)	Actual and projected cost and operating information for the base year (for existing units) or first full year of operations (for new units) and the basis for projecting the information to each of the fifteen (15) forecast years (for example, cost escalation rates). All cost data shall be expressed in nominal and real base year dollars	
	a. Capacity and availability factors;	Table 2.3(b) Key Performance Indicators per IEEE Standards, Section 7.1.4 Assumptions: Resource Options
	b. Anticipated annual average heat rate;	Tables 7.1.4(a), 7.1.4(b) and 7.1.4(c)
	c. Costs of fuel(s) per millions of British thermal units (MMBtu);	Section 7.1.5 Assumptions: Commodity and Market Price Forecasts
	d. Estimate of capital costs for planned units (total and per kilowatt of rated capacity);	Section 7.1.4 Assumptions: Resource Options
	e. Variable and fixed operating and maintenance costs;	Section 7.1.4 Assumptions: Resource Options
	f. Capital and operating and maintenance cost escalation factors;	Section 7.1.3 Assumptions: Budgeting and Finance
	g. Projected average variable and total electricity production costs (in cents per kilowatt-hour).	Technical Appendix Table

Appendix F
Cross-Reference to 807 KAR 5:058

Citation	Integrated Resource Plan Regulation	2023 IRP Reference *(Where Applicable)*
807 KAR 5:058 Section 8 (3) (c)	Description of purchases, sales, or exchanges of electricity during the base year or which the utility expects to enter during any of the fifteen (15) forecast years of the plan	Section 7.1.1 Modeling Overview, Section 7.4.1 Base Portfolio
807 KAR 5:058 Section 8 (3) (d)	Description of existing and projected amounts of electric energy and generating capacity from cogeneration, self-generation, technologies relying on renewable resources, and other nonutility sources available for purchase by the utility during the base year or during any of the fifteen (15) forecast years of the plan	Section 7.1.1 Modeling Overview, Section 7.4.1 Base Portfolio

Appendix F
Cross-Reference to 807 KAR 5:058

Citation	Integrated Resource Plan Regulation	2023 IRP Reference *(Where Applicable)*
807 KAR 5:058 Section 8 (3) (e)	For each existing and new conservation and load management or other demand-side programs included in the plan:	
	1. Targeted classes and end-uses;	Appendix B Demand Side Management Potential Study
	2. Expected duration of the program;	Appendix B Demand Side Management Potential Study
	3. Projected energy changes by season, and summer and winter peak demand changes;	Appendix B Demand Side Management Potential Study
	4. Projected cost, including any incentive payments and program administrative costs; and	Appendix B Demand Side Management Potential Study
	5. Projected cost savings, including savings in utility's generation, transmission and distribution costs	Appendix B Demand Side Management Potential Study

Appendix F
Cross-Reference to 807 KAR 5:058

Citation	Integrated Resource Plan Regulation	2023 IRP Reference *(Where Applicable)*
807 KAR 5:058 Section 8 (4) (a)	The utility shall describe and discuss its resource assessment and acquisition plan which shall consist of resource options which produce adequate and reliable means to meet annual and seasonal peak demands and total energy requirements identified in the base load forecast at the lowest possible cost. The utility shall provide the following information for the base year and for each year covered by the forecast:	
	(a) On total resource capacity available at the winter and summer peak:	
	1. Forecast peak load;	Section 7.4.1 Base Portfolio
	2. Capacity from existing resources before consideration of retirements;	Section 7.4.1 Base Portfolio
	3. Capacity from planned utility-owned generating plant capacity additions;	Section 7.4.1 Base Portfolio
	4. Capacity available from firm purchases from other utilities;	Section 7.4.1 Base Portfolio
	5. Capacity available from firm purchases from nonutility sources of generation;	Section 7.4.1 Base Portfolio
	6. Reductions or increases in peak demand from new conservation and load management or other demand-side programs;	Section 7.3.3 DSM Expansion Planning on Portfolios
807 KAR 5:058 Section 8 (4) (a)	7. Committed capacity sales to wholesale customers coincident with peak;	Section 7.1.6 Assumptions: Load Forecast Summary

Appendix F
Cross-Reference to 807 KAR 5:058

Citation	Integrated Resource Plan Regulation	2023 IRP Reference *(Where Applicable)*
	8. Planned retirements;	Section 7.1.4 Assumptions: Resource Options, Section 7.2.1 Inputs and Constraints
	9. Reserve requirements;	Section 7.2.2.4 MISO Peak Reserve Margin Requirements, Section 7.4.1 Base Portfolio
	10. Capacity excess or deficit;	Section 7.4.1 Base Portfolio
	11. Capacity or reserve margin.	Section 7.4.1 Base Portfolio

Appendix F
Cross-Reference to 807 KAR 5:058

Citation	Integrated Resource Plan Regulation	2023 IRP Reference *(Where Applicable)*
807 KAR 5:058 Section 8 (4) (b)	On planned annual generation:	
	1. Total forecast firm energy requirements;	Section 7.4.1 Base Portfolio
	2. Energy from existing and planned utility generating resources disaggregated by primary fuel type;	Section 7.4.1 Base Portfolio
	3. Energy from firm purchases from other utilities;	Section 7.4.1 Base Portfolio
	4. Energy from firm purchases from nonutility sources of generation; and	Section 7.4.1 Base Portfolio
	5. Reductions or increases in energy from new conservation and load management or other demand-side programs	Section 7.3.3 DSM Expansion Planning on Portfolios
807 KAR 5:058 Section 8 (4) (c)	For each of the fifteen (15) years covered by the plan, the utility shall provide estimates of total energy input in primary fuels by fuel type and total generation by primary fuel type required to meet load. Primary fuels shall be organized by standard categories (coal, gas, etc.) and quantified on the basis of physical units (for example, barrels or tons) as well as in MMBtu.	Section 7.4.1 Base Portfolio

Appendix F
Cross-Reference to 807 KAR 5:058

Citation	Integrated Resource Plan Regulation	2023 IRP Reference *(Where Applicable)*
807 KAR 5:058 Section 8 (5) (a)	The resource assessment and acquisition plan shall include a description and discussion of: General methodological approach, models, data sets, and information used by the company;	Chapter 7 Electric Integration Analysis
807 KAR 5:058 Section 8 (5) (b)	The resource assessment and acquisition plan shall include a description and discussion of: key assumption and judgments used in the assessment and how uncertainties in those assumptions and judgments were incorporated into analyses	Chapter 7 Electric Integration Analysis
807 KAR 5:058 Section 8 (5) (c)	The resource assessment and acquisition plan shall include a description and discussion of: Criteria (for example, present value of revenue requirements, capital requirements, environmental impacts, flexibility, diversity) used to screen each resource alternative including demand-side programs, and criteria used to select the final mix of resources presented in the acquisition plan	Chapter 7 Electric Integration Analysis
807 KAR 5:058 Section 8 (5) (d)	The resource assessment and acquisition plan shall include a description and discussion of: Criteria used in determining the appropriate level of reliability and the required reserve or capacity margin, and discussion of how these determinations have influenced selection of options	Chapter 9 MISO Resource Adequacy Planning and Section 7.1 Power Planning Model (EnCompass)
807 KAR 5:058 Section 8 (5) (e)	The resource assessment and acquisition plan shall include a description and discussion of: Existing and projected research efforts and programs which are directed at developing data for future assessments and refinements of analyses	Section 5.1.1 Member Load Research
807 KAR 5:058 Section 8 (5) (f)	The resource assessment and acquisition plan shall include a description and discussion of: Actions to be undertaken during the fifteen (15) years covered by the plan to meet the requirements of the Clean Air Act amendments of 1990, and how these actions affect the utility's resource assessment	Chapter 6 Environmental

Appendix F
Cross-Reference to 807 KAR 5:058

Citation	Integrated Resource Plan Regulation	2023 IRP Reference *(Where Applicable)*
807 KAR 5:058 Section 8 (5) (g)	The resource assessment and acquisition plan shall include a description and discussion of: Consideration given by the utility to market forces and competition in the development of the plan. Technical discussion, descriptions and supporting documentation shall be contained in a technical appendix	Chapter 7 Electric Integration Analysis and Appendix E Technical Appendix
807 KAR 5:058 Section 9 (1)	Financial Information. The integrated resource plan shall, at a minimum, include and discuss the following financial information: Present (base year) value of revenue requirements stated in dollar terms	Section 7.4.4 Summary Evaluation and Appendix E Technical Appendix
807 KAR 5:058 Section 9 (2)	The integrated resource plan shall, at a minimum, include and discuss the following financial information: Discount rate used in present value calculations	Section 7.1.3 Assumptions: Budgeting and Finance
807 KAR 5:058 Section 9 (3)	The integrated resource plan shall, at a minimum, include and discuss the following financial information: Nominal and real revenue requirements by year	Section 7.4.4 Summary Evaluation and Appendix E Technical Appendix
807 KAR 5:058 Section 9 (4)	The integrated resource plan shall, at a minimum, include and discuss the following financial information: Average system rates (revenues per kilowatt hour) by year	Table 10(a)
807 KAR 5:058 Section 10	Notice. Each utility which files an integrated resource plan shall publish, in a form prescribed by the commission, notice of its filing in a newspaper of general circulation in the utility's service area. The notice shall be published not more than thirty (30) days after the filing date of the report	Big Rivers will publish notice as required

Appendix F
Cross-Reference to 807 KAR 5:058

Citation	Integrated Resource Plan Regulation	2023 IRP Reference *(Where Applicable)*
807 KAR 5:058 Section 11 (1)	Procedures for Review of the Integrated Resource Plan. Upon receipt of a utility's integrated resource plan, the commission shall develop a procedural schedule which allows for submission of written interrogatories to the utility by staff and intervenors, written comments by staff and intervenors, and responses to interrogatories and comments by the utility	Noted
807 KAR 5:058 Section 11 (2)	The commission may convene conferences to discuss the filed plan and all other matters relative to review of the plan	Noted
807 KAR 5:058 Section 11 (3)	Based upon its review of a utility's plan and all related information, the commission staff shall issue a report summarizing its review and offering suggestions and recommendations to the utility for subsequent filings	Noted
807 KAR 5:058 Section 11 (4)	A utility shall respond to the staff's comments and recommendations in its next integrated resource plan filing	Noted

Appendix G

Cross Reference
Big Rivers Responses to Staff Recommendations from 2020 IRP

Appendix G
Cross-Reference to Staff's 2020 IRP Staff Recommendations

Section / Number	Staff Recommendation	2023 IRP Reference
Load Forecast Recommendation 1	BREC's load forecasting methodology shifted from a SAE modeling framework to a pure econometric framework. There was insufficient explanation as to why the change in methodologies was made or why it was judged superior. Even though elements of SAE modeling were included in select variable construction for the econometric modeling methodology, many utilities have adopted the SAE methodology. The shift toward econometric modeling does not appear to be as comprehensive as SAE modeling in capturing all of the effects of energy efficiency and DSM programs, though larger efforts such as HVAC were included. For the next IRP, BREC should provide a clear comparison of the efficacy of its current forecasting methodology versus SAE modeling. In addition, if BREC shifts forecasting methodologies again, it should provide a clear explanation of the change and the advantage of the new methodology over econometric modeling.	Appendix A, section on Model Development
Load Forecast Recommendation 2	A 15-year weather normalization is the shortest of any utility's IRP filed this far. For the next IRP, BREC should provide a comparison of forecasts using both a 20 and 30-year weather normalization with the 15-year normalization. If a different weather normalization benchmark is selected, BREC should provide a clear explanation why the change provides better forecasts.	Appendix A, Section on Model Development and Tracking Analysis Section, paragraph above the "Cooling Degree Day Normal Values" and "Heating Degree Day Normal Values" Graphs
Load Forecast Recommendation 3	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.	Appendix A, Energy Forecast Results Section and Tracking Analysis Section
Load Forecast Recommendation 4	Continue to provide comparisons of 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	Appendix A, Peak Demand Section, and Tracking Analysis Section

Appendix G
Cross-Reference to Staff's 2020 IRP Staff Recommendations

Section / Number	Staff Recommendation	2023 IRP Reference
Load Forecast Recommendation 5	Continue to explore new markets, including economic development efforts within its service territory. In addition, provide an update on the current and future status of Non-Member sales contracts.	Appendix A, section on Non-Member Energy Sales and section on Non-Member Energy Sales
Demand-Side Mangement & Efficency Recommendation 1	Continue to support Member Systems with educational opportunities and work with CAA to enhance the low-income weatherization program.	Demand Side Management Chapter section 5.7 Recommendation
Demand-Side Mangement & Efficency Recommendation 2	Continue to look for and provide updates of future opportunities to support Member-Owners with new DSM/EE programs.	Section 10.1 Action Plan Detail
Supply Side Resource Assessment Recomendation 1	Recommendations pertaining to the Supply Section are included in the Demand and Supply Integration Section below.	
Demand & Supply Integration Recommendation 1	BREC provided well thought out sensitivity analyses and supporting tables in the Appendices. For the next IRP, BREC should continue to rigorously test its base case least cost plan and provide appropriate supporting tables and documentation. In addition, it would also be helpful to be able to visualize (in tabular form) when various levels of capacity are added over the forecast period. This information should be provided in the next IRP.	Chapter 7 Electric Integration Analysis Chapter

Appendix G
Cross-Reference to Staff's 2020 IRP Staff Recommendations

Section / Number	Staff Recommendation	2023 IRP Reference
Demand & Supply Integration Recommendation 2	BREC's LT Plan was premised on the 2020 Load forecast for its Members only and did not include any energy or capacity requirements from its Non-Member customers. As long as BREC has the excess capacity to provide service to these customers or that BREC intends to purchase any energy or capacity shortfalls, then, everything else being equal, there is no need to include them in its forecast modeling. However, if that is not the case, then BREC should include Non-Member obligations in its modeling to provide a more complete analysis of potential LT Plans. For the next IRP, BREC should include Non-Member obligations in its forecasts and modeling or provide a detailed explanation as to why it is not included.	Chapter 7 Electric Integration Analysis Chapter
Demand & Supply Integration Recommendation 3	Only four months after filing this IRP, BREC filed Case No. 2021-00079 to convert the Green Station units to natural gas. While Staff notes that BREC continued its analysis of least cost generation options for the benefit of its owner-Members, in the IRP, BREC had no additional partners for the NGCC unit and was only modeled as a single sensitivity run based on the existing LT Plan. In that instance, the Green Station unit conversions had already been rejected. Staff appreciates that modeling runs take place well in advance of filing the IRP and that the IRP represents only a snapshot in time of BREC's ongoing analyses; however, additional assumptions could have been made that would realistically acknowledge that partners would not be found immediately and that Green Station's conversion may be a viable option. For the next IRP, BREC should carefully weigh the reasonableness of and when various technologies will be available or implemented.	Chapter 7 Electric Integration Analysis Chapter
Demand & Supply Integration Recommendation 4	Staff appreciates that the forecasts were run at least two years ago. However, natural gas prices have increased substantially and it is unclear whether another coal-fired unit will ever be built. While renewable and battery costs are forecast to continue to decline, MISO is changing the method of assigning capacity to renewables. The potential role of energy efficiency, DSM, and cogeneration could be more important in the future. For the next IRP, BREC should include these options as potential resources in its modeling.	Chapter 7 Electric Integration Analysis Chapter

Appendix G
Cross-Reference to Staff's 2020 IRP Staff Recommendations

Section / Number	Staff Recommendation	2023 IRP Reference
Demand & Supply Integration Recommendation 5	To ensure greater clarity and understanding, BREC should ensure that information provided in tables is described completely and is consistent across tables. For example, in Tables 8.10 and 8.11, there is a 4-5 MW difference between the natural gas generation capacity, which carries over to the Total column in Table 8.10 and Firm Capacity in Table 8.11. Also, the Table provided in BREC's response to Staff's first information request, Item 56 contains much more detailed explanation in column headings and in footnotes that would have been helpful in understanding information and explanations provided in the IRP text. In addition, information provided in the response does not match exactly with information provided in Tables 8.10 or 8.11. Without proper contextual and descriptive information, the information provided in Tables 8.10 and 8.11 could be misconstrued as providing a complete picture of BREC's forecasted positions.	Noted

Appendix H

Acronyms and Glossary

Acronyms and Glossary

2020 IRP	Integrated Resource Plan filed by Big Rivers in Case No. 2020-00299 September 21, 2020
2023 DSM Study	2023 Demand Side Management Potential Study - Appendix B of this IRP
2023 IRP	This Integrated Resource Plan
AAR	Ambient Adjusted Ratings
ACE	Affordable Clean Energy rule
ACR	Aggressive Carbon Reduction portfolio in this IRP
ARS	Automatic Restoration and Sectionalization
Big Rivers	Big Rivers Electric Corporation
BSER	Best system of emission reduction
C & I	Commercial and Industrial
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CCR	Coal Combustion Residuals
CCR Rule	EPA final rule regulating the disposal of CCR
CCS	Carbon Capture and Sequestration/storage
CEO	Chief Executive Officer
CFO	Chief Financial Officer
CIP	Critical Infrastructure Protection
Clearspring	Clearspring Energy Advisors, LLC, authors of 2023 Long Term Load Forecast
CO_2	Carbon Dioxide
COD	Commercial Operation Date
Commission	Kentucky Public Service Commission
Company	Big Rivers Electric Corporation
CONE	Cost of New Entry
CP	Coincident Peak
CPCN	Certificate of Public Convenience and Necessity
CPP	Critical Peak Pricing when referring to Demand Response, Clean Power Plan when referring to Environmental Issues
CPP	Clean Power Plan
CRO	Control Room Operators
CSAPR	Cross State Air Pollution Rule
CT	Combustion Turbine
Direct-LOL	MISO's Direct Loss of Load method of capacity accreditation

Acronyms and Glossary

DLC	Direct Load Control
Domtar	Domtar Paper Company, LLC
DR	Demand Response
DSM	Demand-Side Management
DSM Study	2023 Demand Side Management Potential Study - Appendix B of this IRP
EGUs	Fossil-fuel fired electric generating units
EIA	Energy Information Administration
ELCC	MISO's Effective Load Carrying Capability
EPA	Environmental Protection Agency
FAC	Fuel Adjustment Clause
FIPS	Federal Implementation Plans
Fitch	Fitch Ratings
G & T	Generation & Transmission Cooperatives
GHG	Greenhouse gas emissions standards
Green Hydrogen	Low Greenhouse Gas Hydrogen
GRP	Gross Regional Product
HMP&L	Henderson Municipal Power & Light
HVAC	Heating, ventilating, and air conditioning
ICAP	Installed Capacity Accreditation
IIJA	Infrastructure Investment and Jobs Act
IMM	MISO's Independent Market Monitor
IRA	Inflation Reduction Act
IRP	Integrated Resource Plan
JPEC	Jackson Purchase Energy Corporation, Member-Owner headquartered in Paducah, Kentucky
KEMI	Kentucky Employers' Mutual Insurance
Kenergy	Kenergy Corp., Member-Owner headquartered in Henderson, Kentucky
LIC	Large Industrial Customer tariff
LICSS	Large Industrial Customer Standby Service
LMP	Locational Marginal Price
LOI	Letter of Interest
LOLE	Loss of Load Expectation
MCRECC	Meade County Rural Electric Cooperative Corporation, Member-Owner headquartered in Brandenburg, Kentucky
Member-Owners	JPEC, Kenergy, and MCRECC
Members	JPEC, Kenergy, and MCRECC

Acronyms and Glossary

MISO	Midcontinent Independent System Operator
Mitigation Plan	Load Concentration Analysis and Mitigation Plan
Moody's	Moody's Investor Services
MRSM	Member Rate Stability Mechanism
MTEP21	MISO Transmission Expansion Plan 2021
NAAQS	National Ambient Air Quality Standards
NAG	Net Actual Generation delivered to grid
NCP	Non-coincident Peak
NERC	North American Electric Reliability Corporation
NewERA	The Empowering Rural America Program
NGCC	Natural Gas Combined Cycle Gas Turbine
NOx	Oxides of Nitrogen
NPV	Net Present Value
NREL	National Renewable Energy Laboratory
NYMEX	New York Mercantile Exchange
O&M	Operation and maintenance production costs
OPGW	Optical Ground Wire
OSHA	Occupational Safety and Health Administration
PACE	Powering Affordable Clean Energy Program
PCT	Participant Cost Test
PPA	Power Purchase Agreement
PRA	MISO Planning Resource Auction
PRM	MISO Planning Reserve Margin
PRMR	MISO Seasonal Planning Reserve Margin Requirement
Proposed GHG Rule	Proposed new greenhouse gas emissions standards for fossil-fuel fired electric generating units.
PSC	Kentucky Public Service Commission
PV	Solar Photovoltaic
QF	Qualifying Facilities
QFP	Cogeneration/Small Power Production Purchase Tariff
QFS	Cogeneration/Small Power Production Sales Tariff
RFP	Request for Proposal
ROE	Return on Equity
RRA	Regional Resource Assessment
RTO	Regional Transmission Organization
RUS	United States Department of Agriculture Rural Utilities Service
S&P	S&P Global Ratings
SEPA	Southeastern Power Administration

Acronyms and Glossary

SERC	SERC Reliability Organization
SIP	State Implementation Plans
SO_2	Sulfur Dioxide
Southern Star	Southern Star Central Gas Pipeline, Inc.
TIER	Times Interest Earned Ratio
TOU	Time of Use
TRC	Total Resource Cost
TVA	Tennessee Valley Authority
UCAP	MISO Unforced Capacity
UCT	Utility Cost Test
USDA	United States Department of Agriculture

Appendix I

Figures and Tables Listing

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